DECISION **2025 NSEB 8**
M12012

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for approval of its **Annual Capital Expenditure Plan for 2025**

BEFORE: Richard J. Melanson, LL.B., Panel Chair
Steven M. Murphy, MBA, P.Eng., Member
Jennifer L. Nicholson, CPA, CA, Member

APPLICANT: **NOVA SCOTIA POWER INCORPORATED**
Jennifer Power, Senior Regulatory Counsel
Mollie Morris, Regulatory Counsel

INTERVENORS: **CONSUMER ADVOCATE**
David J. Roberts, Counsel
Michael Murphy, Counsel

SMALL BUSINESS ADVOCATE
Melissa P. MacAdam, Counsel
Rebekah Powell, Counsel

INDUSTRIAL GROUP
Nancy G. Rubin, K.C.
Brianne Rudderham, Counsel

PROVINCE OF NOVA SCOTIA
Nova Scotia Department of Energy
Daniel Boyle, Counsel

PORT HAWKESBURY PAPER LP
James MacDuff, Counsel
Melanie Gillis, Counsel

ENERGY STORAGE CANADA
Andrew Thiele
Senior Director Policy & Government Affairs
(Not Appearing)

BOARD COUNSEL: William L. Mahody, K.C.

FINAL SUBMISSIONS: **June 13, 2025**

DECISION DATE: **August 19, 2025**

DECISION: **The ACE Plan is approved, except for C0051815-RTU Replacements Program – Phase 6. The Board has provided directions to NS Power in paragraph 208 of this Decision.**

TABLE OF CONTENTS

1.0 INTRODUCTION

[1] Each year, Nova Scotia Power Incorporated files an Annual Capital Expenditure (ACE) Plan outlining its proposed capital expenditures for the upcoming year. NS Power must seek approval from the Board for capital projects exceeding $1,000,000, pursuant to ss. 35, 35A and 35AA of the *Public Utilities Act,* R.S.N.S. 1989, c. 380 *(PUA)*.

[2] NS Power's 2025 ACE Plan sought approval for capital projects totalling approximately $263.8 million. This included individual capital projects estimated at $69.3 million and Routine Capital Expenditures totaling approximately $194.6 million. The forecasted total capital spending for 2025, including items that do not require Board approval, is $692.4 million.

[3] At the start of the hearing, NS Power addressed an issue raised by the Board about the repeal of ss. 36 and 37 of the *PUA* that became effective on April 1, 2025. Before this change, capital projects for the Point Aconi generating station were exempt from the requirements for Board approval. Therefore, NS Power provided the Board with its planned spending on the Point Aconi generating station as part of the ACE Plan application, for informational purposes only.

[4] NS Power said it would not raise any potential jurisdictional issues arising from the legislative changes that became effective after the filing of the 2025 ACE Plan application. NS Power said it would seek approval of individual capital projects related to Point Aconi later. The Utility requested approval for the Point Aconi routine capital expenditures described in the application. No party objected to this way of proceeding. The 2025 ACE Plan application and NS Power's Closing Submission provided a list of Routines for the Point Aconi facility which have a budget of $556,713. Therefore, this

increased the amount for the routine capital expenditures for which approval was sought to $195.2 million.

[5] Based on the evidence presented, and after considering the submissions of the participating parties, the Board determined that there was sufficient justification for the proposed capital projects except for CI C0051815, Remote Terminal Units (RTUs) Replacements Program-Phase 6. The Board found that the proposed projects assist in maintaining a reliable supply of electricity. Accordingly, in the interest of time, the Board issued an Order on June 17, 2025, approving the 2025 ACE Plan, with reasons to follow, and reserved the right to issue a further Order with directives related to outstanding issues raised during the proceeding.

[6] In addition to considering the specific projects submitted for approval in the ACE Plan, the Board has taken the opportunity presented by the annual filing to address more general issues relating to capital spending and the project approval process. In this Decision, the Board has commented on the following:

- Reliability investments;
- Update to *The Path to 2030: Clean Power and Decarbonization Goals*;
- Mersey Hydro Redevelopment Plan;
- Cost Minimization;
- Contingencies and contingency guidelines;
- Capital Expenditure Justification Criteria Changes; and
- Sections 35 and 35AA of the *PUA.*

[7] Finally, the Board directs NS Power to take the actions outlined in paragraph 208 of this Decision.

2.0 ANALYSIS AND FINDINGS

2.1 Content of the 2025 ACE Plan

[8] The 2025 ACE Plan application provides a comprehensive forecast of NS Power's capital expenditure program. It includes the following:

- A description of capital projects for which NS Power is seeking approval;
- Details about routine capital expenditures requiring Board approval;
- A list of capital projects to be submitted for approval later;
- Lists of capital items not requiring Board approval; and
- Responses to Board directives from prior ACE Plan proceedings.

[9] The ACE Plan forecasts total capital spending of $692.4 million. This amount is for individual capital items, including capital items under $1 million which do not require Board approval; routine capital expenditures; carryover spending from previous years; Point Aconi investments; and items that will be filed later for approval. NS Power stated that its 2025 capital plan is "focused on providing customers with safe and reliable electric service in a cost-effective manner."

[10] NS Power requested Board approval for $69.3 million for individual capital projects. In 2025, NS Power plans to initiate 24 individual capital projects, each with a budget exceeding $1 million, including four projects with budgets greater than $5 million. NS Power anticipates spending $41.0 million on these individual projects in 2025, with the remaining $28.3 million scheduled in subsequent years.

2.1.1 Routines

[11] Routine Capital Expenditures, also called Routines, are recurring expenses to sustain the operation of installed equipment, and to accommodate system and customer growth. NS Power requested approval for its Routine Capital Expenditures in the amount of $195.2 million, including Point Aconi Routines.

[12] The proposed Routines budget in 2025 is approximately 27.4% higher than the budget presented in the 2024 ACE Plan; and 13% higher than forecast spending for 2024 as presented in the 2025 ACE Plan. The 2025 ACE Plan routine budget is significantly higher than in previous years, primarily due to increased spending on the following Routines: New Customers, Provincial Widening, Distribution Upgrades & Replacements and Work Vehicle Replacements.

[13] John Wilson is a Vice President of Grid Strategies LLC. He filed evidence on behalf of the Consumer Advocate (CA), raising concerns with C0056240 2024/25 Transmission Switch and Breaker Replacements that were approved in the 2024 ACE Plan. Mr. Wilson recommended this project be submitted for a post-project review to ensure that reliability, safety and cost minimization are adequately addressed. In response to CA questions during the hearing, NS Power explained that it considers projects like the Switch and Breaker Replacements to be routine because the project work meets the requirement of “like-for-like” replacements, taking place over several years. Therefore, it would be both appropriate and more efficient to include this project in the Routine Capital Expenditures. In its Rebuttal Evidence, NS Power expressed its intention to include projects like the Transmission Switch and Breaker Replacements in the 2026 ACE Plan Routines. This appears reasonable to the Board.

[14] The Board approves the Routine Capital Expenditures totaling approximately $195.2 million, inclusive of Point Aconi. An Order has already been issued for this approval.

2.1.2 Capital Work Order Applications

[15] NS Power provided a detailed description, justification, and cost support for each of its capital work order applications. NS Power also provided substantial supporting

information in its responses to Information Requests (IRs) submitted by intervenors and the Board.

[16] The Board notes that during the proceeding, the CA questioned the budgets for two capital projects submitted in the 2025 ACE Plan. Specifically, the CA believes that the Administrative Overhead amounts identified in CI-C0048990 AVO2 Switchgear Replacement and CI-C0039266 Gulch Overhaul are excessive. In its Rebuttal Evidence, NS Power confirmed that the Administrative Overhead amounts are correct and in keeping with accounting policies.

[17] Apart from CI-C0051815 RTU Replacements Program – Phase 6, which is discussed in section 2.2.1 of this Decision, the Board finds that the capital projects listed in Schedule A of this Decision are necessary. Further, the Board is satisfied that the plan is prudent and that the spending has been justified in accordance with the Board-approved Capital Expenditure Justification Criteria (CEJC).

[18] The Board approves the projects and capital expenditures set out in Schedule A. Should any of them be cancelled or deferred beyond 2025, NS Power must resubmit them for Board approval. An Order has already been issued for this approval.

2.2 Discussion of Specific Projects

[19] The Board had concerns about two specific projects. After further review, one was sufficiently justified and the Board determined there was insufficient support to approve the other project.

2.2.1 C0051815 - RTU Replacements Program-Phase 6 RTU

[20] One of the 24 individual capital projects submitted for Board approval is CI-C0051815 RTU Replacements Program – Phase 6. RTUs are deployed in substations and generating stations to allow recording and transmission of data on a real-time basis.

The application identified a total of 74 RTUs that require replacement. Replacement of RTUs at 14 sites will be covered under Phase 6 at an estimated cost of $5,959,915. The detailed cost estimate for Phase 6 indicated significant labour (internal, external) costs compared to the material costs. The material costs are approximately 20% of the total project cost.

[21] Board staff requested additional information regarding this project in IR-140(a) to (c). In response the Utility provided the allocated average hours to replace a single RTU in Phase 6 and Phase 1. The Utility stated that "the increase in estimated labour hours for Phase 6 in comparison to Phase 1 is a direct result of evolving infrastructure complexity, changes in compliance requirements, accessibility challenges, enhanced technological scope and testing procedures, and workforce constraints."

[22] NS Power stated that Phase 1 included the replacement of eight RTUs, with a total of 3,880 labour hours and an average of 485 labour hours per unit. In contrast, Phase 6 included the replacement of 14 RTUs, with a total of 35,084 labour hours (internal, external) and an average of 2,506 hours per unit. The average labour hours in Phase 6 are four times greater than those in Phase 1.

[23] During the hearing, Board Counsel asked the Utility to explain the significant difference between the average hours required to replace one RTU in Phase 1 compared to Phase 6. The Utility did not provide any explanation during the hearing; rather, it took an undertaking (Undertaking U-6) to provide an explanation. In addition, the Board requested a breakdown of the increased labour hours, categorized by the reasons provided by the Utility above.

[24] In Undertaking U-6, NS Power stated that the increased hours for Phase 6 reflect the natural evolution of the project's scope and complexity and further explained the primary reasons for the significant increase in labour hours under four key categories: evolving infrastructure complexity, changes in compliance requirements, enhanced technological scope and testing procedures and accessibility challenges and work force constraints. The Utility noted challenges in specifying the exact number of additional hours across these four key categories. However, for each RTU replacement, it allocated 300 hours to project management and approximately 1,000 hours to engineering design and field labour to cover the broader installation scope. The remaining additional hours were allocated to changes in compliance requirements, accessibility issues, and workforce constraints.

[25] In response to Board IR-66, NS Power stated that the contract cost for this work order was determined using external advice and internal expertise. It did not provide any comment on the internal labour estimates. The Board acknowledges that the expanded scope, increased travel time, compliance requirements, and overtime efforts would increase the number of hours required to replace a single RTU. However, the Board understands that these RTUs are off-the-shelf devices, widely used in power system infrastructure such as substations and power generation facilities. Therefore, the Board still did not see a justification for a four-fold increase in estimated hours based on the evidence provided.

[26] Phase 6 covers only 14 of the total 74 RTUs requiring replacement. There are more costs to come. The Utility's comments on the natural evolution of scope and complexity raises concerns about why precisely such an increase in the estimated costs

can be justified. A significant amount of internal labour forms part of the estimate, without a detailed explanation of how that labour will be allocated and why it is all needed. It also begs the question of whether it would be cheaper to have an external supplier do the work. The Board has, therefore, concluded that it is important to obtain third-party verification of the budget estimate.

[27] The Board intends to engage an expert to review the project scope and provide an opinion on the reasonableness of the estimated project costs.

2.2.2 C0053295 L-5004 Kearney Lake Structure Replacement

[28] Built in 1966, the L5004 transmission line is 13.06 km long, 69kV and includes 83 structures. This project involves replacing nine existing wooden pole structures with six new steel structures. Additionally, the wires of the six steel structures will be uprated.

[29] Board staff requested additional information regarding this application in IR-114 to 116. In response to an IR requesting ratings for both existing and replacement conductor wires, and the need for using improved wire rating for only six steel structures, the Utility stated: “The existing conductor is ACSR Dove with a rated ampacity of 726A. The new conductor is ACSR Drake with a rated ampacity of 907A” and added, “The improved wire rating is aligned with NS Power’s 138kV standards. The 138kV design allows for future uprating to address any increases in load demands in the area as necessary.”

[30] During the hearing, the Board asked about upgrading only a section of the conductors and whether this will provide any particular benefits until the entire line is upgraded. NS Power indicated the line’s rating would not improve until all the conductors had been upgraded and that “it’s really just that the new section is being built to our current

design standard relative to what would have been the standard at the time the line was originally built, …" In this case, it was not possible to reuse the conductors.

[31] The Board notes that the application identifies a L5004 voltage rating of 69kV, whereas the IR responses reference upgrades based on the improvements in the 138kV standards. Further, a quick review of recent line replacement and upgrade projects involving 69kV or 138kV transmission lines indicated that while conductor additions were made, no uprating of any transmission line sections were reported.

[32] The new conductors will not provide a significant benefit unless the entire line is upgraded and higher rated conductors are placed along the upgraded line. A full upgrade of all conductors and associated devices could take many more years. Therefore, the Board is concerned about the potential for capital underutilization in this project. Even if the upgrades require conductor replacement, the Utility could potentially have opted for conductors with the same rating to minimize the impact of capital underutilization.

[33] The proposed project involves difficult terrain. The Board can therefore accept the argument that it is cost effective to replace the conductors to the current standard at the same time other necessary work is underway on the project. The Board simply cautions NS Power to carefully analyze the benefits, and the timing of benefits, in future replacement and upgrade projects.

2.3 Reliability Investments

[34] Reliability continues to be a primary focus for NS Power and its stakeholders. In the *2024 ACE Plan* Decision, 2024 NSUARB 143 (M11458), the Board issued several directives related to reliability and resilience:

> [215] The Board has the following directives in this matter:

1. The Board directs NS Power to file the CEATI report upon receipt.

2. The Board directs NS Power to consider the issue of developing better metrics and analysis to evaluate the cost-effectiveness of resiliency investments. These should be capable of both quantifying the expected benefits of a resiliency investment and measuring the effectiveness of that specific intervention once it is in place. NS Power is to provide this report to the Board in its 2025 ACE Plan application.

3. The Board directs NS Power to continue to study the issue of Normalized SAIDI and provide further information about potential alternatives to the manner in which Normalized SAIDI is presented, in the 2025 ACE Plan.

4. The Board directs NS Power to consider if there are alternative metrics to assess investments to address reliability in the context of proposed capital expenditures, and report back to the Board in the 2025 ACE Plan.

2.3.1 Five Year Reliability Plan [Exhibit N-3]

[35] In response to ongoing concerns and Board directives in the *2024 ACE Plan* Decision, NS Power submitted a Five-Year Reliability Plan as Exhibit N-3 in this matter. In this Plan, the Company outlines how it intends to invest approximately $1.3 billion from 2025-2029 to improve customer reliability. NS Power believes this investment will reduce the System Average Interruption Duration Index (SAIDI) by 20% from the current five-year average of 5.10 and achieve the Performance Standards' System Average Interruption Frequency Index (SAIFI) target of 2.05 by the end of 2029. This Plan is intended to continue to strengthen grid resilience to address climate change and achieve the Performance Standards for restoring service to customers within 48 hours after a Major Event.

[36] The Plan focuses on three core programs which include storm hardening the transmission and distribution system through vegetation management, targeted equipment replacements and upgrades, and Advanced Grid Modernization.

[37] Spending is forecasted as outlined in Exhibit N-3, Figure 1:

Figure 1: Forecast Investment by Reliability Program 2025-2029 ($ million)

Reliability Program	2025	2026	2027	2028	2029	Total Plan
Storm Hardening - Targeted Equipment Replacement and Upgrades	152.4	181.1	198.7	192.4	191.8	**916.4**
Storm Hardening - Vegetation Management	45.0	45.0	45.0	65.0	65.0	**265.0**
Advanced Grid Modernization	9.2	7.9	7.9	15.3	37.6	**77.9**
Total	**206.6**	**234.0**	**251.6**	**272.7**	**294.4**	**1,259.3**

Storm Hardening and Vegetation Management

[38] As about 50% of outages are caused by tree contacts, vegetation management is a key part of the Plan. This includes distribution and transmission corridor widening to expand rights-of-way to reduce vegetation-related outages. It also includes development of new rights-of-way to establish additional corridors to enhance access and redundancy. As well, there is increased spending on proactive tree trimming and removal to focus on vegetation control around existing rights-of-way.

Targeted Equipment Replacement

[39] The second area of focus is on replacing high-risk or obsolete infrastructure. Replacements will be prioritized based on historical outage data, asset condition, location in storm-prone areas and load criticality. This is expected to reduce the frequency and duration of outages from asset failure, particularly during severe weather and improve the resilience of the most vulnerable parts of the system. It is also expected to improve asset lifecycle management and cost control through planned vs. reactive replacements.

Advanced Grid Modernization Programs

[40] The final area of focus is advanced grid modernization to enable a smarter, more adaptive, and resilient grid that can adapt to evolving system conditions and customer needs while supporting electrification and renewable integration.

[41] Some of the programs planned include the installation of reclosers and communication-enabled devices on distribution feeders to reduce outage duration through faster fault location detection, isolation, and restoration. The installation of these devices will provide the Utility with wide-ranging visibility and control of the distribution network, increasing its capability to minimize system interruptions during both normal conditions and severe weather events. Other programs include the integration of distributed energy resources to facilitate integration of rooftop solar, battery storage, and EV charging, as well as system control and data analytics to improve decision-making and grid reliability using Artificial Intelligence (AI).

[42] In his evidence, Mr. Wilson stated that he believes the Five-Year Reliability Plan is concentrated in the right areas as most of the investment, and growth in investment, is focused on equipment replacement and upgrades and on vegetation management. He stated that he is impressed by the ambition in NS Power's goals, but skeptical that they can be achieved given the recent track record of falling short of its reliability goals.

[43] All intervenors agreed that NS Power needs to improve the reliability and resilience of its system. Their shared concern is how to determine the right amount to spend and over what period to see measurable results without causing an unacceptable increase in customer rates.

[44] The Industrial Group (IG) has reservations regarding the extent of the spending, and whether customers will derive sufficient value and benefits:

> The Industrial Group agrees that NSPI must endeavor to provide a reliable and resilient grid. The concern is the level of investment needed to meet these goals over the next five years, and the absence of any overt or transparent consideration of affordability for ratepayers. There has been no analysis completed (or at least provided) to determine that this level of investment is warranted, and specifically on the proposed timeframe. An "open and frank dialogue" on affordability has not occurred, either in an engagement process to create the Plan or as part of this regulatory process when intervenors first saw the Plan. Through the hearing process, very little additional information has been provided by NSPI on the process or methodology used to confirm that the proposed $1.3 billion investment is the most measured approach.
>
> [IG Closing Submission, p. 2]

[45] The Small Business Advocate (SBA) stated in its Closing Submission that determining whether progress is being made on improving NS Power's reliability and resiliency is a crucial issue. This needs to be addressed to ensure that a proper balance is struck between costs and benefits when it comes to the durability of the electricity system:

> The SBA respectfully submits that it is essential that a metric to assess the effectiveness of the capital projects undertaken by NSPI in the interests of reliability and resiliency be developed. Such a metric will allow for consideration and assessment of the benefits of increasing reliability and resiliency versus the affordability of pursuing such projects. Without this type of metric, it is difficult, if not impossible, to assess the reasonableness of certain capital projects, which are being pursued to meet the goals of improved reliability and resiliency.
>
> [SBA Closing Submission, pp. 2-3]

[46] The CA stated that there are significant issues with the way the performance metrics will be used to measure the success of the Five-Year Reliability Plan:

> Overall, Nova Scotia Power needs to clarify the means by which it measures and reports on its performance, especially given the investments it is about to make in its Five-Year, Reliability Plan.
>
> [CA Closing Submission, p. 3]

[47] The intervenors also expressed concern that some of the measures used to determine results and progress are not well explained and cannot be benchmarked against other similar utilities. This was the primary focus of the SBA's Evidence and Submissions:

> There is no question that there are two, or arguably three, competing goals within the electricity system in Nova Scotia today. Ratepayers want reliable and affordable electricity, and governments (both provincial and federal) have legislated obligations with respect to environmental limits and decarbonization that affect both of these ratepayer priorities.
>
> The SBA respectfully submits that one key difference between these three goals is how they can be measured and assessed. Environmental targets are calculated and set through government policy and can be easily evaluated. Affordability is more difficult to assess, as rate classes have different tolerances for rate changes, and as rate classes are not homogeneous, there are further significant differences within rate classes. There are also other measures that can be used for comparison, such as the consumer price index, and, at a minimum, the Board has made clear that at some point rate shock will apply to a proposed increase and therefore there is a theoretical maximum rate increase against which any proposed increase may be assessed.
>
> [SBA Closing Submission, p. 1]

[48] The IG shared the same concerns and discussed the lack of consultation about the size of the investment, the period over which it will be spent, the impact on rates, the metrics used to determine progress and the longer-term financial impact:

> There has been no consultation with respect to the level of investment proposed. The 2025 ACE Plan proceeding has not provided the level of engagement needed to adequately review this issue, and it remains unclear how this magnitude of investment is viewed as the most measured and cost-effective approach.
>
> Even more, NSPI has also not calculated any corresponding financial savings related to this increased level of investment outlined in the Reliability Plan. The "benefit" is tied to outage duration and frequency metrics, SAIDI and SAIFI. While NSPI accepted that there may be benefits with respect to savings associated with post-storm costs, NSPI has not "evaluated that in detail and not year for year". These are important details needed in order to verify the validity of the spending proposed, especially considering how these investments relate to the storm restoration costs already built into rates, or recovered through the interim Storm Rider pilot. This is particularly so if NSPI intends for this to be a permanent rider. Surely, NSPI cannot propose to increase spending at this magnitude, with no corresponding savings being realized for ratepayers elsewhere.
>
> [IG Closing Submission, p. 6]

[49] Per the Board's direction from its *2024 ACE Plan* Decision, NS Power put forward several proposals for alternative metrics that it argued could potentially provide additional context and insight into power grid reliability and resilience in conjunction with the foundational performance standards metrics of SAIFI, SAIDI, Circuit Average Interruption Frequency Index (CKAIFI) and Circuit Average Interruption Duration Index (CKAIDI). The Company says these proposals are intended to provide the Board and

stakeholders with supplemental data on system reliability and resiliency, not to replace the current standards. Some of the supplemental metrics that could be used and have been put forward by NS Power include Normalized SAIDI, SAIDI with Hurricanes Removed, assessment of the Resiliency Gap, and the Value of Lost Load (VoLL).

[50] The Resiliency Gap is a measure that was introduced by NS Power in the ACE Plan application. The Company suggested it may help measure the cumulative impact of resilience investments over time. The Resiliency Gap measures the difference between all-in SAIDI (inclusive of major events) versus SAIDI with these major events excluded. NS Power stated that it is a potential complementary measure to other traditional metrics. The Company said as investments are made in the transmission and distribution system over time, a slowing or narrowing of the resilience gap may demonstrate the positive impact of such investment.

[51] Also, in his evidence, Mr. Wilson referenced 10 potential metrics that could provide valuable information about performance and was surprised by the lack of quantitative responses from the Company:

> A: To my surprise, no. In response to an information request for the following metrics, NS Power did not supply any quantitative data.
>
> 1. Emergency staff deployed per level 3/4 storm event
> 2. Emergency staff deployment cost per level 3/4 storm event
> 3. Count of damaged distribution equipment per level 3/4 storm event
> 4. Count of damaged transmission equipment per level 3/4 storm event
> 5. Replacement cost of damaged distribution equipment per year
> 6. Replacement cost of damaged transmission equipment per year
> 7. Replacement cost of damaged distribution equipment per level 3/4 storm event
> 8. Replacement cost of damaged transmission equipment per level 3/4 storm event
> 9. Average replacement cost per item of damaged distribution equipment
> 10. Average replacement cost per item of damaged transmission equipment
>
> I was surprised at the lack of *any* quantitative response to the information request because it would seem like NS Power would have at least *some* of these data tracked in its accounting system or in other core operational databases and available to produce in response to the question, even if it did not endorse their usefulness.
>
> [Exhibit N-11, pp. 16-17]

[52] NS Power said it continues to investigate these potential metrics and has not yet undertaken the collection of specific data associated with them. The Company is still in the evaluation stage and does not yet know if any new metrics are useful or if the benefits will outweigh the administrative effort necessary to collect background data. Through its ongoing industry collaboration on these, and other metrics, NS Power anticipates that it will be able to provide an update on evaluation progress in the 2026 ACE Plan.

[53] Another metric that has been discussed is the VoLL. This represents the monetary value that electricity customers place on the reliability of their electricity supply, essentially how much they would be willing to pay to avoid an outage. VoLL could serve as a metric to evaluate the economic impact of power outages and for making decisions about investments in grid reliability. The Company discussed this concept in its' Five-Year Reliability Plan.

> NS Power acknowledges the Board's direction in its Decision on NS Power's Storm Cost Recovery Rider Application, that evaluating the Value of Lost Load (VoLL) by customer classes could provide valuable support for investment decisions. NS Power believes that assessing the specific economic impacts of customer outages must be tailored to Nova Scotia and derived through customer engagement. In other jurisdictions in the United States and Canada, surveys have been distributed to customers to gather this information, which is then presented to regulators for approval and used by utilities to support investment decisions. NS Power supports this approach and is prepared to integrate these factors into the company's existing risk framework to prioritize investments. As directed by the Board, NS Power will study and report on the potential use of VoLL in the reliability investment planning process in the 2026 ACE Plan application.
>
> [Exhibit N-3, pp. 6-7]

[54] NS Power responded to comments about the development of new reliability and resiliency metrics and the desire to have metrics that can be benchmarked against other utilities when they currently do not exist.

> The process of developing new metrics is resource intensive. NS Power should not be required to continue developing novel metrics for presentation to the Board and stakeholders if a central factor for the adoption of that metric is existing, widespread adoption. As discussed at the 2025 ACE Plan Hearing, at this time, there are no vetted or

> widely used metrics for assessing power grid resiliency on an isolated basis within North America. In addition to this, metrics such as SAIDI and CKAIDI already assess reliability and overall system performance and the Percentage of Customers Restored in 48 Hours during a major storm is an existing Performance Standard that measures resiliency. These are widely adopted metrics that the SBA itself has acknowledged are "key reliability metrics" in other proceedings. NS Power has already provided several alternative ways of applying SAIDI, and related metrics, to its system performance to give a more holistic picture of system reliability and resiliency.
>
> Given the above concerns, NS Power commits to continue to monitor and report on any industry developments for metrics concerning reliability and resiliency, but that otherwise there are no other metrics to be proposed, and that the utility should not be required to continue generating new metrics outside of this industry monitoring. NS Power will also continue to be receptive to stakeholder feedback on this issue but notes that no stakeholder group has put forward a proposal for, or identified, a specific metric that they would like NS Power to consider incorporating. Finally, NS Power will continue to offer additional context and insight into the many factors that contribute to the reliability of individual feeders and overall system reliability in order to ensure that the entire story on reliability performance is understood by all.
>
> [NS Power Reply to Closing Submission, p. 11]

2.3.1.1 Findings

[55] The Board finds that NS Power's Five-Year Reliability Plan is focused on the right areas to target improvements where they are needed. The Board agrees with Mr. Wilson that the goals may be optimistic, and further work is needed to determine the appropriate scope and timeframe of the Plan to balance reliability improvements with affordability.

[56] The Board directs NS Power to provide annual updates in its ACE Plan applications on the progress of its Five-Year Reliability Plan. The Board also directs NS Power to provide an update on its evaluation of potential new reliability and resiliency metrics in the 2026 ACE Plan. The Board will address metrics further in a later section when addressing a third-party review.

[57] The Board notes that SBA IR-9 addressed information in Figure 3 in the Five-Year Reliability Plan about the highest priority distribution feeders. The SBA wanted to be able to discern in the 2026 ACE Plan which of the highest priority lines had been addressed in 2025; which had not been addressed but remained highest priority lines;

which had not been addressed and were no longer highest priority lines; and, if there were any new highest priority lines. NS Power said it "…will commit to providing an update on the 2025 priority feeders as a part of the 2026 ACE Plan." [Exhibit N-10, PDF pg. 20]

[58] Accordingly, the Board directs NS Power to update the equivalent of Figure 3 about priority distribution feeders in the 2026 ACE Plan.

2.3.2 Normalized SAIDI

[59] NS Power defines Normalized SAIDI as its annual SAIDI result divided by the number of hours in the respective year with a recorded wind gust at or above 80 km/hr. In this context, SAIDI measures the average duration of power outages per customer in a particular year. NS Power contends that wind-normalized SAIDI is an additional, complementary reference point to gauge its reliability performance trends under changing (worsening) climatic conditions, a perspective that the Company believes is difficult to present and compare using traditional, non-normalized metrics. NS Power believes that strong consideration of this weather factor provides valuable, although not perfect, insights into the effectiveness of its reliability investments and programs.

[60] In its *2024 ACE Plan* Decision the Board expressed concerns with the Normalized SAIDI metric. Specifically, the Board noted that one singular gust of wind over 80 km/hr could be interpreted as representing an hour of sustained wind gusts according to NS Power's Normalized SAIDI definition. The Board was concerned that this would overstate the number of hours of sustained wind used in the calculation for Normalized SAIDI.

[61] In addition to concerns about whether the Normalized SAIDI overstates the frequency or severity of wind gusts over 80 km/hr, the Board also expressed concern

about how such a metric is used. In its *2024 ACE Plan* Decision at pages 35-36, the Board stated that:

> A distinction can be drawn between performance standards that carry a penalty if they are not met and those used in evaluating the need for, and effectiveness of, a capital investment program. When looking at capital expenditures, there is always the question of whether the proposed work on resiliency and reliability, such as vegetation management, is having or will have a measurable impact. When one of the major effects of climate change is removed, such as wind gusts over 80 km/hour, in the case of the Normalized SAIDI, the Board has concerns about the utility of such a metric. This is not to say that there is not a sound underpinning for the proposition that vegetation management, and other storm hardening initiatives discussed in this Decision, should have a positive impact on resilience and reliability.

[62] Given these concerns, the Board directed NS Power to continue to study the issue of Normalized SAIDI and provide further information in the 2025 ACE Plan about potential alternatives to the way Normalized SAIDI is presented. NS Power complied with this directive. The Board also welcomed information on any appropriate metrics from other participants in the ACE Plan proceeding. However, no intervenors in the 2025 ACE Plan proceeding suggested any alternative metrics.

[63] In its 2025 ACE Plan application, NS Power stated that it has continued to study the impact of adverse weather on SAIDI and, in particular, the hours with wind gusts greater than 80 km/hr. NS Power continues to believe that the increasing frequency and severity of adverse weather conditions plays a role in overall system performance, even when controlling for Major Event Days. The Company did note, however, that improvements in its use of Normalized SAIDI are possible and that it continues to pursue potential enhancements as a complementary weather normalized metric. In particular, NS Power is evaluating the quantification of gusts in excess of 80 km/hr, in order to better consider the impacts from more extreme conditions experienced during severe weather events such as hurricanes. NS Power is also reviewing historic Environment and Climate Change Canada (ECCC) weather data to produce a more refined view of these variable

forces. Further, NS Power continues to engage with its industry colleagues to identify and explore developments in weather normalization of performance metrics where applicable.

[64] NS Power's Normalized SAIDI metric was criticized by the parties for its "opacity." The SBA's experts, John G. Athas and Tim Pelzer, of Daymark Energy Advisors said this measure does not inform customers of the Utility, or the Board, of the actual level of reliability they are experiencing, and it does not show conclusively whether NS Power's reliability investments are having the desired results. Daymark also noted that NS Power applies different forms of weather adjustments to its data depending on the regulatory context in which it is being used, that the measure is overly simplistic and it is impossible to draw conclusions about weather variations and the impact on reliability. Generally, parties expressed confusion about how the Normalized SAIDI was developed and how it can be applied consistently year after year to show progress.

2.3.2.1 Findings

[65] The Board remains concerned that Normalized SAIDI can potentially overstate the frequency or severity of wind gusts over 80 km/hr in that one singular gust of wind over 80 km/hr could be interpreted as representing an hour of sustained wind gusts according to NS Power's Normalized SAIDI definition. NS Power has argued that since ECCC sampling of wind gusts occurs only once per hour, the sampling may not record a wind gust greater than 80 km/hr, but yet wind gusts greater than 80 km/hr could still occur outside the sampling period. In such a case, those wind gusts would not be counted as gusts greater than 80 km/hr and would not be included in the Normalized SAIDI calculation. NS Power, therefore, believes that the calculation of Normalized SAIDI offers a conservative approach that, if anything, potentially underestimates wind impacts.

[66] This argument does not lessen the Board's concerns. In particular, in response to the SBA's IR-4(h), NS Power provided a map showing the geographic distribution of the weather stations used to measure winds gust used in the Normalized SAIDI calculation. The map shows five weather stations (Yarmouth, Greenwood, Halifax, Truro and Sydney) from which the wind gust data is collected. In Undertaking U-4, NS Power confirmed that a wind gust greater than 80 km/hr only needs to be recorded at one of these stations for it to be included in the Normalized SAIDI calculation. During the hearing, NS Power provided some rationale explaining how this geographic diversity of wind data is valid for use in the Normalized SAIDI calculation. The Board is not convinced that a wind gust greater than 80 km/hr measured in Yarmouth is applicable to outage data in other areas of the province much further away from Yarmouth. The Board believes that this methodology can result in overestimation of the impacts resulting from wind gusts greater than 80 km/hr, thereby inappropriately lowering calculated Normalized SAIDI values.

[67] The Board also notes that NS Power stated that it is in the process of reviewing historic ECCC weather data to produce a more refined view of the variability in wind forces. The Company indicated in the application that it expected to present an updated version of Normalized SAIDI in consideration of this enhancement in its 2024 Performance Standards Report. However, during questioning from Daniel Boyle, NS Power confirmed that it did not provide that information in the 2024 Performance Standards report.

[68] In its ACE Plan application, NS Power stated that it believes a strong consideration of wind gust effects using Normalized SAIDI provides valuable, although not perfect, insights into the effectiveness of its reliability investments and programs. The Company stated that this approach is consistent with the overall necessity to consider the influence of weather understood by industry and referenced a report by the Electric Power Research Institute (EPRI) entitled “Weather Normalization of Reliability Indices”. The report was provided by NS Power in response to Board IR-51c).

[69] The EPRI report notes that overall, correlations indicate that weather parameters do influence system reliability performance indices. However, the report also notes that weak correlations among most of the weather parameters and reliability indices makes it challenging to use weather data directly to normalize reliability indices. When asked about this, NS Power stated that context is important when considering the EPRI statement, as each utility is unique. NS Power suggested that correlations between reliability indices and weather need to consider jurisdiction specific variables that have the highest impact on reliability performance, which NS Power argues is wind gusts greater than 80 km/hr. This notwithstanding, the EPRI report finding still concerns the Board, particularly given the unique and not widely used nature of NS Power’s Normalized SAIDI metric.

[70] In Undertaking U-11, NS Power indicated that it is not aware of any other utilities using Normalized SAIDI calculated specifically as it has done by dividing All-In SAIDI by the number of hours in the respective year with a recorded wind gust at or above 80 km/hr. However, the Company noted that it would not expect this approach to necessarily be appropriate, and consequently appropriately applied, in other jurisdictions

depending on their specific operating environment. NS Power said that consideration of other weather factors may provide more value for utilities in those cases. The Company then provided some examples of other utilities that report normalized reliability data and how that data is used to try and better understand reliability trends over time. While the examples provide some interesting context, it is clear to the Board that no other utilities use the Normalized SAIDI metric as used by NS Power. Therefore, as perhaps a novel metric, the Board continues to believe that use of Normalized SAIDI as a reliability metric is somewhat questionable.

[71] Finally, during the hearing NS Power was asked if it believes that customers expect the Company to meet its reliability performance standards in increasingly severe weather. In response, NS Power stated that it does, in fact, believe that its customers expect the Company to meet its reliability standards and the performance-based standards as the weather continues to intensify. In this context, the Board notes that the Normalized SAIDI metric effectively isolates the effects of system performance from the increasing variability and severity of weather. Therefore, while the metric may help NS Power with internal planning and performance evaluation, the Board finds that it does not provide a useful measure to assess meeting customer expectations in the face of increasingly severe weather.

[72] The evidence and arguments in this proceeding have not lessened the Board's concerns about the usefulness of the Normalized SAIDI. While the Board understands NS Power is not proposing to replace traditional metrics with Normalized SAIDI, its limited utility does not warrant the amount of time being spent reviewing it. As such, the Board directs that no further reporting on Normalized SAIDI be provided in future

ACE Plans. The Board notes, however, that a new matter (M12376) has been started to review and establish/update NS Power's performance standards for 2027 to 2031. As discussed below, the Board has also directed NS Power to complete a third-party review of its Five-Year Reliability Plan, complete with an assessment of related reliability metrics. Should either of these reviews recommend that Normalized SAIDI be used as an appropriate reliability metric for NS Power, the Board may reconsider its directive related to ACE Plan Normalized SAIDI reporting.

2.3.3 Third-Party Review

[73] In the *2024 ACE Plan* Decision at para. 83, the Board found that a third-party review of NS Power's reliability investments was not necessary at that time.

> [83] The Board recognizes that reliability, resilience and NS Power's performance have been and continue to be analyzed in several other NS Power proceedings. In the Board's decision for M11169, it directed NS Power to undertake several initiatives to improve its asset management activities. The Board stated: "However, the Board continues to be of the view that a third-party review of NS Power's reliability investments would not be efficient at this time. Many of the issues that would be addressed in such a review will likely be considered in these other processes and the further engagement with stakeholders that is contemplated." The Board agrees with NS Power that spending time and money on additional reviews may not be the best use of ratepayer money but agrees with Intervenors about the importance of seeing and measuring the Company's progress on these items.

[74] However, things have changed. The Five-Year Reliability Plan [Exhibit N-3] forecasts $1.3 billion in spending over the next five years with a targeted 20% reduction in SAIDI and a goal to achieve the Performance Standards' SAIFI target of 2.05 at the end of 2029. NS Power stated that the level of spending is required to balance reliability and resiliency improvement objectives with affordability for customers. The Company did not provide details in the Plan about how this spending will impact customer rates.

[75] In his evidence, Mr. Wilson recommended a third-party review of the Plan:

> To determine whether or not the goals are achievable and that the plan is well-designed, it would be useful for the Board to seek a review by a firm with deep expertise in all aspects of distribution system management (e.g., similar to the FAM Audit process). Considering

> that NS Power's five-year forecast reliability investments total $1.3 billion, a thorough review of the plan now (in 2025) and then again towards the end of the five-year plan (before the next five-year plan is drafted) would seem to be a worthwhile investment that could pay off even if it just improves the cost-effectiveness of the plan by 1%.
>
> [Exhibit N-11, p. 11]

[76] The IG supports Mr. Wilson's recommendations and shares NS Power's desire not to undertake work unless it provides value:

> …However, an external review of the reliability investments, the standards it employs, the means and methods to prioritize and implement investments and whether customers are deriving good value from these investments, would be of benefit at this time. This is especially so, considering the escalating level of investment planned over the next five years. The lack of insight derived from the highly anticipated CEATI report, on which NSPI placed so much reliance in the 2024 ACE Plan hearing, further supports that additional review is needed now.
>
> The Industrial Group submits that there is currently insufficient information to support the magnitude of investment proposed in the Reliability Plan over the next five years.
>
> [IG Closing Submission, pp. 6-7]

[77] NS Power agreed that given the size of the investment in the Plan, it understands the desire to have an external review.

> While NS Power has confidence in its planning and investment processes that have developed the plan and the regulatory processes that are in place to assess the proposed investments, it also understands the importance of customer confidence in the plan, particularly given the magnitude of the investment. As such, if broader confidence can only be obtained with a third-party review, then NS Power welcomes the opportunity for an external review to aid in ensuring the Five-Year Reliability Plan delivers on customer expectations. If such a review were to be undertaken, then NS Power would expect to participate in defining a process with intervenors, to contribute to the source of the inputs and scope. In doing so, NS Power believes it could better ensure that any outcome aligns with NS Power's planning processes and would help to alleviate resource strain and maintain pace with the work planned for 2025 and beyond.
>
> [Exhibit N-14, p. 11]

2.3.3.1 Findings

[78] The Board agrees that a third-party review of the Five-Year Reliability Plan is warranted. The Board will look to engage the appropriate expert. The Board also agrees with NS Power that a scoping exercise is an important component for a successful third-party review. NS Power is directed to work with the Board's expert and stakeholders to

help determine the scope of the review. Draft Terms of Reference shall be provided to the Board for review. The goal is to have the report by the 2027 ACE Plan. The ultimate production of the report may well be determined by the availability of the required expert and how quickly the Terms of Reference can be finalized.

[79] As directed in paragraph 56, the Board expects NS Power to continue evaluating resilience and reliability metrics to use in assessing the Five-Year Reliability Plan. That said, the Terms of Reference for the third-party review should include a review and evaluation of potential metrics which might assist in later processes involving the Five-Year Reliability Plan. The Board anticipates there will be a constructive dialogue about some of the data Mr. Wilson indicated would be helpful in trying to assess reliability outcomes, as outlined in paragraph 51 of this Decision.

2.3.4 CEATI Benchmarking Study

[80] In the 2024 ACE Plan hearing, NS Power discussed its work with the Centre for Energy Advancement through Technological Innovation (CEATI) on its vegetation management program. Additionally, NS Power said it was working with the other members of the CEATI group, and other member utilities, to benchmark its vegetation management program. The Company expected there would be feedback based on the data provided by member utilities and there might be recommendations which would further enhance NS Power's program.

[81] The CEATI Benchmarking Study was filed in the current proceeding as a confidential document as directed in the 2024 ACE Plan hearing. NS Power acknowledged in its Rebuttal Evidence that the level of detail or specificity in the CEATI vegetation management benchmarking report's recommendations did not meet the expectations set during the 2024 ACE Plan hearing. NS Power said it was disappointing

that only three utilities participated in the study which was not enough to benchmark against. The Board reviewed the document and agrees with NS Power.

[82] The Company said it continues to participate in industry groups including CEATI and Electricity Canada which have included resiliency as a key focus for collaboration. NS Power plans to participate in a Grid Resiliency working group initiated by CEATI, anticipated to begin in Q2 2025. The Company expects that a combination of framework and a suitable set of metrics can be developed through this process.

[83] The Board directs NS Power to provide an update on the CEATI Grid Resiliency working group in the 2026 ACE Plan.

2.3.5 Enhanced Pole Design Standards and Distribution Standards

[84] In the 2024 ACE Plan hearing NS Power stated that installing higher class poles was part of its storm hardening activities that would have a positive impact on both reliability and the resiliency of the power system.

[85] In the 2025 Plan, NS Power included investment in stronger, more robust poles as part of its Reliability Plan. The Company has updated some of its overhead distribution design standards to align with the latest CSA C22.3 overhead line standards. These updates include specifying larger class poles to replace existing poles when they break or get to the end of their useful lives.

[86] Advanced pole modeling software is being used to study the effects of wind, ice, equipment, and attachment loads on pole integrity. The analysis completed with this modeling software provides a more accurate assessment of how poles respond to external forces such as high-speed wind gusts, ensuring poles that are capable of withstanding heavy weather and extreme wind conditions are specified and installed.

[87] During the hearing, NS Power stated that about 10% of its customer hours of interruption in 2024 were due to pole failures. This includes poles breaking, being uprooted or other issues with the pole. Most poles in the province are being replaced with higher class poles when they break or are determined to require proactive replacement through inspection.

[88] Upon questioning by the Board, NS Power described the investment in poles as more about resiliency than about reliability and that it will take several years to see measurable improvements related to this investment.

[89] The Board is encouraged by the Utility's approach to using upgraded class poles. The upgraded class is more likely to improve the strength and bending capacity of the Utility's wooden poles. However, to demonstrate the effectiveness of these upgraded class poles, it is important to assess their performance immediately after a major weather event. Additionally, the installations should be prioritized in areas that are more frequently exposed to the highest winds and are likely to have the greatest impact on customer outages.

[90] The Board directs NS Power to monitor the installation of the upgraded class poles across the Utility's four operating regions, and to provide a post-storm evaluation to determine pole status, survival rate, impact on customer outages, and whether the upgraded class improved the resilience of the wooden poles.

2.4 Update to *The Path to 2030*

[91] In its *2023 ACE Plan* Decision, 2023 NSUARB 159, (M11017), the Board directed NS Power to file a detailed plan about how it is going to achieve legislated decarbonization goals by 2030, as follows:

> [6] …file a detailed and specific plan outlining how the Company will achieve the 2030 obligations, what specific steps are required to meet these obligations, how the proposed steps will accomplish that goal, and when these steps will be taken.

[92] On January 2, 2024, NS Power filed a detailed plan called *The Path to 2030*. The plan was reviewed during the 2024 ACE Plan proceeding. NS Power committed to providing an annual update on *The Path to 2030* as part of ACE Plan proceedings. The goal is to keep stakeholders, and the Board, informed about whether NS Power is on track to meet the legislated decarbonization obligations. This will be done as part of the ACE Plan proceedings.

[93] There are several decarbonization goals being advanced by the provincial and federal governments. Two specific targets that must be met by 2030 are enshrined in the following enactments: the provincial *Environmental Goals and Climate Change Reduction Act*; the provincial *Renewable Electricity Regulations* and the federal *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*. The legislation requires NS Power to achieve 80% of electricity sales from renewable resources and to phase out coal generation by 2030. *The Path to 2030* provides details on how NS Power plans to achieve these legislated requirements.

[94] NS Power filed *The Path to 2030* Update as Appendix H in the 2025 ACE Plan. Like last year, Figure 1 in the Executive Summary shows the various resources NS Power anticipates will be required to meet the 2030 decarbonization requirements, along with projected times when these resources will be available:

1 **Figure 1 – 2030 Clean Power Plan Resources**

	Nameplate Capacity (MW)	Initial Anticipated COD (Year)	Updated Anticipated COD (Year)
Wind & Solar Resources			
Rate Base Procurement	306	2025	2025-2026
Green Choice Program	416	2028	2028
Port Hawkesbury Paper Wind	168	2025	2026
Renewable to Retail Wind	149	2024	2026[1]
Community Solar	50	2025-2029	2025-2029[2]
Commercial Net Metering	50	2024-2029	2024-2029
Energy Storage Resources			
NS Power BESS Project	150	2025-2026	2025-2026
NSIESO Procurement	50-250[3]	2026	2027[4]
Fast Acting Generation Resources			
Stage 1	300	2027	2027
Stage 2	300	2029-2030	2029-2030
Fuel Conversions at Existing Units			
Gas Conversion – Point Tupper 2	150	2028	2028
HFO Operation – Lingan 1/3/4	459	2029	2029
Total New Wind & Solar	1,139		
Total New Energy Storage	200 - 400[3]		
Total New Fast Acting Generation	600		
Total Fuel Conversions	609		
Load Management Initiatives	150	2025-2029	2025-2029
Total Coal Phase Out	1,229		

[Exhibit N-1, Appendix H, Figure 1, PDF p. 511]

[95] Figure 1 in *The Path to 2030* Update also shows any changes in the anticipated commercial operation dates (COD) by year for the various resources needed to meet the legislated decarbonization goals. The Board notes that the anticipated COD for the rate-based procurement program now extends to 2026. The original plan anticipated completion of this procurement by the end of 2025. In addition, the COD for the Port Hawkesbury Paper Wind Generation project has been extended by one year to 2026. The Nova Scotia Independent Energy System Operator (NSIESO) energy storage procurement program COD is also extended by one year to 2026. Finally, Renewable to Retail wind generation is now anticipated to be available by the end of 2026 instead of

the end of 2024. NS Power adjusted the coal generation station retirement dates based on the 2024 10-Year System Outlook. Lingan 2 had been scheduled for retirement in 2025. It is now scheduled for retirement in 2027 and currently operating in cold reserve. The retirement of Trenton 6 was scheduled for 2028. The anticipated retirement date is now 2029.

[96] As discussed in the *2024 ACE Plan* Decision, and emphasized in the Department of Energy (DOE) opening statement in this proceeding, the timeline to 2030 is short. Unexpected deviations from the CODs for the various and integrated components of *The Path to 2030* create risks that NS Power will not meet the legislated decarbonization targets.

[97] Since *The Path to 2030* was first developed, the Board has approved NS Power's three grid-scale battery storage projects on June 13, 2024. NS Power advised during oral testimony in this proceeding that two of these three projects were expected to be in operation by the end of 2025, which is consistent with the timeline in *The Path to 2030*. Another major project, to build a new transmission intertie with New Brunswick, was filed for approval by the Board in 2025. NS Power has consistently indicated this project is needed to integrate the large amount of intermittent wind energy required to achieve *The Path to 2030*. That application is currently in progress.

[98] Since last year's ACE Plan hearing, the Federal *Clean Energy Regulations* (CER) came into force. They provide some key flexibility which should allow NS Power to use the coal plants scheduled to be converted to burn heavy fuel oil at the Lingan Generation Station and natural gas at the Point Tupper Generating Station as modeled in the Evergreen Integrated Resource Plan (IRP). *The Path to 2030* contemplates that

these converted plants would provide peaking capacity during periods of net peak demand and firm dispatchable capacity to meet reliability and reserve margin requirements. Essentially, the converted coal plants would be able to generate power from carbon-based fuels other than coal, at low annual capacity factors. This alleviates some of the Board's conceptual concerns discussed in the *2024 ACE Plan* proceeding, about the need for certainty that generating plants, burning natural gas and heavy fuel oil, will be compliant with the CER, before proceeding with very expensive conversions.

[99] The COD for the rate-based procurement project for nameplate capacity of 306 MW and 1,165 GWh of new wind generation has been extended from 2025 to 2026. That said, all required system integration and facility studies have been completed for the four wind projects in question. Generator interconnection agreements have been executed by all proponents and there are specific anticipated CODs for these projects ranging from October 15, 2025, to December 31, 2026. NS Power is now responsible for completing the network upgrades and interconnection facilities for the projects. Therefore, it appears rate-based procurement will be completed on time.

[100] Port Hawkesbury Paper Wind (PHP Wind) is developing a proposed 409MW windfarm to support the long-term sustainable operation of Port Hawkesbury Paper's mill. All required system integration studies have been completed for Phase 1 of the project, which is anticipated to produce 168MW, and a generator interconnection agreement has been executed. The Board understands Phase 2 of the PHP Wind project is less advanced, but only Phase 1 is included in *The Path to 2030*. NS Power provided no indication that the delay in the anticipated COD for Phase 1 of the project will jeopardize the goals of *The Path to 2030*.

[101] There is one Renewable to Retail licensee authorized to provide the electricity it generates directly to retail customers using NS Power's grid. First commercial operation is now anticipated in 2026. There have been growing pains associated with this new type of offering in Nova Scotia. One generator interconnection agreement has been executed for Phase 1 of the licensee's Mersey windfarm. There is at least a reasonable prospect that the 2026 COD can be achieved.

[102] The only other change in the anticipated COD of new electricity resources outlined in Figure 1 of *The Path to 2030* is further energy storage battery capacities that may be procured by the new NSIESO. The NSIESO will be taking over responsibilities for the bulk electricity system from NS Power. There was little new insight about this provided in the proceeding. The new date of 2027 is based on the most recent 10-Year System Outlook at the time of the application.

[103] *The Path to 2030* anticipates 600MW of fast-acting generation will be required to integrate the amount of intermittent renewable electricity required under the plan and to retire the coal plants. The NSIESO will be responsible for this procurement. NS Power indicated that it has no information, at this time, to indicate the timelines for this component in *The Path to 2030* will not be met and there has been no change to the anticipated COD from last year for this project. That said, the Board has not gained much insight through the ACE Plan process about the status of the fast-acting generating procurement. The Board would only caution that the COD of 2027 for Phase 1 (300MW) of the fast-acting generation project contemplated in *The Path to 2030* is just around the corner. Fast-acting generation projects, such as installing natural gas generating units, may have long lead times because of worldwide demand.

[104] There were no changes to the anticipated CODs for the other major components of *The Path to 2030*. There was additional discussion about demand side management, including hybrid peak electrification profiles that would include the adoption of mini-split heat pumps while retaining existing backup heating sources such as oil and natural gas during colder periods when heat pumps are less efficient. This scenario continues to be explored as part of the ongoing Evergreen IRP update process. *The Path to 2030* also discussed the evolving landscape related to green hydrogen projects and offshore wind, along with the need to continue evaluating the impact of these initiatives on *The Path to 2030*.

[105] There was some discussion during the 2025 ACE Plan proceeding about the need to address or assess potential contingencies. Mr. Wilson expressed particular concern about the need to have contingencies in place in case the New Brunswick intertie project is not completed on time. In response to questions from the CA and the Board, NS Power indicated that, in the short term, the Utility could integrate intermittent wind and solar power with its existing generating fleet if the New Brunswick intertie project is delayed. This would probably mean changing the proposed retirement dates of the coal plants. Dave Pickles, NS Power's Chief Operating Officer, gave similar answers with respect to potential delays in other grid stability and reliability initiatives such as fast-acting generation.

[106] The Board acknowledges that NS Power may have some flexibility in the short term, prior to 2030, to manage the retirement of its coal fleet. This would probably allow the integration of substantial new wind projects, and additional solar projects, contemplated in *The Path to 2030*, in accordance with the existing timeline. This assumes

that using the coal plants longer can be done within the current carbon emission restrictions. This is probably not a solution if project delays impact the 2030 goals in the current legislation. The Board agrees with NS Power that the issue of contingency planning related to delays with the New Brunswick intertie project can be addressed in that proceeding. Nevertheless, as we are now fast approaching 2030, the Board expects a robust assessment of NS Power's ability to meet the timelines in *The Path to 2030* in the 2026 ACE Plan update. Any significant contingency investment to achieve compliance, which may only be required in the short term, would have to be carefully assessed when considering the impact on ratepayers. Early recognition of potential delays may require frank discussions about costs and benefits with governments and stakeholders.

[107] The Board recognizes the logic of completing the very substantial investments in new fast-acting generation and coal plant conversions, for the most part, in the last two years of *The Path to 2030*. One of the goals is to match the costs of these large investments as closely as possible to when they will be needed or provide the most benefit. This is in line with traditional concepts of when such assets are used and useful, although the Board is mindful that s. 6(2) of the recently proclaimed *Energy and Regulatory Appeals Board Act* may provide the Board with some flexibility. However, because of the potentially significant impact on rates arising from these major investments, timing is important. The flip side of this coin is that it leaves very little room for error when it comes to project timelines. It may also mean additional maintenance costs and sustaining capital expenditures.

[108] Having reviewed *The Path to 2030* Update, the Board is generally satisfied with its contents, and the direction NS Power's plan is proceeding. The Board does have concerns about the potential for delays with large projects. In some cases, such as fast-acting generation and additional grid scale battery storage, NS Power is largely relying on the NSIESO to be able to achieve *The Path to 2030* goals. NS Power should be continually evaluating *The Path to 2030* timelines and assessing if there are mitigating strategies ratepayers can afford if issues arise that put the implementation of the plan by the prescribed date in peril. Therefore, NS Power is directed to continue filing updates to *The Path to 2030* in the annual ACE Plan applications.

2.5 Mersey Hydro System Redevelopment Project

[109] The Mersey Hydro System Redevelopment Project (Mersey Redevelopment Project) is a long-term project aimed at redevelopment of NS Power's complete Mersey Hydro System (MHS):

> The MHS water retaining structures and powerhouses require capital investment to replace existing structures. At present, the optimal path to maintaining long-term operation of the MHS is through a series of redevelopment projects, which would allow the existing structures to be decommissioned and replaced with new, modern water retaining structures and powerhouses, currently expected to take place over a period of 20-30 years from the start of construction. Approaching the redevelopment in this way allows for continued generation through the construction period.
>
> [Exhibit N-1, Appendix G, p. 2]

The total cost of the Mersey Redevelopment Project was estimated to be $1.13 billion in NS Power's 2023 ACE Plan and $1.205 billion in the 2024 ACE Plan. In response to NSUARB IR-167 in the current proceeding, the estimated total cost for the project is $1.204 billion.

[110] Phase 1 of the Mersey Redevelopment Project was included in every NS Power ACE Plan application between 2017 and 2022 as a subsequent submittal item. As such, NS Power's intent was to submit the project for Board approval following the related

ACE plan application but prior to the subsequent ACE Plan application. In its *2023 ACE Plan* application, NS Power indicated that the project had been deferred until 2031. At that time, the Company stated that the deferral will allow it to continue evaluating the fundamental project alternatives with consideration for key items, including how the project fits into the overall plan to achieve 80% renewable energy by 2030 while managing asset risk, evolving fisheries permitting requirements and affordability.

[111] In the 2024 ACE Plan, the Mersey Redevelopment Project continued to be deferred until 2031, and it remains deferred to 2031 in the 2025 ACE Plan. With the deferral, NS Power noted that additional risk mitigation strategies are required to sustain the safe, environmentally compliant operation of the MHS. These additional risk mitigation strategies will lead to increased maintenance and sustaining capital costs. In the 2025 ACE Plan application, NS Power further stated:

> The deferral of the Mersey Redevelopment is consistent with NS Power's asset management methodologies. Where possible, deferring projects where safety and economic risks associated with the project can be managed is in the best interest of customers. This approach also ensures the Company can complete the required engagement with Rights holders and external stakeholders, as well as continue discussions with DFO on the priority investments in fish passage to be in a position to submit a complete application to the NSUARB for approval.
>
> [Exhibit N-1, Appendix G, p. 6]

[112] To facilitate the safe deferral of the Mersey Redevelopment Project, in its *2023 ACE Plan*, NS Power identified $21.9 million in incremental, smaller scale sustaining investments for the MHS which will be required before the start of the Mersey Redevelopment Project in 2031. These costs were initially incorporated into the Company's 2023 Hydro Interval Plan (HIP). The HIP provides an annual high-level directional overview of the Company's estimated annual capital expenditures that will be

required for its hydro generation assets over the next 40 years. In its 2024 HIP, NS Power identified further sustaining capital investments of $12.5 million prior to 2031 for the MHS.

[113] In its 2025 ACE Plan application, NS Power provided clarity about the HIP estimates:

> Input assumptions for the HIP or IRP are not developed at the detailed level that they are for capital project justification; rather they are directional and provide ranges of costs, generally low, medium and high, to capture uncertainties.
>
> …
>
> The HIP incorporates the best information available at the time of planning, as well as predictions about potential decisions that are subject to change as constraints and priorities evolve. As such, both the sustaining investment and forecast for the Mersey Redevelopment included in the HIP will change as additional information is obtained. In particular, the forecast cost and scope requirements associated with archaeology and environment will be refined as engagement and discussion continues and the associated impacts can be incorporated into long-term project planning. However, in order to confirm that investments in various hydro systems continue to be the lowest cost option for customers, the NPV figures included in the annual HIP updates provide a tool for analyzing the economics of various options.
>
> [Exhibit N-1, Appendix G, p. 7]

[114] The Board's *2024 ACE Plan* Order directed NS Power to provide a comprehensive update on the Mersey Redevelopment Project in the 2025 ACE Plan. In accordance with this directive, NS Power provided the MHS comprehensive update in Appendix G of the 2025 ACE Plan application.

[115] In its 2025 ACE Plan, NS Power stated that further updates and prioritization of sustaining capital for the Mersey system have been incorporated into the 2025 HIP for the years 2025 to 2064. The total capital required for sustaining investment over this period has increased from $118.6 million in the *2024 ACE Plan* to $160.7 million in the 2025 ACE Plan. The increase in total investment is partially attributed to bridge refurbishment work at Big Falls, Lower Great Brook and Lower Lake Falls, which are all scheduled to take place towards the end of the period. The increased sustaining capital is also a result of additional powerhouse structure investments, a planned fish ladder at

Upper Lake Falls, and fishway modifications expected at Lower Great Brook, Deep Brook, and Cowie Falls. The Net Present Value (NPV) for sustaining investment has slightly decreased from $69.3 million in the *2024 ACE Plan* MHS update to the current forecast of $68.1 million.

[116] For the years 2025 to 2030, the current HIP includes total sustaining investment of $45.5 million for the MHS. This is consistent with the estimated $46.6 million for the same time period included in NS Power's *2024 ACE Plan* Mersey Hydro System update. The sustaining investment over this period is to allow for continued safe and reliable operation of the system until the redevelopment project begins. This includes mechanical and electrical overhauls of the generating units and the supporting crane equipment to facilitate the overhauls, replacement and/or refurbishment of critical water control devices (e.g., log hoists, sluice gates), minor civil structural restoration to powerhouse, dam and spillway structures, and other minor investments to the balance of plant equipment.

[117] The redevelopment project is large and complex. NS Power stated that it must complete additional preliminary engineering work, Mi'kmaq and stakeholder engagement and environmental studies to confirm the full scope of work and ensure that the path forward remains the best value for customers prior to submission for Board approval. NS Power stated that it continues to work through the environmental permitting process for the Mersey Redevelopment Project. The Utility noted that there are many archaeological and environmental considerations associated with the MHS, and it continues to have meaningful conversations with the relevant Mi'kmaw communities, as

well as the Federal Department of Fisheries and Oceans (DFO) and the Nova Scotia Government.

[118] In particular, NS Power noted that its recent experience with DFO suggests that continued compliance with the modernized *Fisheries Act* (2019) may result in material project impacts. The Company stated that it must have a clear understanding of the conditions associated with modernized *Fisheries Act* compliance and requirements for related permit approval in order to move forward with the Mersey Redevelopment Project. As such, NS Power is continuing conversations with DFO to better understand requirements associated with fish passage, as recent hydro projects have seen a trend in increased DFO requirements associated with fish passage and subsequent impacts to project timing, cost and scope. More recently, NS Power has increased regular engagement with DFO to improve information sharing and feedback on upcoming projects and DFO priorities. In addition, NS Power is continuing to build on lessons learned from other projects, including those on the MHS, that require engagement with DFO, Mi'kmaw communities and other stakeholders. In response to NSUARB IR-167b), NS Power confirmed that the Mersey Redevelopment Project cost estimates included in the 2025 ACE Plan account for the requirements of the modernized *Fisheries Act*.

[119] Finally, NS Power indicated that it will continue to evaluate and optimize the long-term plan for the MHS to the benefit of customers and will submit CI 39472 HYD - Mersey Redevelopment Phase 1 once the Company is in a position to provide a complete application to the Board.

2.5.1 Findings

[120] The Board's *2024 ACE Plan* Order directed NS Power to include an updated capital cost estimate for the Mersey decommissioning option, complete with all

assumptions used to develop the estimate, in its next deprecation study to be filed with the Board. Further, after filing its depreciation study, NS Power was directed to also include an NPV analysis comparing the decommissioning option to the redevelopment option, complete with a description of all assumptions used in the analysis in its subsequent ACE Plan application. As of the 2025 ACE Plan hearing date, NS Power had yet to file its most recent depreciation study. As such, the two directives noted above remain outstanding.

[121] In its Rebuttal Evidence, NS Power stated that following the filing of its depreciation study, it will incorporate an NPV analysis into the Mersey Update in the 2026 ACE Plan, which will continue to demonstrate that deferring the large-scale investment needed for either re-development or decommissioning, while maintaining the safe operation of the MHS, is in the best interest of customers. The Board directs NS Power to provide a comprehensive update on the Mersey Redevelopment Project in the 2026 ACE Plan. The Board also expects the NPV analysis referenced in NS Power's Rebuttal Evidence to be included as part of this update.

[122] However, the Board does not consider such an analysis to meet the Board's *2024 ACE Plan* directive requiring NS Power to provide an NPV analysis comparing the Mersey decommissioning option to the redevelopment option, complete with a description of all assumptions used in the analysis. If NS Power files its next depreciation study with the Board before filing the 2026 ACE Plan, this comparative analysis must be included in the Mersey Redevelopment Project update in the 2026 ACE Plan.

[123] Notwithstanding the above, in response to IG IR-7, NS Power provided a high-level review of the Mersey decommissioning options currently being considered by

the Company. The Utility noted that it believes there are two decommissioning options that are relevant, namely de-energizing (partial decommissioning) and re-naturalizing. The de-energizing option involves decommissioning of all six powerhouses on the MHS, while maintaining the dams and spillways. The capital costs associated with this option would be limited to upgrading the dams and spill structures and modifying the powerhouses. All energy, capacity, and ancillary services provided by the MHS sites would be lost but the obligations to maintain the infrastructure to meet the *Fisheries Act*, as well as alignment with the Canadian Dam Association' Dam Safety Guidelines for dam safety and public safety would remain. The re-naturalizing option involves removal of all infrastructure on the MHS and restoring the Mersey River to its pre-development condition. All energy, capacity, and ancillary services, including flood attenuation, currently provided by the system would also be removed.

[124] In addition, in Undertaking U-8, NS Power provided copies of its "Hydro System Decommissioning Study Update" (dated December 11, 2024) and its "Hydro Asset Archaeological Program 2024 Revised Costing Document" (dated October 2024). In the Undertaking, NS Power also provided a summary table outlining updated cost estimates to decommission each of its existing hydro systems. These summary estimates are based on the cost estimates developed in the two reports provided in the Undertaking. The updated cost estimate to fully decommission (re-naturalize) the MHS is $507.8 million, while the updated cost to partially decommission (de-energize) the system is $60.6 million. The Board notes, though, that these estimates exclude cost provisions for updated fish passage provisions that may be required under the 2019 modernized *Fisheries Act*.

[125] The Board finds this information useful. Therefore, in addition to filing an NPV analysis comparing the Mersey decommissioning option to the redevelopment option per the Board's *2024 ACE Plan* direction, the Board directs NS Power to file an NPV analysis comparing the partial decommissioning option to the redevelopment option, complete with a description of all assumptions used in the analysis. The analysis is to be filed in the ACE Plan application that follows NS Power's filing of its next depreciation study. If NS Power does not file its next depreciation study with the Board before filing the 2026 ACE Plan, the Board expects the Company to provide an update on the activities it conducted since the filing of the 2025 ACE Plan related to evaluating and costing the MHS decommissioning and partial decommissioning options.

[126] In response to NSUARB IR-165a), NS Power confirmed that it has not updated any archaeology or environmental cost allowances for the Mersey Redevelopment Project since the *2024 ACE Plan* proceeding, as it continues to work towards achieving a common understanding and agreement regarding the respective scopes. Consequently, there have been no changes to the cost allowance percentages for archaeological, fish passage and environmental costs between the 2024 and 2025 ACE Plans. The project cost allowances for these items in the 2025 ACE Plan Mersey update remain as archaeological costs: 0.5%, fish passage costs: 3%, and environmental costs: 1%. Further, in response to NSUARB IR-165a)i), NS Power provided a table showing the archaeological, fish passage, and environmental costs (as a percentage of total project costs) incurred to date on the Tusket Falls Main dam project, the Ruth Falls Main dam project, and the Gaspereau dam project. The related cost percentages to date

for these projects are significantly higher than those allowed for in the current Mersey Redevelopment Project cost estimates.

[127] This issue was discussed during the hearing. Following these discussions, the Board asked NS Power to provide an update on the expected archaeological, fish passage and environmental costs of the Mersey Redevelopment Project as a percentage of the overall project cost estimate. In Undertaking U-10, NS Power stated that considering the scope of work relative to the overall investment, the archaeological, fish passage and environmental costs expressed as a percentage of the total Mersey Redevelopment Project cost estimate remain appropriate. The Company further noted:

> The primary reason is that the total project cost is not a direct proxy for the construction or disturbance footprint. Approximately 70 percent of the Mersey Redevelopment costs are associated with the powerhouse and substation components, which have relatively small physical footprints. In contrast, only about 30 percent of the costs are related to water-retaining and control structures, which account for the majority of the site disturbance.
>
> By comparison, the Tusket and Ruth Falls projects involved significant reservoir drawdowns, which expanded the area of disturbance and, consequently, the potential for archaeological impact. In the case of the Mersey Redevelopment, the execution plan includes the use of cofferdams to limit dewatered areas, thereby reducing the risk of archaeological exposure.
>
> Finally, while the Gaspereau site is known for an exceptionally high concentration of archaeological artifacts, it is important to note that extensive shovel testing was also conducted in advance of that project to mitigate potential impacts. Similarly, the Mersey Hydro System—also recognized for its archaeological sensitivity—has undergone a substantial shovel testing program.
>
> These proactive measures in both cases were designed to reduce the likelihood of encountering significant archaeological findings during construction.
>
> [Exhibit N-21, Undertaking U-10]

[128] The Board accepts NS Power’s update and related explanations. The Board also accepts NS Power’s response to NSUARB IR-167b) where the Company confirmed that current fish passage cost estimates for the Mersey Redevelopment Project account for the requirements of the modernized *Fisheries Act*. However, the Board remains concerned that costs associated with archaeological work, fish passage, and

environmental considerations for the Mersey Redevelopment Project may be understated. While the Board understands NS Power’s explanations, these concerns arise from past and on-going projects where such costs have increased (and in some cases, significantly) over time compared to initial cost estimates.

[129] The Board is particularly concerned about the current allowance for archaeological costs. At a 0.5% cost allowance, the archaeological cost component in the current Mersey Redevelopment Project cost estimate amounts to roughly $6 million. As noted in Undertaking U-10, the bulk of these costs are expected to be primarily associated with redevelopment of existing water-retaining and control structures, which account for the majority of the expected site disturbance and for about 30% of the redevelopment project cost. The Board notes that 30% of the current Mersey Redevelopment Project cost estimates equates to approximately $361 million. At $6 million, the current archaeological cost allowance for the project amounts to 1.67% of this cost. This is significantly lower than the current percentage of archaeological costs for both the Tusket Main Dam Project and the Gaspereau Dam Project, and comparable to that for the Ruth Falls Main dam project. The Board further notes that according to the “Hydro Asset Archaeological Program 2024 Revised Costing Document” filed in Undertaking U-8, the Ruth Falls Dam area was initially identified with three areas of high archaeological potential. Subsequently, two of the three high potential areas were subjected to archaeological shovel testing, which yielded negative results for archaeological resources. The same document identifies the MHS as having high potential for archaeological resources.

[130] Therefore, the Board expects NS Power to continue evaluating and refining costs associated with archaeological work, fish passage and environmental considerations as the Mersey Redevelopment Project progresses. In addition, the Board expects these costs to be identified separately and fully supported in NS Power's filing of its NPV analysis comparing the Mersey Redevelopment Project to the decommissioning and partial decommissioning options.

[131] On page 4 of Appendix G of the 2025 ACE Plan, NS Power noted that the complex nature of the Mersey Redevelopment Project and the multitude of factors which must be considered for a project of this scope and size, required the Utility to complete additional preliminary engineering work, Mi'kmaq and stakeholder engagement and environmental studies to confirm the full scope of work and ensure that the path forward remains the best value for customers prior to submission to the Board for approval. In Attachment 1 of Appendix G, NS Power identified anticipated spending of $40,000 in 2025, 2027 and 2029, and $0 in 2026, 2028 and 2030 for the project. In NSUARB IR-167c)i), NS Power was asked to explain how total expenditures of $40,000 in each of 2025, 2027 and 2029 are enough to complete the work needed in advance of proceeding with the redevelopment project in 2031. In response NS Power indicated that $120,000 forecast for 2025-2029 is to fund post-monitoring of an offsetting project that was developed and executed for Phase I of the project.

[132] This was canvassed further in the hearing:

> **Q.** (Murphy) …So my question, really, is -- I think it was asked in the IR, but it wasn't really answered, I don't think. That particular attachment that Jeff still had -- or had up on the screen showed $40,000 investment in the Mersey Redevelopment Project in '25, 40,000 in 2027, 40,000 in 2029, which Nova Scotia Power acknowledged in an IR response that strictly related to an offsetting project.

So given what I read from Appendix G, the amount of work that's required to evaluate the Mersey Redevelopment Project and they haven't started construction, how does basically no spending from 2025 to 2030 address those needs?

A. (MacIntosh) Yes, Mr. Murphy, I can appreciate your question on that. So this is referring to the post-monitoring and the offsetting work, but to say that the detailed engineering is completed for Mersey and we have the final cost for redevelopment at this point in time in the update, I would say that we're not at the maturity level where we're able to submit the project at a Class 3 estimate. There's still more work being done.

And to your point that probably is not all supported in the current model that we're showing, there's more costs there to complete the engineering.
…

Q. (Murphy) The total capital investment for that project is $1.2 billion. Would you have an estimate of how much advanced work ahead of 2030 would be required to address design and other studies to get that project at least ramped up to move in 2030?

A. (MacIntosh) So this year we focused on the decommissioning scenario and did the updated studies and work in that space. But to your point, additional preliminary engineering would need to be completed between now and application of that -- of this project.
…
Q. (Murphy) You know, it doesn't appear to be -- you know, maybe it is further out because presumably you're not doing design for the whole project up front, but there's certainly a fair bit of design that can be done in the first five years that's going to be a relatively big number.

A. (MacIntosh) Yes, and we have completed already design work on Mersey. The actual Mersey amount I don't have it in front of me how much we've already spent on preliminary engineering for Mersey to develop this project. There's been a substantial amount of work already completed.

Q. (Murphy) But to do that -- but to complete that work, that total capital investment number, I would suspect, if you're going to include up-front engineering study work in the first five years, that at next year's ACE Plan there'd be a lot more spending on those five years.

A. (MacIntosh) It would -- excuse me. One moment. Yes.

Q. (Murphy) Okay. So it was missed this year?

A. (MacIntosh) We just didn't have the details of that cost for this update.

[Transcript, pp. 347-351]

[133] It is clear to the Board that capital expenditure estimates for 2025 to 2030 associated with further preliminary engineering work, Mi'kmaq and stakeholder engagement and environmental studies to confirm the full scope of the Mersey Redevelopment Project have been excluded from NS Power's 2025 HIP and Attachment

1 of Appendix G of the 2025 ACE Plan. In addition, given that the redevelopment project is currently scheduled to begin construction in 2031, the Board would expect that NS Power would also incur detailed engineering design costs, and, perhaps, procurement costs over this period. The Board believes that the 2025 to 2030 cost for all these items could be significant, given the scope and expected cost of the entire redevelopment project. As such, the Board directs NS Power to include these cost estimates in its Mersey system update in the 2026 ACE Plan. These cost estimates are also to be included in NS Power's filing of its NPV analysis comparing the Mersey Redevelopment Project to the decommissioning and partial decommissioning options.

2.6 Cost Minimization

[134] The issue of NS Power's capital cost minimization efforts became an area of focus for the Board and stakeholders during the *2019 ACE Plan* (2019 NSUARB 60) proceeding. As noted in the Board's *2021* and *2022 ACE Plan* Decisions (2021 NSUARB 77 and 2022 NSUARB 93) the Board considers it useful to address cost minimization through two separate themes. These include the effectiveness of NS Power's cost minimization practices, including capital cost budgeting and project scoping; and NS Power's capital project cost minimization and related project management practices themselves.

2.6.1 NS Power's Capital Project Cost Minimization Effectiveness, including Capital Cost Budgeting and Project Scoping

[135] The Board's *2024 ACE Plan* Order directed NS Power as follows:

> The Board directs NS Power to continue to track the information noted in Paragraph 92 of the Board's 2020 ACE Plan decision for each completed capital project that was submitted for Board approval in 2017, 2018, 2019, 2020, 2021, 2022, 2023 and 2024 (either through or outside of the ACE Plan proceedings, including projects submitted for subsequent approval, but excluding U&U projects). Further the Board directs that the following information be included in the related 2025 ACE Plan reporting:

a) Identification of all new projects that have been added to the Contingency Report (Appendix D);

b) A summary table of Contingency Report (Appendix D) data, similar to Figure 90 in the 2024 ACE Plan application, organized by the year projects were placed in service;

c) A summary table of Contingency Report (Appendix D) data, similar to NS Power's response to Figure 91 in the 2024 ACE Plan application, organized by the year projects were submitted for Board approval; and

d) For any capital projects in the Contingency Report (Appendix D) that have a negative variance greater than or equal to 25% of the Board approved capital cost estimate, NS Power is to provide an explanation detailing the reasons for the variance.

The Board directs NS Power to continue to track this information, including information related to projects approved by the Board after 2024, and report it in future ACE Plan applications. The Board directs that the data continue to be presented in the 2024 ACE Plan application Appendix D format in future ACE Plan applications. This reporting is to also categorize projects by function (i.e., generation, transmission, distribution, and general plant), with "generation" projects further categorized by type of project (i.e., hydro, steam, gas, other renewables).

[136] NS Power provided the information related to 8.b) and 8.c) above from the Order on page 136 in its 2025 ACE Plan application. This information is intended to allow the Board to better discern trends over time in NS Power's capital cost estimating and spending performance. The Utility submitted the remaining material directed in item 8 of the *2024 ACE Plan* Order in Appendix D of its 2025 ACE Plan application. Appendix D presents an analysis comparing Board-approved project budget amounts to final spending on the completed projects. Appendix D provides the Board with information to better assess NS Power's capital cost minimization and capital cost budgeting effectiveness, as well as its use of contingencies.

[137] In response to NSUARB IR-156, NS Power answered questions related to the 2025 ACE Plan Appendix D data. The Board has summarized the Utility's responses as follows, and includes, where relevant, comparative figures from the 2024, 2023, 2022, 2021 and *2020 ACE Plan* proceedings in brackets:

- There are 398 projects included in Appendix D (356 projects were included in Appendix D of the *2024 ACE Plan* application).

- The average variance for the listed projects amounts to approximately +3.47% of the original submission approved project cost estimate (2024: +5.5%; 2023: +4.7%; 2022: +9.5%; 2021: +10.8%; 2020: +10.47%).

- The total net variance of $22,968,305 for the listed projects is over and above the total contingency amount of $53,133,549 included in the total of the original submission approved cost estimates.

- The average contingency amount for the listed projects amounts to approximately 8.7% of the original submission approved cost estimate less the contingency amount (2024: 7.1%; 2023: 7.0%; 2022: 5.9%; 2021: 5.6%; 2020: 5.03%).

- For projects approved by the Board prior to November 8, 2019, that have an original submission approved cost estimate greater than $250,000 but less than $5,000,000, amounting to 292 projects in total:

    a. 31% had a negative variance (2024[1]: 31%; 2023: 32%; 2022: 31%; 2021: 28%; 2020: 31%);

    b. 69% had a positive variance (2024[1]: 69%; 2023: 68%; 2022: 69%; 2021: 72%; 2020: 69%); and

    c. Of the projects that had a positive variance, 88%, or 178 projects did not require an Authorization to Overspend (ATO) submission to the Board (2024[1]: 91%; 2023: 92%; 2022: 92%; 2021: 92%; 2020: 91%)

- For projects approved by the Board after November 8, 2019, that have an original submission approved cost estimate greater than $1,000,000 but less than $5,000,000, amounting to 64 projects in total:

    a. 61% had a negative variance (2024[1]: 59%; 2023: 33%);

    b. 39% had a positive variance (2024[1]: 41%; 2023: 67%); and

    c. Of the projects that had a positive variance, 92%, or 23 projects, did not require an ATO submission to the Board (2024[1]: 100%; 2023: 100%).

[1] Per the Board's *2024 ACE Plan* Decision, this number is based on the Board's own analysis of the 2024 ACE Plan Appendix D data.

- For projects that have an original submission approved cost estimate greater than $5,000,000, amounting to 25 projects in total:

  a. 44% had a negative variance (2024: 31%; 2023: 36%; 2022: 0%; 2021: 0%; 2020: 33%);

  b. 56% had a positive variance (2024: 69%; 2023: 64%; 2022: 100%; 2021: 100%; 2020: 67%); and

  c. Of the projects that had a positive variance, 71%, or ten projects, did not require an ATO submission to the Board.

- For all projects that have an original submission approved cost estimate less than $250,000, amounting to 17 projects in total, the total sum of the individual project variances as a percentage of the total sum of the individual project original submission approved cost estimates is 216% (2024: 216%; 2023: 216%; 2022: 206%; 2021: 206%; 2020: 210%). These projects did not change from the 2024 ACE Plan application, and updated for their subsequently approved greater than $250,000 submissions, the total sum of the individual project variances as a percentage of the total sum of the individual project original submission approved cost estimates is 9% (2024: 9%; 2023: 9%; 2022: 10%; 2021: 10%: 2020: 9%).

[138] A further review by the Board of the data in Appendix D of the 2025 ACE Plan application reveals the following (the Board has provided the comparative percentages from the 2024, 2023, 2022, 2021 and *2020 ACE Plan* proceedings in brackets):

- For projects that have a negative variance, the total variance amount is approximately $30.98 million or 4.7% of the total of the original approved cost estimates (2024: 4.4%; 2023: 5.7%; 2022: 3.2%; 2021: 2.7%; 2020: 3.1%).

- For projects that have a positive variance, the total variance amount is approximately $53.95 million or 8.1% of the total of the original approved cost estimates (2024: 9.9%; 2023: 10.5%; 2022: 12.7%; 2021: 13.5%; 2020: 13.6%).

[139] Based on the year that each project listed in Appendix D was placed into service, Figure 91 of the application provided the following additional information:

- 75% of the projects listed in Appendix D have a variance to the original approved estimate that falls within the expected accuracy range of -20% to

+30% for an AACE (Association for the Advancement of Cost Engineering) Class 3 cost estimate.

- 16% of the projects listed in Appendix D have a variance to the original approved estimate greater than +30%.

Further, in response to NSUARB IR-157(a), NS Power provided the following comparison of the Figure 91 information versus similar summary data from its 2024, 2023, 2022 and *2021 ACE Plan* applications:

All Years	**Total # of projects placed in service**	**Percentage of projects under-spent by greater than 20%**	**Percentage of projects with total spending between - 20% and +30% of budget**	**Percentage of Projects over-spent by greater than 30%**
2021 ACE Plan	154	8%	71%	21%
2022 ACE Plan	211	10%	72%	18%
2023 ACE Plan	315	10%	72%	18%
2024 ACE Plan	356	10%	73%	17%
2025 ACE Plan	398	9%	75%	16%

[Exhibit N-9, Response to NSUARB IR-157(a)]

[140] The original approved project budgets noted in Appendix D are typically prepared at an AACE Class 3 level. As noted during the *2021 ACE Plan* proceeding, AACE Class 3 capital cost estimating expectations generally suggest that no more than 10% of capital projects should have final spending exceeding the +30% upper accuracy limit; no more than 10% of capital projects should have final spending less than the -20% lower accuracy limit; and at least 80% of capital projects should incur final spending falling within these accuracy limits. In its 2025 ACE Plan application, NS Power stated that while Figure 91 shows the number of projects overspent by more than 30% slightly exceeds what can be expected from a portfolio of projects with Class 3 estimates, the trend is continuing in a positive direction and NS Power’s performance is approaching the expected range. The Utility also noted that of the 42 projects added to Appendix D since

the *2024 ACE Plan* application, 37 (or 88%) fall within the range of -20% to +30%, and only two of the projects have an overspend of greater than 30%.

[141] In his evidence, Mr. Wilson appears to concur with NS Power's observation that the trend appears to be in a positive direction. However, he also stated that the observed trend is very brief and suggested that the related data is subject to selectivity bias. In particular, he noted that that data shows significant underspending for more recent projects. He suggested that this may result from NS Power's more recent budgeting practices compensating for over-spending concerns by over-budgeting some projects. Mr. Wilson also noted that projects with substantial overspending may be delayed, and, therefore, do not appear in the current ACE reporting. Given these concerns, Mr. Wilson recommended that NS Power be directed to continue including the Appendix D contingency directive in future ACE Plan applications. In its Rebuttal Evidence, NS Power confirmed that it will continue to provide this information if directed by the Board.

[142] With regard to projects that had a negative project spending variance greater than or equal to 25%, NS Power provided a list of these projects, complete with detailed reasons for the associated variances, in Appendix D of its application. Twenty-eight of the projects in Appendix D have negative variances greater than 25%, primarily due to:

- Reduced scope following more detailed assessments;
- Labour costs being less than initially estimated. Contingency was not required;
- Contractor costs being less than initially estimated. Contingency was not required; and
- Savings in contract and materials costs. Contingency was not required.

2.6.1.1 Findings

[143] NS Power stated that Figure 91 in its application shows that the Company's cost estimating trend is continuing in a positive direction and its performance is approaching the expected AACE range. The Board reproduced Figure 91 from the application as follows, with numbers from the *2024 ACE Plan* provided for comparison in brackets:

Year	Total # of projects placed in service	Percentage of projects under-spent by greater than 20%	Percentage of projects with total spending between -20% and +30% of budget	Percentage of Projects over-spent by greater than 30%
2016	5 (4)	0% (0%)	40% (25%)	60% (75%)
2017	72 (72)	8% (8%)	63% (63%)	29% (29%)
2018	95 (95)	11% (11%)	72% (72%)	18% (18%)
2019	91 (89)	9% (8%)	82% (83%)	9% (9%)
2020	39 (36)	15% (14%)	72% (72%)	13% (14%)
2021	40 (34)	8% (9%)	78% (74%)	15% (18%)
2022	31 (19)	13% (16%)	77% (74%)	10% (11%)
2023	15 (7)	0% (0%)	100% (100%)	0% (0%)
2024	10	0%	90%	10%

This comparison supports NS Power's assertion of an improving trend. In addition, the Company's responses to NSUARB IR-156 and IR-157(a) show an improving trend in cost estimating accuracy between the 2021 and 2025 ACE Plan applications. Although NS Power's "percentage of projects over-spent by greater than 30%" still exceeds AACE expectations, the Board is encouraged that of the 42 projects added to Appendix D since the *2024 ACE Plan ap*plication, only two projects (or 5%), have an overspend of greater than 30%.

[144] As per the Board's *2024 ACE Plan* Order, NS Power also provided Figure 92 in its 2025 ACE Plan application, which gives a summary table of the Appendix D data organized by the year that projects were submitted for Board approval. In its *2022 ACE Plan* Decision, the Board noted that presenting the data in this format will allow the Board to better discern trends over time in NS Power's capital cost estimating and spending performance. The Board has reproduced Figure 92 from the application as follows, with numbers from the *2024 ACE Plan* provided for comparison in brackets:

Year	**Total # of projects submitted for Board approval**	**Percentage of projects under-spent by greater than 20%**	**Percentage of projects with total spending between -20% and +30% of budget**	**Percentage of Projects over-spent by greater than 30%**
2015	2 (1)	0% (0%)	50% (0%)	50% (100%)
2016	8 (7)	0% (0%)	38% (29%)	63% (71%)
2017	113 (112)	8% (7%)	66% (67%)	26% (26%)
2018	109 (108)	13% (13%)	69% (69%)	18% (19%)
2019	87 (85)	7% (7%)	85% (85%)	8% (8%)
2020	29 (23)	7% (4%)	93% (96%)	0% (0%)
2021	16 (6)	13% (33%)	88% (67%)	0% (0%)
2022	20 (12)	20% (25%)	75% (75%)	5% (0%)
2023	11 (2)	0% (0%)	91% (100%)	8% (0%)
2024	3	0%	100%	0%

[145] The Board finds that this table also suggests an improving trend in NS Power's cost estimating and/or project execution over time. However, if over time, a high degree of over-spending becomes evident, that would likely suggest either poor budgeting or poor cost-minimization practices by the Company. This is an issue that the Board may wish to continue monitoring in future ACE Plan applications. Further, as noted in the Board's *2024 ACE Plan* Decision, the trend of an increasing percentage of projects with under-spending greater than 20% since 2019 could, as suggested by Mr. Wilson's evidence, result from some "padding" of budgets submitted for Board approval. This is also an issue that the Board may wish to continue monitoring in future ACE Plan applications. The Board will also wish to continue monitoring large negative project variances in future ACE Plan proceedings to ensure that such variances related to significant project scope reduction do not skew NS Power's capital cost performance reporting.

[146] Given what appears to be improvement over time in the effectiveness of NS Power's capital project cost minimization practices related to capital cost budgeting and project scoping, the Board finds that continued regular reporting and review of these practices is no longer necessary. As such, at this time the Board will not direct any further Appendix D contingency reporting in subsequent ACE plan applications. Nonetheless, NS Power should continue internal tracking and documentation of Appendix D data, recognizing the importance of cost minimization, and in the event the Board directs such reporting in a future proceeding.

2.6.2 NS Power's Capital Project Cost Minimization and Related Project Management Practices

[147] As it relates to NS Power's project management practices, the Board's *2024 ACE Plan* Order directed NS Power as follows:

> 9. The Board directs NS Power to revise its PDM to include a quality control step to verify that maturity matrices, risk registers, and other relevant documents are accurate and have been appropriately relied upon in reaching relevant conclusions. In its 2025 ACE Plan application, the Company is further directed to describe this quality control measure and explain how it will be used and managed internally.

[148] NS Power's Project Delivery Model (PDM) serves as the overarching framework that provides guidance on documenting and sharing cost minimization expectations and practices within the Utility's business. The PDM also describes the process for the proactive review and tracking of cost minimization opportunities during all stages of the project life cycle. In its 2025 ACE Plan application, NS Power indicated that a quality control measure, in the form of a checklist, has been added to its PDM.

[149] NS Power noted that the checklist will be required support documentation for all NS Power capital work orders submitted for internal approval. It will require a project owner to detail the elements of the PDM that they feel will be additive to the capital project being submitted, or to other capital projects in the future. In addition, the checklist will be reviewed by the Utility's capital planning team, who will confirm that the elements selected are sufficient, and all elements that could provide value to the project in review are selected. The capital planning team will add elements as requirements, if the appropriate ones are not selected initially. NS Power filed a copy of the checklist in response to NSUARB IR-8.

[150] In his evidence, Mr. Wilson suggested that the quality control checklist appeared to be misaligned with the Board-approved criteria. Specifically, he noted that the criteria NS Power uses to define a "complex" project in the checklist (as identified by

the Utility in response to CA IR-1(a)) are not the same as those approved by the Board in its *2022 ACE Plan* Decision. In its Rebuttal Evidence, NS Power agreed in principle with Mr. Wilson, excluding criteria that cannot be known at the time a "Basis of Estimate" or "Risk Register" is completed. As such, the Utility filed an updated version of the PDM quality control checklist in its Rebuttal Evidence to include the definition of a "complex" project.

[151] With regard to NS Power's capital project cost minimization efforts, paragraph 196 of the Board's *2024 ACE Plan* Decision stated:

> [196] In its application, NS Power noted that since its cost minimization efforts are actively included in its budgeting process for future capital projects, this will likely result in diminishing opportunities to further reduce costs for similar projects going forward. As such, this may result in fewer or less impactful examples of cost minimization as the Company continues to track this information. The Board agrees with this assertion. However, the Board continues to find the cost minimization examples and related supporting information provided by NS Power to be useful and informative, and it remains important to track. As such, the Board directs NS Power to continue to provide such information in subsequent ACE Plan applications, per Directive 7 of the Board's 2023 ACE Plan Order. Further, the Board continues to encourage NS Power to incorporate its cost minimization successes into future capital project planning to ensure improvements in cost minimization, schedule adherence, and risk management.

[152] The cost minimization information associated with Directive 7 from the Board's *2023 ACE Plan* Order is to include specific examples of cost minimization practices used during the execution and construction of the prior year's projects, fully describing specific cost minimization efforts, complete with a description of the cost savings accrued by these efforts. This information is to be presented in the format used in Section 11.1.5 and Appendix F of the *2022 ACE Plan* application. Projects selected for inclusion in the cost minimization examples are to meet the criteria identified in NS Power's 2021 Stakeholder Engagement Report. Further, NS Power is to report on any new cost minimization techniques that it adopts.

[153] NS Power provided this information in Appendix E of its 2025 ACE Plan application. Section 11.1.4 of NS Power's 2025 ACE Plan application also summarized the capital cost minimization efforts undertaken by the Company over the past year. The savings related to these efforts were grouped into the following categories: Design and Project Scoping; Procurement Process/Negotiated Savings; and Project Execution/Construction Efficiencies. For each of these categories, Appendix E described specific project cost minimization examples (36 in total) that were completed to help achieve these project cost savings. The total project cost savings NS Power assigned to these efforts was roughly $3.9 million, as presented in Figure 60 of the application. NS Power also noted that while not included in the referenced $3.9 million costs savings, the Company also secured government funding for multiple projects, leading to additional savings in excess of $125 million.

[154] NS Power's 2025 ACE Plan application stated that cost minimization is embedded into all stages of capital project development and execution. The Company also noted that it continues to follow its processes through project development and execution, leveraging resources and procurement across multiple projects to minimize costs. As it stated in its *2024 ACE Plan* application, NS Power believes that these practices continue to be the primary means of achieving capital cost minimization, with the largest benefit of these achieved in the early stages of project planning.

[155] As it relates to NS Power's project cost minimization efforts, Mr. Wilson's evidence stated that compared to prior ACE Plan proceedings, NS Power has demonstrated more specific and actionable information that is capable of being replicated in future projects. He further noted that, for the most part, NS Power's costs minimization

activities identified in the 2025 ACE Plan reflect specific, proactive initiative or deviation from initial plans to achieve a more cost-effective result. Mr. Wilson also stated that NS Power's post-project reviews show active identification of lessons learned to achieve more cost-effective results. Mr. Wilson recommended that the Board recognize NS Power's improvement in tracking cost minimization and conducting post-project reviews.

[156] In their evidence, Mr. Athas and Mr. Pelzer noted their concerns related to NS Power's statement about project costs savings associated with obtaining government funding. They believe that this statement blurs the line between true cost minimization efforts and those that seek to obtain external funding. They stated that identifying and recognizing efficiencies within NS Power is fundamentally different than seeking external project funding that aligns with the Company's strategic goals. As such, Mr. Athas and Mr. Pelzer recommended that the Board require NS Power to confirm that it has equated access to government funding with cost reductions due to achieving operational efficiencies and submit revised data in the 2025 ACE Plan application, and any related filings, that show cost savings with and without access to government loans or other sources of funding.

2.6.2.1 Findings

[157] The revised PDM quality control checklist filed in NS Power's Rebuttal Evidence appears to satisfy the concerns expressed by Mr. Wilson in his evidence. However, the Board's 2024 ACE Plan directive stated: "Revise NS Power's PDM to include a quality control step to verify that maturity matrices, risk registers, and other relevant documents are accurate and have been appropriately relied upon in reaching relevant conclusions." The Board questioned the Utility about how the checklist satisfies

this directive related to verifying the accuracy of the associated documents and that they have been appropriately relied upon:

> **Q.** (Murphy) In the Board's directive last year, the Board directed Nova Scotia Power to revise its PDM to include a quality control step to verify that maturity matrices, risk registers and other relevant documents are accurate and have been appropriately relied upon in reaching relevant conditions.
>
> And I'm just wondering how this checklist actually addresses that by providing verification that the related documents have been appropriately relied upon.
>
> …
>
> **A.** (Beaton) So I would say this is the -- this checklist that we provided really drives the behaviour on that, and so this checklist gets submitted with every capital project whether it's a capital project being filed with the Board for approval or just it's a project less than a million and just being approved internally.
>
> Where this gets included in each one of those, it draws the behaviour of a proper review of all of those documents, whether it's a maturity matrix or the cost estimate, and it's really on my team, the capital planning team, to ensure that through the review of -- the approval process review that we're ensuring that those documents are properly filled out and properly relied upon 1 when developing a project estimate.
>
> **Q.** So is there a formalized process or steps within the PDM now that outlines that process?
>
> **A.** (Beaton) I wouldn't say -- it's not a formalized process because it's the review. It's an approval requirement. We certainly -- I think if we were to put a process, it would probably just be expanding on this saying this document needs to be reviewed to make it by the capital planning team ahead of approval to ensure the proper analysis was done and it's informing the decisions in the project, but that won't necessarily change the behaviour. It's really just this is the impetus to force -- to make sure everyone's aware of the requirement, step one.
>
> It makes sure that it's submitted in the first initial step so we don't have to chase it and then the capital -- my team, the capital planning team, is well aware what needs to get reviewed as part of any capital approval.
>
> So we certainly are confident that the requirement's being met but understand that this document may not meet your expectations related to that directive.
>
> [Transcript, pp. 352-355]

[158] The Board understands NS Power's response in this exchange but notes that the Utility's last statement is correct. The checklist does not satisfy the expectations of the Board. Consequently, the Board repeats its directive from its *2024 ACE Plan* Decision and directs the Utility to incorporate provisions in its PDM to include a quality

control step to verify that maturity matrices, risk registers, and other relevant documents are accurate and have been appropriately relied upon in reaching relevant conclusions. NS Power is directed to report on this PDM update in its 2026 ACE Plan application.

[159] As per its findings in *its 2024 ACE Plan* Decision, the Board finds that the examples provided in Appendix E of the 2025 ACE Plan application continue to provide clear evidence of the continued effort by NS Power to minimize costs during capital project execution. In particular, the examples provide relevant and meaningful examples of NS Power's cost minimization through all phases of capital project execution. The Board also agrees with Mr. Wilson and commends NS Power for its improved and ongoing efforts related to tracking cost minimization and conducting post-project reviews.

[160] In its application, NS Power noted that since its cost minimization efforts are shared, considered and actively included in its budgeting process for future capital projects, this will likely result in diminishing opportunities to further reduce costs for similar projects going forward. As such, this may result in fewer or less impactful examples of cost minimization as the Company continues to track this information. The Board agrees with this assertion. As a result, and given the apparent improvement over time in tracking cost minimization and conducting post-project reviews, the Board finds that continued regular reporting of the Company's cost minimization examples is no longer necessary. As such, at this time the Board will not direct any further Appendix E cost minimization reporting in subsequent ACE plan applications. Nonetheless, NS Power should continue internal tracking and documentation of Appendix E data, recognizing the importance of cost minimization, and in the event the Board directs such reporting in a future proceeding.

[161] In response to the IG’s IR-15, NS Power stated that it considers cost minimization successful when it successfully pursues and secures external funding opportunities which offset capital costs on behalf of customers. Further, in its Rebuttal Evidence, the Company noted that it does not equate access to external funding with cost reductions associated with achieving operational efficiencies. Instead, NS Power believes that the process to successfully achieve external funding is a valuable cost minimization activity. The Board agrees that successfully obtaining external capital project funding by NS Power results in lower project costs for customers, and is, therefore, an important cost minimization tool. As such, the Board finds that it is not necessary to implement the recommendation of Mr. Athas and Mr. Pelzer related to reporting on capital project cost savings with and without external funding sources.

[162] This notwithstanding, the Board notes the following excerpt from NS Power’s Rebuttal Evidence:

> The Company notes that through its ACE Plans, irrespective of the level of expenditure, the Board has oversight over all capital projects. NS Power could commit to highlighting projects that have secured external funding for the NSEB and stakeholders to ensure there is ample opportunity to ask IRs and questions through the course of annual ACE Plan processes.
>
> [Exhibit N-14, p. 52]

[163] The Board believes that such a commitment would provide valuable information for the Board and stakeholders when reviewing capital project applications. Therefore, in future ACE Plan and capital approval applications, the Board directs NS Power to highlight the capital projects that have received external funding and to identify the amount of funding received.

2.7 Contingency and Contingency Guidelines

[164] Directive 7 of the Board's *2020 ACE Plan* Order directed NS Power to develop non-binding contingency guidelines "…describing how it determines when a capital cost estimate contingency amount is merited and at what level…" The Company issued the Non-Binding Contingency Guidelines (Contingency Guidelines) on November 20, 2020, and revised them on August 31, 2021. These Contingency Guidelines have been a point of review and discussion in subsequent ACE Plan proceedings.

[165] In its IR-4 in the *2024 ACE Plan* proceeding, the CA asked NS Power to identify a list of changes the Company believes would be appropriate in an update to the Non-Binding Contingency Guidelines. In response, NS Power stated:

> Changes are not required to the Non-Binding Contingency Guidelines (Guidelines) at this time. The Guidelines provide a high-level framework for how contingency is estimated, and when it should be applied, but do not prescribe the format or detail to be provided in capital work orders. Rather, consistent with the stakeholder engagement sessions held in the Fall of 2023, NS Power intends to include additional detail on the specific risks that are being considered as part of the contingency allocation, as well as a reference to similar projects that have been completed and are used in determining the percentage contingency to be applied. These two items are in addition to the expansion of the commentary within the Maturity Matrix.
>
> [Exhibit N-5, Response to IR-4(a)]

The Company also stated that as part of a separate contingency statement in capital work order applications, it was amenable to including information in Note 3 of the project detailed cost estimate, as well as referencing similar projects used to determine contingency and the specific risks that were considered as part of the contingency determination.

[166] In the *2024 ACE Plan* proceeding, Mr. Wilson identified constraints associated with providing contingency-related information in Note 3 of project detailed cost estimates. He, therefore, recommended that the Board endorse NS Power's offer to provide separate contingency statements in the description page of future capital work

order applications. The Board agreed, and, beginning with the 2025 ACE Plan application, directed NS Power to include a separate contingency statement in the description page of its capital work order applications instead of using Note 3 in the detailed cost estimates. In its 2025 ACE Plan application, NS Power confirmed that it has adopted and used this approach and will do so moving forward.

[167] In his evidence, Mr. Wilson stated that NS Power's new approach appears to have facilitated clearer and more supportive contingency allowances. He also noted that the Utility's non-binding contingency guidelines now appear to be an effective tool in both providing clear budgets for the Board's review and supporting cost minimization outcomes. Further, after reviewing the project contingency statements in the 2025 ACE Plan, Mr. Wilson did not identify any unsupported contingency amounts in the projects presented for Board approval.

2.7.1 Findings

[168] The Board accepts NS Power's change to its contingency statement approach in capital work order applications and expects the Utility to continue using this approach moving forward.

[169] With regard to the contingency amounts included in the project costs for which NS Power seeks Board approval in the 2025 ACE Plan application, the Board finds them appropriate. However, an issue arose during the proceeding related to the four transmission line replacement and upgrade projects for which NS Power sought Board approval. The contingency statement for each of these projects states:

> Contingency is determined using a combination of internal subject matter expert judgment (professional engineers and field personnel) based on previous line replacement and upgrade experience and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency value appropriate to that range. Risks intended to be covered by this contingency are additional overtime work that may be required to complete the project within the available outage

> window, unforeseen material or contract cost increases, or unforeseen costs related to accessing structures in wet or remote locations. NS Power completes approximately 8-10 of these Transmission Line Replacement and Upgrade projects each year and generally experiences cost pressures in the 8-15 percent range above the NSUARB approved project budget which generally used a 10 percent contingency amount. Based on these past similar projects and recent volatility in material pricing, an increased contingency of 15 percent is being applied to this project.
>
> [Exhibit N-1, p. 195]

[170] In response to CA IR-16c), NS Power provided a table (Attachment 1) depicting the approved project budget without contingency, the approved contingency amount, and the actual final cost for each of the eight transmission line replacements and upgrade projects approved by the Board since the *2021 ACE Plan* and since completed. The Attachment shows that the projects had an average actual underspend of 12.96% compared to the approved budget inclusive of contingency. When contingency is excluded from the approved budget amount, the projects had an average actual underspend of 2.90%.

[171] This presented a concern to the Board, given the actual average spending for these types of projects has been appreciably less than the Board-approved budget, yet NS Power has included a 15% contingency for these projects in the 2025 ACE Plan. This issue was canvassed during the hearing:

> **Q.** (Murphy) So my question is, really, you have some cost history here of eight projects, similar projects, where they've been under budget by roughly three percent excluding the contingency amounts. If you include the contingency amount, they're under budget by 12 percent. So my question is, really, why do you continue to believe that 15 percent's an appropriate contingency to use on these projects?
>
> **A.** (Beaton) So I think the first thing I think this highlights (a) I think we need to update the wording a little bit in the contingency statement because the thought behind that average amount of contingency used that we put in the contingency statement, that would really be related to projects that experience cost overruns. If we were to take an average variance similar to this table, it would show or it would tell us that we probably shouldn't have any contingency on these projects, which we wouldn't think is appropriate.
>
> So if we look at the projects that have overspent their budget or -- including and not including continency, we feel that's a better barometer for determining that percentage, recognizing we didn't do a good job explaining that in the contingency statement and we can certainly make that more clear on a go forward.
>
> [Transcript, pp. 295-296]

[172] While this exchange does provide some clarity, the Board remains concerned about the amount of contingency included in transmission line replacement and upgrade projects submitted for Board approval. As such, in the 2026 ACE Plan application, the Board directs NS Power to include an updated Attachment 1 of NS Power's response to CA IR-16c), to include any additional transmission line replacement and upgrade projects completed since filing of the 2025 ACE Plan application.

2.8 Capital Expenditure Justification Criteria Changes

2.8.1 Justification for Authorization to Overspend

[173] NS Power appended the current Summary and Detailed versions of the CEJC, with proposed amendments, as Appendix H to the application. NS Power requested "…Board acceptance and approval of amendments to the CEJC detailed and summary versions, respectively." The IG took no position on the proposed amendments but requested clarity about the ATO and Scope Change processes under the CEJC.

[174] The IG raised the following issues: the timing of ATO applications under the CEJC; the lack of any NS Power written policy which can assist in determining the reasonableness of an overspend nor what is required in an ATO application; the lack of any definition of Scope Change and uncertainty about what qualifies as a Scope Change. The IG's main concerns related to the need to clearly be distinguished between ATOs and Scope Changes, the need for clarity about when an ATO had to be filed and the criteria for ATO approval.

[175] Section 12.3 of the CEJC requires that if there are variances of more than 5% or $250,000 from the Board-approved annual amounts for routine capital expenditures, an ATO must be filed in the first half of the following year. The situation is somewhat more flexible for individual capital items that are not part of ACE Plan routine

capital expenditures. Pursuant to s. 12.1 of the CEJC, ATOs for these individual capital items must be submitted within six months of exceeding the Board-approved amounts "…if NS Power intends to include costs in excess of Board approval in its regulated rate base." Section 11.3 of the CEJC says that if no approval is sought within the six-month period, the excess amount must be removed from the rate base.

[176] The CEJC specifies that the following must be included in an ATO application for individual capital items: updated Board approval sheet reflecting the revised project amount if applicable; revised Capital Item Description Page reflecting the revised project costs; cost support for the ATO request (if applicable); and updated economic analysis and/or production costing modelling results (if applicable).

[177] Scope Change applications are addressed in s. 12.2 of the CEJC to address "…a change in scope as compared to the previously Board-approved scope." This is like the description of Scope Change in s. 10.0 of the CEJC. Section 12.2 specifies that documentation like what is needed for an individual capital item ATO is required.

[178] The IG asked for a Board directive about a consultative process to be initiated by NS Power to amend the CEJC to address the ATO and Scope Change provisions. This was in addition to the previously discussed request about integrating reliability criteria to justify the increased expenditures related to reliability-based projects into the CEJC. The IG asked that amendments be filed with the next ACE Plan.

[179] NS Power agreed to consult stakeholders about incorporating a definition of Scope Change in the CEJC. While NS Power said it was always open to discussing potential refinements to the CEJC, it did not agree that amendments to the ATO provisions were required. NS Power's main points were:

- the ATO requirements are clearly spelled out;
- additional timeline requirements are not needed and could be counter-productive if they resulted in premature applications; and
- the Board has established a long series of precedents about what criteria must be met for an ATO approval, therefore, prudency criteria did not need to be incorporated in the CEJC.

[180] The Board is satisfied that there is no need to revisit the ATO provisions at this time. NS Power files numerous ATO applications during a year. The information requirements are like an original application. As with original capital applications, when the amount of the ATO warrants it, a public hearing process is initiated. That said, like with original capital applications, in most cases, the ATOs are processed internally by the Board. If Board staff are not satisfied with the information provided by NS Power, IRs are issued. The Board reviews the ATO applications to determine if an increase in the approved amount is justified. This is based on the same necessity, prudency and cost justifications as would be applicable to an original application. The Board is satisfied with how this process functions.

[181] With respect to timing, there must be a balance between timely applications and the need to have sufficient information about a final estimate on costs to avoid numerous proceedings about the same project. The Board does not currently believe hard and fast rules about the timing of applications for individual projects are needed, or necessarily desirable.

[182] The Board acknowledges hydro dam projects have perhaps seen the most dynamic cost estimate evolution. Examples include the Tusket Main Dam Refurbishment Project and the Gaspereau Dam Refurbishment Project. ATO applications are premature until solutions are found to address the issues involved in such matters, including

engineering solutions for dewatering, addressing aboriginal rights issues under s. 35 of the *Constitution Act*, and satisfying the applicable government permitting departments such as DFO. That said, the Board does follow developments on these types of projects by requiring updates on a regular basis.

[183] While there is an understandable urge for stakeholders to provide input at an earlier stage, NS Power is responsible for managing its capital works program. If it does not do so in a cost-effective manner, the ATO application can be rejected in whole or in part. As well, if the threshold amounts that trigger an ATO are met, no amount above what the Board approves goes into rate base if an ATO is not filed within six months. If NS Power spends beyond the approved amount, this is at shareholder risk.

[184] Because routine capital expenditures are reviewed on an annual basis in the ACE Plan, the requirement to file ATOs within six months is reasonable. Many of the Routines are based on annual costs averages and it is helpful to know what capital costs were actually approved for prior years.

[185] The Board is, therefore, satisfied with the ATO process in its current form and does not see the need, at this time, to direct a formal review through a stakeholder process. That said, the Board agrees that more clearly defining what constitutes a Scope Change would be beneficial. If circumstances reveal that a project cannot or should not proceed as originally approved by the Board, this seems materially different than an unexpected increase in costs to complete the original project. The Board would only warn that even with a Scope Change, sufficient cost certainty would be most beneficial before proceeding with an application.

[186] Based on the foregoing, the Board directs that NS Power consult with stakeholders about incorporating a definition of Scope Change in the CEJC with the goal of providing proposed amendments in the 2026 ACE Plan.

2.8.2 Voltage Sag

[187] As discussed previously, the Board does not approve the Detailed CEJC. Many of the same considerations about NS Power being responsible for the management of the Utility form the rationale for the Board not approving this level of detail. Nevertheless, the document is filed with the Board and a proposed amendment to the Detailed CEJC was discussed during the hearing. Board questioning focused on amendments to the Detailed CEJC about voltage sag parameters following a fault for the primary and secondary transmission systems. These parameters are the same in both cases:

> 7. From normal system conditions, following a fault, the minimum post-fault positive sequence voltage sag shall remain greater than 70% of nominal voltage, and shall not remain below 80% of nominal voltage for greater than 250ms during the 10s period following a fault.
>
> [Exhibit N-1, PDF p. 484]

[188] This deals with not only the depth of a voltage sag after a fault event, but the length of time it takes to clear it, measured in milliseconds. Both the depth of a voltage sag and the length of time for recovery impact such things as when generators start disconnecting to avoid system instability.

[189] The Board explored the origin of these metrics and whether they were sufficient to ensure reliable service and maintain adequate power quality. NS Power explained that the Northeast Power Coordinating Council, Inc. (NPCC) requires that each utility on the interconnected bulk power grid document their transient voltage criteria used to test its system. NPCC is a not-for-profit corporation in the state of New York responsible

for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC is one of six Regional Entities which, together with the North American Electric Reliability Corporation, make up the Electric Reliability Organization Enterprise. The geographic area covered by NPCC includes Nova Scotia, New Brunswick, Ontario, Quebec and seven New England states.

[190] The voltage sag criteria were developed in conjunction with New Brunswick Power which provides the reliability corridor between NS Power and the rest of the NPCC bulk electrical grid through the New Brunswick intertie. NS Power further confirmed these were not new criteria, but a codification of the existing ones to meet the NPCC requirement that the voltage sag criteria be documented. NS Power noted that NPCC does not actually approve the voltage sag parameters which have been in place in the Maritimes for some time. Periodically NS Power must demonstrate to NPCC that its transmission system meets the established criteria.

[191] NS Power explained that different utilities in different regions can have different transient voltage metrics based on different system designs and load. The Utility has explored other potential metrics but was satisfied that the criteria were appropriate for the NS Power system. NS Power re-evaluates these metrics periodically, for example, when it conducts system impact studies. NS Power further explained that changing the system design to accommodate more stringent metrics could involve significant capital investments. Finally, NS Power confirmed that the Company did not anticipate power quality issues based on the established voltage sag criteria.

[192] The Board explored this part of the Detailed CEJC from the perspective of understanding how the voltage sag parameters were established and seeking

confirmation that they were sufficiently stringent to avoid power quality issues. NS Power has provided the information sought. NS Power must remain vigilant to make sure that no power quality issues arise because of the chosen and longstanding criteria.

2.9 Application of Section 35AA (2) of the *Public Utility Act* to projects of more than $1,000,000 receiving external funding, reducing the net project expenditure

[193] The *PUA* establishes a threshold where NS Power must seek approval for capital projects. The relevant parts of ss. 35 and 35AA of the *PUA* establish this threshold:

> **35** **(1)** No public utility shall proceed with any new construction, improvements or betterments in or extensions or additions to its property used or useful in furnishing, rendering or supplying any service which requires the expenditure of more than two hundred and fifty thousand dollars without first securing the approval thereof by the Board.
>
> **(2)** When determining whether to grant approvals under subsection (1), the Energy Board shall consider the extent to which such approval accords with the purpose of the *More Access to Energy Act* and policy guidelines issued under this Act.
>
> **35AA** **(1)** In this Section and Section 35AB, "large-scale public utility" means a public utility with an annual revenue of one hundred million dollars or more.
>
> **(2)** A large-scale public utility is not required to secure the approval of the Board under Section 35 for new construction, improvements or betterments in or extensions or additions to its property used or useful in furnishing, rendering or supplying any service that requires the expenditure of one million dollars or less.

[194] NS Power is a large-scale public utility as defined in the *PUA*. In the past, the Board has interpreted ss. 35 and 35AA to mean that if the expenditure that forms part of a utility's rate base is less than the threshold amount, no Board approval is required. The Board has not allowed NS Power to include capital contributions made by third parties in the Utility's rate base. This means that the Utility cannot claim a rate of return, or a depreciation expense on that portion of a project's capital costs when establishing a revenue requirement for the purpose of setting rates.

[195] The IG submitted that only requiring capital approval applications where the capital cost net of third-party funding is more than $1 million is not a proper interpretation

of the relevant provisions. The IG summarized the relevant principles of statutory interpretation as follows:

> The Board should apply the modern principles of statutory interpretation. The predecessor to this Board recently summarized these principles in the Demand Side Management Cost Recovery Rider decision, *Nova Scotia Power Incorporated (Re)*, 2024 NSUARB 216 at paras 28-30, citing the leading decision in *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65. Summarizing:
>
> - Words of a statute must be read "in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament. [sic]
> - An administrative decision maker's interpretation of a statutory provision must be consistent with the text, context and purpose of the provision.
> - Guidance is also found in the *Interpretation Act*, R.S.N.S. 1989, c. 235, including ss. 9(1) and 9(5) which provides that every enactment shall be deemed remedial and interpreted to insure the attainment of its objects.
>
> [IG Closing Submissions, p. 11]

[196] The IG made the following points in support of her position that the total amount of the project costs establishes the threshold:

- the purpose of the *PUA* is well summarized in *Nova Scotia (Public Utilities Board) v. Nova Scotia Power Corporation*, 1976 CanLII 1234 (NSCA), at para. 17, where it was held that "…[t]he scheme of regulation established by the Act envisages and indeed compels control by the Board of all aspects of a utility's operation in providing a controlled service…"

- there are no qualifiers in the *PUA* threshold provisions that say that the threshold expenditure must be a net total or recoverable in rate base.

- the money obtained from third parties is under NS Power's control and the way it is spent is important to ratepayers.

- pursuant to s.35(2) of the *PUA*, the Board must now consider the policy directions in the *More Access to Energy Act*, S.N.S. 2024, c. 2, Sch. B (*MAEA*), which include competition, innovation, economical energy supply, coordinated and transparent energy-supply planning and sustainable development. This means there are important resource planning and energy supply considerations in capital approvals that go beyond costs to the Utility and its ratepayers.

- projects with a cost magnitude over $1 million could have ongoing impacts on ratepayers and must also be considered based on the overarching goals in s.35(2) of the *PUA*. Limiting approvals to projects based only on the impact on rate base does not align with the *PUA*'s oversight and resource planning objectives.

- it would be incongruous for the *PUA* to require approval for projects costing just over $1 million but not requiring approval for much more significant projects if government funding takes the amount recoverable in rates below the $1 million threshold.

- in all case, projects costing more than $1 million dollars should be subject to review, with the potential to discover inefficiencies, and the Board should decide whether the project is in the best interest of ratepayers and in accord with the policy directions in the *MAEA*.

[197] NS Power responded to the IG's arguments by indicating the Utility had always interpreted the threshold in s. 35AA of the *PUA* "…to be the net capital expenditures of the Utility, which have the potential to impact costs to customers." This is consistent with the approach the Board has taken to NS Power capital approvals in the past. NS Power went on to say it would defer to the Board's discretion and authority about the application and interpretation of s. 35AA of the *PUA*.

[198] NS Power addressed some of the issues about potential oversight gaps if projects with a significant capital cost are not scrutinized by the Board because of significant government funding. NS Power correctly pointed out that the prudency of capital expenditures can be reviewed in a general rate application. The Board would add that this would include the prudency of any investments, whether they are below the $1 million threshold or not, and the impact on operating costs for projects when viewed through the prudency lens.

[199] NS Power is correct that, in the past, the Board has only required capital cost approval applications under ss. 35 and 35AA of the *PUA* where the cost of the project, exclusive of third-party funding, exceeds the $1 million threshold. Historically, this appears to have been based on interpreting the word “expenditure” to mean NS Power’s net capital expenditures which impact ratepayer costs. This approach has never been challenged in a hearing or tested in a court proceeding. The IG has squarely raised the issue in this proceeding and, therefore, the Board will address it.

[200] *Vavilov,* cited by the IG*,* is a reaffirmation of the modern principle of statutory interpretation first adopted by the Supreme Court of Canada in *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27 at para. 21. In *Sparks* v. *Holland*, 2019 NSCA 3, at para. 28, the Nova Scotia Court of Appeal said the following about the modern principle of statutory interpretation:

> [28] This Court typically asks three questions when applying the modern principle. These questions derive from Professor Ruth Sullivan’s text, *Sullivan on the Construction of Statutes*, 6th ed (Markham, On: LexisNexis Canada, 2014) at pp. 9-10.
>
> [29] Ms. Sullivan’s questions have been applied in several cases, including *Keizer v. Slauenwhite*, 2012 NSCA 20, and more recently, in *Tibbetts*. In summary, the Sullivan questions are:
>
> 1. What is the meaning of the legislative text?
> 2. What did the Legislature intend?
> 3. What are the consequences of adopting a proposed interpretation?

[201] The IG is correct that the word “expenditure” in its grammatical and ordinary sense, is not limited to expenditures net of third-party contributions. Regardless of the source of the funding, it is NS Power that will expend funds required to acquire a capital asset or construct a project. The word “expenditure” is not expressly qualified by any language in the *PUA* which would limit its meaning to expenditures net of third-party funding. Reading in such a qualification might have been justified under historical views

about utility regulators being only charged with pure economic regulation. In this context, it could be argued that the Board need not concern itself with capital expenditures that do not impact rate base, depreciation expense or other aspects of the revenue requirement of a utility. However, while the Board's main role is as an economic regulator, it is not limited to a pure economic analysis of the least-cost alternative. This was discussed to some extent at paras. [88] to [93] in *Nova Scotia Power Incorporated (Re*), 2018 NSUARB 154 (CanLII) (affirmed in *Nova Scotia (Attorney General) v. Nova Scotia (Utility and Review Board), 2019 NSCA 66*). In addition, the regulatory scheme has been somewhat altered by s. 35(2) of the PUA, which only became effective on April 1, 2025. This amendment provides that when considering the approval of capital expenditures, the Board "… shall consider the extent to which such approval accords with the purpose of the *More Access to Energy Act*…"

[202] As discussed in the IG's Closing Submission, in addition to the traditional least-cost option approach to public utility regulation, the Board can now consider such factors such as competition, innovation, coordinated and transparent energy-supply planning and sustainable development. These involve broader policy issues than pure economic regulation based on the least-cost option approach. Given the expanded nature of the factors the Board can consider, it would not be reasonable to take a restrictive approach when interpreting the word "expenditure". Restricting the meaning of the word "expenditure" would not appear to operate in harmony with the overall scheme of the current *PUA*. The Board believes some of the hypothetical examples provided by the IG, of very large expenditures with sufficient government funding to bring the project below the review threshold, appear highly unlikely. Nevertheless, material expenditures which

might impact on the policy factors outlined in the *MAEA* could be removed from the Board's review and stakeholder input, which would not be in keeping with the general policy direction in the current *PUA*. Also, the IG correctly points out that the original amount of a capital expenditure is not the only factor that can be considered in capital approval applications. Life cycle costs might conceivably mean that a somewhat more expensive option, without third-party funding, could be the better option. There is also the question of the overall benefit derived from various options. While these types of issues can be addressed in a prudency review, there is a benefit to having them vetted prior to the utility incurring the capital expenditure.

[203] Turning to consequences, adopting the interpretation proposed by the IG does not appear to have any material negative or unintended consequences. The situation where third-party funding brings a project below the monetary *PUA* threshold appears to have been historically rare. The suggested interpretation is unlikely to create material additional regulatory burden or other unintended consequences.

[204] After performing the interpretation analysis discussed in *Vavilov*, the Board finds that the word "expenditure" in s. 35 and 35AA of the *PUA* means an expenditure inclusive of any third-party funding. Therefore, NS Power is directed to submit any future capital expenditures that exceed $1 million for approval to the Board, regardless of the source of funding.

3.0 SUMMARY

[205] The Board approves NS Power's 2025 ACE Plan, except for C0051815 - RTU Replacements Program-Phase 6. The approved projects are listed in the attached

Schedule A. The Board has provided a directive about the RTU Replacements Program-Phase 6.

[206] The Board has requested further submissions on the issue of whether it is the capital cost of projects net of third-party funding that is used when considering the threshold amount requiring Board approval for capital expenditures under ss. 35 and 35AA of the *PUA*.

[207] The Board has provided comments on vegetation management, reliability and resiliency, NS Power's plan to meet the legislated goals of phasing out coal-fired generating plants and achieving 80% of electricity sales from renewable resources by 2030, the Mersey Hydro System, cost minimization, contingency matters, and the CEJC.

[208] The Board has the following directives in this matter:

1. The Board directs NS Power to provide annual updates on its progress with the Five-Year Reliability Plan in alignment with the ACE Plan. The Board also directs NS Power to provide an update on its evaluation of potential new reliability and resiliency metrics in the 2026 ACE Plan.

2. The Board directs that no further reporting on Normalized SAIDI be provided in future ACE Plans.

3. The Board directs NS Power to work with a Board-appointed expert and stakeholders to determine the scope of a third-party review of the Five-Year Reliability Plan and provide draft Terms of Reference to the Board as outlined in paragraph 78 of this Decision.

4. The Board directs NS Power to update the equivalent of Figure 3 in the 2025 ACE Plan application about priority distribution feeders in the 2026 ACE Plan.

5. The Board directs NS Power to provide an update on the CEATI Grid Resiliency working group in the 2026 ACE Plan.

6. The Board directs NS Power to monitor the installation of 40 to 50 upgraded class poles across the Utility's four operating regions, and to provide a post storm

evaluation to determine pole status, survival rate, impact on customer outages, and whether the upgraded class improved the resilience of the wooden poles.

7. The Board directs NS Power to file an update to *The Path to 2030* in the 2026 ACE Plan.

8. The Board directs NS Power to provide a comprehensive update on the Mersey Hydro System Redevelopment Project in the 2026 ACE Plan. The Board also expects the NPV analysis referenced in NS Power's Rebuttal Evidence to be included as part of this update.

9. In addition to filing an NPV analysis comparing the Mersey decommissioning option to the redevelopment option per the Board's *2024 ACE Plan* direction, the Board directs NS Power to file an NPV analysis comparing the partial decommissioning option to the redevelopment option, complete with a description of all assumptions used in the analysis. The analysis is to be filed in the ACE Plan application that follows NS Power's filing of its next depreciation study. If NS Power does not file its next depreciation study with the Board prior to filing the 2026 ACE plan, the Board expects the Company to provide an update on the activities it conducted since the filing of the 2025 ACE Plan related to evaluating and costing the MHS decommissioning and partial decommissioning options.

10. The Board directs NS Power to include cost estimates for further preliminary engineering work, Mi'kmaq and stakeholder engagement and environmental studies, detailed engineering design costs, and procurement costs, in its Mersey system update in the 2026 ACE Plan. These cost estimates are also to be included in NS Power's filing of its NPV analysis comparing the Mersey Redevelopment Project to the decommissioning and partial decommissioning options.

11. The Board repeats its directive from its *2024 ACE Plan* Decision and directs the Utility to incorporate provisions in its PDM to include a quality control step to verify that maturity matrices, risk registers, and other relevant documents are accurate and have been appropriately relied upon in reaching relevant conclusions. NS Power is directed to report on this PDM update in its 2026 ACE Plan application.

12. The Board directs NS Power to submit any future capital expenditures that exceed $1 million for approval to the Board, regardless of the source of funding.

13. In the 2026 ACE Plan application, the Board directs NS Power to include an updated Attachment 1 of NS Power's response to CA IR-16c), to include any

additional transmission line replacement and upgrade projects completed since filing of the 2025 ACE Plan application.

14. The Board directs that NS Power consult with stakeholders about incorporating a definition of Scope Change in the CEJC with the goal of providing proposed amendments in the 2026 ACE Plan.

[209] An Order about the directives will issue accordingly.

DATED at Halifax, Nova Scotia, this 19th day of August 2025.

Richard J. Melanson

Steven M. Murphy

Jennifer L. Nicholson

Schedule "A"

SCHEDULE "A" 2025 ACE Plan Approved Projects			
CI Number	Title	2025 Budget	Project Total
	Generation		
C0048990	HYD AVO 2 Switchgear Replacement	$1,254,513	$1,814,631
C0039266	HYD - Gulch Overhaul	$962,156	$1,371,379
C0068882	TUC1 Generator Refurbishment	$1,869,353	$2,124,211
C0068887	TUC3 Turbine Valves Refurbishment	$1,869,104	$1,869,104
C0068659	TRE5 - IP-LP Turbine Refurbishment	$1,175,875	$1,282,670
	Transmission		
C0031048	91H-T11 Transformer Replacement	$5,837,478	$6,914,622
C0068961	2025 PCB Substation Sampling and Replacement	$4,680,871	$6,650,933
C0069232	L6021 Replacements and Upgrades Phase 1	$1,080,940	$3,253,068
C0069227	L6516 Replacements and Upgrades Phase 3	$478,214	$3,104,925
C0069231	L8002 Replacements and Upgrades Phase 1	$798,306	$3,093,176
C0070048	L5027B Replacements and Upgrades Phase 1	$1,184,984	$2,916,728
C0053295	L5004 Kearney Lake Structure Replacement	$1,101,784	$2,478,537
C0069238	2025/2026 Steel Tower Refurbishment	$715,698	$2,337,250
C0057682	Spare Transformer Replacement	$2,046,568	$2,286,389
C0050852	10V-T1 Transformer Replacement	$1,933,466	$2,113,337
C0050834	Spare EHV Breaker Replacements	$317,190	$1,178,832
	Distribution		
C0068952	2025 PCB Poletop Sampling and Replacement	$3,689,063	$7,158,974
C0068953	2025 PCB Light Replacement	$3,900,672	$4,225,224
C0068954	2025 PCB Downline Device Sampling and Replacement	$1,129,576	$1,716,718
C0068786	2025 Padmount Replacement Program	$1,038,460	$1,354,219
C0070787	91W-411 Labelle Road Phase Extension	$762,420	$1,150,616
	General Plant		
C0070907	MDR-8000 Microwave Radio Replacement	$511,996	$1,572,478
C0069270	2025 SCADA/EMS Upgrade	$749,671	$1,306,288
	TOTAL APPROVED AMOUNT	**$39,088,358**	**$63,274,309**