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January 30, 2026

Ms. Crystal Henwood
Regulatory Affairs Officer/Clerk of the Board
Nova Scotia Energy Board
3rd Floor, 1601 Lower Water Street
Halifax, NS B3J 3P6

Dear Ms. Henwood:

Re: Matter M12451 – Nova Scotia Power Inc. ("NS Power") 2026 General Rate Application ("GRA") – Closing Submissions of the Berwick Electric Commission, the Riverport Electric Light Commission, and the Towns of Antigonish and Mahone Bay (the "MEUs")

On September 18, 2025, NS Power filed its 2026 GRA with the Nova Scotia Energy Board (the "Board"). Pursuant to the schedule established by the Board, please accept this letter as the closing submissions on behalf of the MEUs in this matter, which support approval of the Consensus Agreement reached with NS Power and its customer representatives.

In previous decisions, the Board has set out the principles it applies in its consideration of settlement agreements. In its November 5, 2008 decision regarding a NS Power GRA (2008 NSUARB 140), the Board stated as follows:

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest…
>
> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.

The Board decisions considering settlements in the most recent GRAs for both NS Power and Eastward Energy each cite this excerpt from the 2008 decision. The MEUs fully agree that a properly supported settlement agreement is a success of the regulatory process, and that where such an agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

In this case, the settlement reached by the parties in good faith was comprehensive in dealing not only with complex Cost of Service issues, but also with NS Power's overall revenue requirement and the proposed general rates for the 2026 and 2027 test years. The Consensus Agreement executed in August 2025 and filed as Attachment 1 to NSPI (NSEB) IR-1 addresses issues that have been part of collaborative discussions involving NS Power and the various parties since December 2023.[1] With respect to Cost of Service ("COS"), the Consensus Agreement states, in part, as follows (emphasis added):

> "The COS as set out in the Draft GRA **will be included in the 2026-2027 GRA** and put forward for approval, subject to the following: (a) use of the Minimum System methodology **after the 2026-2027 test period will be subject to a future proceeding and determination by the Board**, for which an application will be made in 2026 and in which parties are free to take any position they so choose…"[2]

The MEUs agree with NS Power's Panel in acknowledging that the Board is not bound by the Consensus Agreement, and that the Board has to make a decision that produces just and reasonable rates, regardless of the agreement.[3] That being said, the MEUs would like to reiterate on the record that this particular COS provision was a fundamental aspect of their willingness to sign on to the Consensus Agreement in this case. Absent confirmation that the Minimum System methodology would continue at least through 2026 and 2027, with a full opportunity to argue in favour of its continued use going forward, the MEUs would not have been a party to the Consensus Agreement.

As the Board is aware, the MEUs currently use the Minimum System methodology as part of their own COS methodologies in developing rates for their customers. Like NS Power and its consultant, Elenchus, the MEUs support the use of the Minimum System methodology. Clearly, the issue is one of the most controversial aspects in cost allocation in utility rate-making, and has been that way "forever", as the Chair suggested in his questions to NS Power's COS Panel.[4] The MEUs recognize that Synapse, an American consulting firm, has repeatedly expressed its preference for use of the Basic Customer method in multiple Nova Scotia proceedings in recent years. But there is also no doubt that the Minimum System method is one of the recognized cost-of-service methods used in Canada,[5] and it has been approved for use in Nova Scotia for all electric utilities for decades. As noted at pages 40-41 in the Elenchus COSS Consultation Report dated April 25, 2025 that was prepared by Mr. Blair and his colleague John Todd and filed as Exhibit N-9, Appendix 12B in this proceeding (pages 1698-1699 of the pdf):

> "The minimum system method is appropriate for classifying poles & fixtures and overhead & underground lines between demand and customer. These costs have two clear cost drivers: the sprawl of the distribution system that NS Power must build to reach each customer and the peak demand the distribution system must support. The number of poles & fixtures and the length of overhead & underground line that must be installed, based on minimum specifications, provide a good representation of the cost of reaching each customer. Incremental costs that NS Power incurs over the minimum system are driven only by the need to meet peak demands so it is appropriate to consider those costs to be demand-related.

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[1] Transcript, page 99, line 17.
[2] Ex. N-27, NSPI (NSEB) IR-1, Attachment 1, Page 10 of 21, Consensus Agreement.
[3] Transcript, page 172, lines 6-14.
[4] Transcript, page 188, line 16 to page 189, line 6.
[5] Transcript, page 1270, line 19 to page 1271, line 14.

> The Minimum System methodology is used by SaskPower, Hydro Quebec, and NL Power. Additionally, the judgement-based classifications used by NB Power and by Ontario distributors are based on analyses of minimum system studies. This methodology appropriately considers the two cost drivers of these distribution assets and remains the most commonly used method to classify distribution costs in Canada. The zero-intercept methodology [is] conceptually consistent with cost causality principles, but the need to approximate the cost of hypothetical assets that are unable to serve any load can create counterintuitive and controversial results that are detached from NS Power's actual costs. The basic customer method classifies costs to demand to a degree that is not consistent with cost causality."

Further, as Mr. Blair stated in response to questions from the Chair, explaining why he did not agree with the 2020 "Electric Cost Allocation for a New Era" manual from the Regulatory Assistance Project that the Basic Customer method is the most equitable solution:

> "So there are some circumstances in cost allocation where there are costs that's not exactly caused by one of the three usual allocators of customer energy and demand, but in these circumstances the customer still remains, in my opinion, the closest allocator to use, the closest cost driver."[6]

The MEUs agree.

NS Power's analysis in Undertaking U-5 appears to demonstrate that adopting the Basic Customer Method for use in the test years, contrary to the Consensus Agreement, would have significant negative impacts on the Municipal Tariff, raising the proposed increases to the Municipal Tariff from 1.7% to 3.0% in 2026 and from 3.1% to 3.9% in 2027. The MEUs also note that NS Power's analysis in Undertaking U-6 demonstrates that modifying the Minimum System methodology by applying a 1.5 kW per customer credit to each rate class' NCP demand for determining minimum system demand allocators of the distribution system costs could also increase the Municipal Tariff as compared to the Consensus Agreement, from 1.7% to 2.2% in 2026 and from 3.1% in 2026 to 3.4% in 2027.

It should be emphasized that Ms. Palmer of Synapse's suggestion to potentially use the 1.5 kW number in the interim appears to be based on its use by one utility in Minnesota and North Dakota[7], and not on any NS Power-specific analysis that would take some time to derive.[8] In response to questions from counsel to NS Power, Ms. Palmer could not explain how that 1.5 kW was calculated.[9] Adoption of either alternative approach to the Minimum System method for 2026 and 2027, even on an interim basis, would not be appropriate. Rather, consideration of alternatives to the existing Minimum System methodology in the future should be done in accordance with the Consensus Agreement, as part of a separate process in 2026. In fact, this is precisely what Ms. Palmer ultimately recommends in both her evidence and her testimony.[10]

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[6] Transcript, page 185, line 15 to page 188, line 15.
[7] Exhibit N-37, Synapse evidence, page 13, lines 4-11.
[8] Transcript, page 1290, lines 2-8.
[9] Transcript, page 1288, line 6 to page 1289, line 4.
[10] Exhibit N-37, Synapse evidence, page 17, line 21 to page 18, line 3 and Transcript, page 1295, line 16 to page 1296, line 7.

Notably, the Consensus Agreement already results in significant increases to the rates charged to the MEUs under the Open Access Transmission Tariff. In addition, the MEUs face significant rate pressures on account of outstanding FAM and Maritime Link assessment costs, due in part to the findings in prior Board decisions.[11] Further exacerbating the cost pressures facing the MEUs by rejecting a key component of this Consensus Agreement in favour of something other than the terms that were agreed to by all parties, including the Consumer Advocate, would not be just and reasonable.

Finally, the MEUs would also like to take the opportunity provided by the closing submissions to reiterate their support for NS Power's efforts to securitize approximately $700 million of assets in the Decarbonization Deferral Account ("DDA") over the GRA period. Securitization is an approach that lowers costs for customers by converting the outstanding balances owed to debt, which carries a lower cost of capital and does not provide NS Power with the opportunity to earn any further return on equity in relation to those amounts.

It is worth noting that NS Power was initially opposed to securitization. In a May 3, 2022 response to questions in its 2022-2024 General Rate Application ("GRA"), NS Power stated: "…there are other factors which make securitization not the preferred approach for NS Power at this time."[12]

The Settlement Agreement in the 2022-2024 GRA included an agreement in principle to the DDA to recover undepreciated thermal asset NBV and unrecovered decommissioning costs. Although the Board's decision in the 2022-2024 GRA identified several items to be addressed in the subsequent filing, including potential use of securitization, NS Power's June 30, 2023 application for the DDA in Matter M11220 proposed deferring any investigation of securitization. Intervenors noted NS Power reiterated securitization was not its preferred mechanism and did not conduct any form of economic analysis to assess the cost or benefit of securitization compared to financing at NS Power's Weighted Average Cost of Capital ("WACC").

At para. 111 of its April 10, 2024 decision approving the DDA in that matter, the Board agreed that NS Power was non-responsive on the issue of securitization and endorsed the intervenor comments. The Board directed a meaningful investigation of the potential use of securitization with a report due no later than April 30, 2025. The *Energy Reform Act* received Royal Asset on April 5, 2024, and it was following this Act and the Board's DDA decision that NS Power began meaningful engagement to facilitate the securitization of costs at a lower cost than would otherwise be the case if the financing was done at WACC, which includes an equity component for NS Power.

The financial benefits of securitization for ratepayers are clear. At page 41 of its 2026-27 GRA (Exhibit N-3), NS Power states:

> "Applying the proposed depreciation rates to forecast monthly balances of depreciable plant throughout the test period results in forecast depreciation and accretion expense of $309.0 million in 2026 and $327.4 million in 2027. However, as NS Power intends to securitize certain asset pools that will be retired prior to 2030, depreciation and accretion expense is further reduced by $26.6 million annually, resulting in totals of $282.4 million in 2026 and $300.8 million in 2027."

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[11] See 2025 NSUARB 33 at paras. 30-38 and 2025 NSUARB 2 at paras. 67-69.
[12] M10431, Exhibit N-41, NSPI (NSUARB) IR-151(b).

In response to IR-7 from the Board's consultant, Morrison Park Advisors (Exhibit N-26), NS Power noted that using the most recent interest rate expectation of approximately 5 percent results in a benefit of approximately $85 million over 2026-2027. The MEUs are concerned about the delays in obtaining this benefit on behalf of ratepayers, and believe it would be helpful if the Board's decision could reiterate the value to all parties in moving securitization forward as quickly as possible. That said, NS Power's request for the Board to approve the deferral of depreciation expense and financing costs of the assets to be securitized from January 1, 2026 should not be approved. The MEUs submit that such a deferral should only begin from the date of approval of new rates that do not include any costs associated with these assets. This is consistent with the intent of the Consensus Agreement and the GRA as filed, which contemplated new rates taking effect consistent with the start date of any potential deferral on account of a delay in securitization.

Thank you for the opportunity to make these submissions.

Yours truly,

James MacDuff

cc: M12451 Participants