Nova Scotia Energy Board

IN THE MATTER OF Section 35A of *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Inc. for Approval of the **2026 Annual Capital Expenditure (ACE) Plan**

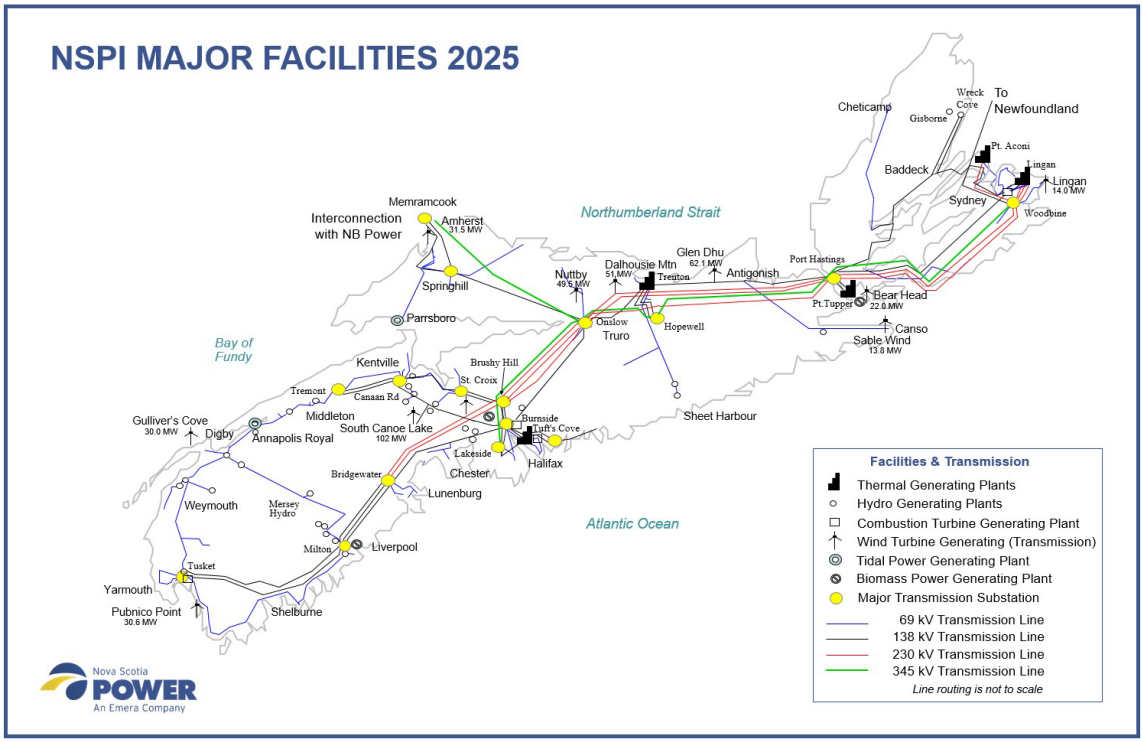
2026 ACE Plan

Date Filed: December 12, 2025

CONFIDENTIAL (Attachments Only)

Nova Scotia Power

2026 Annual Capital Expenditure Plan


NSPI MAJOR FACILITIES 2025
Cheticamp
Wreck Cove
To Newfoundland
Gisborne
Pt. Aconi
Baddeck
Lingan
Lingan 14.0 MW
Sydney
Woodbine
Memramcook
Interconnection with NB Power
Amherst 31.5 MW
Northumberland Strait
Glen Dhu 62.1 MW
Dalhousie Mtn 51 MW
Trenton
Nuttby 49.5 MW
Antigonish
Port Hastings
Springhill
Parrsboro
Onslow
Truro
Hopewell
Pt.Tupper
Bear Head 22.0 MW
Canso
Sable Wind 13.8 MW
Bay of Fundy
Kentville
Brushy Hill
St. Croix
Tremont
Canaan Rd
Middleton
Gulliver's Cove 30.0 MW
Digby
Annapolis Royal
South Canoe Lake 102 MW
Burnside
Tuft's Cove
Lakeside
Halifax
Sheet Harbour
Bridgewater
Chester
Lunenburg
Weymouth
Mersey Hydro
Milton
Liverpool
Atlantic Ocean
Tusket
Yarmouth
Pubnico Point 30.6 MW
Shelburne
Facilities & Transmission
Thermal Generating Plants
Hydro Generating Plants
Combustion Turbine Generating Plant
Wind Turbine Generating (Transmission)
Tidal Power Generating Plant
Biomass Power Generating Plant
Major Transmission Substation
69 kV Transmission Line
138 kV Transmission Line
230 kV Transmission Line
345 kV Transmission Line
Line routing is not to scale
Nova Scotia POWER
An Emera Company

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1.0 EXECUTIVE SUMMARY

The Nova Scotia Power Incorporated (NS Power, Company) Annual Capital Expenditure (ACE) Plan Application provides customers, the Nova Scotia Energy Board (NSEB, Board), and other stakeholders with a comprehensive and transparent overview of the Company's intended capital investments for the year ahead.

NS Power is focused on providing customers with safe and reliable electric service in a cost-effective manner. The capital investments proposed under the 2026 ACE Plan are aligned with these key objectives and continue to be vetted and planned in compliance with the NSEB-approved Capital Expenditure Justification Criteria (CEJC).

NS Power's total capital budget for 2026 (inclusive of capital projects under $1,000,000 as well as previously approved multi-year project profiles) is $702.1 million. In this Application, within the overall 2026 capital budget, NS Power is requesting NSEB approval of 20 capital work orders with total project investment of $76.7 million and the 2026 capital routine program of $207.3 million for an aggregate total of $284.0 million.

The provincial government released its 2030 Clean Power Plan in October 2023, which aligns with NS Power's Evergreen IRP Action Plan & Roadmap Update. Together, these documents outline the various investments and actions required to achieve the 2030 Decarbonization Goals. In 2024, the creation of a new Independent Electricity System Operator in Nova Scotia (IESO-NS) changed the electricity planning landscape in Nova Scotia, and starting in 2025, the IESO-NS has begun taking on its responsibilities of planning and management of Nova Scotia's bulk electricity system. This change has resulted in several amendments to project accountability in NS Power's *The Path to 2030* report. The Company continues to engage with both federal and provincial governments to meet the 2030 decarbonization targets in a way that is as cost-effective as possible for customers and remains committed to supporting the transition of accountabilities to the IESO-NS, as applicable. In accordance with the Board's 2025 ACE Plan directive, an update to NS Power's *The Path to 2030* report is provided as **Appendix F**.

In preparing its capital plans, NS Power utilizes its established asset management approach, and considers safety, reliability, climate change adaptation, and affordability, while incorporating the Company's decarbonization targets. The Company's asset management approach is detailed in **Section 3.0**.

Reliability and resiliency were a large focus in the 2025 ACE Plan (among other recent proceedings). The Company's approach to improving customer reliability is focused on balancing optimized investments with affordability for NS Power's customers. This means that various teams and committees across NS Power work closely together with the NS Power Reliability team to prioritize and execute programs aimed at driving reliability improvements for NS Power's customers and making the system more resilient in the face of climate change. Following the Board's direction in the 2023 Performance Standards process, NS Power filed its Five-Year Reliability Plan on December 20, 2024, and it was reviewed and considered as part of the 2025 ACE Plan process. In accordance with the Board's 2025 ACE Plan directives, **Section 11.1.4** has been updated, and an update to NS Power's Five-Year Reliability Plan is provided as **Appendix G.**

The investments in the 2026 ACE Plan:

- Provide benefits to communities throughout the province, including reliability-focused improvements to the transmission and distribution (T&D) system and responses to reliability challenges arising from increasingly frequent and severe weather events. The focus for all of the teams supporting the T&D system is prioritizing capital investments that enhance customer reliability. These targeted reliability projects include vegetation management, storm hardening and reliability upgrades, targeted device replacements, and grid modernization.

- Support NS Power's business priority of safely delivering electricity service to customers. Safety compliance projects in the 2026 ACE Plan include upgrades to hydro dam safety, fire suppression systems, and guard rail systems.

- Continue to support ongoing environmental compliance, such as the maintenance of hydro and wind renewable energy resources, remediation of equipment containing polychlorinated biphenyls (PCBs) and management of asbestos through corresponding recurring capital programs aligned with regulation timelines.

- Align with planning for coal phase-out and achievement of the 80 percent renewable electricity standard by 2030. This includes making prudent investments to ensure continued reliability amid increasing load demands, while managing thermal assets that may be retired or repurposed by 2030.

The 2026 ACE Plan also addresses the directives arising from the 2025 ACE Plan Decision.[1]

Consistent with recent practice, NS Power intends to host a technical conference following submission of the 2026 ACE Plan to address any questions from intervenors after their initial review and prior to the issuance of information requests (IR).

[1] Please refer to Section **4.0**.

2.0 2026 ACE PLAN STRUCTURE

The following provides an overview of how the 2026 ACE Plan is organized.

- **Section 3.0** – **Introduction** – This section provides a high-level summary of the overall expenditures in the 2026 ACE Plan, including a breakdown of expenditures into various categories such as sustaining and strategic capital, as well as a forecast of expenditures in those categories for the next five years.

- **Section 4.0** – **2025 ACE Plan Follow-Up** – This section addresses the status of items from the 2025 ACE Plan, including a list of capital items pending submission in 2025 from the 2025 ACE Plan, and the 2025 ACE Plan deferred and cancelled items.

- **Section 5.0 – 2026 ACE Plan** – This section provides a summary of 2026 capital expenditures. These include the list of projects for which NS Power is seeking approval, the list of projects forecast for subsequent submission, and the list of projects with a value of less than $1,000,000. NS Power is not seeking approval of those capital projects identified for subsequent submittal at this time. In addition, capital projects under $1,000,000 undertaken by large-scale utilities do not require NSEB approval under the *Public Utilities Act* (PUA); however, the Company includes them in its ACE Plan for informational purposes and to provide a complete picture of annual capital expenditures on NS Power's system.

- **Section 6.0** – **Generation** – This section lists all generation capital projects submitted for approval, as well as related carry-over spending. Generation assets generate electricity through a variety of methods and fuel sources, including hydro, coal, oil and gas, biomass, and wind.

- **Section 7.0** – **Transmission** – This section lists all transmission capital projects submitted for approval, as well as related carry-over spending. Transmission assets transmit

electricity from the generation plants to the distribution system throughout the province. Transmission includes assets and equipment operating at 69 kV level or higher, and also includes substation assets.

- **Section 8.0** – **Distribution** – This section lists all distribution capital projects submitted for approval, as well as related carry-over spending. Distribution assets include equipment for delivering electric energy from substations to customers served at voltages below 69 kV.

- **Section 9.0** – **General Plant** – This section lists all general plant capital projects submitted for approval, as well as related carry-over spending. General plant assets include computer infrastructure and communication equipment, which comprise the majority of capital expenditures in this category. Other items such as office equipment, vehicles, telecom, construction equipment and buildings (except generating and substation facilities) are also included within this category.

- **Section 10.0** – **Routine Capital Program** – This section lists all routine capital items submitted for approval, by generation, transmission, distribution, and general plant. Routine capital items are recurring annual expenditures for replacement of equipment (like-for-like replacement), additions to existing equipment base resulting from system growth, and addition of customers to the system.

- **Section 11.0** – **Directives and Miscellaneous –** This section provides information in response to the various directives issued by the Board in respect to the Company's ACE Plan over the years as well as other miscellaneous information previously included in the Company's Application. The Board's directives include requests for information on transmission and distribution investment reliability impacts, and the ranking of projects submitted in the ACE Plan for approval.

The 2026 ACE Plan also includes the following information provided as separate appendices:

- **Confidentiality Matrix (Appendix A)** – The confidentiality matrix provides a listing of capital items submitted for approval, their attachments, and their confidentiality status so that the Board may evaluate the confidential portions of the ACE Plan. NS Power has minimized the information for which it seeks confidential treatment in this Application in order to facilitate transparency.

- **Listing of all 2026 ACE Plan projects in Excel format (Appendix B)** – This provides the Board and interested parties a convenient reference of all expenditures in 2026, regardless of whether they are submitted for approval in the ACE Plan. Details include Capital Item Numbers (CI #s), names, functional class, and investment details.

- **Updated Q3 Capital Reports (Appendix C)** – NS Power's Q3 capital reports, submitted to the NSEB on November 14, 2025, have been updated with 2026 ACE Plan projects submitted for approval and subsequent submittal, and provided in Excel format. The updated Q3 capital reports provide a comprehensive listing of the status of all "active" projects (i.e., those that have been submitted to the Board or referenced on the ACE Plan subsequent submittal list and are currently underway).

- **Capital Expenditure Justification Criteria Update (Appendix D)** – Updates have been made to the Capital Expenditure Justification Criteria (CEJC) to address the Board's 2025 ACE Plan directive and additional updates have been recommended as well; a list of CEJC revisions, and updates in track changes for the Detailed and Summary CEJC are provided. In accordance with the Board's 2016 ACE Plan directive which requires stakeholder engagement of CEJC amendments prior to submission to the Board, and in accordance with the Board's 2025 ACE Plan directive specific to engaging with stakeholders to improve its definition of a Scope Change capital application, NS Power engaged with stakeholders and a summary of the engagement is provided in **Section 4.1**.

- **Mersey Update (Appendix E)** – In accordance with the Board's 2023-2025 ACE Plan directives, a comprehensive update on the Mersey Hydro Redevelopment Project is provided.

- **Path to 2030 Update (Appendix F)** – In accordance with the Board's 2024-2025 ACE Plan directives, an update on *The Path to 2030* report is provided.

- **Five-Year Reliability Plan Update (Appendix G)** – In accordance with the Board's 2025 ACE Plan directives, an update on NS Power's Five-Year Reliability Plan is provided.

- **Capital Approvals – PDM Documentation Review Process (Appendix H)** – In accordance with the Board's 2025 ACE Plan directives, a process document to guide the quality control review of capital documentation is provided.

- **Completed Transmission Line Replacement and Upgrade Projects (Appendix I)** – In accordance with the Board's 2025 ACE Plan directives, a list of transmission line replacement and upgrade projects that have been approved since the 2021 ACE Plan and completed is provided.

3.0 INTRODUCTION

3.1 2026 ACE Plan Summary

The Company's overall 2026 capital budget (inclusive of capital projects under $1,000,000 that do not require NSEB approval, carryover spending, capital routines, and subsequent submittal items) is $702.1 million. Within the overall 2026 ACE Plan budget, NS Power is requesting NSEB approval of 20 capital work orders and the 2026 capital routine program, for a total approval amount of $284.0 million.

Figure 1 and **Figure 2** below illustrate NS Power's overall capital budget for 2026 and total forecast capital spending for 2027 through 2030, as well as NS Power's total annual capital expenditures by function. The forecast for 2027 through 2030 includes the total cost of the projects and does not include considerations for external funding that is not already in place. While external funding for these initiatives is expected, the amount cannot be forecast at this time.

Figure 1: NS Power Total Capital Investment: Historical, Budget and Forecast
(Millions of Dollars)

F = Forecast, B = Budget in above figure

Figure 2: Total Annual Capital Expenditures by Function

(Millions of Dollars)

	Actuals						ACE Plan	Forecast			
Year	**2021**	**2022**	**2023**	**2024**	**2025 Q3F***	**2025 ACE Budget**	**2026**	**2027**	**2028**	**2029**	**2030**
Generation	$157.7	$194.4	$147.0	$142.1	$203.4	$188.1	$178.2	$211.6	$229.8	$207.2	$184.9
Transmission	$56.9	$56.2	$97.8	$89.6	$239.9	$256.5	$241.1	$233.1	$216.4	$171.9	$116.8
Distribution	$116.1	$209.9	$148.5	$141.7	$179.3	$182.6	$190.5	$195.9	$201.3	$228.4	$201.3
General Plant	$56.9	$79.6	$57.8	$59.7	$76.5	$65.1	$92.4	$83.7	$125.3	$105.0	$86.5
Total	**$387.6**	**$540.2**	**$451.1**	**$433.1**	**$699.1**	**$692.4**	**$702.1**	**$724.3**	**$772.8**	**$712.5**	**$589.5**

Note: Totals may be off by $0.1M due to rounding.
*The 2025 Q3 Forecast includes actuals up to July and forecast amounts for the remainder of the year.

NS Power's capital investments in the 2026 ACE Plan focus on maintaining and improving existing system performance, as well as supporting the province in executing on the Clean Power Plan. NS Power continues to make timely investments based on equipment condition and criticality to maintain the performance of assets for customers while in parallel continuing to develop and implement the investments that are necessary to positively transform the power system by the end of the decade.

Generation, transmission, distribution, and general plant projects in the 2026 ACE Plan are subject to the Board-approved project selection and asset management methodologies pursuant to Section 6.2 of the CEJC. All projects brought forward for approval and completion have been vetted to ensure each provides value to customers per the CEJC.

As shown in **Figure 3** and **Figure 4** below, the projected costs associated with Sustaining Capital, Customer/Load Driven, and the ECEI – Synchronous Condenser projects comprise the largest

investment types for 2026. NS Power's investments toward sustaining the Company's assets, customer driven investments required for load growth, investments required by regulatory or environmental standards, and investments for right-of-way widening are forecast to remain relatively stable over the next five years. These figures are the Company's current forecast. The accuracy of these estimates will improve over time as new information informs the potential investments.

Figure 3: Breakdown of Capital Forecast by Investment Type

(Millions of dollars)

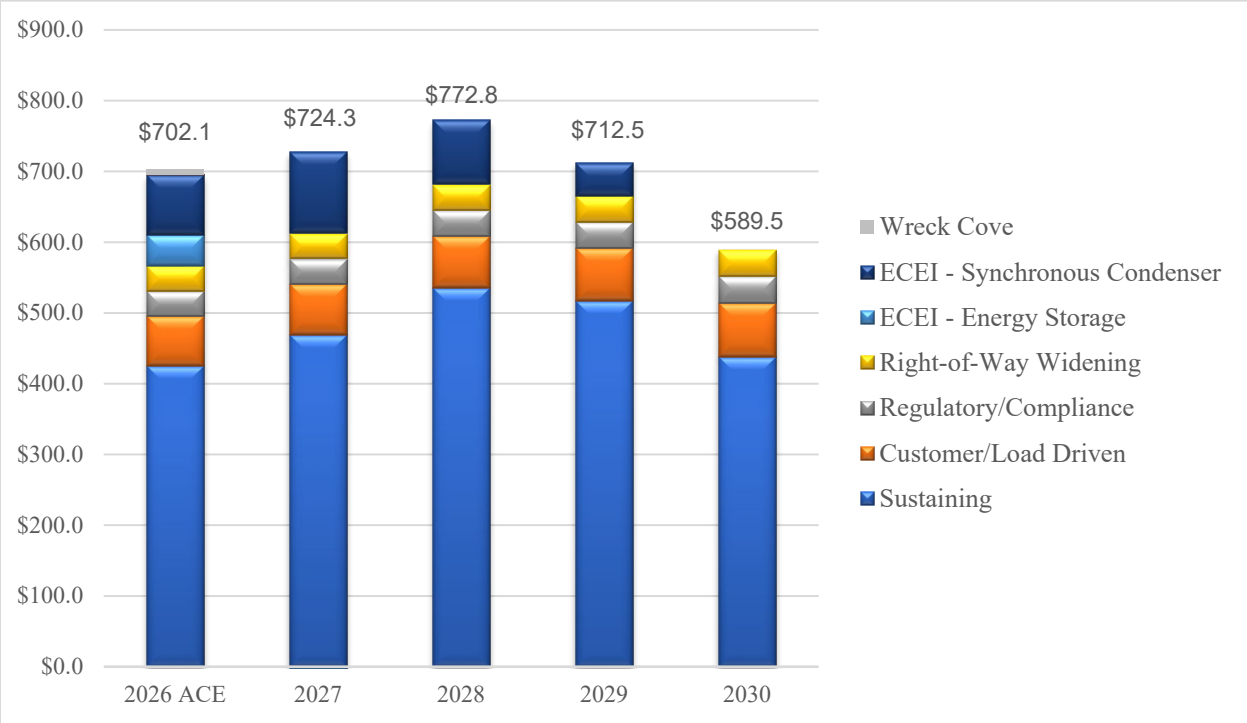


Figure 4: Breakdown of Capital Forecast by Investment Type

(Millions of dollars)

Investment Type	2026	2027	2028	2029	2030
Sustaining	425.3	475.4	541.9	523.5	444.5
Customer/Load Driven	70.6	72.0	73.5	74.9	76.4
Regulatory/Compliance	34.8	29.4	30.0	30.6	31.2
Right-of-Way Widening	35.1	35.4	36.1	36.7	37.4
ECEI - Energy Storage	44.2	(3.3)	-	-	-
ECEI - Synchronous Condenser	84.7	115.3	91.3	46.7	-
Wreck Cove	7.3	-	-	-	-
	$702.1	**$724.3**	**$772.8**	**$712.5**	**$589.5**

Note: Totals may be off by $0.1M due to rounding.

Figure 5: Breakdown of Capital Forecast by Investment Type

(Millions of Dollars)

Investment Type	2026	2027	2028	2029	2030
Generation Reliability	178.2	211.6	229.8	207.2	184.9
T&D Reliability	234.9	247.9	256.0	281.7	244.9
New Customer	67.7	69.0	70.4	71.8	73.3
Core	92.4	83.7	125.3	105.0	86.5
ECEI - Energy Storage	44.2	(3.3)	-	-	-
ECEI - Synchronous Condenser	84.7	115.3	91.3	46.7	-
	702.1	**724.3**	**772.8**	**712.5**	**589.5**

Note: Totals may be off by $0.1M due to rounding.

NS Power's Asset Management Mechanism

NS Power's Asset Management (AM) Mechanism, illustrated in **Figure 6**, is a foundational tool within the Company's Strategic Asset Management Plan (SAMP). It enables risk-informed decision-making by evaluating the criticality and condition to determine the level of risk associated with each asset. This mechanism supports the prioritization and selection of appropriate risk

mitigation strategies, ensuring alignment with NS Power's operational mission and delivering the greatest value to customers.

A clear understanding of both criticality and condition is essential to assess asset risk. Assets with risk scores of 15 or higher on the AM risk matrix (highlighted in red) require a mitigation plan. Mitigation strategies are selected based on primary risk drivers and may include:

- Capital investment
- Refurbishment
- Procurement of critical spares
- Monitoring and diagnostics
- Re-design
- Modification to maintenance or operating practices

While high-risk assets often warrant investment, not all require capital expenditure. Subject Matter Expert (SME) knowledge is applied to determine the most appropriate and cost-effective mitigation approach, considering affordability and execution feasibility.

Asset Criticality

Criticality reflects the consequence of failure and the asset's importance to achieving organizational goals. It is evaluated across three impact categories:

- Health & Safety – for personnel, service providers, and the public
- Environment – stewardship of natural resources and regulatory compliance
- Business Sustainability – reliability, resiliency, customer impact, and reputation

Criticality is generally stable but may be re-evaluated due to changes in asset mission, or operating modes. NS Power applies both intuitive and formalized methods (e.g., FMECA) to assess

criticality, particularly for new or complex assets. Assignments range from 1 (minor) to 5 (critical), as defined in the Capital Expenditure Justification Criteria (CEJC).

Asset Condition

Asset condition is evaluated using a multi-factor risk-based methodology, with ratings informed by health indicators, performance data, and field-level expertise, as defined in NS Power's Asset Management Plans and aligned with the Capital Expenditure Justification Criteria (CEJC). NS Power continues to enhance visibility into asset health through its Data Strategy, integration of systems such as GE APM and CMMS, and deployment of predictive analytics. Assignments range from 1 (rare) to 5 (almost certain), as defined in the Capital Expenditure Justification Criteria (CEJC).

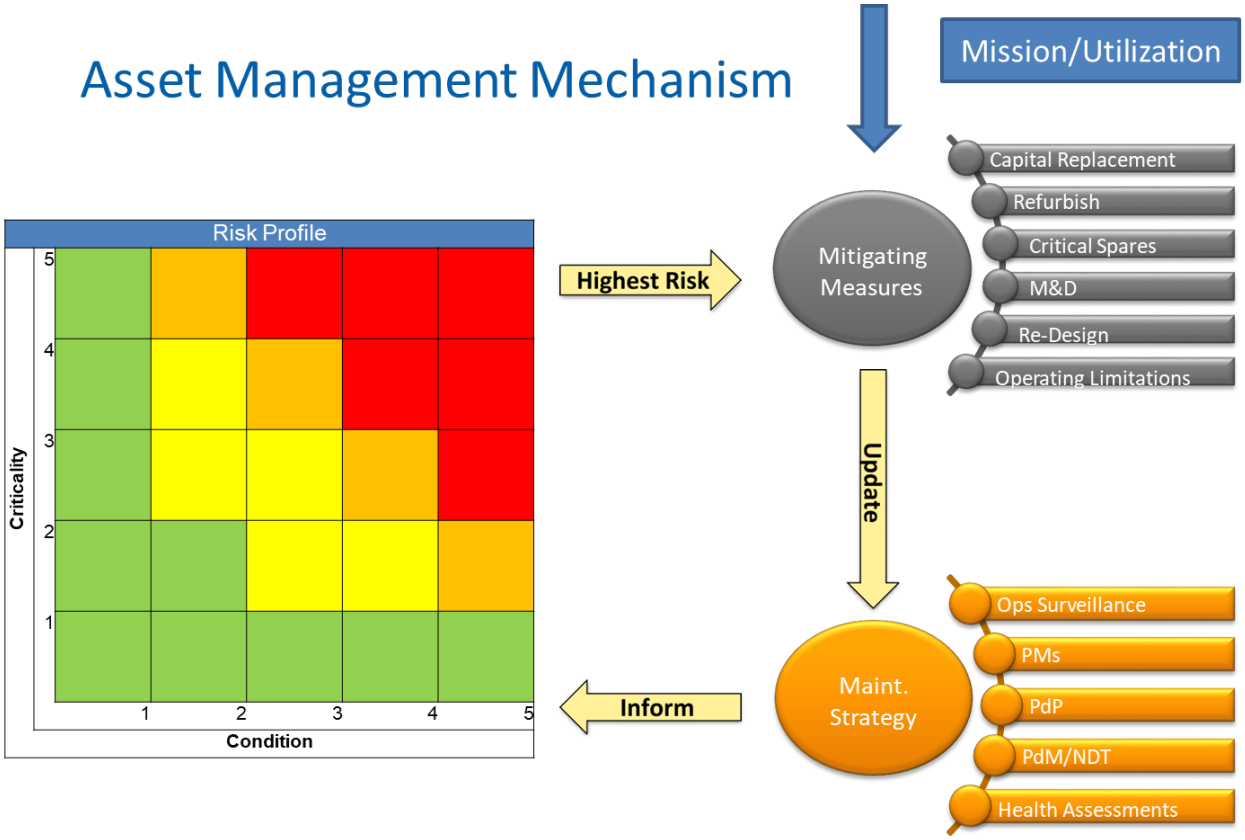
Risk Evaluation and Mitigation

The AM Mechanism normalizes risk across NS Power's asset portfolio, enabling consistent prioritization. Risk ratings are reviewed by asset strategy committees to ensure reasonability. High-risk assets (e.g., steam turbines) typically receive higher priority than low-consequence assets (e.g., redundant pumps). Final investment decisions also consider:

- Asset mission and utilization forecasts
- Execution feasibility and resource availability
- Customer affordability and regulatory context

Figure 6 below provides a visual representation of the AM Mechanism and its role in risk evaluation and mitigation.

Figure 6: Asset Management Mechanism



3.2 Relief Sought from the Board

NS Power respectfully requests Board approval of the following, in accordance with Section 35A of the PUA:

- 20 Capital Items with 2026 budget investment of $49.0 million and total project investment of $76.7 million (please refer to **Section 5.2**); and
- Capital routine programs with 2026 budget investment of $207.3 million (please refer to **Section 10.1**).

In addition, NS Power requests:

- Board acceptance and approval of amendments to the CEJC detailed and summary versions, respectively.

4.0 2025 ANNUAL CAPITAL EXPENDITURE PLAN FOLLOW-UP

This section addresses items arising from the 2025 ACE Plan. These items include a list of subsequent submittal capital items from the 2025 ACE Plan that are planned to be submitted before year-end, as well as items from the 2025 ACE Plan that have been deferred or cancelled.

The Board provided the following directives in its 2025 ACE Plan Order, all of which NS Power has complied with in the 2026 ACE Plan:

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] Please refer to **Appendix G** for the Five-Year Reliability Plan Update, and **Section 11.1.4** for an update on the Company's evaluation of potential new reliability and resiliency metrics.
2. *The Board directs that no further reporting on Normalized System Average Interruption Duration Index (SAIDI) be provided in future ACE Plans*.[3] Discussion pertaining to Normalized SAIDI has been removed from **Section 11.1.4**.
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 the 2025 ACE Plan Decision*.[4] The Board initiated this process on November 17, 2025 under matter M12558; NS Power confirms its intention to comply with the Board's directive through this process.
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] Please refer to **Appendix G**.

[2] M12012, NS Power 2025 Annual Capital Expenditure Plan, Board Order, August 19, 2025, page 1.
[3] Ibid.
[4] Ibid, page 2.
[5] Ibid.

5. *The Board directs NS Power to provide an update on the Centre for Energy Advancement through Technological Innovation (CEATI) Grid Resiliency working group in the 2026 ACE Plan*.[6] Please refer to **Section 11.1.4**.
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] Please refer to **Appendix G**.
7. *The Board directs NS Power to file an update to The Path to 2030 in the 2026 ACE Plan*.[8] Please refer to **Appendix F**.
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] Please refer to **Appendix E**.
9. *In addition to filing a Net Present Value (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 Mersey Hydro System decommissioning and partial decommissioning options*.[10] Please refer to **Appendix E**.
10. *The Board directs NS Power to include cost estimates for further preliminary engineering work, Mi'kmaq and stakeholder engagement and environmental studies, detailed*

[6] Ibid.
[7] Ibid.
[8] Ibid.
[9] Ibid.
[10] Ibid.

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] Please refer to **Appendix E**.

11. *The Board repeats its directive from its 2024 ACE Plan Decision and directs the Utility to incorporate provisions in its Project Delivery Model (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] NS Power has been completing this verification as part of the capital project internal approval process since the 2025 ACE Plan was submitted, along with the updated PDM Documentation checklist that was provided as a response to the 2024 ACE Plan directive to implement a quality control step related to PDM documentation and process. NS Power has since developed a process document to be used by the capital planning team as part of the capital project approval process to ensure that a review of all relevant PDM documentation has been completed, and that the documentation that has been completed is consistent with all information presented within the project documentation. Please refer to **Appendix H** for a copy of this process document.

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] NS Power acknowledges the Board's directive, and confirms its intention to comply; the first project applicable to this directive is included for approval as CI C0080252 Intelligent Asset Data Capture & Integration Platform, which due to federal funding has a project total below $1 million. Please refer to **Section 5.2**, and the attached capital work order documentation for further detail.

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*

[11] Ibid.
[12] Ibid, pages 2-3.
[13] Ibid, page 3.

transmission line replacement and upgrade projects completed since filing of the 2025 ACE Plan application.[14] Please refer to **Appendix I**.

14. *The Board directs that NS Power consult with stakeholders about incorporating a definition of Scope Change in the Capital Expenditure Justification Criteria (CEJC) with the goal of providing proposed amendments in the 2026 ACE Plan.*[15] Please refer to **Section 4.1** and **Appendix D**.

4.1 Stakeholder Engagement – CEJC Update

As noted above, the Board provided a stakeholder engagement directive in its Order approving the 2025 ACE Plan.

In accordance with the Board's directive, NS Power held an engagement session on October 29, 2025, inviting the Consumer Advocate (CA), Small Business Advocate (SBA), Industrial Group (IG), and Board staff. During the session, the Company provided an overview of proposed amendments relating to Scope Change capital work orders, Final Cost work orders, and several smaller amendments, and solicited feedback from attendees.

Following the session, NS Power provided stakeholders with updated documents on November 3, 2025. All stakeholders were invited to provide written comments within one week of receiving the amended documents.

Following the session, written feedback was received from the CA, SBA, and IG:

- The CA confirmed that the revisions made reflected discussion during the session.
- The SBA recommended updating the definition of Scope Change, to align with the definition of Scope. Specifically, the SBA suggested that Scope Change should include changes to deliverables and boundaries as set out in the original capital application.

[14] Ibid.
[15] Ibid.

- The IG provided comments on the proposed definitions of Scope and Scope Change, noting that they differ from traditional project management terminology and how NS Power has historically defined Scope in capital project applications. The IG suggested that Scope within the CEJC should be defined as (1) the intent of the project, (2) the detailed tasks or work required to complete the project (including the key lowest-cost method of completion), and (3) the main deliverables. In addition, they stated that the definition of "scope" must be consistent across NS Power's capital projects, cost minimization efforts, and the approach to Scope Change applications, because once the definition of scope is confirmed for a project, it becomes clear what constitutes a "Scope Change" and when an application is warranted. The IG cited examples such as the Tusket Main Dam Refurbishment ATO and Gaspereau Dam Safety ATO as projects that experienced scope changes but did not advance Scope Change applications.

NS Power has carefully considered the feedback from the SBA and IG. While the Company acknowledges that the proposed definition differs from historic usage, its intent is to establish a clear and consistent application of the term in future project descriptions, informed by the stakeholder feedback and discussions during this engagement.

The proposed Scope Change definition has been intentionally limited to changes in stated intent as this provides a practical trigger for when a Scope Change application is required. Expanding the definition to include changes in deliverables, boundaries or detailed tasks, as suggested by the SBA and IG, would significantly increase the number of regulatory filings (potentially before cost impacts are fully understood) and create unnecessary complexity. Under such an approach, any design refinement or task adjustment could require a separate application, resulting in multiple filings for a single project. This would impose a substantial regulatory burden on the Company, the Board, and stakeholders, requiring projects to be reviewed multiple times before completion without delivering any meaningful improvement in oversight.

To avoid this, NS Power relies on long-standing and tested processes within this jurisdiction. When a project is forecasting in an ATO position and includes a scope change, NS Power submits a

single ATO or, if the project is complete, a FIN application with explanatory commentary rather than filing a separate Scope Change application. This approach consolidates all known information into one filing, ensuring transparency and regulatory efficiency. For larger, complex projects, such as the examples cited by the IG, NS Power also provides ongoing reporting until sufficient information is available to bring forward a new capital application for approval.

From a prudency perspective, the focus should remain on significant changes that affect the underlying rationale for a project. Routine adjustments, such as design refinements, or changes in the tasks required, do not alter the prudency of the original decision and should not require a separate filing. NS Power's proposed definition of Scope Change ensures that any change to the core objectives outlined in the original application is captured, while allowing the Company the flexibility to manage projects efficiently. This approach strikes the right balance between regulatory oversight and efficiency.

Based on discussions with the IG subsequent to the broader stakeholder engagement efforts, NS Power is open to adding further language that would also consider a scope change to have taken place when there are multiple alternatives detailed in the project under "Why do the Project This Way", and the alternative chosen changes to one of the other alternatives discussed. This updated language is not in the current proposed CEJC updates as it was not canvassed with all intervenors prior to this filing.

NS Power thanks stakeholders and their consultants for their contributions during this process. The Company continues to believe that the stakeholder engagement process provides an open and collaborative forum to address areas of interest.

Please refer to **Appendix D**, which includes the stakeholder engagement materials, the list of CEJC revisions, and updates in track changes for the Detailed and Summary CEJC. NS Power respectfully requests acceptance and approval of the Detailed and Summary CEJC, respectively.

4.2 2025 ACE Plan Subsequent Submittal List Status Update

Figure 7 below provides an update to the list of projects that were identified by NS Power in the 2025 ACE Plan for later submission for NSEB approval.

Figure 7: Subsequent Submittal Project Status Update

		ACE 2025		Updated		
CI#	Project Title	2025 Budget ($)	Project Total ($)	2025 Budget ($)	Project Total ($)	Status
Generation						
48913	HYD - Tusket Facility Refurbishment	1,093,904	12,972,226	595,132	12,561,587	Deferred
C0057361	HYD - ANN Facility Isolation	210,689	2,899,094	947,775	4,083,925	2026 ACE Plan Subsequent Submittal
C0063803	HYD AVO 2 Access Road Stabilization	1,932,533	2,406,283	80,666	1,688,583	Approved
C0059783	HYD ULF 2 Overhaul	976,892	1,678,153	148,334	1,582,057	Approved
C0070486	HYD LGB Spillway Drawdown	1,121,577	1,288,404	3,125,751	3,593,884	Awaiting Approval
C0068655	LM6000 191-332 Life Extension	5,913,584	6,013,454	18,731,004	18,948,560	Awaiting Approval
C0069166	POT-Turbine Valve Refurbishment	2,529,633	2,872,598	1,287,845	1,287,845	Pending Submission
C0061484	PTMT - E-Crane Refurbishment	1,804,683	2,433,081	490,468	568,317	Project less than $1M
C0068566	LIN DCS Upgrade 2025	1,300,715	1,440,911	697,061	1,270,573	Approved
C0067023	LIN2 2024/25 Capacity Requirement	371,610	1,083,800	1,290,724	1,257,127	Approved
Transmission						
C0044391	Eastern Clean Energy Initiative (ECEI) - Transmission	20,641,301	800,229,290	42,563,143	684,624,989	Filed by Wasoqonatl Transmission Inc. (WTI) - Approved
C0072808	Synchronous Condensers (ECEI)	27,197,774	243,807,241	26,578,829	364,566,804	2026 ACE Plan Subsequent Submittal
C0011358	New Bridgewater Substation	1,385,538	18,173,047	2,141,464	18,173,047	Deferred
C0032382	Susie Lake Substation Addition	5,149,415	13,954,518	2,993,635	8,256,386	2026 ACE Plan Subsequent Submittal
C0021140	New 138KV-25KV Substation Stellarton	3,187,370	10,511,998	589,591	12,960,396	Approved
C0053214	76W-T1 Transformer Replacement	1,938,848	2,279,295	2,054,425	2,818,855	2026 ACE Plan Submission
C0061552	L6043 Replacements and Upgrades	796,677	1,346,809	-	2,457,629	2026 ACE Plan Subsequent Submittal
C0041830	Spare Power Production Unit Transformer	1,258,324	1,264,622	1,205,613	1,266,552	Approved

CI#	Project Title	ACE 2025 2025 Budget ($)	ACE 2025 Project Total ($)	Updated 2025 Budget ($)	Updated Project Total ($)	Status
Distribution						
C0071528*	Fault Location, Isolation, Service Restoration (FLISR) Implementation	1,578,360	5,299,248	1,195,233	4,640,900	Awaiting Approval
General Plant						
C0021835	IT - CIS Replacement	2,243,592	77,890,771	1,442,723	84,502,844	2026 ACE Plan Subsequent Submittal
C0061284	IT - OT Cyber Security Control Implementation	2,723,682	5,459,313	198,246	6,780,461	Approved
C0053699	Renewable to Retail Implementation	1,505,726	5,062,652	1,437,530	5,644,467	Awaiting Approval
C0068719*	IT - Distributed Intelligence Apps	2,086,440	4,353,461	47,015	2,637,356	2026 ACE Plan Subsequent Submittal
C0047278	IT - Oracle MDM Upgrade	912,789	3,010,689	3,265,320	7,949,409	2026 ACE Plan Subsequent Submittal
C0068718*	IT - DERMS Solution Project	1,950,047	2,993,200	236,595	2,954,002	2026 ACE Plan Subsequent Submittal
C0032202	Sydney Depot Improvements	1,578,174	1,879,855	-	2,700,000	2026 ACE Plan Subsequent Submittal
C0062624	IT - Mobile Field Connectivity Enhancements	386,072	1,576,633	262,857	729,652	2026 ACE Plan Subsequent Submittal
C0068714	IT - Identity & Access Management	963,267	1,275,524	1,641,892	4,324,589	2026 ACE Plan Subsequent Submittal
C0061285	IT - Enterprise Governance, Risk and Compliance	664,056	1,179,857	29,797	848,825	2026 ACE Plan Subsequent Submittal
C0067863	IT - Managed Detect & Respond	668,280	1,126,413	223,679	2,585,071	2026 ACE Plan Subsequent Submittal

* This project total has been reduced due to federal funding.

4.2 2025 ACE Plan Capital Items Deferred / Cancelled

NS Power's list of deferred and cancelled capital work orders relative to the 2025 ACE Plan is contained in **Appendix C**. Given the timing of the filing of this Application, Appendix C does not include 2025 ACE Plan Subsequent Submittal items that are planned to be submitted after this Application has been filed and prior to 2025 year-end and does not include additional 2026 expenditures.

These 60 projects were originally included in the 2025 ACE Plan with a forecast investment of $60.3 million in 2025. 21 of these projects have been cancelled, while 39 have been deferred to future years. NS Power's asset management processes guide the Company's decisions related to

project deferrals to ensure risks are being appropriately managed and capital investments are appropriately prioritized.

Of the 60 projects listed, no projects were included in the 2025 ACE Plan for approval. 15 of these projects were listed in the 2025 ACE Plan subsequent submittal list, to be filed separately as individual capital items, and 45 projects were listed in the 2025 ACE Plan as projects under $1,000,000.

5.0 2026 ANNUAL CAPITAL EXPENDITURE PLAN

5.1 Summary of Expenditures

Figure 8 below provides the proposed capital investment by category for NS Power's 2026 ACE Plan. This Application seeks NSEB approval of the 2026 routine capital and 20 2026 projects, which total approximately $256.3 million of forecast investment in 2026. Certain items do not require NSEB approval but are included in NS Power's annual capital plan for transparency and informational purposes. The 2026 ACE Plan budget also includes investment on multi-year projects that were previously approved by the NSEB (Carryover Projects).

Figure 8: 2026 Capital Investments by Category

2026 ACE Spend	2026 NSEB Approval Request	NSEB Approval Not Required	Capital Items Forecast for Later Filing & Approval in 2026	Previously Approved Capital Projects with 2026 Carryover	2026 ACE Plan
Capital Item Approval Sought through the 2026 ACE Process (Including Routine Capital Projects)	256.3				**256.3**
Capital Items Submitted for Later Approval in 2026			174.5		**174.5**
2026 Carryover Projects				154.3	**154.3**
Capital Items Less Than $1M		116.9			**116.9**
2026 ACE Plan	**$256.3**	**$116.9**	**$174.5**	**$154.3**	**$702.1**

Note: NS Power is seeking approval of $207.3 million of routine investment in 2026.

Note: Figures presented in the ACE Plan document reflect rounding differences on some line items.

5.2 2026 ACE Plan Capital Items Submitted for Approval

Figure 9 below provides the list of 20 new Capital Items for which NS Power seeks NSEB approval in the 2026 ACE Plan, totaling approximately $49.0 million of spending in 2026, with a total forecast investment of approximately $76.7 million.

Figure 9: 2026 Capital Items Submitted for Approval

Tab #	CI#	Project Title	2026 Budget ($)	Project Total ($)
Generation				
Steam				
Boiler				
G01	C0080206	POA Boiler Refurbishment 2026	1,195,706	1,304,600
G02	C0080205	POA Boiler Refractory Replacement 2026	936,645	1,024,385
Turbine				
G03	C0021608	TUC Shoreline Sheetpile Refurbishment	4,727,595	5,691,466
G04	C0068898	TUC1 IP LP Last Stage Blade Replacement	2,756,011	5,215,861
G05	C0080134	TUC2 Stack Coating and Structural Refurbishment	3,593,719	4,256,511
G06	C0080133	TUC3 IP Turbine Refurbishment	13,621	2,588,734
G07	C0068888	TUC3 Continuous Ash Hauling System	1,192,814	1,359,984
		Total New Steam Spending	**$14,416,111**	**$21,441,542**
Gas Turbine				
G08	C0080135	CT - BGT2 Engine Refurbishment	2,147,663	2,462,664
		Total New Gas Turbine Spending	**$2,147,663**	**$2,462,664**
		Total New Generation Spending	**$16,563,774**	**$23,904,206**
Transmission				
T01	C0080110	L7012 Replacements and Upgrades Phase 1	2,195,905	5,370,318
T02	C0070909	70W-T52 Transformer Addition	3,474,286	3,957,128
T03	C0080109	L7001 Replacements and Upgrades Phase 1	1,019,910	3,063,280
T04	C0053214	76W-T1 Transformer Replacement	614,732	2,818,855
T05	C0070586	L6536 Switch Replacements	1,626,611	2,074,494
T06	C0053234	96H-T1 Transformer Replacement	1,794,354	2,056,752
T07	C0068969	2026 Pennsylvania Breaker Replacements	398,876	1,620,028
		Total New Transmission Spending	**11,124,674**	**20,960,855**

Tab #	CI#	Project Title	2026 Budget ($)	Project Total ($)
Distribution				
D01	C0080266	New Distribution Right of Way Phase 11	18,551,713	20,889,694
D02	C0080104	36V-303 Baxter's Harbour Rd Reconductor Phase 1	979,830	1,062,416
D03	C0080612	57C-426 Melrose Reconductor and Line Extension Phase 1	629,268	1,288,474
		Total New Distribution Spending	**20,160,811**	**23,240,584**
General Plant				
GP01	C0080111	2026 RTU Deployment Project	901,513	8,322,655
GP02	C0080252*	Intelligent Asset Data Capture & Integration Platform	251,719	267,941
		Total New General Plant Spending	**1,153,232**	**8,590,596**
		Total New Capital Spending	**$49,002,491**	**$76,696,240**
		Total Routine Capital Spending	**$207,302,889**	**$207,302,889**
		Total Capital Items for which Approval is Sought	**$256,305,380**	**$283,999,129**

* This project total has been reduced below $1M due to federal funding.

5.3 2026 ACE Plan Capital Items Forecast for Subsequent Approval

Figure 10 below identifies 2026 projects forecast in excess of $1 million that are not yet ready for submission to the NSEB but which NS Power anticipates will be filed for review and approval in 2026. NS Power estimates approximately $174.5 million of investment in 2026 on these projects, which are currently estimated for total investment of approximately $688.9 million. The budget numbers indicated below are estimates as NS Power needs additional time to refine the specific project budget proposals. This section of the application is designed to provide an indication of these anticipated 2026 projects.

Figure 10: 2026 Capital Items Forecast for Subsequent Submittal

CI#	Project Title	2026 Budget ($)	Project Total ($)
Generation			
Hydro			
47649	HYD Salmontail Gate Pedestal and Main Dam Refurbishment *This project aims to refurbish the dam structures to manage asset risk for safe operation.*	463,325	5,870,708
C0047973	HYD ANN Sluice Gates and Check Refurbishment *This project will involve refurbishment of the sluice structure gate slots.*	950,246	5,673,491
49595	HYD - TUS 1 Overhaul *This project includes the refurbishment of the 0.9MW unit in the Tusket Hydro Plant.*	3,411,894	5,649,954
C0057361	HYD ANN Facility Isolation *This project involves the long-term isolation of the Annapolis Generating Facility to prevent flooding.*	685,354	4,083,925
C0080219	HYD Deep Brook Spillway & Intake Refurbishment *This project will replace the stoplogs at the spillway and address existing asset deficiencies at the Deep Brook site.*	2,907,557	3,142,201
C0073368	HYD Malay Falls Rubber Dam *This project will replace the aging rubber dams to ensure continued safe operation.*	350,817	2,237,339
C0052514	HYD MacDonald Dam Access Improvements *This project is for the construction of an access walkway along the top of the spillway to a low level sluiceway gate for the Hydro Operations team to be able to adjust downstream flow required for new environmental requirements.*	963,078	1,547,398
C0064966	Tusket Powerhouse Tidal Pool Fish Passage *This project will construct an engineered solution to prevent future fish mortalities within a tidally influenced pool located downstream of the Tusket Powerhouse. The solution will provide additional waterflow and oxygen to the pool while reducing fish access to the pool and improving water retention in the pool during tidal fluctuations.*	377,048	1,315,495
C0067686	HYD Lumsden Rubber Dam Replacement *This project will replace the Rubber Dam (RBD) due to the existing RBDs having surpassed their expected service life and displaying visible signs of delamination, which present safety risks to the operation.*	729,149	1,304,068
47650	HYD - Annapolis Decision Analysis *This project involves decommissioning of the Annapolis Tidal Generating Station and associated site restoration.*	1,264,569	30,732,442
	Total New Hydro Spending for Subsequent Approval	**12,103,037**	**61,557,021**
Steam			
C0076273	Bear Head Ash Management Site - Life Extension *This project will complete the appropriate environmental and operational feasibility assessments to determine the most cost-effective way to modernize the Bear Head Ash Management site (BHAMS) for continued operation, with the focus on extending the asset's life.*	691,260	10,148,108
C0080671	LIN1 HIP Turbine Refurbishment 2026 *This project is for the refurbishment of the LIN1 High and Intermediate Pressure (HIP) section of the steam turbine including inspection of the shaft and blades. The HIP Turbine is used to extract energy from high pressure steam*	2,780,967	3,244,992

CI#	Project Title	2026 Budget ($)	Project Total ($)
	and intermediate pressure steam from the boiler to produce power through the generator.		
C0082195	LIN2 2025/26 Capacity Requirement *This project is for the component refurbishment and replacement of Lingan 2 assets to allow for the unit to be reliably available when system load requires.*	299,478	3,162,203
C0080768	POT - CW Pump & Motor Replacement *This project is for the replacement of one circulating water (CW) pump and motor assembly at Point Tupper Generating Station to reduce the risk of unplanned outages and support the plant's operational reliability and energy performance.*	2,615,777	2,872,183
C0080732	POA Ash Cell Capping/ Cell Development 2026 *This Project is to complete the permanent capping of Cell 1 at the Point Aconi Ash Management Site since it has reached the final elevation and capacity. Permanent capping is required in order to comply with the Operations Manual and environmental regulations.*	2,212,546	2,420,358
C0080691	LIN3 DCS Migration 2026 *This project is to migrate the current, obsolete Demand Control System on one of the Lingan units to a new modern system.*	700,000	1,359,218
C0076672	ICP - RC SCR Bridge 10.10 Refurbishment *This project is for refurbishment of priority areas of the roof at the Sydney Coal Railway Transportation & Rail Maintenance Centre (Rail Centre).*	1,102,575	1,353,592
	Total New Steam Spending for Subsequent Approval	**10,402,603**	**24,560,654**
	Total New Generation Spending for Subsequent Approval	**22,505,640**	**86,117,675**
Transmission			
C0072808	ECEI Synchronous Condensers *This project includes the procurement and installation of Synchronous Condensers at four locations across Nova Scotia to support integrating increasing volumes of renewable energy generation.*	84,693,670	364,566,804
51098	L-6014 Shannon Park Transmission Towers *This project involves rerouting of high-voltage transmission line L-6014 and the relocation of a steel transmission tower in the Shannon Park area of Dartmouth.*	4,532,569	39,471,723
C0081985	Michelin DVR Phase 2 *This project is for the supply, install and integration of an additional 5MVA of Dynamic Voltage Restorer (DVR) capacity at Michelin Waterville-92V.*	6,000,000	13,000,000
C0070367	IR 618 Network Upgrade Goose Harbour Lake Wind *This project is to construct Network Upgrades (NU) associated with the transmission interconnection of the new Goose Harbour Lake (Port Hawkesbury Paper) Wind Farm in Guysborough County, in the Provincial Rate Base Procurement (RBP) program.*	2,591,926	11,015,684
C0069534	IR 669 Network Upgrade Higgins Mountain Wind *This project is for the Network Upgrades associated with the transmission interconnection of the Higgins Mountain Wind Project in the Provincial Rate Base Procurement (RBP) program.*	4,497,188	9,496,174
C0032382	142H - Susie Lake Substation *This project is for the construction of a new substation in the Susie Lake area of Bayers Lake Business Park in Halifax.*	624,824	8,256,386

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CI#	Project Title	2026 Budget ($)	Project Total ($)
C0071888	New Tidewater Substation *This project is to build a new Tidewater Substation to address increased residential electricity demand, improve system reliability, and reduce environmental and flooding risks associated with the current site.*	4,119,741	4,141,223
C0023802	L-6515 Canso Causeway Rebuild *This project includes the installation of new assets and the removal of six deteriorated assets to increase the reliability of the transmission line.*	477,049	3,925,352
C0022247	1N Onslow Transformer Addition (1N-T66) *This project is for the addition of a 25/33/42 MVA transformer to the 1N Onslow substation to serve local load growth.*	2,055,587	3,645,131
C0071889	77V-T1 Transformer Replacement *This project is to replace 77V-T1 with a 15/20/25 MVA unit to serve local load growth in the Digby area.*	3,486,796	3,486,796
C0080107	L-5532 Reliability Upgrade - 91W Middle Field Substation *This project is to install additional protection and sectionalizing capabilities to 69kV transmission line L-5532.*	2,537,039	3,053,526
C0070086	10H-T2 Transformer Replacement *This project is for the replacement of the 10H-T2 transformer which serves the Victoria General Hospital and the IWK Children's Hospital in Halifax.*	2,508,966	2,878,891
C0080108	L-5532 Replacements and Upgrades Phase 1 *This project is for the replacement of assets throughout L5532, a 95.9 kilometer (1,128 structures) transmission line built in 1955 that connects 13V Gulch and 3W Big Falls substations.*	908,755	2,490,532
C0061552	L-6043 Replacements and Upgrades *This project is for the replacement of assets on L6043, a 28.9 kilometer (150 structures) transmission line built in 1985 that connects 113H Dartmouth East and 87H Musquodoboit substations.*	1,626,537	2,457,629
C0059483	83V L-5017 and L-5046 Rebuild Tap *This project involves the rebuild of the L-5046 tap at its intersection with L-5017 due to deteriorated tap structures and switches. The overall investment for this project is greater than $1M.*	927,126	1,207,318
C0070327	IR 673 Network Upgrade Benjamins Mill Wind *This project is for the Network Upgrades associated with the transmission interconnection of the new Benjamin's Mill Wind Farm in Hants County in the Provincial Rate Base Procurement (RBP) program.*	265,000	265,000
	Total New Transmission Spending for Subsequent Approval	**121,852,772**	**473,358,167**
Distribution			
C0080102	92H-331 Double Circuit Peggys Cove Rd *This project will add a second circuit along 4.5kms of Peggy's Cove Road, and transfer Customers along this section to a unique feeder.*	1,704,973	1,882,573
C0080101	539N-210 Big Island Sub-Sea Cable Replacement *This project will replace a sub-sea cable feeding Big Island.*	1,112,927	3,539,067
	Total New Distribution Spending for Subsequent Approval	**2,817,900**	**5,421,640**

CI#	Project Title	2026 Budget ($)	Project Total ($)
General Plant			
C0082133	IT - Renew Microsoft Enterprise Agreement *This project funds the on-premises portion of the Microsoft Enterprise Agreement for software assurance on our Microsoft SQL Server, Windows Server and Visual Studio licenses over a 3 year license term.*	1,800,000	1,800,000
C0068719	IT - Distributed Intelligence Apps *This project will evaluate, pilot, procure and deploy distribution intelligence solutions through the Advanced Metering Infrastructure (AMI) network meters. The implementation of these applications will enable precise analysis, advanced event detection and improve situational awareness of system conditions at the meter. NS Power has received confirmation of funding for this project.*	1,312,110	2,637,356
C0068718	IT - DERMS Solution Project *This project will procure and implement a Distributed Energy Resource Management System (DERMS) allowing for the visibility, monitoring, control and optimization of distribution-connected energy resources on the power grid. NS Power has received confirmation of funding for this project.*	857,294	2,954,002
C0032202	Sydney Depot Improvements *This project includes facility improvements at the Townsend St location.*	1,200,000	2,700,000
C0068714	IT - Identity & Access Management *This project will enhance NS Power's security infrastructure by transitioning the Company's existing Access Management, Privileged Access Management (PAM) and Identity and Access Management (IAM) tools to a new, advanced and streamlined software.*	2,561,279	4,324,589
C0067863	IT - Managed Detect & Respond *The IT – Managed Detect and Response project aims to enable cyber threat detection and autonomous cyber incident response for the NSPI IT infrastructure and endpoints.*	2,349,927	2,585,071
C0021835	IT - CIS Replacement *This project will replace Nova Scotia Power's Customer Information System (CIS). The CIS system is critical to delivering customer care, billing and communications to customers.*	3,199,578	84,502,844
C0082274	Storm Management Software Implementation *This project will deploy advanced tools to strengthen emergency preparedness and optimize the deployment of resources to reduce restoration times and remain fiscally responsible.*	2,142,280	2,235,914
C0047301	IT - Cloud Integration Platform *This project will implement a scalable cloud integration solution to streamline the secure exchange of data between on-premises and cloud-based business systems. It will improve our ability to deliver and manage data integrations in a more timely and cost effective manner.*	1,775,710	2,004,962
C0047278	IT - Oracle MDM Upgrade *The Meter Data Management (MDM) System is nearing end-of-life and requires an upgrade to maintain vendor support. Upgrading the current version ensures vendor support is available; allows NS Power to apply newly released bug fixes, cybersecurity vulnerabilities or system patches that are released by the vendor; and ensures that new system features can be utilized as they are released by the vendor.*	4,684,089	7,949,409
C0068721	IT - ADMS Upgrade 2026 *This project will upgrade the Advanced Distribution Management System to the latest major version to ensure vendor support and compatibility with emerging technologies. This upgrade encompasses the design and implementation of both physical and software assets, positioning the system for future enhancements and improved outage restoration capabilities.*	3,500,000	7,200,000

CI#	Project Title	2026 Budget ($)	Project Total ($)
C0062043	IT - SharePoint Technical Migration	1,990,219	3,134,674
	This project will migrate business records to SharePoint online to enable the secure, supported document management of business records in accordance with corporate Records and Information Management standards.		
	Total New General Plant Spending for Subsequent Approval	**27,372,486**	**124,028,821**
	Total Capital Items for Subsequent Approval	**174,548,798**	**$688,926,304**

5.4 2026 ACE Plan Capital Items with Estimated Total Project Cost of Less Than $1,000,000

Historical dollar values and numbers of projects for capital items with a total project cost of less than $1,000,000 are provided in **Figure 11** and **Figure 12** below, respectively, in accordance with the agreement reached with stakeholders pursuant to NS Power's report provided to the Board on September 5, 2017 (2017 stakeholder agreement).

Figure 11: Historical Value of Projects Less Than $1M

(Millions of dollars)

Value of Projects Less than $1M				
Function	**2023**	**2024**	**2025**	**2026**
Gas Turbine	1.5	1.6	2.1	5.6
Steam	31.3	49.3	56.0	82.6
Hydro	3.5	6.6	4.8	3.5
Wind	0.6	0.3	1.5	2.2
Transmission	2.9	2.8	1.0	2.7
Distribution	5.6	5.1	9.2	11.5
General Plant	7.8	10.7	3.4	8.8
Total	**$53.2**	**$76.4**	**$78.1**	**$116.9**

Note: Totals in the tables above may be off due to rounding

Figure 12: Historical Number of Projects Less Than $1M

# of Projects Less than $1M				
Function	**2023**	**2024**	**2025**	**2026**
Gas Turbine	21	22	11	46
Steam	159	226	263	330
Hydro	13	15	15	15
Wind	2	2	3	5
Transmission	13	7	3	6
Distribution	27	17	22	28
General Plant	25	38	14	23
Total	**260**	**327**	**331**	**453**

Note: Totals in the tables above may be off due to rounding

A list of capital items with a total project cost of less than $1,000,000 is provided in **Appendix B**, tab 'Less than $1M'. These projects do not require NSEB approval but are provided for transparency and informational purposes.

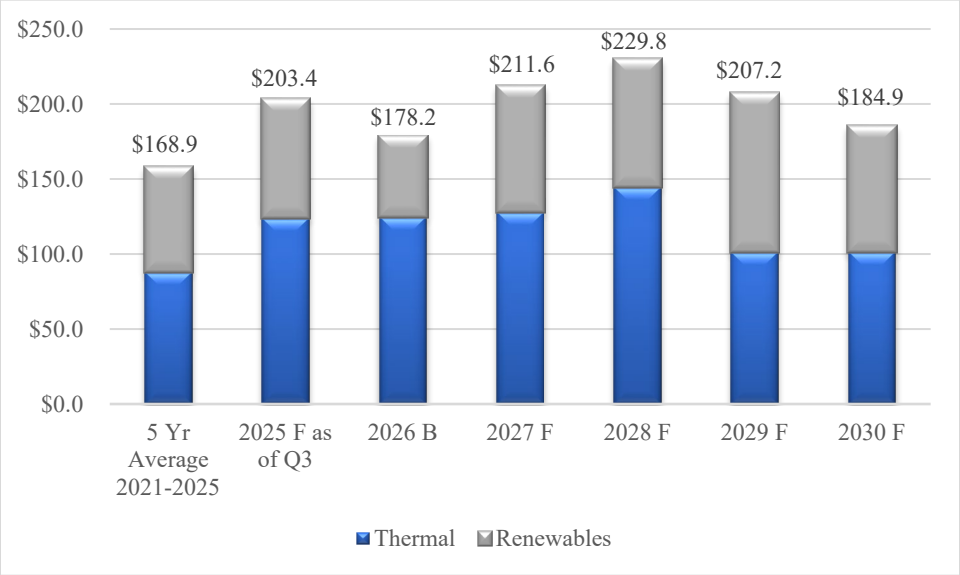
6.0 GENERATION

Generation capital includes replacements, refurbishments and additions to NS Power's Thermal, Hydro, Wind, Combustion Turbine and Biomass facilities.

Figure 13 below illustrates NS Power's capital investment on generation, including historical, forecast and budget. The increase in investment in 2026-2028 is largely attributable to an increase in major thermal outages along with larger Hydro dam safety projects. This investment aligns with the updated unit missions of the legacy thermal fleet outlined in the Company's 10 Year System Outlook filing.

Figure 13: Generation Investment – Historical, Forecast and Budget

(Millions of dollars)



F = Forecast, B = Budget in above figure

Figure 14 and **Figure 15** provide a breakdown of the 2026 generation investment by investment type.

Figure 14: 2026 Thermal Investment by Investment Type

(Millions of dollars)

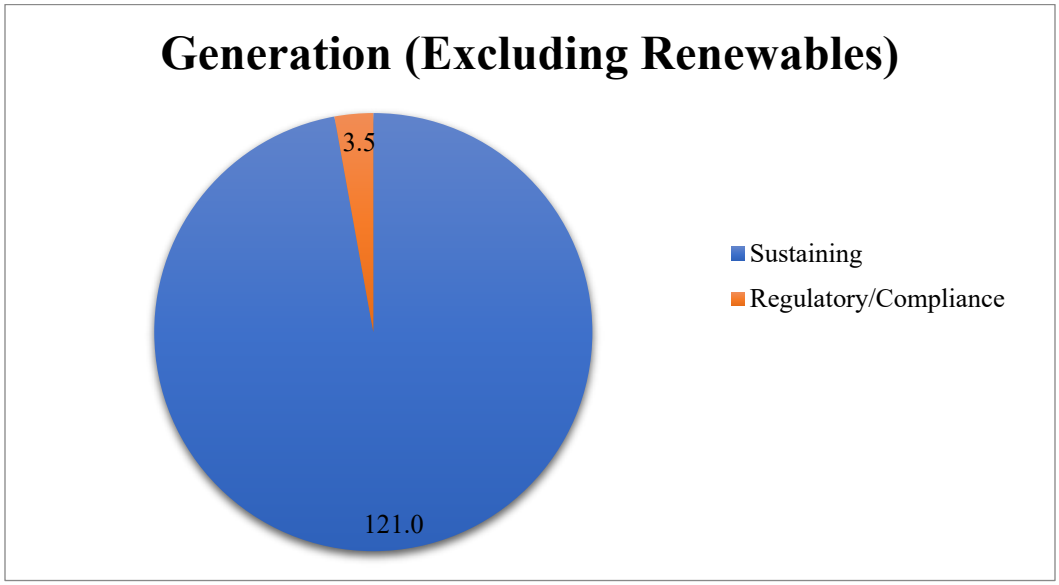
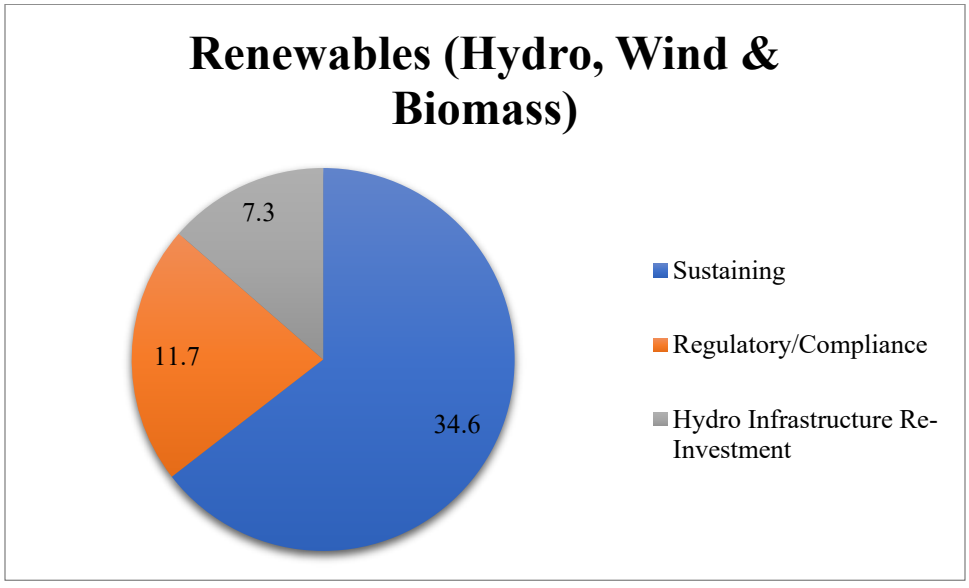


Figure 15: 2026 Renewable Generation Investment by Investment Type

(Millions of dollars)



NS Power's generation investment planning is guided by its Asset Management mechanism and the Capital Expenditure Justification Criteria (CEJC). Asset condition and criticality are assessed

using the Asset Management Mechanism described in **Section 3.0**, which enables consistent, risk-informed prioritization across the fleet. Investments are selected to maintain safety, reliability, and affordability, with consideration for forecast utilization and long-term strategic objectives.

For thermal generation, this includes adapting to evolving operational demands as legacy coal-fired units transition toward retirement or fuel conversion by 2030, in alignment with the NS Clean Power Plan. This plan supports the Province's Clean Power Plan to achieve 80 percent renewable electricity sales and phase out coal generation, requiring significant changes to NS Power's generation portfolio and operating context. Asset health assessments, risk profiling, and economic analysis (e.g., NPV) are applied to ensure investments are defensible and aligned with this transition.

Key elements of the generation asset management approach include:

- Fleet-wide asset class programs
- Risk-based inspection and monitoring
- Integration of predictive analytics and operational support tools
- Engagement with industry experts and best practices
- Responsiveness to emerging risks and regulatory requirements

This approach ensures that sustaining capital is deployed effectively, balancing near-term reliability with long-term system transformation.

The focus for thermal generation capital investments in 2026 is on current requirements to provide for the safe, environmentally compliant, and reliable operation of the thermal assets based on utilization outlooks. The focus for renewable generation capital investments in 2026 is similar, with particular consideration given to the role they play with respect to achieving renewable energy and coal phase-out goals. The approximately $178.2 million generation capital investment plan for 2026 is summarized in **Figure 16** below.

Figure 16: Summary of 2026 Generation Capital Investments

(Millions of Dollars)

i	New 2026 capital spending for projects with total estimated project spend greater than $1,000,000 and for which approval is sought. (As provided in Section 6.2)	16.6
ii	2026 capital spending for projects with total estimated project spending greater than $1,000,000 for which approval will be sought subsequent to the filing of the 2026 ACE Plan. (As provided in Section 5.3)	22.5
iii	New capital spending for projects with total estimated spending less than $1,000,000 for which approval is not sought. (As provided in Appendix B)	93.9
iv	Carry-over capital spending. (As provided in Section 6.1)	38.5
v	Routine capital spending. (As provided in Section 10)	6.7
	Total 2026 Generation Capital Investment Plan	178.2
	Request for ACE Approval (Items i and v)	23.3

Note 1: Totals may be off due to rounding.

6.1 Generation – Carry-over Capital Spending Summary

Figure 17: Generation Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
Hydro Generation Plant							
C0013838	WRC LEM Unit Rehabilitation	2019/01	2026/08	103,155,974	2,028,957	-	105,184,931
29807	Tusket Falls Main Dam	2008/01	2030/12	21,846,960	1,945,937	55,181,513	78,974,410
C0014218	WRC LEM Balance of Plant	2019/11	2027/01	22,266,479	5,259,767	-	27,526,247
16374	HYD - Gaspereau Dam Safety Remedial Works	2007/05	2029/12	12,639,789	1,956,609	6,677,000	21,273,399
50518	HYD Ruth Falls Main Dam	2017/02	2026/10	12,332,154	2,481,481	-	14,813,635
C0006418	HYD WRC Tailrace Rock Bolting Phase 2	2018/06	2026/05	13,853,095	24,047	-	13,877,142
49756	HYD Marshall Falls Dam Refurbishment	2016/12	2030/09	917,387	641,240	12,291,829	13,850,456
C0050414	HYD Roseway Asset Decommissioning	2022/07	2026/09	4,738,368	47,619	-	4,785,987
C0070486	HYD Lower Great Brook Stoplog Replacement	2025/11	2027/03	3,125,751	465,806	2,327	3,593,884
C0080228	HYD - Hollow Bridge Stator Refurbishment	2025/09	2026/10	715,901	1,871,269	-	2,587,170
48791	HYD - WRC Safety Standards Upgrades	2016/01	2026/04	1,919,441	32,168	-	1,951,609
C0073348	WRC Surge Lake Volume Optimization	2025/04	2026/12	609,204	1,200,908	-	1,810,112
C0063803	HYD AVO 2 Access Road Stabilization	2023/12	2027/06	196,196	1,492,387	-	1,688,583
C0059783	HYD Upper Lake Falls 2 Overhaul	2023/08	2027/04	148,783	1,297,570	135,704	1,582,057
49942	HYD Tidewater Facility Refurb	2018/06	2026/06	1,283,197	100,981	-	1,384,178

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CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
C0080112	HYD Big Falls Unit 6 Rotor Reinsulation	2025/05	2026/10	692,018	195,706	137,902	1,025,626
49036	HYD - Avon 2 Controls Upgrade	2016/03	2027/01	589,333	429,457	-	1,018,790
C0019025	HYD - GUL Overhaul	2019/05	2028/03	403,071	575,601	-	978,672
C0048990	HYD Avon 2 Switchgear Replacement	2022/05	2027/01	616,712	316,586	-	933,298
C0042526	HYD - ULF2 Generator Refurbishment	2024/07	2027/04	79,387	671,377	114,071	864,835
C0049192	HYD - GUL Generator Refurbishment	2022/04	2026/10	310,633	449,745	-	760,378
C0019038	Hydro Water Management	2020/05	2026/12	509,217	45,316	-	554,533
C0039266	HYD - GUL Overhaul	2022/07	2026/10	66,442	408,701	-	475,143
C0049456	HYD ANN Safety Boom Replacement	2022/12	2026/12	248,901	191,039	-	439,940
C0020883	Gulch Enhanced Monitoring	2019/12	2026/06	250,269	41,508	-	291,777
C0068251	HYD WRC D11 Valve and Housing Replacement	2024/06	2027/02	52,425	232,209	-	284,634
Total Hydro Generation Plant				**203,567,087**	**$24,403,993**	**$74,540,346**	**$302,511,425**
Steam Generation Plant							
C0060608	TUC6 Turbine Refurbishment	2024/01	2026/07	562,396	1,900,000	-	2,462,396
C0068566	LIN DCS Migration	2024/07	2027/01	697,457	573,116	-	1,270,573
C0055155	TUC2 Stack 1 Platform Replacement	2022/12	2026/12	109,474	849,149	-	958,623
C0060598	TUC6 HRSG Boiler Refurbishment	2024/05	2026/07	285,000	650,668	-	935,668
C0074148	ICP - RC May St Crossing Gate U&U	2025/04	2026/07	207,909	304,975	-	512,884
C0060594	TUC6 Turbine Valves	2024/05	2026/07	471,972	438,027	-	909,999
C0060578	TUC2 Air Foil Replacement	2024/08	2026/12	50,000	399,945	-	449,945
C0052113	ICP Main Storage Area Water Mgmt	2023/02	2026/08	273,742	107,270	-	381,012
C0063550	ICP Conveyor Take-Up Refurb	2024/10	2027/01	26,986	344,907	-	371,893
C0074210	ICP Sluice Channel Covers U&U	2025/07	2026/02	159,019	129,362	-	288,381
C0040186	TRE - PCB Equipment Replacement	2021/06	2027/01	189,000	52,665	-	241,665
C0010331	TRE6 Precipitator Controls Upgrade	2022/03	2027/01	116,405	42,915	-	159,320
C0060781	POT - Fuel Delivery Control & Instrumentation Refurbishment 2024	2024/03	2026/11	97,520	155,604	-	253,124
C0041548	TUC Relay Information Management	2022/01	2026/12	3,265	36,251	-	39,516
Total Steam Generation Plant				**3,250,145**	**5,984,853**	**-**	**9,234,999**
Gas Turbine Generation Plant							
C0073491	LM6000 191-443 Engine Replacement	2024/08	2025/10	61,326	4,745,151	19,410,812	24,217,289
C0060707	CT BGT1 Generator Refurbishment	2024/02	2027/12	7,684	924,949	2,910,000	3,842,633
C0050648	LM6000 Air Compressor Replacement	2023/01	2026/12	6,250	62,545	-	68,795
C0050651	VJ1 Vibration System Upgrade	2023/01	2026/11	27,254	9,931	-	37,185
C0050652	VJ2 Vibration System Upgrade	2023/01	2026/10	27,254	9,931	-	37,185
C0069587	BGT4 Inverter Replacement	2026/04	2026/04	32,000	19,900	-	51,900

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
Total Gas Turbine Generation Plant				**161,767**	**5,772,407**	**22,320,812**	**28,254,986**
Wind Generation							
C0044030	WIN - DIG Haights Brook Crossing Replacement	2022/02	2027/03	287,490	1,929,592	-	2,217,082
C0010758	HYD WIN South Lake WRC Turbine Decommissioning	2020/07	2027/03	141,162	389,650	86,223	617,035
C0047930	WIN - DIG Collector Circuit Switch Install	2024/07	2026/09	88,343	63,563	-	151,906
Total Wind Generation Plant				**516,995**	**2,382,805**	**86,223.00**	**2,986,023**
Total Generation Carry-Over Spending				**207,495,994**	**38,544,059**	**96,947,381**	**342,987,433**

6.2 Generation – New 2026 Capital Items for ACE Plan Approval

Figure 18: Generation – New 2026 Capital Items for ACE Plan Approval

Tab #	CI#	Project Title	2026 Budget	Project Total ($)
	Steam Generation Plant			
Boiler				
G01	C0080206	POA Boiler Refurbishment 2026	1,195,706	1,304,600
G02	C0080205	POA Boiler Refractory Replacement 2026	936,645	1,024,385
Turbine				
G03	C0021608	TUC Shoreline Sheetpile Refurbishment	4,727,595	5,691,466
G04	C0068898	TUC1 IP LP Last Stage Blade Replacement	2,756,011	5,215,861
G05	C0080134	TUC2 Stack Coating and Structural Refurbishment	3,593,719	4,256,511
G06	C0080133	TUC3 IP Turbine Refurbishment	13,621	2,588,734
G07	C0068888	TUC3 Continuous Ash Hauling System	1,192,814	1,359,984
		Total Steam Generation Plant	**14,416,111**	**21,441,542**
	Gas Turbine Generation Plant			
G08	C0080135	CT - BGT2 Engine Refurbishment	2,147,663	2,462,664
		Total Gas Turbine Generation Plant	**2,147,663**	**2,462,664**
	Total Generation New Spending		**16,563,774**	**23,904,206**

7.0 TRANSMISSION

Transmission includes items for replacement, reinforcement, or expansion of the transmission system, which transmits electrical energy from the generation plants to distribution substations throughout the province. Transmission includes assets and equipment operating at 69 kV or higher. NS Power operates over 5,000 km of transmission circuits and related protection, controls, and substation equipment. **Figure 19** below illustrates NS Power's capital investment in transmission, including historical, forecast, and budget. The increased investment for 2024-2028 is driven by the Energy Storage and Synchronous Condenser projects.

Figure 19: Transmission Investment – Historical, Forecast and Budget

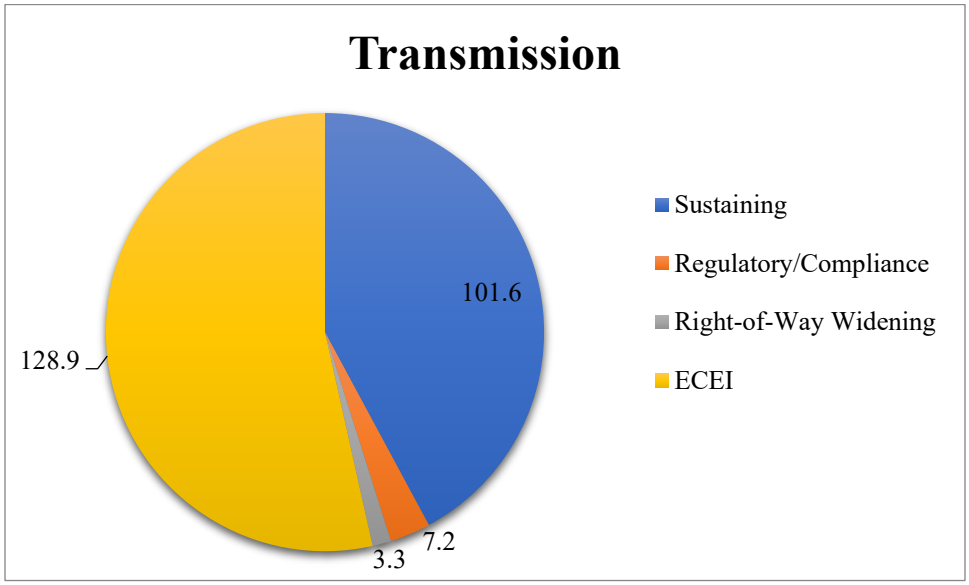
(Millions of dollars)

F = Forecast, B = Budget in above figure

Figure 20 provides a breakdown of the 2026 transmission investment by investment type.

Figure 20: 2026 Transmission Investment by Investment Type

(Millions of dollars)



Transmission investment is guided by NS Power's Asset Management mechanism and the Capital Expenditure Justification Criteria (CEJC). Asset condition and criticality are evaluated using the Asset Management Mechanism described in **Section 3.0** enabling consistent prioritization of maintenance, refurbishment, and replacement activities across the transmission fleet.

This risk-based approach is supported by inspection programs, asset health assessments, and lifecycle planning, with a focus on sustaining capital investment and regulatory compliance. Key drivers include reliability improvement, customer and load growth, environmental obligations (e.g., PCB phase-out), and strategic initiatives aligned with the NS Clean Power Plan.

The Clean Power Plan outlines a transition to 80 percent renewable electricity by 2030, requiring significant upgrades to NS Power's transmission system. These include investments in the Eastern Clean Energy Initiative (ECEI), such as for synchronous condensers, and battery energy storage systems—all of which are integrated into NS Power's long-term planning and investment roadmap.

For additional detail on NS Power's reliability strategy, including metrics and resilience planning, please refer to **Section 11.1.4**.

The focus for transmission capital investments in 2026 is on sustaining and improving system reliability and transformational investment in Energy Storage and Synchronous Condensers. The approximately $ 241.1 million transmission capital investment plan for 2026 is summarized in **Figure 21** below.

Figure 21: Summary of 2026 Transmission Capital Investments

(Millions of dollars)

i	New 2026 capital spending for projects with total estimated project spend greater than $1,000,000 and for which approval is sought. (As provided in Section 7.2)	11.1
ii	2026 capital spending for projects with total estimated project spending greater than $1,000,000 for which approval will be sought subsequent to the filing of the 2026 ACE Plan. (As provided in Section 5.3)	121.9
iii	New capital spending for projects with total estimated spending less than $1,000,000 for which approval is not sought. (As provided in Appendix B)	2.7
iv	Carry-over capital spending. (As provided in Section 7.1)	83.4
v	Routine capital spending. (As provided in Section 10)	22.0
	Total 2026 Transmission Capital Investment Plan	241.1
	Request for ACE Approval (Items i and v)	33.1

Note 1: Totals may be off due to rounding.

7.1 Transmission – Carry-over Capital Spending Summary

Figure 22: Transmission Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
Transmission							
C0045132	ECEI Energy Storage	2022/06	2028/06	199,429,231	44,249,331	(3,291,005)	240,387,557
C0021140	138KV-25KV Substation Stellarton	2020/09	2026/09	3,259,643	5,084,736	4,616,017	12,960,396
C0062123	143H - Mt Uniacke Substation	2023/09	2026/06	8,040,869	1,000,000	-	9,040,869
C0031048	91H-T11 Transformer Replacement	2023/01	2026/06	4,585,569	2,329,053	-	6,914,622
C0068961	2025 PCB Substation Sampling and Replacement	2025/09	2026/06	39,831	1,224,293	5,386,809	6,650,933

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CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
C0031122	L6539 2021 Replacements and Upgrades	2021/01	2026/06	1,547,125	2,780,796	1,172,203	5,500,124
C0061550	L5031 Hubbards to East Chester Phase 2	2024/10	2026/04	3,520,682	1,898,274	-	5,418,956
C0061545	L6006 Replacements and Upgrades	2024/04	2026/02	4,873,564	206,436	-	5,080,000
C0056240	2024 Transmission Switch & Breaker Replacements	2023/08	2026/12	3,086,118	1,049,910	-	4,136,028
C0061551	L7009 Replacements and Upgrades	2024/04	2026/02	1,251,531	1,472,353	465,000	3,188,883
C0069232	L6021 Replacements and Upgrades	2025/01	2027/09	908,771	1,953,732	300,000	3,162,503
C0069231	L8002 Replacements and Upgrades	2025/06	2027/11	1,228,797	1,812,896	-	3,041,692
C0069227	L6516 Replacements and Upgrades Phase 3	2025/01	2028/01	1,785,121	1,125,133	-	2,910,254
C0055539	10H-T1 Transformer Replacement	2023/01	2027/03	41,917	2,794,480	-	2,836,396
C0070048	L5027B Replacements and Upgrades Phase 1	2025/06	2027/07	226,367	2,130,943	350,000	2,707,310
C0053295	L5004 Kearney Lake Structure Replacement	2023/06	2026/09	1,416,569	1,090,202	-	2,506,771
C0050842	2024 Bulk Oil (KSO) Breaker Replacements	2023/05	2026/12	859,084	635,204	1,000,004	2,494,292
C0061403	2024/2025 Sacrificial Anode Installation	2024/07	2026/02	2,233,034	142,517	-	2,375,551
C0069238	2025/2026 Steel Tower Refurbishment	2025/12	2027/12	278,654	1,391,030	665,676	2,335,361
C0061547	L7022 Replacements and Upgrades	2024/08	2026/12	1,029,979	896,998	264,000	2,190,977
C0052299	2023/2024 Steel Tower Life Extension	2023/04	2026/12	1,708,713	469,206	-	2,177,919
C0061546	L6514 Replacements and Upgrades	2024/05	2026/12	1,642,574	484,426	-	2,127,000
C0041791	L6551 Replacements and Upgrades	2022/06	2026/12	1,392,497	241,491	261,012	1,895,000
C0041807	L5534 Replacements and Upgrades	2023/03	2027/03	1,280,026	274,987	-	1,555,013
C0057882	2024 Pennsylvania Breaker Replacements	2023/09	2026/12	520,466	990,156	-	1,510,621
C0055796	2023 EHV Breaker Replacements	2022/12	2027/12	489,115	733,370	-	1,222,485
C0050834	Spare EHV Breaker	2023/11	2027/12	163	511,097	667,573	1,178,832
C0041804	2022 Line Retirement Program	2022/01	2027/03	507,938	340,094	300,000	1,148,032
C0061387	2024/2025 Wood Pole Retreatment Program	2024/08	2026/05	259,751	847,264	-	1,107,015
C0061883	129-H Kearney Lake Substation Rebuild	2024/03	2026/09	71,077	946,245	-	1,017,322
C0052654	L5541 Water Crossing Upgrades	2023/05	2027/03	3,264	305,788	584,906	893,958
C0061046	2024 Merlin Gerin Breaker Replacements	2023/09	2026/06	358,403	423,012	-	781,416
C0041812	L6040 Replacements and Upgrades	2022/07	2027/03	9,532	688,563	-	698,095
C0067866	2024 Substation Recloser Replacements	2024/10	2026/12	221,735	425,799	-	647,535
C0061544	L6536 Replacements and Upgrades	2024/01	2026/12	3,251	423,807	-	427,058
Total Transmission Carry-Over Spending				**248,110,960**	**83,373,621**	**12,742,195**	**344,226,776**

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7.2 Transmission – New 2026 Capital Items for ACE Plan Approval

Figure 23: Transmission – New 2026 Capital Items for ACE Plan Approval

Tab #	CI#	Project Title	2026 Budget	Project Total ($)
	Transmission Plant			
T01	C0080110	L7012 Replacements and Upgrades Phase 1	2,195,905	5,370,318
T02	C0070909	70W-T52 Transformer Addition	3,474,286	3,957,128
T03	C0080109	L7001 Replacements and Upgrades Phase 1	1,019,910	3,063,280
T04	C0053214	76W-T1 Transformer Replacement	614,732	2,818,855
T05	C0070586	L6536 Switch Replacements	1,626,611	2,074,494
T06	C0053234	96H-T1 Transformer Replacement	1,794,354	2,056,752
T07	C0068969	2026 Pennsylvania Breaker Replacements	398,876	1,620,028
	Total Transmission New Spending		**11,124,674**	**20,960,855**

8.0 DISTRIBUTION

Distribution includes replacement of, and additions to, equipment for delivering electricity from points on the transmission system to customers served at voltages below 69 kV. NS Power operates approximately 28,000 km of distribution circuits and related protection, controls, and transformers. **Figure 24** below illustrates NS Power's capital spending on distribution, including historical, forecast and budget.

Figure 24: Distribution Investment – Historical, Forecast and Budget

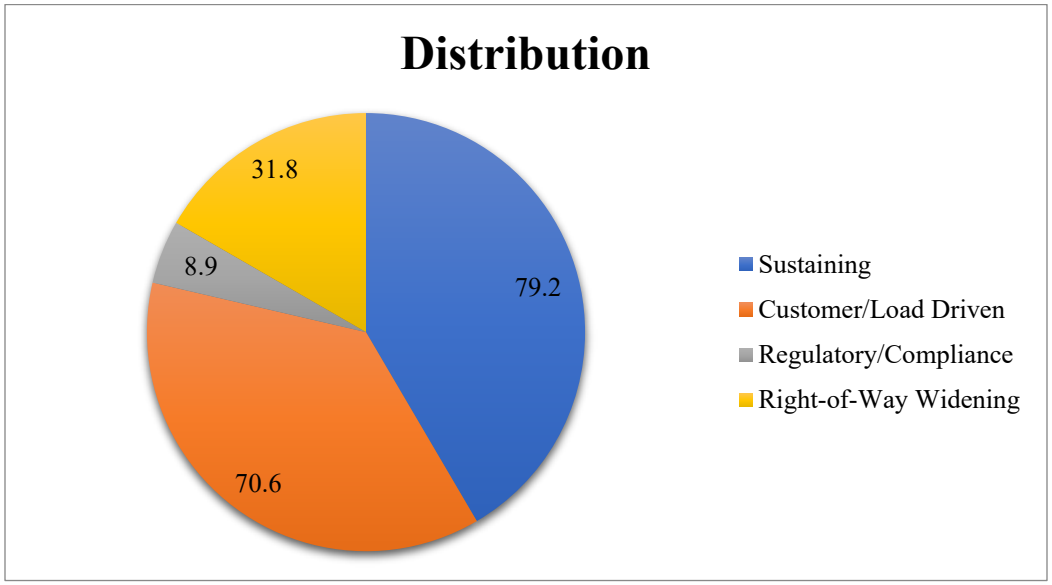
(Millions of dollars)

F = Forecast, B = Budget in above figure

Figure 25 provides a breakdown of the 2026 distribution investment by investment type.

Figure 25: 2026 Distribution Investment by Investment Type

(Millions of dollars)



Distribution investment is driven by the asset management mechanism as described in **Section 3.0** above and Section 6.2 of the CEJC. The asset management approach evaluates both condition and criticality to determine the failure risk of different asset groups, resulting in prioritization for the maintenance, refurbishment, and replacement of these assets as appropriate. NS Power's asset management strategy and condition assessments feed into this evaluation process, aimed largely at sustaining capital investments. Please refer to **Section 11.1.4** for additional detail on NS Power's strategy related to reliability.

The focus for Distribution capital investments in 2026 continues to reflect localized customer load growth and customer reliability. The approximately $190.5 million Distribution capital investment plan for 2026 is summarized in **Figure 26** below.

Figure 26: Summary of 2026 Distribution Capital Investments

(Millions of dollars)

i	New 2026 capital spending for projects with total estimated project spend greater than $1,000,000 and for which approval is sought. (As provided in Section 8.2)	20.2
ii	2026 capital spending for projects with total estimated project spending greater than $1,000,000 for which approval will be sought subsequent to the filing of the 2026 ACE Plan. (As provided in Section 5.3)	2.8
iii	New capital spending for projects with total estimated spending less than $1,000,000 for which approval is not sought. (As provided in Appendix B)	11.5
iv	Carry-over capital spending. (As provided in Section 8.1)	15.5
v	Routine capital spending. (As provided in Section 10)	140.5
	Total 2026 Distribution Capital Investment Plan	190.5
	Request for ACE Approval (Items i and v)	160.7

Note 1: Totals may be off due to rounding.

8.1 Distribution – Carry-over Capital Spending Summary

Figure 27: Distribution Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
Distribution Plant							
47124	Advanced Meter Infrastructure	2015/01	2027/06	142,937,589	294,212	-	143,231,801
C0008638	D- Cogswell HRM Redevelopment Program	2018/07	2026/03	7,464,318	537,430	-	8,001,748
C0071528	FLISR Implementation	2024/12	2028/06	1,195,233	3,445,667	-	4,640,900
C0074130	Robie Street Underground	2025/01	2027/12	1,256,042	2,798,771	410,306	4,465,119
C0068952	2025 PCB Poletop Sampling and Replacement	2024/10	2026/12	1,635,465	2,777,749	-	4,413,214
C0068954	2025 PCB Downline Device Sampling and Replacement	2025/12	2026/06	101	1,100,618	1,185,364	2,286,083
C0071954	87W-312 Dauphiness Mill Lake Rebuild	2024/10	2026/06	5,934	500,000	1,259,111	1,765,045
52184	37N-412-Glooscap Trail Rebuild PH2	2017/09	2026/09	786,166	49,303	337,901	1,173,369
C0070787	91W-411 Labelle Road Phase Extension	2025/08	2026/12	1,102	1,051,545	-	1,052,647
C0031117	2H-411-Prospect Rd Phase Extension	2022/04	2026/12	410,157	75,857	491,050	977,064
C0068956	2025 PCB Program - Reclosers	2025/12	2026/12	22,261	926,007	-	948,268
C0070827	99V-314G Lake George Line Extension	2024/06	2026/02	25,756	672,694	-	698,450
C0070426	2025 Downline Recloser Additions	2024/12	2026/06	499,010	147,822	10,001	656,833
C0070347	2025 Hydraulic Recloser Replacements	2024/12	2026/06	584,157	52,773	-	636,930
C0070268	2025 Voltage Regulator Replacements	2024/12	2026/06	3,025	547,973	-	550,998
C0070506	2025 Vault Replacements	2024/10	2026/12	66,420	349,585	-	416,005
C0070508	2025 Manhole Automatic Pumps	2026/01	2026/12	335	154,527	-	154,862

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
C0053517	9H-221 University Ave and Morris St Conversion	2023/02	2026/09	15,516	36,643	-	52,159
Total Distribution Carry-Over Spending				**156,908,587**	**15,519,175**	**3,693,732**	**176,121,494**

8.2 Distribution – New 2026 Capital Items for ACE Plan Approval

Figure 28: Distribution – New 2026 Capital Items for ACE Plan Approval

Tab #	CI#	Project Title	2026 Budget	Project Total ($)
	Distribution			
D01	C0080266	New Distribution Right of Way Phase 11	18,551,713	20,889,694
D02	C0080104	36V-303 Baxter's Harbour Rd Reconductor Phase 1	979,830	1,062,416
D03	C0080612	57C-426 Melrose Reconductor and Line Extension Phase 1	629,268	1,288,474
	Total Distribution New Spending		**20,160,811**	**23,240,584**

9.0 GENERAL PLANT

General Plant includes information technology (IT), operational technology (OT), computer infrastructure, vehicle replacements, tools, and communication equipment, comprising the majority of capital expenditures under this function. Other assets such as office equipment, and construction equipment are also included, along with buildings not classified as generation or substation facilities.

General Plant investments are essential to sustaining and enhancing NS Power's cross-functional tools, systems, and facilities that support safe, reliable, and cost-effective service delivery. These investments also enable digital transformation, customer experience enhancements, regulatory compliance, and operational resilience, particularly in support of strategic initiatives aligned with the NS Clean Power Plan, including grid modernization, cybersecurity, and distributed energy resource integration.

Figure 29 below illustrates NS Power's capital investment in General Plant, including historical, forecast, and budget.

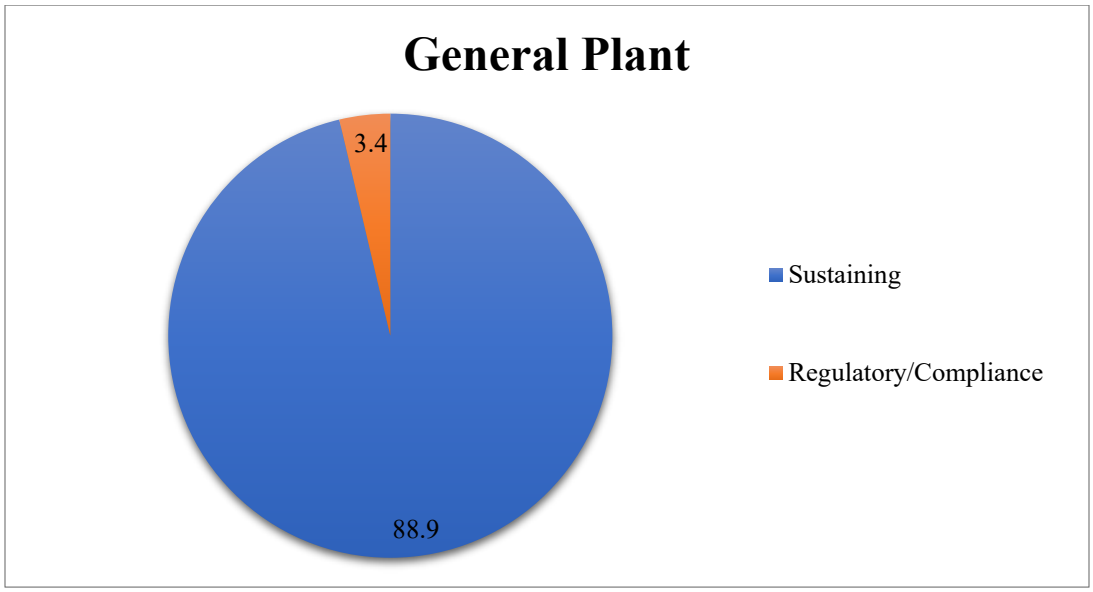
Figure 29: General Plant Investment – Historical, Forecast and Budget
(Millions of dollars)

F = Forecast, B = Budget in above figure

Figure 30 provides a breakdown of the 2026 general plant spend by investment type.

Figure 30: 2026 General Plant Spend by Investment Type

(Millions of dollars)



General plant capital investment in 2026 is primarily in Information Technology and Operational Technology. The approximately $92.4 million general plant capital investment plan for 2026 is summarized in **Figure 31** below.

Figure 31: Summary of 2026 General Plant Capital Investments

(Millions of dollars)

i	New 2026 capital spending for projects with total estimated project spend greater than $1,000,000 and for which approval is sought. (As provided in Section 9.2)	1.2
ii	2026 capital spending for projects with total estimated project spending greater than $1,000,000 for which approval will be sought subsequent to the filing of the 2026 ACE Plan. (As provided in Section 5.3)	27.4
iii	New capital spending for projects with total estimated spending less than $1,000,000 for which approval is not sought. (As provided in Appendix B)	8.8
iv	Carry-over capital spending. (As provided in Section 9.1)	16.9
v	Routine capital spending. (As provided in Section 10)	38.2
	Total 2026 General Plant Investment Plan	92.5
	Request for ACE Approval (Items i and v)	39.4

Note 1: Totals may be off due to rounding.

9.1 General Plant – Carry-over Capital Spending Summary

Figure 32: General Plant Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
C0051815	2025 RTU Replacement Program	2024/01	2027/11	1,430,134	1,669,606	1,594,959	4,694,700
C0070907	MDR-8000 Microwave Radio Replacement	2025/12	2028/12	125,100	526,010	914,900	1,566,010
C0069270	2025 SCADA Upgrade	2024/07	2026/09	210,127	719,540	357,000	1,286,667
C0021133	SCADA Mobile Application	2020/06	2026/09	28,000	428,330	-	456,330
C0070868	LEDR Radio Link Replacement	2025/02	2026/12	245,130	164,874	-	410,004
	Total Telecommunications			**2,038,491**	**3,508,360**	**2,866,859**	**8,413,711**
C0061284	IT - OT Cyber Security Control Implementation Phase 1	2023/11	2026/12	1,957,397	1,917,601	2,905,463	6,780,461
C0047277	IT - GIS Utility Network Migration	2022/07	2026/12	3,343,461	2,968,305	-	6,311,766
C0054755	IT - Connect My Data (Green Button)	2022/12	2026/04	2,920,684	71,996	-	2,992,680
C0056461	IT - Contact Centre Cloud Migration	2023/04	2026/04	2,472,418	356,538	-	2,828,956
C0073777	IT - Complex Customer Projects	2025/03	2026/12	675,058	1,834,347	-	2,509,405
C0047214	IT - CIS HW Replacement/OS Upgrade	2023/05	2026/12	909,017	81,162	-	990,179
C0062624	IT - Mobile Field Connectivity Enhancements	2023/10	2026/03	588,426	141,226	-	729,652
C0049614	IT - Network Video Recorders	2023/07	2026/12	139,308	27,713	-	167,021
C0075753	BI Portal	2025/04	2027/06	57,417	108,495	-	165,911
	Total Computers			**13,063,186**	**7,507,383**	**2,905,463**	**23,476,032**

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2026 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
C0032664	ECC Optimization Tools	2021/06	2026/09	6,595,975	890,093	-	7,486,068
C0053699	Renewable to Retail Implementation	2023/02	2027/04	4,415,135	1,229,332	-	5,644,467
C0053696	ECC Wind Integration	2025/09	2027/01	900,806	3,527,529	-	4,428,335
C0075751	APM Content Library and Implementation	2015/11	2026/04	231,379	24,618	-	255,997
C0065685	Enhanced Substation Analytics	2024/03	2027/06	75,555	95,866	-	171,421
C0064663	Rounds Pro Upgrade	2024/02	2027/03	42,140	63,405	-	105,545
C0065731	GE APM Connect Interface	2024/08	2027/06	35,691	54,678	-	90,370
	Total Other General Plant			**12,296,682**	**5,885,521**	**-**	**18,182,203**
Total General Plant Carry-Over Spending				**27,398,359**	**16,901,264**	**5,772,322**	**50,071,946**

9.2 General Plant – New 2026 Capital Items for ACE Plan Approval

Figure 33: General Plant – New 2026 Capital Items for ACE Plan Approval

CI#	Project Title	2026 Budget	Project Total ($)
General Plant			
C0080111	2026 RTU Deployment Project	901,513	8,322,655
C0080252	Intelligent Asset Data Capture & Integration Platform	251,719	267,941
Total General Plant New Spending		**1,153,232**	**8,590,596**

10.0 ROUTINE CAPITAL PROGRAM

NS Power's routine capital program is for recurring annual expenditures of like-for-like replacement of equipment, additions to existing equipment base resulting from system growth, and addition of customers to the system. This section details all routine capital expenditures for generation, transmission, distribution and general plant asset classes. NS Power seeks NSEB approval of the 2026 routine capital program in the amount of approximately $207.3 million.

10.1 Routine Capital Spending by Function Yr/Yr

Figure 34: Routine Capital Spending by Function Yr/Yr

	2024 Actual	2025 Budget	2025 Forecast*	2026 ACE Plan
Generation				
Generation Equipment Replacements	$3,384,982	$5,702,198	$5,735,210	$4,774,519
Generation Other Hydro	$1,202,879	$1,352,219	$1,423,003	$1,390,776
Generation Other Thermal	$563,050	$537,973	$544,902	$495,729
	$5,150,911	$7,592,390	$7,703,116	$6,661,024
Transmission				
Transmission Substation Replacement, Add'ns/Mod'ns	$4,327,200	$4,375,511	$4,370,346	$4,025,131
Primary Equipment Spares	$91,829	$300,000	$205,969	$192,433
Protection Modification & Replacement	$1,006,327	$987,791	$749,316	$862,088
Transmission Line Replacement, Add'ns/Mod'ns	$9,328,980	$9,329,311	$9,290,302	$13,595,755
Transmission Right-of-Way Widening	$610,491	$2,999,500	$2,783,122	$3,314,050
	$15,364,827	$17,992,113	$17,399,055	$21,989,457
Distribution				
Meters	$4,243,038	$4,876,834	$4,622,931	$3,870,540
Distribution Upgrades and Replacement	$44,925,409	$44,744,622	$38,830,652	$51,842,231
New Customers	$74,959,476	$69,444,057	$66,638,493	$67,837,497
Joint Use	$3,579,613	$4,581,202	$4,193,491	$3,723,004
Distribution Right-of-Way Widening	$9,945,185	$12,502,942	$11,044,925	$13,223,181
	$137,652,721	$136,149,656	$125,330,493	$140,496,453

	2024 Actual	2025 Budget	2025 Forecast*	2026 ACE Plan
General Plant				
Work Vehicles	$7,749,175	$19,199,029	$19,181,421	$23,178,690
Tools and Test Equipment	$2,148,827	$1,921,927	$1,310,689	$2,728,540
Telecommunications	$1,597,599	$1,387,013	$1,383,262	$1,507,720
Computing Asset Management	$2,356,066	$4,506,479	$2,853,527	$4,503,704
Property Improvements and Furniture	$3,393,573	$4,882,004	$4,932,004	$4,797,200
Other	$1,298,642	$1,450,720	$1,446,207	$1,440,100
	$18,543,882	$33,347,172	$31,107,111	$38,155,954
Total Routine Capital Spending	**$176,712,341**	**$195,081,331**	**$181,539,774**	**$207,302,889**

*The Forecast includes actuals up to July and forecast amounts for the remainder of the year.

10.2 Routine Capital Spending Project Breakdown Yr/Yr

Figure 35: Routine Capital Spending Project Breakdown Yr/Yr

Project #	CI #	Project Title	2024 Actual	2025 Budget	2025 Forecast*	2026 ACE Plan
G001	10634	CT - Routine Equipment Replacements	$319,592	$305,936	$304,668	$301,648
H001	11622	HYD - Routine Equipment Replacement	$1,000,346	$951,549	$980,014	$223,356
H004	27867	HYD - Roofing Routine	$146,615	$132,189	$124,078	$241,392
S001	10645	POT - Routine Equipment Replacement	$202,363	$227,451	$233,111	$223,262
	10673	TRE - Routine Equipment Replacement	$523,902	$385,427	$384,668	$322,170
	43646	PHB - Routine Equipment Replacement	$274,519	$232,603	$239,581	$230,940
	10621	TUC - Routine Equipment Replacement	$(1,058,413)	$378,649	$360,184	$349,897
	10626	LIN - Routine Equipment Replacement	$335,953	$397,910	$413,255	$397,319
	10718	POA - Routine Equipment Replacement	$202,802	$234,581	$225,936	$159,361
S004	27858	POA - Roofing Routine	$63,365	$150,102	$166,877	$149,596
	27856	TRE - Roofing Routine	$95,993	$269,732	$258,741	$122,842
	27855	POT - Roofing Routine	$145,501	$134,857	$115,073	$132,813
	27854	TUC - Roofing Routine	$32,082	$50,571	$50,891	$50,709
	C0068934	PHB - Roofing Routine	$-	$125,774	$128,734	$167,434
	27857	LIN - Roofing Routine	$143,056	$176,095	$200,626	$189,111
W001	41830	Wind - Routine Equipment Replacement	$957,304	$1,548,773	$1,548,773	$1,512,669
	Generation Equipment Replacements Total		**$3,384,982**	**$5,702,198**	**$5,735,210**	**$4,774,519**

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Project #	CI #	Project Title	2024 Actual	2025 Budget	2025 Forecast*	2026 ACE Plan
H005	35583	HYD - Oil Release Risk Assessment	$401,047	$459,164	$540,199	$472,672
H006	35584	HYD - Gate Refurbishment	$193,592	$208,428	$222,740	$227,557
	C0053718	HYD - Dam Safety Routine	$608,240	$684,627	$660,064	$690,547
	Generation Hydro Total		**$1,202,879**	**$1,352,219**	**$1,423,003**	**$1,390,776**
S005	C0068935	PHB - Heat Rate Routine	$-	$125,023	$131,255	$126,799
	33871	TUC - Heat Rate Routine	$85,150	$87,482	$81,029	$87,489
	33865	POA - Heat Rate Routine	$26,254	$62,030	$57,444	$30,130
	33867	POT - Heat Rate Routine	$58,413	$107,264	$110,761	$104,395
	33869	TRE - Heat Rate Routine	$167,447	$79,311	$79,085	$66,212
	33863	LIN - Heat Rate Routine	$225,786	$76,863	$85,328	$80,705
	Generation Thermal Total		**$563,050**	**$537,973**	**$544,902**	**$495,729**
T003	23120	Provincial - Trans Substation Primary	$3,298,931	$3,450,150	$3,454,431	$3,122,388
T004	23121	Provincial - Substation Additions & Replacements	$1,028,268	$925,361	$915,914	$902,743
	Transmission Subs Replace, Adds/Mods Total		**$4,327,200**	**$4,375,511**	**$4,370,346**	**$4,025,131**
T018	14973	Primary Equipment Spares	$91,829	$300,000	$205,969	$192,433
	Primary Equipment Spares Total		**$91,829**	**$300,000**	**$205,969**	**$192,433**
T016	14841	Protection Modification & Replacement	$1,006,327	$987,791	$749,316	$862,088
	Protection Modification & Replacement Total		**$1,006,327**	**$987,791**	**$749,316**	**$862,088**
T001	23115	Provincial Transmission Line Replace	$3,135,399	$3,274,053	$3,251,791	$3,322,385
T011	23118	Provincial Planned Trans Line Replacement	$6,193,581	$6,055,258	$6,038,511	$5,680,154
T020		Transmission Switch & Breaker Replacements	$-	$-	$-	$2,326,441
T030**		Transmission Tower Life Extension / Replacement	$-	$-	$-	$2,266,774
	Transmission Line Replacements Total		**$9,328,980**	**$9,329,311**	**$9,290,302**	**$13,595,755**
T010	43827	Transmission Right of Way Widening	$610,491	$2,999,500	$2,783,122	$3,314,050
	Transmission Right-of-Way Widening Total		**$610,491**	**$2,999,500**	**$2,783,122**	**$3,314,050**
D009	26496	Meter Routine	$4,243,038	$4,876,834	$4,622,931	$3,870,540
	Meters Total		**$4,243,038**	**$4,876,834**	**$4,622,931**	**$3,870,540**

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Project #	CI #	Project Title	2024 Actual	2025 Budget	2025 Forecast*	2026 ACE Plan
D005	23158	Unplanned Replace Deteriorated	$26,385,283	$21,246,256	$19,078,092	$22,418,590
D006	23135	Regulatory Replacements - Province	$3,984,809	$4,124,211	$2,016,761	$4,118,292
D008	23361	Provincial Storm	$1,254,914	$8,023,575	$7,873,900	$6,927,211
D051	29038	System Performance Improvement Routine	$788,225	$729,719	$468,989	$1,099,867
D055	23137	Planned Replacement Of Distribution	$12,512,179	$10,620,862	$9,392,911	$15,000,016
D020**		2026 Padmount Replacement Program	$-	$-	$-	$2,278,256
	Distribution Upgrades and Replacement Total		**$44,925,409**	**$44,744,622**	**$38,830,652**	**$51,842,231**
D004	26716	New Customer Upgrades	$20,888,924	$17,342,537	$18,942,962	$19,283,936
D018	23511	Primary Equipment Spares - Distribution	$86,160	$160,000	$160,000	$162,391
D061	39766	New Customers - Residential	$40,528,401	$39,490,277	$35,425,441	$36,063,099
D062	39770	New Customers - Commercial	$13,455,991	$12,451,243	$12,110,090	$12,328,071
	New Customers Total		**$74,959,476**	**$69,444,057**	**$66,638,493**	**$67,837,497**
D007	23136	Contractual Replacements (Joint Use)	$3,579,613	$4,581,202	$4,193,491	$3,723,004
	Joint Use Total		**$3,579,613**	**$4,581,202**	**$4,193,491**	**$3,723,004**
D010	23127	Provincial Widening	$9,945,185	$12,502,942	$11,044,925	$13,223,181
	Right of Way Widening Total		**$9,945,185**	**$12,502,942**	**$11,044,925**	**$13,223,181**
P006	20945	Replacement and Additional Work Vehicles	$472,697	$1,098,000	$1,043,378	$417,500
P063	39304	Class 3 Work Vehicle Replacements	$339,902	$300,000	$318,456	$740,000
P062	39305	Work Vehicle Replacements	$1,318,804	$11,590,824	$11,608,586	$15,452,790
P061	40236	Transportation Vehicle Replacements	$5,617,771	$6,210,205	$6,211,001	$6,568,400
	Work Vehicles Total		**$7,749,175**	**$19,199,029**	**$19,181,421**	**$23,178,690**
P002/ P016		Meter Shop - Tools and Equipment	2,139,286	1,794,409	1,177,749	2,597,197
P015	11611	Hydro Production Tools, Test Equipment	9,542	127,517	132,940	131,343
	Tools and Test Equipment Total		**$2,148,827**	**$1,921,927**	**$1,310,689**	**$2,728,540**
P025	16365	Mobile Radio Routine	$234,110	$238,819	$248,243	$224,550
P027	16551	Telecommunication Radio and Fibre Optics	$189,831	$222,168	$206,222	$222,400
P028	16550	Telecommunication Systems Replace & Modifications	$994,759	$741,326	$728,795	$852,510
P814	38243	Telecommunications Spares	$178,899	$184,700	$200,002	$208,261
	Telecommunications Total		**$1,597,599**	**$1,387,013**	**$1,383,262**	**$1,507,720**

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Project #	CI #	Project Title	2024 Actual	2025 Budget	2025 Forecast*	2026 ACE Plan
P010	16073	SCADA Improvements Routine	$66,249	$50,596	$44,469	$120,428
P031	29114	NS Power IT Infrastructure	$280,976	$2,568,500	$918,500	$2,528,500
	C0061443	IT - WAM Capital Enhancement Routine	$1,732,283	$1,677,413	$1,678,940	$1,625,040
P040	28522	CT's DCMS Routine	$53,212	$20,229	$21,502	$21,177
	25647	POA - DCMS Equipment Replacement Routine	$41,830	$35,000	$38,246	$49,785
	25667	POT - DCMS Equipment Replacement Routine	$69,274	$35,000	$30,147	$29,250
	25626	TRE - DCMS Equipment Replacement Routine	$7,737	$28,750	$35,235	$32,551
	25646	TUC - DCMS Equipment Replacement Routine	$81,230	$56,000	$56,060	$57,000
	25668	LIN - DCMS Equipment Replacement Routine	$23,274	$34,992	$30,429	$39,973
	Computing Asset Management Total		**$2,356,066**	**$4,506,479**	**$2,853,527**	**$4,503,704**
P001/ P030	11744	Property Improvement and Furniture	$3,393,573	$4,882,004	$4,932,004	$4,797,200
	Property Improvement and Furniture Total		**$3,393,573**	**$4,882,004**	**$4,932,004**	**$4,797,200**
P012/ P041	20706	Other (HYD - Security Improvement & FAC - Land Acquisition)	$528,890	$600,720	$613,565	$590,100
P018	48158	Environment Equipment Replacement Routine	$117,146	$100,000	$75,000	$100,000
P816	38897	FAC Enviro Property Remed Routine	$259,842	$325,000	$359,563	$325,000
P815	38896	FAC Environment Site Assess Routine	$189,390	$325,000	$296,547	$325,000
P032	38848	Purchasing Equip & Warehouse Routine	$203,374	$100,000	$101,532	$100,000
	Other Total		**$1,298,642**	**$1,450,720**	**$1,446,207**	**$1,440,100**
	Routine Capital Spending		**$176,712,341**	**$195,081,331**	**$181,539,774**	**$207,302,889**

*The 2025 Forecast includes actuals up to July and forecast amounts for the remainder of the year.

**The table above includes three new Routine Categories; Transmission Tower Refurbishment / Life Extension, Transmission Switch & Breaker Replacement and Padmount Replacement Program. These have been added to the Routine Program as they are investments that occur year over year, with no planned end date at this time. Including these as routines as opposed to stand-alone projects for approval improves regulatory efficiency, while still providing a similar level of transparency on project costs.

1

10.3 Like-for-Like Routine Replacements

The Board's 2013 ACE Plan Order Directive 2 provided as follows:

> The Board directs NSPI, in the next ACE Plan application, to analyze the routine expenditures to determine what are the "like-for-like" totals. NSPI is further directed to explain why those totals, if they are similar in magnitude to the Board's analysis, are growing at an annual rate in excess of inflation.[16]

A summary of NS Power's total routine and like-for-like routine spending is provided in **Figure 36** below.

Figure 36: Annual Cost of Like-for-Like Routine Replacements

NOVA SCOTIA POWER ($M)	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 ACE
Total Routine Spending	230.0	153.3	176.7	181.5	207.3
Less:					
New Customers	40.8	54.1	75.0	66.6	67.8
System Growth and Performance	1.9	3.4	12.9	15.8	21.3
Other	1.7	1.3	1.5	1.9	1.8
Like-for-Like	185.6	94.5	87.3	97.3	116.4
Work Vehicles (Like-for-like)	10.2	8.9	7.7	19.2	23.2
Net (Like-for-like)	175.4	85.6	79.6	78.1	93.2

Routine classifications are determined by the primary classification of each routine project. If the majority of the work completed under the routine is like-for-like replacements, the routine is classified as like-for-like. New Customer routines, System Growth and Performance routines (such as heat rate, system improvement, and right-of-way widening routines), and other routines (such as environmental assessment routines) are not included in the like-for-like totals.

[16] NSUARB-P-128.13, 2013 Annual Capital Expenditure Plan, Board Order, June 4, 2013.

10.4 2026 Routine Capital Spending Project Details

Transmission

Figure 37: Transmission Substation Replacements, Additions and Modifications

T003 Provincial: Transmission Substation Primary Equipment	2026 ACE Plan Forecast
Unplanned Replacements	2,452,388
Lightning Arrestor Replacements	150,000
Transformer Regaskets	150,000
Breaker Regaskets	70,000
Insulating Fluids Replacements	150,000
Battery Bank Replacements	150,000
Total T003 Provincial: Transmission Substation Primary Equipment	**$3,122,388**
T004 Provincial: Substation Additions & Replacements	
Unknown Additions	182,743
Oil Containment Additions	720,000
Total T004 Provincial: Substation Additions & Replacements	**$902,743**
Total Transmission Substation Replacements, Additions and Modifications	**$4,025,131**

Figure 38: Primary Equipment Spares

T018 Primary Equipment Spares	2026 ACE Plan Forecast
Online DGA Monitors	59,500
Tap Changer Components	78,433
Transformer Auxiliary Devices	54,500
Total Primary Equipment Spares	**$192,433**

Figure 39: Protection Modification and Replacement

T016 Protection Modification & Replacement	2026 ACE Plan Forecast
This routine is budgeted based on historical T016 investment.	**$862,088**

1

2 **Figure 40: Transmission Line Replacement, Additions, Modifications**

		2026 ACE Plan Forecast
T001 Provincial Transmission Line Replacement (Unplanned)		
This routine is budgeted based on historical T001 investment		**$3,322,385**
T011 Provincial- Planned Transmission Line Replacement		
LINE #	**Description**	
L5538	Sissiboo 15V to Weymouth 16V	750,000
L5563	Victoria Junction 2S to Townsend St. 4S	650,000
L5575	Whitney Pier 82S to New Waterford 15S	200,000
L5524	Lochaber Rd 4C to Salmon River 57C	550,000
L5040	Onslow 1N to Tatamagouche 4N	450,000
L6531	Milton 50W to Bridgewater 99W	650,000
L6511	Trenton 50N to Glen Dhu 93N	650,000
Various	1-6 Month Inspection Driven Work	1,780,154
T011 Provincial - Planned Transmission Line Replacement		**$5,680,154**

T020 Transmission Switch & Breaker Replacements

Asset	Quantity	Avg Unit Price	2026 ACE Plan Forecast
Switch (<69 kV)	2	25,721	51,441
Switch (69 kV)	7	33,500	234,500
Switch (138 kV)	9	104,500	940,500
Breaker (69 kV)	2	225,000	450,000
Breaker (138 kV)	2	325,000	650,000
			$2,326,441

T030 Transmission Tower Life Extension / Replacement

Description	Quantity	Avg Unit Price	2026 ACE Plan Forecast
Sacrificial Anode Installation Program	80	14,097	1,127,764
Steel Tower Life Extension Program	20	56,951	1,139,010
			$2,266,774
Total Transmission Line Replacement, Additions, Modifications			**$13,595,755**

T010 – Provincial: Transmission Right of Way Widening

In its 2017 ACE Plan Order, the Board directed NS Power as follows:

> The Board directs NSPI to update the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan (and future years) based on actual historical costs incurred for this project.[17]

NS Power confirms that the cost estimates for vegetation management and right-of-way widening projects in the 2026 ACE Plan are based on actual historical costs incurred. This forecast is also developed based on the known level of widening in the current year as set out in **Figure 41** below.

Figure 41: T010 Forecast by Line

> 69 kV	
L-7003	747,934
L-7004	971,074
L-7009	747,934
L-6503	847,108
Total T010	**$3,314,050**

[17] M07745, NS Power 2017 Annual Capital Expenditure Plan, Board Order, April 4, 2017.

The Board's 2016 ACE Plan Order provided the following directive:

> The Board directs that the Routine for Transmission widening be treated as a separate project, and not a routine, in future ACE Plan Applications. NSPI is to provide an annual progress report on the expenditure, works undertaken, results achieved and future plans as part of the annual ACE Plan submissions.[18]

CI C0052055 - 2023/2024 Transmission Right-of-Way Widening 69kV was approved by the Board on March 6, 2023. This was the last phase of the 69kV widening program, which was completed in 2024. The addition of a separate capital work order for transmission Right-of-Way widening since 2016 has led to the transmission vegetation management program being carried-out under three broad initiatives:

1. Operating activities for transmission vegetation management;
2. Capital routine T010 - Transmission Right-of-Way Widening (for 138kV, 230kV, and 345kV ROWs); and
3. New transmission rights-of-way widening individual capital projects (i.e. CI C0052055 and prior phases for 69kV ROWs).

With the conclusion of the 69kV Widening program in 2024, the transmission vegetation management program now includes only items 1 and 2 listed above. NS Power continuously assesses the potential of increasing the width of certain rights-of-way on its 138kV system in areas where additional width is warranted. This is reflected in the continued increased T010 Transmission ROW Widening routine which has increased from a historical budget of $600,000 to the $3.3 million investment included in the 2026 Routine Capital Program. This work will continue to improve the transmission system's ability to withstand significant weather events where tree fall ins from the edge of the ROW can pose a risk to NS Power's infrastructure.

[18] M07176, NS Power 2016 Annual Capital Expenditure Plan, Board Order, June 8, 2016, page 2. NS Power's annual progress report on the expenditure, works undertaken, results achieved and future plans can be found in the 2026 ACE Plan Reliability Directive in **Section 11.1.4**.

Widening these ROWs mitigates the risk of tree fall ins for the vast majority of trees on the edge of the ROW.

The increased investment in T010 for the widening of 138kV, 230kV, and 345kV rights-of-way remains consistent with the 2016 directive. While the 69kV widening program is now complete, there are areas where permission or easements from landowners could not be acquired. In the event that permission or an easement is received, this work is still valuable to be completed and therefore will be included in T010 in the future.

Distribution

In its Decision relating to the 2021 Distribution Routines ATO, the Board directed NS Power to include information in the 2024 ACE Plan as follows:

> 7. To report in the 2024 ACE Plan on the findings and actions taken as a result of the review of each individual routine. NS Power should consider these routines respective increase drivers when budgeting for their costs.

Although this directive was specific to the 2024 ACE Plan, NS Power believes that this information remains helpful. Please refer to **Figure 42** below for a summary of the forecasting methodology used in each Distribution Routine.

Figure 42: Summary of Forecasting Methodology for Distribution Routines

Distribution Routines	Forecasting Methodology
D004 New Customer Upgrades	2025 Q3 Forecast Plus Inflation
D005 Unplanned Replacement Deteriorated Equipment	5 Year Average Plus Inflation
D006 Regulatory Replacements - Province	3 Year Average Plus Inflation
D007 Joint Use	3 Year Average Plus Inflation (excluding 2023 actuals)

Distribution Routines	Forecasting Methodology
D008 Provincial Storm	5 Year Average Plus Inflation (excluding Extreme Events)
D051 System Performance Improvement Routine	Based on project estimates
D055 Planned Replacement Deteriorated Equipment	Partially based on 2025 Q3F Plus Inflation for Bin work, streetlight/service installation and removal and Field Driven Work and individual project estimates
D061 New Customers - Residential	2025 Q3 Forecast Plus Inflation
D062 New Customers - Commercial	2025 Q3 Forecast Plus Inflation

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Figure 43: Meters - D009 Meter Routine

Item#	Prg#	Meter Type	Meter Style	Description	2026 Forecast	Current Unit Cost ($)	Capital for meters ($)
1.0 Element, 120-240 volt							
	103	Form 3S (5 Jaw)	3450560	CP3SRA (HW4.1) 3S CL20 OPENWAY RIVA CENTRON POLYPHASE METER. 120V-277V. BID	384	176.00	67,584
	104	Form 3S (5 Jaw)	3450564	CP3SRA (HW4.1) 3S CL20 OPENWAY RIVA CENTRON POLYPHASE METER. 120V-277V. (TOU)BID	192	176.00	33,792
1.5 Element, 120-240 volt							
	101	C2SRD	3450510	C2SRD (HW 4.1) 2S CL200 OPENWAY RIVA CENTRON W/ DISCONNECT.	1200	125.00	150,000
	102	C2SRD TOU/BID	3450512	C2SRD (HW 4.1) 2S CL200 OPENWAY RIVA CENTRON W/ DISCONNECT (TOU)BID	3480	125.00	435,000
	102	C2SR	3450569	C2SR (HW4.1) 2S CL200 OPENWAY RIVA CENTRON "NO DISCONNECT"	120	125.00	15,000
	0	C2SR 320	3450570	C2SR (HW 4.1) 2S CL320 OPENWAY RIVA CENTRON no DISCONNECT.	240	238.00	57,120
	0	0	adder	Cellular Adder single phase	8	143.00	1,144
2.0 Element, 120-480 volt							
	101	0	3450511	CN2SRD (HW 4.1) 12S CL200 OPENWAY RIVA CENTRON W/ DISCONNECT	3960	139.00	550,440
	102	0	3450513	CN2SRD (HW 4.1) 12S CL200 OPENWAY RIVA CENTRON W/ DISCONNECT (TOU)	360	139.00	50,040
	0	0	3450559	CP3SRA (HW4.1), 12S CL200 OPENWAY RIVA CENTRON POLYPHASE METER. 120V-277V	96	216.00	20,736
	103	45s	3450565	CP3SRA (HW4.1) 45S CL20 OPENWAY RIVA CENTRON POLYPHASE METER. 120V-277V	96	204.97	19,677
3.0 Element, 120-347 volt							
	103	9s	3450561	CP3SRA (HW4.1) 9S/36S CL20 OPENWAY RIVA CENTRON POLYPHASE METER. 120V-277V	288	216.00	62,208
	103	16s	3450562	CP3SRA (HW4.1) 16S CL200 OPENWAY RIVA CENTRON POLYPHASE METER. 120V-277V	288	216.00	62,208
	103	16s	3450563	CP3SRA (HW4.1) 16S CL200 OPENWAY RIVA CENTRON POLYPHASE METER. 240V-480V	384	216.00	82,944
	0	0	adder	Cellular adder, 3 phase	8	143.00	1,144

Total Meters	**11,104**		**1,609,037**
Misc Meters "ION"	6	9,500	57,000
Cellular Meters	12	1,000	12,000
CT and PT requirements			450,000
Wire, Adapters and switches			100,000
CGR Batteries			100,000
Total Materials			**2,328,037**
Freight			**72,176**
Applied Overhead			**805,505**
Labour			**664,822**
D009 Meters Total			**3,870,540**

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Distribution Upgrades and Replacements

Figure 44: Distribution Upgrades and Replacements

	2026 ACE Plan Forecast
D005 Unplanned Replacement Deteriorated Equipment	
This forecast is developed based on a five-year historical average of prior spending levels with an annual inflation of 1.8 percent, resulting in an estimated 8,446 persondays of work at a unit cost of $2,654/personday.	$22,418,590
D006 Regulatory Replacements	
This forecast is developed based on past experience and information from various government agencies. This amount could vary based on current year decisions by these agencies. This forecast is developed based on a three-year historical average of prior spending levels with an annual inflation of 1.8 percent.	$4,118,292
D008 Provincial Storm	
This forecast is developed based on a five-year historical average of prior spending levels with Extreme Event Day storms removed and an annual inflation of 1.8%. There can be significant variation in this amount based on yearly storm activity.	$6,927,211
D051 System Performance Improvement	
6W-201 - Offload to 50W	82,734
50W-411- Milton Station Service	100,000
Recloser Additions	517,132
2026 Tripsaver Additions	300,000
9H Substation Plan	100,000
Total D051 System Performance Improvement	**$1,099,866**

D055 Planned Replacement of Distribution Equipment	
Bin Work (Work resulting from NS Power's distribution line inspection program that has been identified as requiring follow up within one year.)	$1,872,458
Field Driven Work	$3,767,543
Streetlight/service installation & removal (This funding is to support system upgrades required for streetlight installations and upgrades. This includes transformer installs, service upgrades and/or new pole installations.)	$1,751,752
Conversion Work	$940,000
5 year plan feeder level Targeted Equipment Replacement	$6,668,263
Total D055 Planned Replacement of Distribution Equipment	**$15,000,016**
D020 Padmount Replacements	**2,278,256**
Distribution Upgrades and Replacement Total	**$51,842,230**

D005 Forecasting Approach

In its Decision relating to the 2019 Distribution Routines ATO, the Board directed NS Power as follows:

1. NS Power is to provide further breakdown of forecasting and overtime within future ACE/ATO filings in order to improve the transparency of reporting provided for the D005 Routine.

2. NS Power is to improve transparency in future ACE/ATO filings by including further information on how the historical large storm events have been incorporated into this Routine, and how they affect the ongoing forecast.[19]

In its Decision relating to the 2020 Distribution Routines ATO, regarding the D005 Routine, the Board directed NS Power to "provide further details on failed and damaged devices in future ACE Plan and ATO filings, including current and historical operational and financial data"[20].

[19] M09656, NS Power 2019 Distribution Routines ATO, Board Decision, October 21, 2020.
[20] M10182, NS Power 2020 Distribution Routines ATO, Board Decision, December 13, 2021.

The forecast for D005 for 2026 was developed based on the previous 5-year average for spend from 2021-2025 plus an annual inflation of 1.80 percent. This forecast resulted in an estimated 8,446 person days of work at a unit cost of $2,654/person day. The unplanned asset failures included in this routine can occur at any time of day, including outside of normal business hours. Failures necessitating a reactive response at such times results in crews responding to replace the failed asset and restore service on an overtime basis as needed. Accordingly, the contribution from overtime labour is specifically included in the development of D005 forecasts. Historical details on failed equipment are provided in **Section 11.1.4, Figure 71**. While this information is not broken down by sub-routine (and therefore does not provide specific details for D005), it provides a directional view of the most impactful equipment failures the Company is experiencing. Further detail will be provided as part of future ATO filings, as required. The following breakdown of annual regular labour and overtime labour spend are both inputs into the 5-year average forecast.

Figure 45: 2021-2025 Spend in D005

Year	Regular Labour (PH)	Regular Labour $/PH	Overtime Labour (PH)	Overtime Labour $/PH
2021	47,611	$ 49.38	28,394	$ 98.77
2022	38,170	$ 49.19	27,966	$ 98.38
2023	48,741	$ 52.04	28,066	$ 104.08
2024	51,328	$ 54.16	31,090	$ 108.32
2025*	33,869	$ 56.80	30,582	$ 113.60

PH = Personhours

*This value includes Actuals to the end of September 2025 and forecast for the remainder of the year.

Using the 5-year average and an annual inflation factor of 1.80 percent results in a forecast 2026 spend in D005 of the following:

Figure 46: Forecast 2026 Spend in D005

Year	Regular Labour (PH)	Regular Labour $/PH	Overtime Labour (PH)	Overtime Labour $/PH
2026	40,549	$ 59.69	27,021	$ 119.38

This forecasting approach inherently includes an accounting for the impacts of previous years' events, such as an increase of extreme event days, through the influence on the overall D005 spending in each previous reference year detailed above. This ultimately results in budgeted amounts for D005 that reflect the overall trend of impacts from the individual reference years from 2021-2025. The resulting forecast D005 spend is dynamically adjusted as the number of impacts increase (or decrease) in the previous reference years. This supports an evolving response to cumulative effects as the associated trends emerge. The nature of individual replacements undertaken in a reactive manner under D005 does not support clear attribution specifically to the cumulative effects from previous years but result in work in the current year as opposed to in-year effects. However, NS Power believes that the 5-year budgeting methodology presented above is a reasonable approach to account for the overall effects on D005 from storm activity in prior years.

New Customers

Figure 47: New Customers

	2026 ACE Plan Forecast
D004 New Customer Upgrades This forecast is developed based on forecasted spending levels in 2025 for New Customer Upgrades with an annual inflation of 1.8%.	**$19,283,936**
D018 Primary Equipment Spares Distribution This forecast is developed based on the probable amount of distribution spare equipment required during the year.	**$162,391**
D061 New Customers - Residential This forecast is for the costs associated with new residential customers net of capital contributions. Costs include metered services, unmetered services, line extensions and underground services. This forecast is developed based on forecasted spending levels in 2025 with an annual inflation of 1.8%.	**$36,063,099**

D062 New Customers - Commercial This forecast is for the costs associated with new commercial customers net of capital contributions. Costs include metered services, unmetered services, line extensions and underground services. This forecast is developed based on forecasted spending levels in 2025 with an annual inflation of 1.8%.	**$12,328,071**
Total New Customers	**$67,837,497**

Joint Use

Figure 48: Joint Use

D007 Joint Use	**2026 ACE Plan Forecast**
This forecast is developed based on prior spending levels for both Joint Use requests from Nova Scotia Power's Joint Use Partner, Bell and communication utility requests and reflects the continued activities associated with the Internet for NS Program rolled out by the Province of Nova Scotia. This forecast is developed based on a three-year historical average of prior spending levels with an annual inflation of 1.8%.	**$3,723,004**
Distribution Total	**$127,273,271**

Distribution Right-of-Way Widening

In its 2017 ACE Plan Order, the Board directed NS Power as follows:

> The Board directs NSPI to update the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan (and future years) based on actual historical costs incurred for this project.[21]

NS Power confirms that the cost estimates for vegetation management and right-of-way widening projects in the 2026 ACE Plan are based on actual historical costs incurred. This forecast is also developed based on the known level of widening in the current year. The 2026 ACE Plan forecast for D010 ROW Widening is consistent with the approach used in 2024 and 2025, which included a step change in investment under this routine. This step change represents a continuation of the

[21] M07745, NS Power 2017 Annual Capital Expenditure Plan, Board Order, April 4, 2017.

New Distribution ROW where areas with no discernable ROW are being cleared to create a ROW with a clearance of 20 feet on the forested side of the line. That program only focuses on areas with no ROW currently, while prior to 2024, D010 historically widened already defined ROWs from 10 feet to 15-20 feet. With the success of the New Distribution ROW program and the benefits seen from the additional clearance, NS Power is applying the goal of 20 feet of clearance to all areas of NS Power's Distribution system where achievable.

The spend in this routine reflects the work that will be required to widen the rights-of-way to 20 feet on the forested side of the line is noted in **Figure 49**.

Figure 49: Distribution Right-of-Way Widening

Feeder Section	Geographic Location	Length (Km)	Managed Length (Km)	Avg Cost per Km	Cost	Contract Overhead	Total Segment Cost
137H-411	Hammonds Plains	11.00	11.00	39,600	435,600	62,996	498,596
137H-412	Hammonds Plains	8.00	8.00	39,600	325,315	47,047	372,362
137H-414	Hammonds Plains	1.00	1.00	39,600	51,862	7,500	59,362
48H-301	Dartmouth	3.00	3.00	39,600	120,562	17,436	137,998
96H-412	Sheet Harbour	7.00	7.00	39,600	266,044	38,475	304,519
100C-422	Mulgrave	2.00	2.00	39,600	78,803	11,396	90,199
22C-403	Dundee	10.00	10.00	39,600	383,239	55,424	438,663
22C-404	Hureauville	5.00	5.00	39,600	194,650	28,150	222,800
24C-442	Phillips Harbour	1.00	1.00	39,600	51,862	7,500	59,362
3S-308	North Sydney	1.00	1.00	39,600	53,209	7,695	60,904
57S-401	Albert Bridge	18.00	18.00	39,600	697,104	100,815	797,919
57S-402	Albert Bridge	35.00	35.00	39,600	1,386,000	200,443	1,586,443
81S-305	Glace Bay	1.00	1.00	39,600	24,247	3,507	27,754
85S-401	Ingonish	9.00	9.00	39,600	353,603	51,138	404,741
15N-401	Harmony	9.00	9.00	39,600	338,786	48,995	387,781
30N-412	River Hebert	3.00	3.00	39,600	113,153	16,364	129,517
4N-313	Tatamagouche	9.00	9.00	39,600	352,256	50,943	403,199
57C-417	Ogden	0.97	0.97	39,600	38,391	5,552	43,943
57C-426	Jordanville	9.70	9.70	39,600	383,912	55,521	439,433
62N-413	Thorburn	10.68	10.68	39,600	422,977	61,171	484,148
74N-412	Millevale	5.46	5.46	39,600	216,203	31,267	247,470

Feeder Section	Geographic Location	Length (Km)	Managed Length (Km)	Avg Cost per Km	Cost	Contract Overhead	Total Segment Cost
102W-311	Wedgeport	5.94	5.94	39,600	235,062	33,995	269,057
23W-301	Clyde River	2.65	2.65	39,600	105,071	15,195	120,266
25W-302	Shelburne	9.03	9.03	39,600	357,644	51,722	409,366
57W-401	Molega Lake	27.00	27.00	39,600	1,069,200	154,628	1,223,828
57W-402	Caladonia	9.36	9.36	39,600	370,442	53,573	424,015
63V-313	Aylesford	15.77	15.77	39,600	624,362	90,295	714,657
76V-301	Maitland Bridge	1.62	1.62	39,600	64,053	9,263	73,316
77V-401	Tiverton	13.11	13.11	39,600	519,292	75,100	594,392
78W-301	Sunnybrook	8.50	8.50	39,600	336,765	48,703	385,468
78W-302	Spectacle Lakes	3.40	3.40	39,600	134,706	19,481	154,187
80W-301	Tanners Settlement	9.36	9.36	39,600	370,442	53,573	424,015
91W-411	Greenfield	17.01	17.01	39,600	673,530	97,406	770,936
92W-302	Moodys Corner	10.21	10.21	39,600	404,118	58,444	462,562
Total Distribution Right-of-Way Widening							**13,223,182**

Note: Totals may be slightly off due to rounding.

Pursuant to CI 49611 - New Distribution Rights-of-Way Phase I, submitted to the Board on November 1, 2016, Liberty Consulting Group's report on its review of NS Power's response to Post Tropical Storm Arthur (PTSA) included a recommendation that for distribution rights-of-way NS Power should "develop a comprehensive plan for reclaiming and/or widening the overgrown ROW corridors".[22] In its Supplemental Decision on September 21, 2015, the Board directed NS Power as follows:

> [36] A circumstance where it will take 32 years for the distribution vegetation management program to become sustainable causes the Board significant concern.
> //
> [38] The Board is intrigued by the stakeholder discussion concerning innovative financing options and directs NSPI to pursue that issue and report back to the Board the results of those discussions. [23]

[22] M06321, Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, Liberty Consulting Group, Comments on Review of NS Power's Storm Response, Exhibit A-4, September 9, 2014, page 7.

[23] M06321, Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, Board Supplemental Decision, September 21, 2015, page 14. NS Power responded with its proposal to increase spend in D010 in the 2016 ACE Plan.

In response to the Board's concerns, and in order to further reduce the likelihood of tree contact related outages like those during the PTSA event, NS Power increased the budget for the 2016 ACE Plan. NS Power's 2016 ACE Plan provided the following:

> NS Power is seeking approval as part of the 2016 ACE Plan of $3 million for the distribution widening routine, D010, in 2016. The $3 million comes from the portion of the annual $10.4 million that is spent on managing the vegetation in distribution ROWs to a sustainable state.[24]

In its 2016 ACE Plan Decision regarding D010, the Board directed NS Power as follows:

> …the Board assumes that NSPI has increased the distribution Routine budget by an amount of $2.4 million from the operating budget over the $600,000 in the 2015 ACE Plan. This means that NSPI is reducing its operating expenses by $2.4 million in 2016, thus increasing profits, with a corresponding increase in its rate base. This action will only increase rates which the Board does not approve. Accordingly, the Board reduces the routine budget for D010 to $600,000, to be in line with the 2015 ACE Plan amount.[25]

Consistent with prior ACE Plans, for the 2026 ACE Plan, New Distribution ROW spending is not included in the budget for D010. However, as discussed above, the D010 budget has been increased, consistent with the approach used in 2024 and 2025, to allow for the new standard ROW width to be applied to areas of the Distribution system that already have defined ROWs. Investment to establish new distribution rights-of-way where none have previously existed remains with the New Distribution ROW program.

[24] M07176, NS Power 2016 Annual Capital Expenditure Plan, November 12, 2015, page 72.
[25] M07176, NS Power 2016 Annual Capital Expenditure Plan, Board Decision, June 8, 2016, page 18.

General Plant

Figure 50: Work Vehicles

	Quantity	Avg Unit Price	2026 ACE Plan Forecast
P006 Replacement and Additional Work Vehicles			
Reel and Pole Trailers	3	100,000	300,000
UTV / RTV	2	60,000	120,000
Salvage			(2,500)
Total P006 Replacement and Additional Work Vehicles			**$417,500**
P061 Transportation Vehicle Replacements	97	72,076	6,991,400
Salvage			(423,000)
			$6,568,400
P062 Work Vehicle Replacements	27	587,140	15,852,790
Salvage			(400,000)
			$15,452,790
P063 Class 3 Work Vehicle Replacements	4	195,000	780,000
Salvage			(40,000)
			$740,000
		Total Work Vehicles	**$23,178,690**

Figure 51: Tools and Test Equipment

	2026 ACE Plan Forecast
Meter Shop Tools and Equipment	$50,000
Provincial Line Tools & Equipment	
Western Territory	175,000
North Eastern Territory	175,000
Cape Breton Territory	175,000
Central Territory	175,000
T&D Asset	550,000
System Maintenance	900,000
P002 Tools and Equipment Total	**$2,200,000**

	2026 ACE Plan Forecast
P015 Hydro Production Tools & Test Equipment	**$131,343**
P016 Thermal Production Tools & Test Equipment	
POT Tools & Equipment	53,500
TUC Tools & Equipment	58,750
TRE Tools & Equipment	70,521
LIN Tools & Equipment	75,000
CT Tools & Equipment	25,000
PHB Tools & Equipment	45,000
POA Tools & Equipment	69,426
P016 Thermal Production Tools & Test Equipment Total	**$397,197**
Tools and Test Equipment Total	**$2,728,540**

Figure 52: Telecommunication

	2026 ACE Plan Forecast
P025 Mobile Radio	
Replacement radio equipment hardware and upgrades	110,000
Equipment repairs, antenna replacements and repairs	39,000
Mobile radio servers repairs and upgrades	23,550
Miscellaneous support for system	52,000
P025 Mobile Radio Total	**224,550**
P027 Telecommunication Radio & Fibre Ops	
HVAC & Generator Upgrades	119,000
Radio Site repairs - Miscellaneous	58,300
Add Generator Alarms and Controls	18,700
Miscellaneous Upgrades and Replacements	26,400
P027 Telecommunication Radio & Fibre Ops Total	**222,400**

P028 Telecommunication Systems Replace & Modifications	
Miscellaneous teleprotection equipment upgrades (as required)	35,000
Upgrade miscellaneous radio links (as required)	48,500
Misc. Telecom Equipment (as required)	51,156
Nokia Equipment Repairs and Support	23,100
Telecom engineering services	60,000
Telecom engineering support services	85,000
Battery Replacements	83,000
Replace Miscellaneous Power Supplies	9,000
UPS Replacements Various Sites	9,000
Network standardization documentation	35,000
Cable & Entrance Protection - Positron	17,600
Switched Communications - System Operations Phones	6,600
Replace Fibre Optic Equipment (NEC & ADC)	34,125
Install Fibre Links for telecom sites	127,059
Network Monitoring Upgrades	60,500
Alarm Commissioning for new sites into SCADA	61,050
Review and Update System Drawings and Records	55,000
Support Services for Nokia/ALU	29,920
Tower Lighting Upgrades	21,900
P028 Telecommunication Systems Replace & Modifications Total	**852,510**
P814 Telecommunications Spares	
Alcatel-Lucent MPR9500 Microwave Radio	51,000
Net Guardian Alarm Monitoring Equipment	15,000
7705 MPLS Router Spares	25,000
Ethernet Spares	7,261
MDS SD9, Transnet, INet	15,000
SEL 2505, 2506 Spares	15,000
RFL IMUX and 9745 Spares	15,000
Battery Charger Spare	15,000
RTU and Misc. Spares	50,000
P814 Telecommunications Spares Total	**$208,261**
Telecommunications Total	**1,507,721**

1

Figure 53: Computing Asset Management

			2026 ACE Plan Forecast
P010 SCADA Improvements			
	This forecast is developed based on SCADA equipment/operator interfaces failures or modifications		120,428
P010 SCADA Improvements Total			**$120,428**
P031 NS Power IT Infrastructure			
Infrastructure Component	**Asset Management Plan**	**Volume to be Refreshed**	
Voice and Data Network	Network Infrastructure & Equipment		100,000
Physical Security	Physical Security technology (Cameras, DVRs, Controllers)		70,000
	Physical Security Devices		382,000
	Kantech Physical Security Access Control Systems		86,500
Servers	Servers, OS Licenses & Storage		100,000
Power Supplies	UPS units in branch offices		50,000
Laptop and Desktop Computers, Personal Devices	Computers that have or will reach four (4) years old	500	900,000
	New laptops or desktop computers	100	200,000
	Mobile Devices	250	360,000
	Accessories for end user equipment		150,000
	Software		30,000
	Application enhancements/development		100,000
P031 NS Power IT Infrastructure Total			**2,528,500**
P040 DCMS Equipment Replacement			
	CT's DCMS Equipment Replacement		21,177
	POA DCMS Equipment Replacement		49,785
	POT DCMS Equipment Replacement		29,250
	TRE DCMS Equipment Replacement		32,551
	TUC DCMS Equipment Replacement		57,000
	LIN DCMS Equipment Replacement		39,973
P040 DCMS Equipment Replacement Total			**$229,736**
IT - WAM Capital Enhancement Routine			**$1,625,040**
	Computing and Asset Management Total		**$4,503,704**

Figure 54: Property Improvement and Furniture

		2026 ACE Plan Forecast
Property Improvement and Furniture		
P001	Building Envelope Work	25,000
	Roofing & Emergency Repairs	55,000
	Grading/Drainage Investigation and Repairs	96,000
	Fencing Improvements	114,000
	GC Work	320,000
	Power Gate Installations	175,000
	Asphalt Replacement	130,000
	Consultant Services	225,200
	237 Townsend Generator Install Completion	75,000
	HVAC, Generator & Electrical	237,000
	Substations	100,000
	Office Furniture	50,000
	Transformer Dock Improvements	65,000
	Pole Brow	65,000
	Depot Renovation	200,000
	STE Structural	200,000
	PCB Program	65,000
	Lak Sprinkler Improvements	975,000
	R22 Replacements	75,000
	MCC UPS & Battery Bank Replacements	880,000
	Security Improvements	300,000
	1H General Refurbishments	370,000
	Property Improvement and Furniture Total	**$4,797,200**

Figure 55: Other

		2026 ACE Plan Forecast
Other		
P012	HYD - Security Improvements	540,100
P018	Environmental Equipment Replacement	100,000
P041	FAC - Land Acquisition Routine	50,000
P816	FAC - Environment Property Remediation	325,000
P815	FAC - Environment Site Assessment	325,000
P032	FAC - Equipment & Warehouse	100,000
	Other Total	**$1,440,100**
General Plant Total		**$38,155,955**

11.0 DIRECTIVES AND MISCELLANEOUS

11.1 Board ACE Plan Directives and Stakeholder Commitments

NS Power has received a number of Directives from prior ACE Plan Decisions. The Company has also made a number of commitments to stakeholders, and received directives from other proceedings. Responses to each of these Directives and commitments are provided below.

11.1.1 Sustaining Capital – 2026 ACE Plan Alignment with the Evergreen Integrated Resource Plan (IRP)

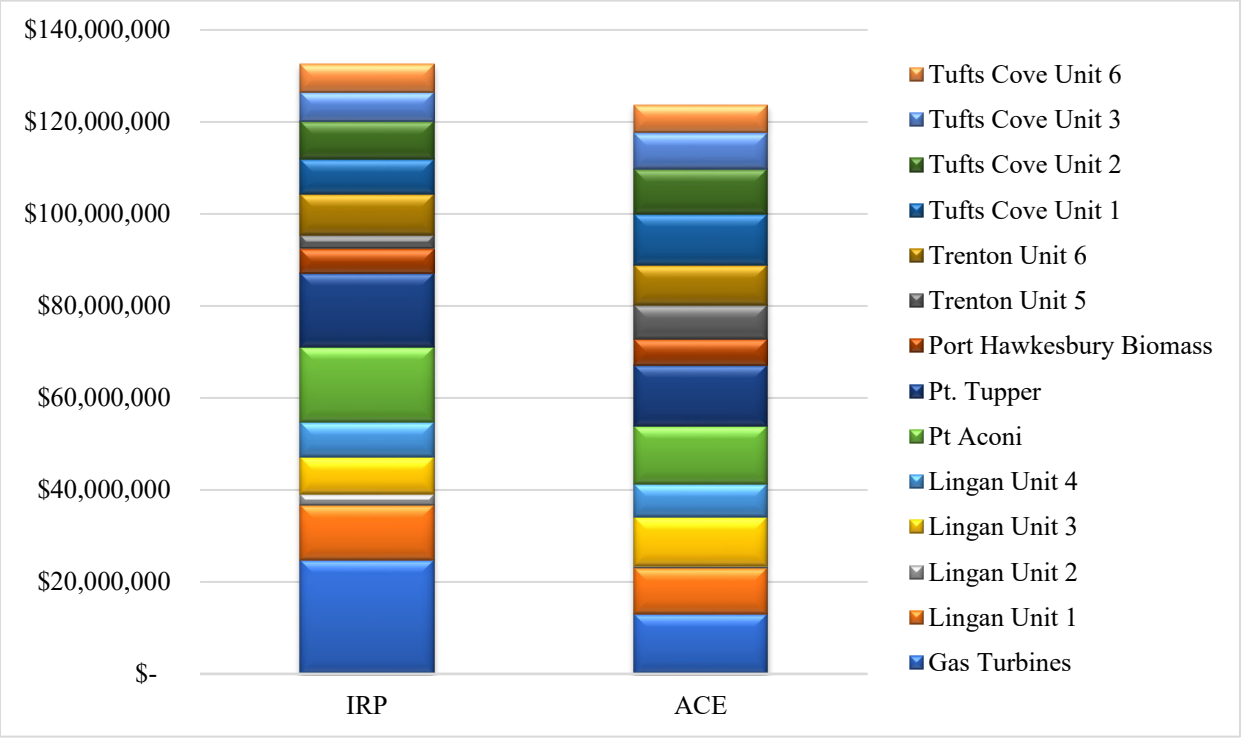
As the Nova Scotia generation mix transitions to meet the Province's decarbonization goals, a lower utilization profile is planned for the remaining emitting generation fleet. The sustaining capital investment for the emitting fleet in the 2026 ACE Plan reflects the level of investment necessary to continue to reliably operate these units into the future at utilization levels reflected in NS Power's 2023 Evergreen IRP and 2025 10-Year System Outlook.

Since the release of the 2023 Evergreen IRP Updated Action Plan and Roadmap report, the Province of Nova Scotia released the 2030 Clean Power Plan in October of 2023, providing a comprehensive path forward for the province, including NS Power, to achieve 80 percent electricity sales from renewable resources and to phase out coal generation. In December 2023, NS Power filed the Path to 2030 report, providing specific information on how the Company will achieve its 2030 obligations. An update to the Path to 2030 has been provided as **Appendix F**, as directed by the Board in its 2025 ACE Plan Decision. Each of these documents highlights the need for adding and integrating renewable energy resources, while phasing out coal and decreasing total emissions from the emitting fleet.

Figure 56 compares the capital investment forecast in the 2026 ACE Plan for NS Power's thermal, natural gas, and biomass generation units to the Evergreen IRP capital investment forecast. When comparing a single year, or subset of years, from an ACE Plan to a long term planning exercise

such as the IRP, it is important to take into consideration the leveling of investment used for the 25-year capital forecast used within the IRP. With respect to investment profile, it should be expected that the timing of investments will change from long-term projections as annual assessments using the latest operational information are essential to optimizing investment. There will be differences in unit investment profiles in future years based on actual utilization and present conditions, which drives the timing of major refurbishment intervals, causing the investment to be lower or higher than the long-term IRP projection in a given year.

Figure 56: Evergreen IRP vs. 2026 ACE Plan Forecast Comparison by Unit



11.1.2 Annual Rating/Prioritization of Capital Projects

In accordance with the Board's 2011 ACE Plan Directive 11 and 2013 ACE Plan Directive 7, below is NS Power's capital project rating criteria.

Pursuant to Section 6.1 of the CEJC, NS Power's generation, transmission and distribution capital projects are rated according to the following criteria:

- Health and Safety: Regulatory Requirements, Operating Permits, Protection of Equipment and Personnel Safety, and JOHSC actions.

- Environment/Regulatory Compliance: Renewable Energy Standards, Greenhouse Gas (GHG) Regulations, or Air Emission Regulations.

- Business Sustainability: SAIDI, SAIFI, CAIDI; unit reliability; system upgrade requirements; code requirements; NERC/NPCC Requirements, or economics (based on payback period, and revenue requirement); requirement to serve.

Technically justified IT projects are broadly rated using the following criteria:

- Customer: service impacts to customers as a result of technical failure

- Finance: financial impacts to the Company as a result of technical failure

- Compliance: safety, environmental, security, legal or regulatory requirements (e.g. NERC/CIP and NI-52 compliance).

- Operating Sustainability: ability for NS Power staff or contractor to perform critical functions of the business.

NS Power's project rating methodology is described in **Section 3.0** above and Section 6.2 of the CEJC. This methodology uses a rating matrix which results in a final rating of 1 to 25. The rating (also termed risk) is developed by determining the "Criticality" (ranked 1 to 5) and "Condition" (ranked 1 to 5) of each asset and multiplying the two to determine the overall risk.

Criticality and Condition values are typically influenced predominantly by the factors discussed previously and assigned accordingly. However, other factors may also influence the rating of a project.

Multiple influencing factors, asset risk ratings, and the prioritization of projects ahead of others are subject to the evaluation and professional judgment of NS Power staff and third-party industry experts as appropriate.

Please refer to **Appendix B**, tab 'Risk Rating', which identifies the new projects included in the 2026 ACE Plan, their rating categories and rating values, where applicable.

11.1.3 2026 to 2030 Forecast ACE Plan Expenditures by Functional Class and Spending Program

Pursuant to 2011 ACE Plan Directive 12, NS Power provides its forecast investments by functional class and spending program. Justifications for projects determined as capital investments are prepared on an annual basis. Capital investment on the basis of health and safety, environmental compliance, and requirement to serve remains non-discretionary. **Figure 57** below identifies anticipated sustaining capital by function and specific notable investments included in this ACE Plan. Investment levels from 2026 to 2030 are subject to change based on operating conditions, updated asset assessments, regulatory directives, identification of emerging and/or accelerating risks (such as climate change, or cyber security) or legislation/regulations.

Sustaining capital funding levels represent typical annual investment by function in a given year to sustain the integrity of existing assets. Notable capital projections reflect specific projects. Included in these specific projects are transformative multi-year program investments and asset growth.

Figure 57: Forecast ACE Plan Expenditures by Functional Class and Spending Program

(Millions of dollars)

	2026 ACE	2027	2028	2029	2030
Base Capital Investment					
Thermal Generation	116.4	109.6	126.7	94.4	82.9
Combustion Turbines	13.8	22.1	21.4	12.8	21.1
Hydro Generation	34.6	77.3	79.0	97.2	77.9
Wind Generation	6.1	2.6	2.7	2.8	2.9
Transmission	108.8	118.1	122.1	122.2	113.8
Distribution	158.7	163.5	168.3	194.7	166.9
General Plant	89.2	66.5	95.1	75.0	86.5
Total Base Capital Expenditure	**527.6**	**559.6**	**615.3**	**599.1**	**552.1**
General Plant					
IT - CIS Replacement	3.2	17.2	30.1	30.0	-
Distribution:					
Distribution R.O.W Widening	31.8	32.4	33.1	33.7	34.4
Transmission:					
Transmission R.O.W Widening	3.3	3.0	3.0	3.0	3.0
ECEI - Energy Storage	44.2	(3.3)	-	-	-
ECEI - Synchronous Condenser	84.7	115.3	91.3	46.7	-
Generation:					
Wreck Cove LEM	7.3	-	-	-	-
Total Notable Capital	**174.5**	**164.7**	**157.5**	**113.4**	**37.4**
Total Annual Capital Investment	**702.1**	**724.3**	**772.8**	**712.5**	**589.5**

11.1.4 Impact of Reliability Projects

The Board's 2013 ACE Plan Decision provided the following directive:

> …the Board expects NSPI to monitor the impact of the deferral of reliability projects in the original 2013 ACE Plan closely and to provide a report on the results in the next ACE Plan.[26]

Pursuant to NS Power's commitment noted in the 2015 ACE Plan Terms of Consensus, this directive is expanded to include additional information regarding continued sustaining capital investments and maintaining reliability performance.

The Board's 2017 ACE Plan Order provided the following directive:

> The Board directs NSPI to identify and list any proposed capital investments related to performance standards established by the Board in future ACE Plan applications.[27]

All T&D projects in the 2026 ACE Plan that are included in the Five-Year Reliability Plan will contribute to having a net positive impact on the metrics tracked under performance standards. The projects are selected based on the asset management methodology described in **Section 3.0** and pursuant to Section 6.2 of the CEJC, guiding investments to where they are needed most.

The Board directed NS Power to continue providing the same information with respect to reliability and severe weather events notwithstanding the Board's approval of the performance standards in 2017 and the Company's obligations to report on those standards:

> …[T]o what extent, if any, certain aspects of the information set out in Section 8.1.7 of the 2017 ACE Plan will be reproduced in the report required by the Performance Standards Decision remains to be seen.

[26] M05339, NS Power 2013 Annual Capital Expenditure Plan, Board Decision, May 27, 2013, page 44, line 174.
[27] M07745, NS Power 2017 Annual Capital Expenditure Plan, Board Order, April 4, 2017.

> It is not clear such items as, for example, plans for replacement of aging transmission and distribution equipment, and storm performance information, beyond the 48-hour restoration metric, will be fully explored in the context of performance standard metrics reporting.
>
> As there is some uncertainty, and a part of the information provided in Section 8.1.7 is derived from an agreement between stakeholders, as part of the 2015 ACE Plan process, the Board will not direct any changes to the current ACE Plan reporting related to reliability at this time. The Board will monitor the ongoing relevancy of this part of the ACE Plan.
>
> The first report arising from the Performance Standards Decision is due March 31, 2018. Once that report has been filed and analyzed, the matter should be revisited in the context of a future ACE Plan. [28]

In NS Power's Action Plan Update in the Property and Assets Inquiry,[29] the Company provided the following ACE Plan commitment:

> For reliability-focused distribution projects > $1 million, NS Power commits to providing the circuit-level risk rating which led to the project being planned and the subsequent post-project rating. As the risk ratings have multiple inputs, NS Power will define which of the inputs are anticipated to be improved through project execution. NS Power will provide an update for circuits which meet these criteria for the five years after the project is put into service.[30]

The risk rating for a feeder follows the methodology described in **Section 3.0** – utilizing both criticality and condition inputs. Specifically for distribution feeders, the criticality assessment includes factors such as usage (kWh sales), regulatory consequences, customer count, redundancy, and ease of access. The condition score includes inputs from performance results, vegetation condition, load conditions, and feeder inspections. Note that subject matter expertise is applied on top of risk rating scores to determine the most appropriate mitigating action to address the resultant risk.

[28] M07745, NS Power 2017 Annual Capital Expenditure Plan, Board Decision, April 4, 2017, paragraphs 98 to 101.
[29] M11067, Property and Assets Inquiry, NS Power Action Plan Update, September 26, 2024.
[30] Ibid.

Within the 2026 ACE Plan, the Distribution projects included for approval (as well as previously identified projects in progress), and associated risk rating inputs are provided in **Figure 58** below.

Figure 58: 2026 ACE Plan Distribution Projects for Approval with Risk Rating Inputs

Proposed and In-Progress Projects	Feeder Criticality	Condition Inputs				
		Load & Balance	Outage Frequency (CKAIFI)	Outage Duration (CKAIDI)	Feeder Inspection	Vegetation Condition
91W-411 Labelle Road Phase Extension (2025)*	5	5	4	4	3	3
36V-303 Baxters Harbour Reconductor (2026)	5	5	3	4	3	3
57C-426 Melrose Country Harbour Rd Line Extension (2026)	5	5	5	5	4	3
92H-331 Double Circuit along Peggys Cove Rd (2026)	4	5	4	4	4	4

*Execution of this 2025 project is still in progress

Note: Projects that are planned for subsequent submittal are not included in this list as scoping and project analysis is not yet completed, therefore these inputs are subject to change.

Updates to the inputs of the condition score for these projects will be provided in subsequent ACE Plans for five years following the in-service date of the project.

The Board's Decision pertaining to the 2023 Performance standards provided the following directive:

> The Board agrees that a comprehensive written version of NS Power's five-year reliability plan is needed to understand how service improvements will be achieved and against which progress in achieving the performance goals can be tracked. This plan must include specific actions and related timing, demonstrate why these specific investments were selected and quantify the level of reliability or resilience improvement expected from each investment. The Board directs NS Power to prepare such a plan, which is to be filed by December 31, 2024.[31]

[31] M11627, NS Power 2023 Annual Performance Standards Report, Board Decision, September 9, 2024, page 15.

In accordance with the Board's directive, NS Power filed its Five-Year Reliability Plan on December 20, 2024, and it was reviewed and considered as part of the 2025 ACE Plan proceeding. The Board's 2025 ACE Plan Order provided the following direction:

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 System Average Interruption Duration Index (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 the 2025 ACE Plan 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 Centre for Energy Advancement through Technological Innovation (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.[32]

Please refer to **Appendix G** for the Five-Year Reliability Plan Update. Many of the above-noted directives have been included in **Appendix G**; please refer to the sections below for the remaining directive responses.

Reliability Strategy

To meet reliability challenges from severe weather and climate change and achieve reliability improvements on the T&D system, enhanced reliability performance analysis, technological innovation, targeted mitigating measures, and new approaches to the way NS Power executes work

[32] M12012, NS Power 2025 Annual Capital Expenditure Plan, Board Order, August 19, 2025.

are necessary. This approach is driven by and aligned with NS Power's asset management strategy for T&D assets and includes implementation by the Reliability team. In addition to the dedicated areas of scope and responsibilities for the Reliability team (vegetation management, transmission line and distribution feeder inspection, capital project engineering, distribution standards, performance standards reporting, and stakeholder engagement related to reliability), the team works closely with others across the broader Energy Delivery team as well as the Enterprise Asset Management (EAM) team to prioritize and execute work that is aimed at driving reliability improvements for NS Power's customers.

More detail regarding the Company's approach and initiatives to address customer reliability is provided in the Five-Year Reliability Plan update in **Appendix G**.

Reliability Director

The Board's 2023 ACE Plan Order Directive 3 provided as follows:

> 3. Provide an update on the progress of the Director, Reliability Implementation, and [their] team.

The Board's 2024 ACE Plan Decision provided the following:

> [103] In the Board's 2023 ACE Plan Decision [2023 NSUARB 159], NS Power was directed to provide an update in the 2024 ACE Plan on the progress of the Director, Reliability Implementation and his team. NS Power provided this update and the Board finds it informative. The Board looks forward to additional updates in the 2025 ACE Plan.[33]

In 2025, the Reliability Team is focused on executing the projects included in the Five-Year Reliability Plan with the overall goal of reducing the duration and frequency of outages experienced by customers.

[33] M11458, NS Power 2024 Annual Capital Expenditure Plan, Board Decision, August 13, 2024, page 36.

Details regarding the execution of year one of the Five-Year Reliability Plan and anticipated activities in year two can be found in **Appendix G**.

The combined benefits of these programs and the positive impacts on the reliability of the system and individual circuits will be realized over the life of the plan with an estimated reduction of approximately one hour of SAIDI overall by 2029.

Centre for Energy Advancement through Technological Innovation (CEATI) Grid Resiliency Working Group Update

As noted above, the Board's 2025 ACE Plan Order provided as follows:

> 5. The Board directs NS Power to provide an update on the Centre for Energy Advancement through Technological Innovation (CEATI) Grid Resiliency working group in the 2026 ACE Plan.[34]

CEATI's Grid Resiliency Working Group was established in late 2024 in response to member utilities' interest to collaborate on addressing resiliency issues in industry. Preliminary discussions on the mission and objectives of the working group took place at the 2024 CEATI T&D conference (attended by NS Power) resulting in the development and distribution of a survey for interested utilities to highlight potential areas of interest and targeted deliverables. The results of the survey were discussed during the working group kick-off call in March 2025 and used to develop a draft terms of reference document for member review in Q3 2025. It is expected that the final terms of reference will be approved by member utilities in late 2025. Also in Q3 2025, the working group began development and review of a Resiliency Benchmarking Survey (pending final approval) as well as a discussion paper on Transmission System Resiliency ahead of a Utility Resiliency Workshop taking place at the 2025 CEATI T&D conference in November 2025 (attended by NS Power). The discussion paper provides the initial findings of the working group and outlines the proposed deliverables, as well as key actions for 2026. These include (subject to approval by the member utilities), development of a unified set of definitions of various key resiliency terms,

[34] M12012, NS Power 2025 Annual Capital Expenditure Plan, Board Order, August 19, 2025.

development of a high-level framework for Resiliency Assessment and Mitigations, investigation of potential key resiliency indicators/metrics, inventory of case studies of past events from across the globe, and creation of a comprehensive report summarizing the findings and conclusions of the working group.

Reliability and Resilience Metrics

As noted above, the Board's 2025 ACE Plan Order provided as follows:

> 1. ... 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 System Average Interruption Duration Index (SAIDI) be provided in future ACE Plans.[35]

The Board's 2025 Storm Cost Recovery (SCRR) Order provided the following:

> NS Power is directed to study and report on the potential use of the Value of Lost Load (VoLL) metric in the Company's reliability investment planning process in the 2026 ACE Plan, focusing on the items outlined in paragraph [65] of the decision.[36]

Paragraph 65 of the Board's decision in the above-noted matter provided as follows:

> [65] The Board does not fully agree with NS Power's submission. Instead, the Board believes that the VoLL metric could be potentially useful in not only completing an assessment of the type recommended by Dr. Gonatas, but also in evaluating NS Power reliability investments. In his Closing Submission, the CA appeared to agree by suggesting that the Board should direct NS Power to look for ways to update its risk-based asset management approach to give consideration to the economic impact of outages. Therefore, the Board directs NS Power to study and report on the potential use of the VoLL metric in the Company's reliability investment planning process. This includes assessing how the metric might be used in NS Power's capital approvals application process. It is too late for NS Power to complete this exercise for incorporation into the Company's five-year Reliability

[35] M12012, NS Power 2025 Annual Capital Expenditure Plan, Board Order, August 19, 2025.
[36] M11692, NS Power 2025 Storm Cost Recovery Rider (SCRR), Board Order, December 3, 2024.

> Plan, which is to be filed with Board by December 31, 2024. Similarly, it is likely too late for the study report to be included with the 2025 ACE Plan application. As such, the Board directs NS Power to provide a report on this VoLL assessment in the Company's 2026 ACE Plan application.

Metrics

Over the course of the last year, NS Power has continued its work to identify and evaluate potential alternative reliability metrics. The reliability metrics included in NS Power's Performance Standards reporting, including SAIDI, SAIFI, CKAIDI, and CKAIFI, measure reliability effectively and were developed through robust stakeholder engagement. NS Power's position is that these metrics are comprehensive and are standard in the industry. They provide straightforward, quantitative measures of reliability that are easy to communicate to regulators, stakeholders, and customers. These metrics remain foundational for evaluating NS Power's reliability. NS Power will continue to evaluate newer measures that address emerging issues that could be used in conjunction with these foundational metrics in the future.

As NS Power has worked to identify a metric (or suite of metrics) that can provide a clear evaluation as to whether a reliability-based project has met its intended benefit, it has become evident that such a metric is not presently in use in the utility sector.

While each project is expected to have a positive, localized impact on performance and a corresponding impact on the overall system performance based on the relative number of customers impacted by the project, these results are affected by numerous factors that can be difficult, if not impossible, to consider in isolation. Factors including, but not limited to, weather, external interference, other reliability programs, and customer demand can all influence the changes in risk on a particular circuit. Consequently, it has proven difficult to identify a metric that will allow a direct measurement of an individual project on circuit performance and overall system performance, as the large number of influencing factors across the province can mask the impact of a single project in any given year.

One option for consideration in evaluating a particular reliability strategy and/or project is utilizing a measure of Reliability Cost Efficiency (RCE). This methodology considers the relative cost of reducing outage impact at a project level based on previous applications of similar projects. A challenge with this metric is that it still tends to vary due to multiple, inter-related factors, and tends to reflect more favorably on projects impacting larger customer counts due to the benefits of scale. In some cases, NS Power has applied this approach in terms of "tiers" of effectiveness, such as Low, Medium, and High reliability cost efficiency, to evaluate competing options for reliability investments. Due to the variability of individual projects and circuits, precise measures such as dollars per avoided customer hours of interruption should be used with appropriate caution when evaluating.

Value of Lost Load (VoLL)

As directed by the Board in its decision of the 2025 SCRR, NS Power is investigating the potential use of VoLL as an input to risk-based decision-making. In 2025, NS Power has engaged a vendor to undertake an assessment of the VoLL, specific to Nova Scotia, building on previous work undertaken in other North American jurisdictions. As of November 2025, a residential customer VoLL survey has been developed by the vendor and NS Power, and the survey has been distributed to a sample of NS Power residential customers. As of the date of this filing, analysis of the results of this survey is underway with a draft report expected for NS Power's review in late 2025. In addition, development of a similar VoLL survey targeting commercial and industrial customers is in progress and expected to be distributed in Q1 2026. The results of both surveys will be reviewed and analyzed to determine the potential applicability in risk-based decision-making at NS Power going forward.

While there is certainly value in some recommendations included in available literature, further work is required to fully consider both the applicability and effectiveness of resilience metrics proposed in these studies and other emerging research along with continued engagement with industry to identify appropriate metrics that will yield valuable insights for the benefit of customers. To this end, NS Power continues to participate in industry groups such as CEATI and

Electricity Canada which have included resiliency as a key focus for collaboration. An update on CEATI's Grid Resiliency working group, which NS Power is participating in, is provided above.

Based on the preliminary work for the CEATI Working Group, some potential categories of metrics may include:

- Energy Not Supplied / Expected Energy Not Supplied (EENS)
- Pace of Performance Level Degradation
- Extent of Degraded System State
- Number or Percentage of Customers Impacted
- Time to Restore 90% and/or 100% of Customers / Normal Operating Level

The development of the specifics on how such metrics would be quantified and the evaluation of their potential usefulness in understanding and trending resilience is of particular focus and expected to be a key element of the CEATI working group's efforts in 2026. As of the date of this filing, NS Power does not believe that sufficient development and detail is available to introduce such metrics on an ongoing basis, but will continue to participate in development activities through CEATI.

In addition to the industry collaboration detailed above, the Company is open to discussing potential approaches and looks forward to engaging in and supporting the third-party review of the Five-Year Reliability Plan. With the data available at this time and while potential other options are identified, NS Power suggests that overall system performance is appropriately measured with existing metrics of SAIDI, SAIFI. NS Power anticipates the third party review will also include discussion of the applicability of potential new metrics, where appropriate, to further understand and evaluate reliability and system resiliency.

Reliability Statistics

As shown in **Figure 59** and **Figure 60** below, with the exception of years with significantly challenging weather conditions, NS Power's annual outage frequency and duration continues to compare favourably with the average of Atlantic Canada utilities. Over the ten year period 2015-2025 NS Power exceeded the Atlantic Canadian utilities average in both frequency and duration in 2019, 2022 and 2023 due to the significant challenges posed by Hurricane Dorian, Hurricane Fiona, and Hurricane Lee, respectively. These extreme weather events represented the significant outliers from typical performance trends in the region.

Figure 59: Annual Atlantic Canada Outage Frequency

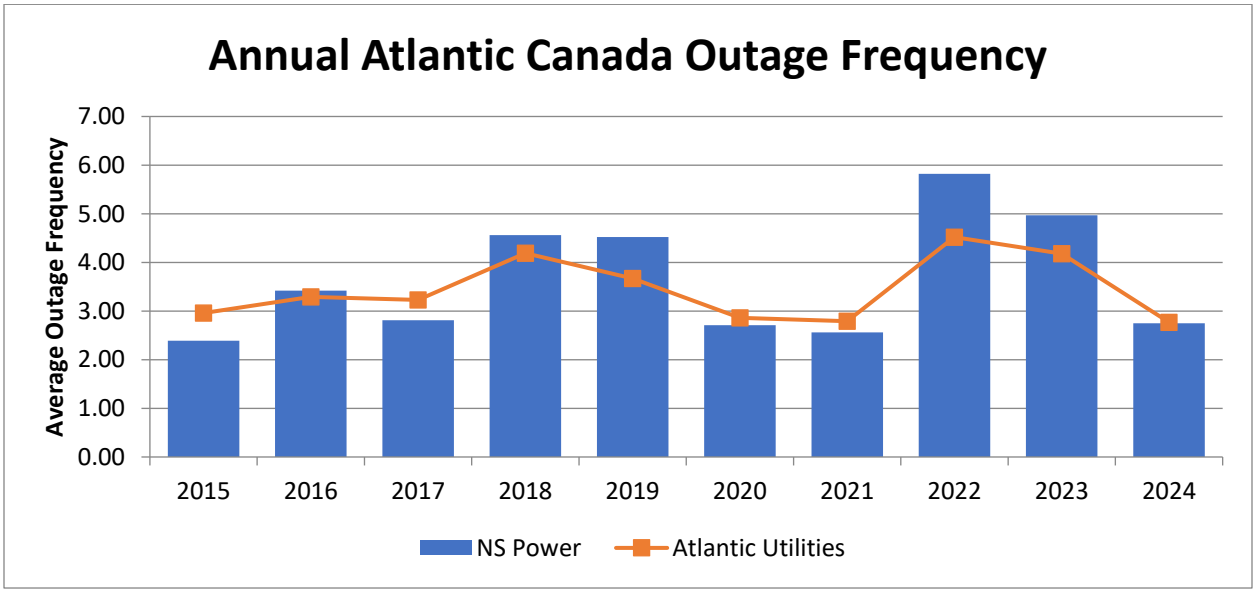


Figure 60: Annual Atlantic Canada Outage Duration

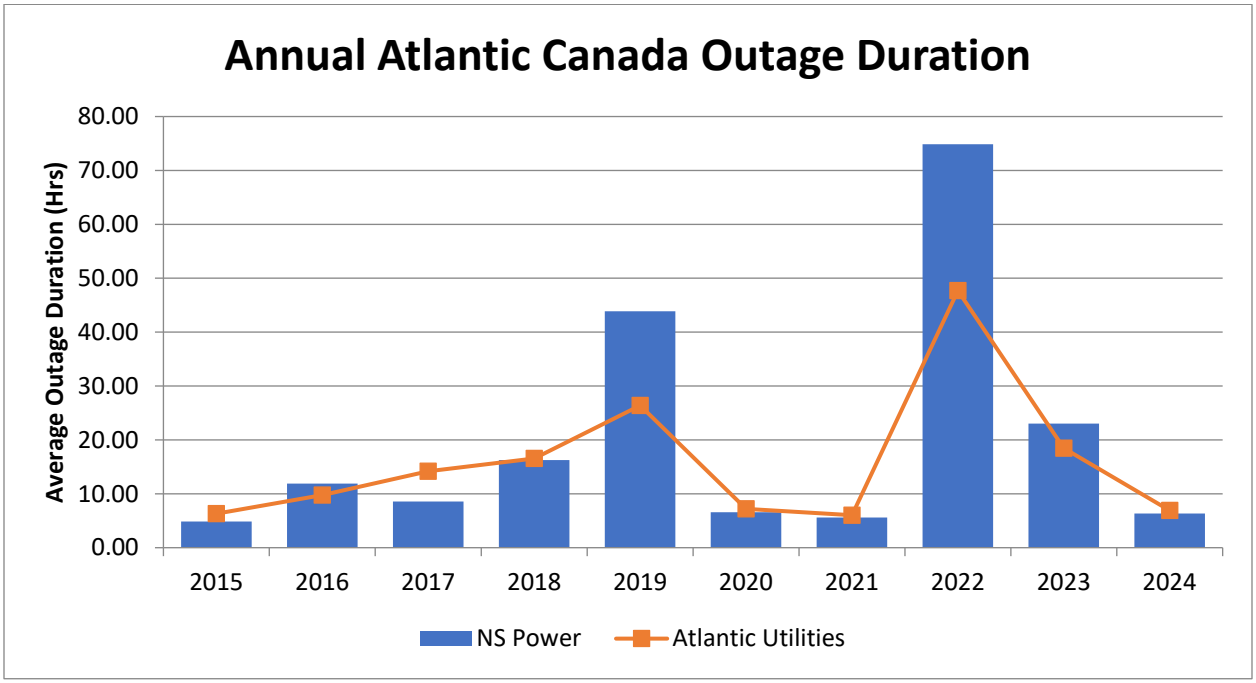


Figure 61 and **Figure 62** below represent NS Power's reliability statistics with Major and Extreme Events (such as Hurricanes Dorian, Fiona, and Lee and as defined by IEEE-1366) removed from the data. This shows a largely normalized comparison between yearly reliability performance. However, performance observed in some years were largely the result of a significant number of localized storm events, that while falling short of the IEEE-1366 standard for a major event, contributed to more frequent and longer outages than would have been experienced in previous years. This in turn led to an increase in both SAIFI and SAIDI. The 10 year trend shows the impact of SEDs and overall challenging weather conditions in recent years. In contrast, only one Significant Event Day (SED) related to adverse weather has occurred in 2025 YTD. The absence of severe weather this year allowed for more capacity for uninterrupted reliability work resulting in a notable improvement in SAIFI. This reflects continued progress and effectiveness of NS Power's outage prevention initiatives. Additionally, SAIDI performance is trending better than recent historical averages.

Figure 61: NS Power Annual SAIFI (Major/Extreme Events Excluded)

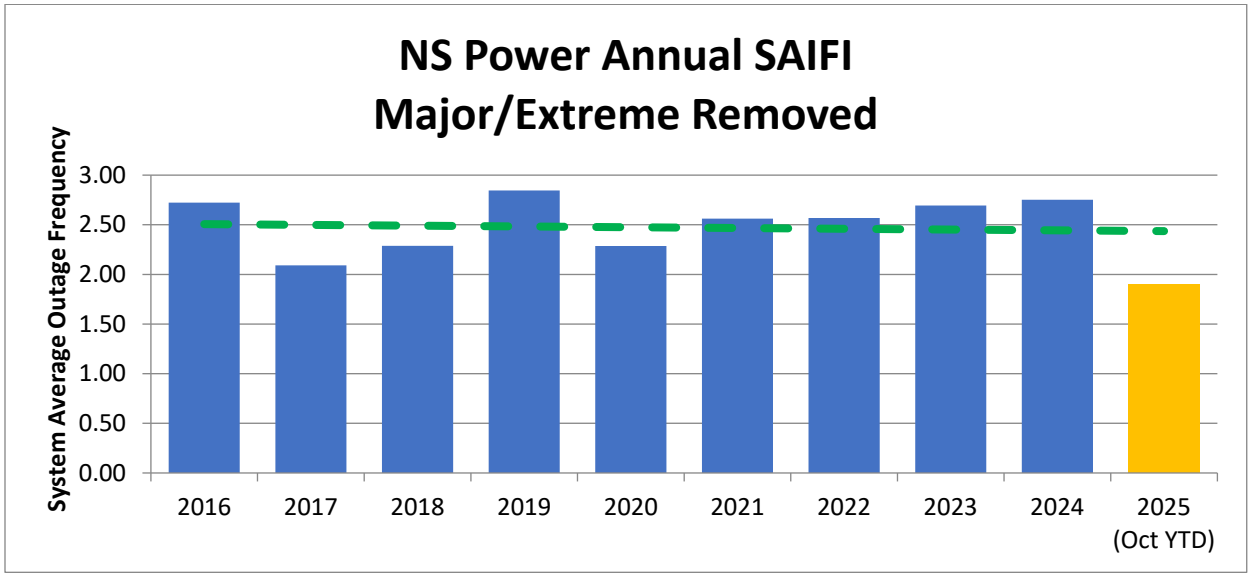


Figure 62: NS Power Annual SAIDI (Major/Extreme Events Excluded)

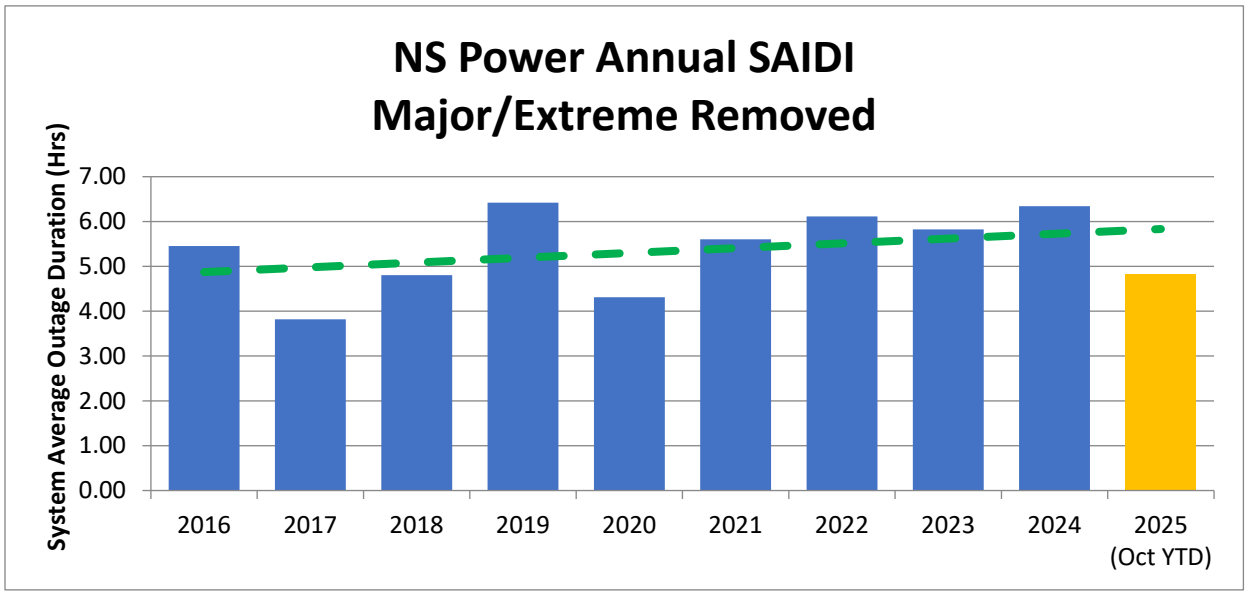


Figure 63 and **Figure 64** below represent NS Power's reliability statistics with Major and Extreme Events included. There have been no Major or Extreme Events between January 1-October 31, 2025. Accordingly, the current 2025 SAIFI and SAIDI values are the same for both Major/Extreme Events Removed and Included.

Figure 63: NS Power Annual SAIFI (Major and Extreme Events Included)

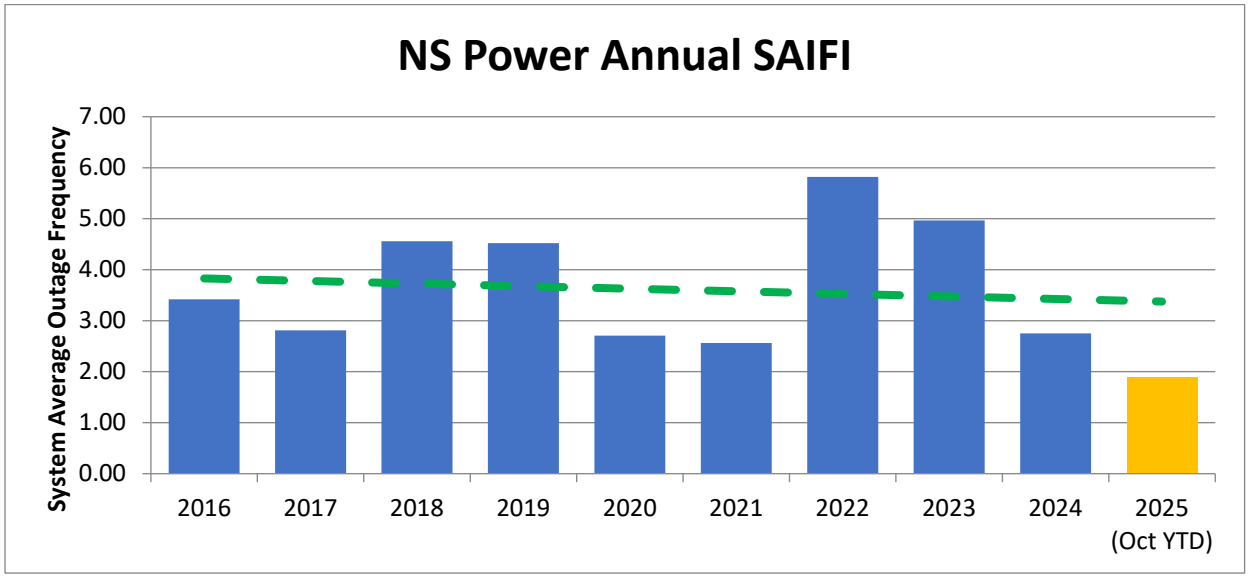
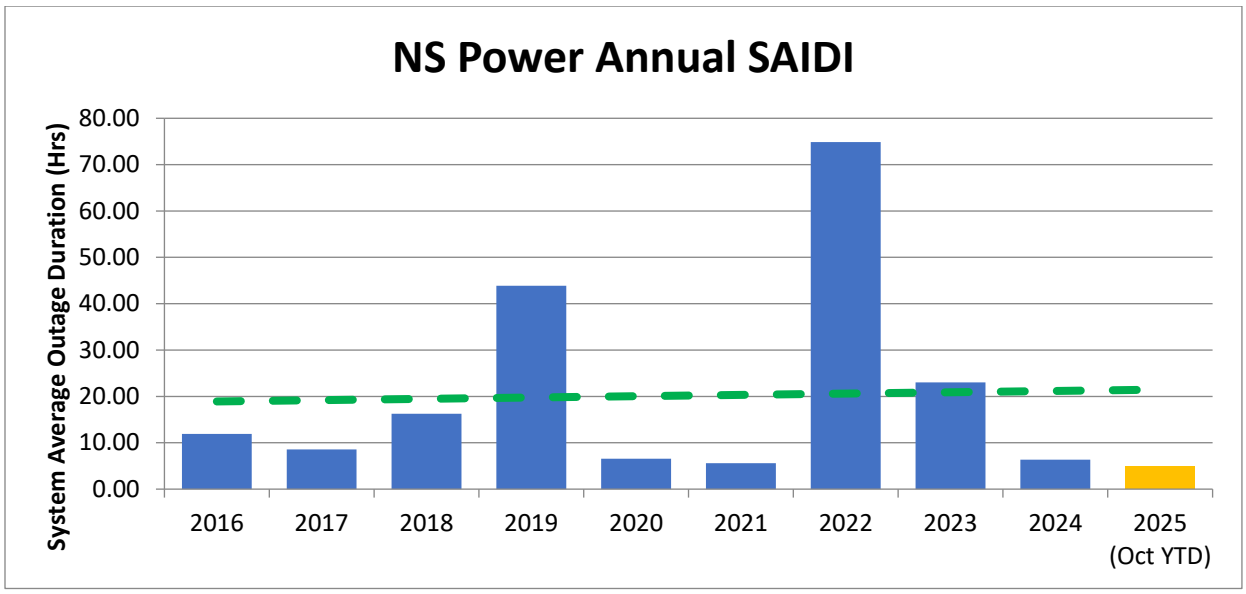


Figure 64: NS Power Annual SAIDI (Major and Extreme Events Included)



The reliability performance for overall SAIFI and SAIDI are strongly correlated with the number of major and extreme events that occur during the calendar year. NS Power continues to see severe and more frequent weather events (Arthur 2014, Matthew 2016, Dorian 2019, Fiona 2022, Lee

2023) as a trend which is expected to continue into the future. However, NS Power's typical performance compares favourably with the Atlantic Canada outage average for frequency and duration, and the Company continues to see positive indications overall for SAIFI and SAIDI when adjusted for weather. Continued investment in annual rights-of-way vegetation clearing and other capital investment initiatives noted herein are expected to continue to support sustaining reliability and improving resiliency over the long term.

Outage Causes

Historically, two of the leading causes of NS Power customer outages for all days (all event days included) are tree contacts and failed equipment. Outage analysis of these causes and NS Power's associated investments are described in more detail below. As elaborated in these sections, both tree contact and failed equipment related outages are influenced by the prevailing weather conditions, further contributing to the overall effects of adverse weather on system performance.

Tree Contacts

Since 2014, tree contacts continue to be one of the largest sources of outage hours for NS Power's customers. **Figure 65** and **Figure 66** below show both customer interruptions and customer hours of interruption due to tree contacts under normal and severe weather conditions.

Figure 65: Annual Tree Contact – Customer Interruptions

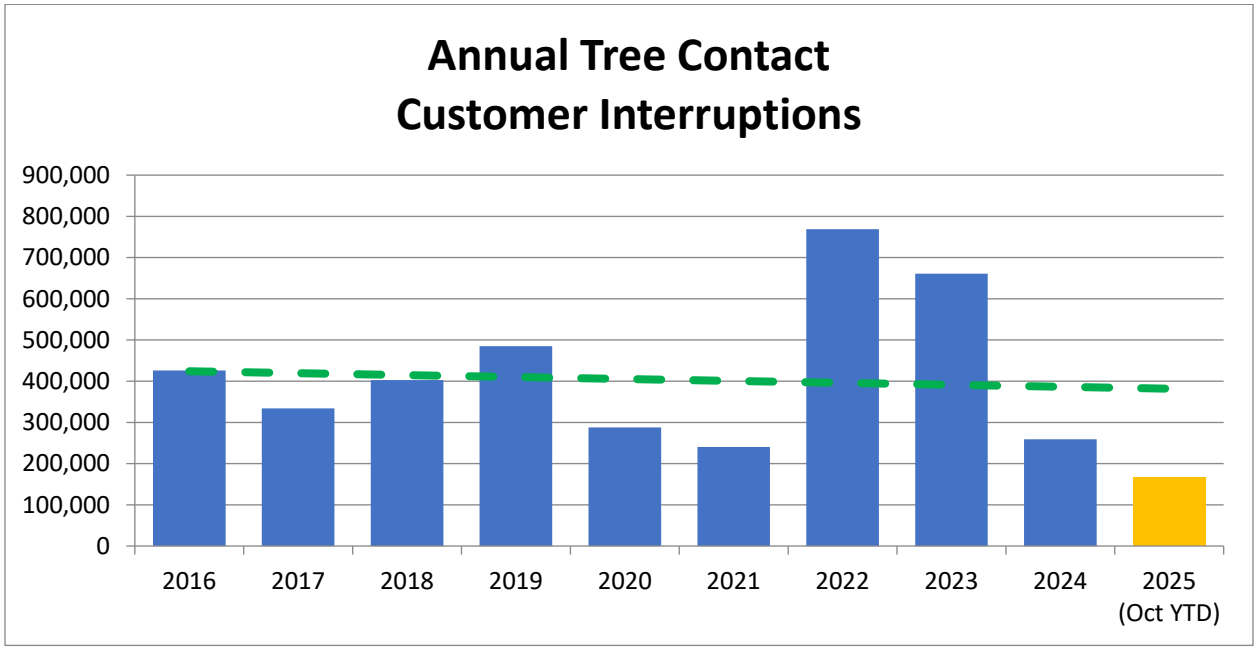


Figure 66: Annual Tree Contact – Customer Hours of Interruption

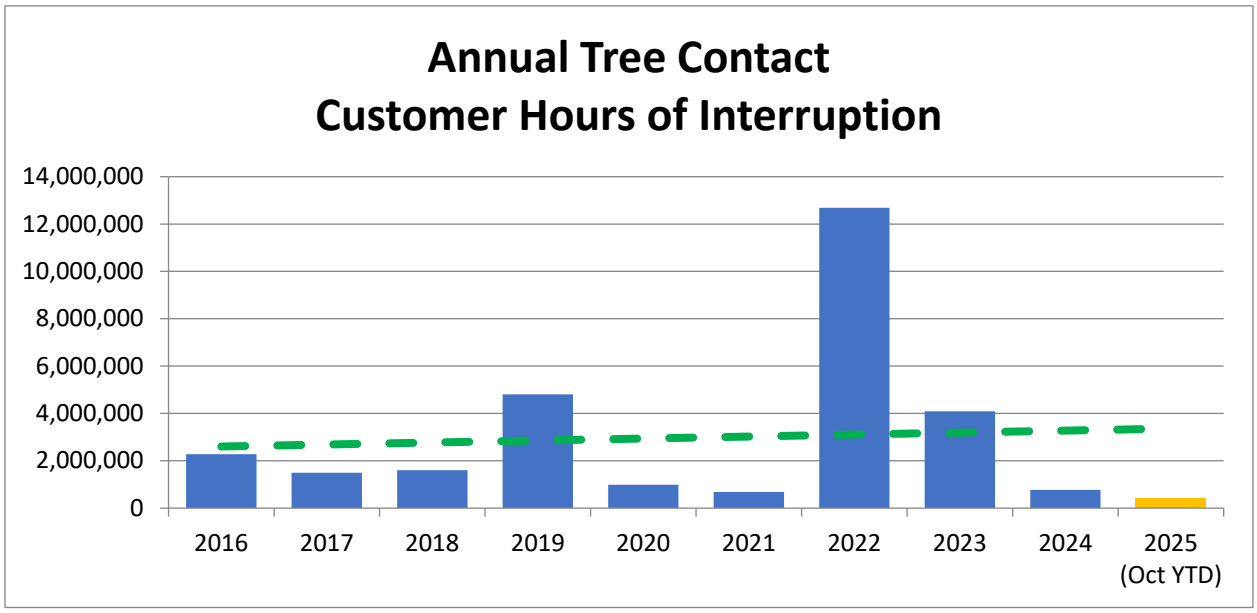


Figure 67 and **Figure 68** below show the tree contact data normalized with Major and Extreme Events removed. With these events removed, the data demonstrates the vegetative effects of major storms and their impact for months following the extreme event.

Figure 67: Annual Tree Contact – Customer Interruptions (Major/Extreme Events Removed)

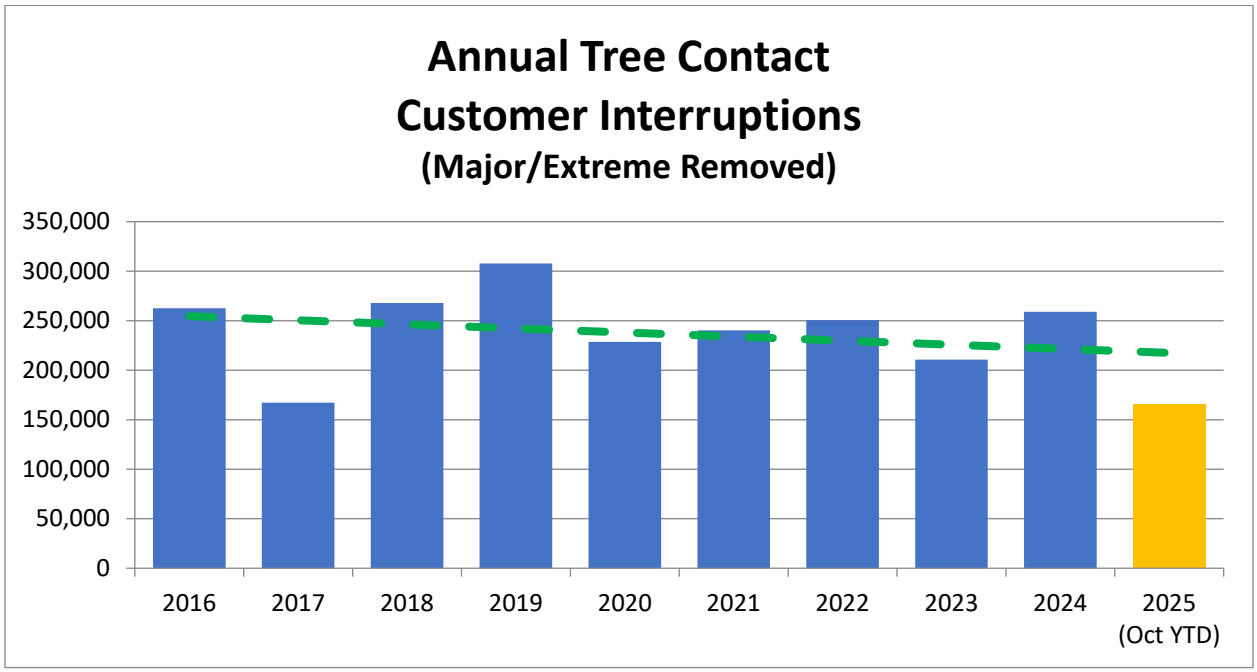
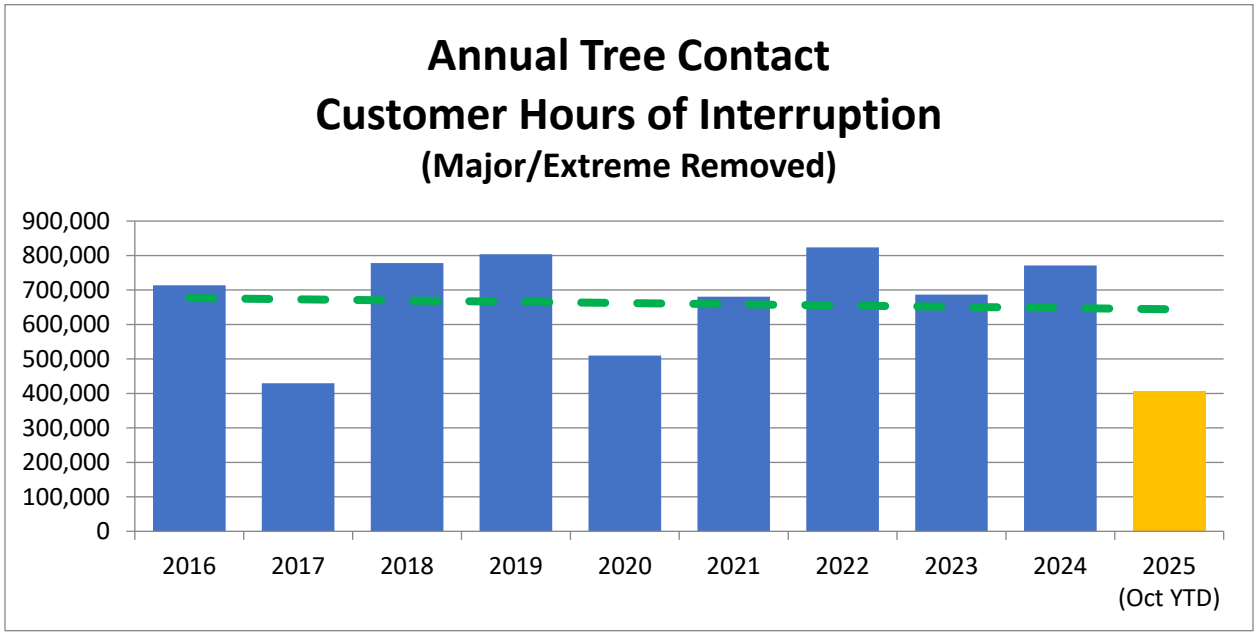


Figure 68: Annual Tree Contact – Customer Hours of Interruption (Major/Extreme Events Removed)



Significant amount of customer hours from non-MED days due to adverse weather in certain years, such as 2021 and 2022 are not excluded above and do contribute to the volume of tree contacts experienced. Despite the increased frequency of severe weather events and higher MED thresholds, there is a positive trend in reducing customer impact compared to the last 5 years (2020 - 2024). This demonstrates that effective measures are in place, successfully preventing tree contact outages and maintaining stable outage durations, even under increasingly challenging conditions.

In a continued effort to minimize storm effects on overall reliability, the following investments are included in NS Power's 2026 ACE Plan for transmission and distribution vegetation management. These targeted investments for managing vegetation aim to mitigate outage frequency and duration, while seeking to improve access to the system for restoration crews.

- CI C0080266 – New Distribution Rights-of-Way Phase 11
- D010 Distribution Right-of-Way Routine
- T010 Transmission Right-of-Way Routine

Failed Equipment

Figure 69 and **Figure 70** below show both the reliability results realized through upgrades and replacements of targeted distribution equipment as well as the significant impact of adverse weather on equipment.

Asset strategy committees are continuing to investigate improvements in maintenance strategies through identification of failure modes for asset classes with the highest contributions to customer impacts. In 2018 and 2019, NS Power experienced an increase of primary aerial conductor failures leading to a higher than typical contribution to frequency and duration of outages caused by failed equipment when compared to recent history. These years were also the most challenging years for severe weather events. The increase in failed primary aerial conductors is believed to be attributed

in large part to the added stress on existing infrastructure due to the high number of hours that winds have exceeded warning levels. The Company observed similar trends in 2022 and 2023, aligned with the severe weather events experienced during these years, including the most significant adverse weather event in Nova Scotia's history, Hurricane Fiona in September 2022, and Post Tropical Storm Lee in September 2023. As anticipated, NS Power's approach to targeted asset investments has contributed to overall improved equipment reliability performance. In 2025, the impact of equipment failures is trending in a positive direction, toward one of the better years for minimizing customer interruptions, with noticeable improvements compared to the last 5 years (2020 - 2024) and reduced hours of interruptions for customers.

Figure 69: Annual Failed Equipment – Customer Interruptions

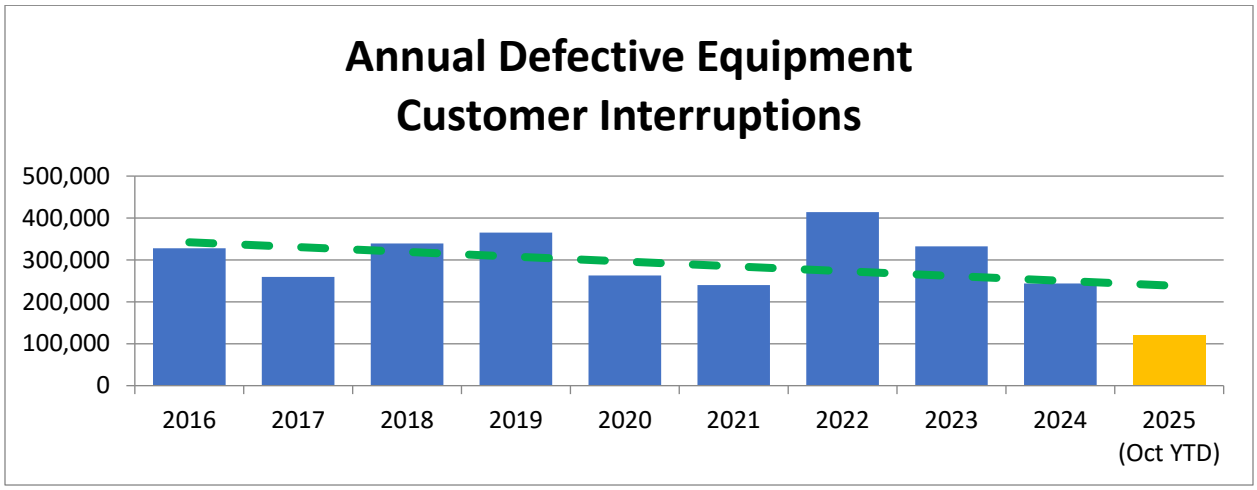
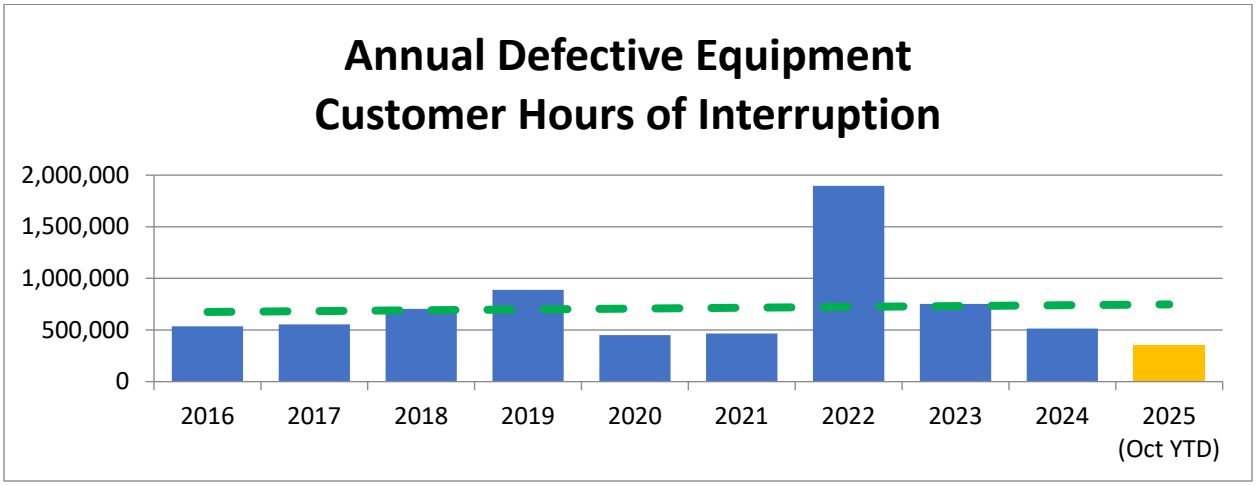


Figure 70: Annual Failed Equipment – Customer Hours of Interruption



Taking a further look into the 2025 reliability data, outages caused by equipment failure can be classified by device type. This is shown in **Figure 71** below.

Figure 71: Customer Hours of Interruption

Customer Hours of Interruption		
Device Type	**Oct 2025 YTD**	**% of Hours**
Pin Insulator	76,735	21.81%
Crossarm	72,573	20.63%
Primary Aerial Conductor	57,020	16.21%
Wood Pole	30,802	8.76%
Cutout	20,924	5.95%
U/G Primary Cable	12,815	3.64%
Fuse Link	11,240	3.20%
Lead	11,069	3.15%
Recloser	9,532	2.71%
Inline Disconnector	7,948	2.26%

All distribution capital projects and routines that replace deteriorated equipment are aimed at sustaining or improving system reliability and contribute to the reduction of customer impacts due to device failures referenced in the table above.

Update on storm performance and related capital investments

The effect of storms and storm response varies storm-to-storm and year-to-year. The wind speeds and direction, ice, snow, lightning, rainfalls, time of year, time of day, and weather forecast accuracy all contribute to a storm's impact. NS Power anticipates that the impacts of a changing climate over the medium and long term will result in increasing weather risks for the power system that must be mitigated. Recent years have been particularly challenging in this respect. Wind gusts at or above warning levels in 2025 year to date have been below the previous 5-year average, but still higher than historical averages 2013 and prior. As previously stated, NS Power SAIDI and SAIFI performance have shown a positive trend in comparison to previous years. Targeted investments in traditional reliability-focused projects, innovative technologies, and increased forecast investment in vegetation management are designed to strengthen both grid resilience and reliability, positioning NS Power to meet the challenges of a changing climate.

NS Power uses the 2.5 Beta Method (IEEE-3366 Standard) to classify Major Event Days. The same methodology is applied to further classify Significant Event Days (2.0 Beta) and Extreme Event Days (3.5 Beta).

As of October 31, 2025, NS Power has experienced two significant event days and no major event days or extreme event days in 2025.

Consistent with prior years, NS Power has the following capital programs for storm response and reactive work for 2026:

- D008 – Provincial Storm Distribution
- T001 – Transmission Line Unplanned

As noted above, NS Power continues to invest in vegetation management and works extensively with landowners and municipalities to gain permission to trim and remove trees. These investments aim to minimize tree contact and maximize access to NS Power's transmission and distribution systems as provided for in routines T010 and D010, as well as capital work order CI C0080266.

2025 Storm Performance vs. Previous Years

Figure 72 to **Figure 74** below show the count of the previously identified event day[37] classifications, and their SAIFI and SAIDI contributions annually. They outline the frequency and impact of Significant, Major, and Extreme event days[38] to customers. The graphs below illustrate the significant impact that adverse weather events have on the overall system performance.

[37] The term "Event Day", rather than the previous term "Storm Day" is used here to refer to those events significantly exceeding normal operations, in order to better reflect that event thresholds determined using the IEEE 1633 methodology are not exclusively due to storms or other inclement weather.
[38] The term "Significant Event Day", rather than the previous term "Storm Day" is used here to reflect that event thresholds determined using the IEEE 1633 methodology, in this case the 2β threshold, are not exclusively due to storms or other inclement weather.

Figure 72: Historical Year End Event Days

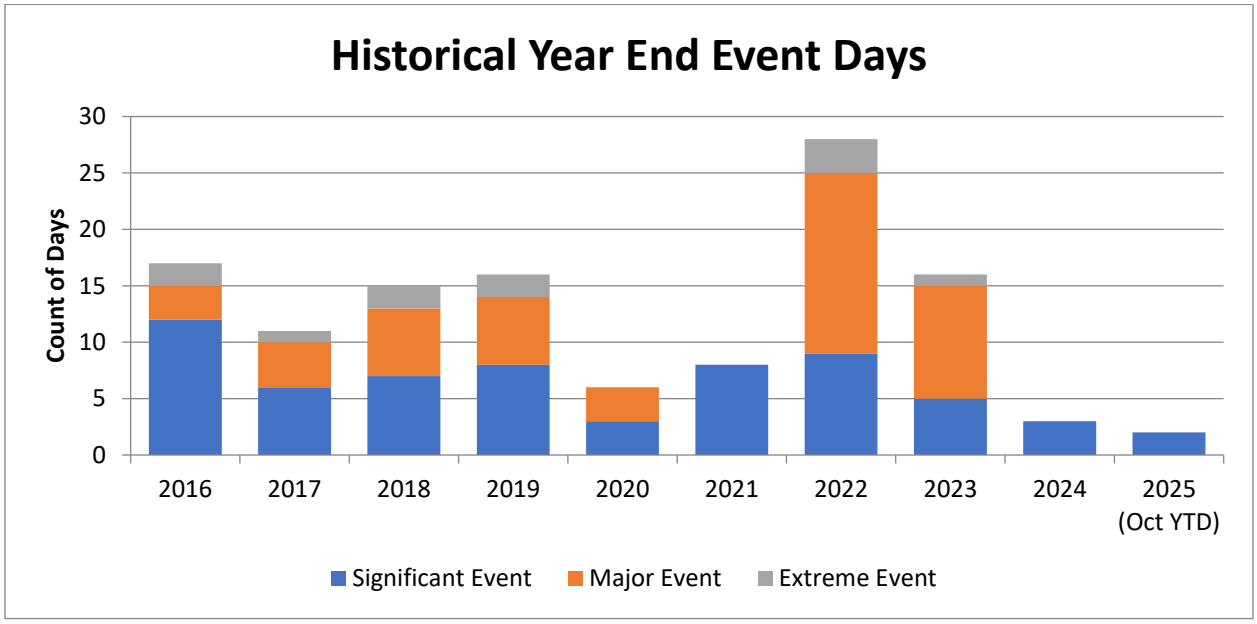


Figure 73: SAIFI- Event Class Contribution

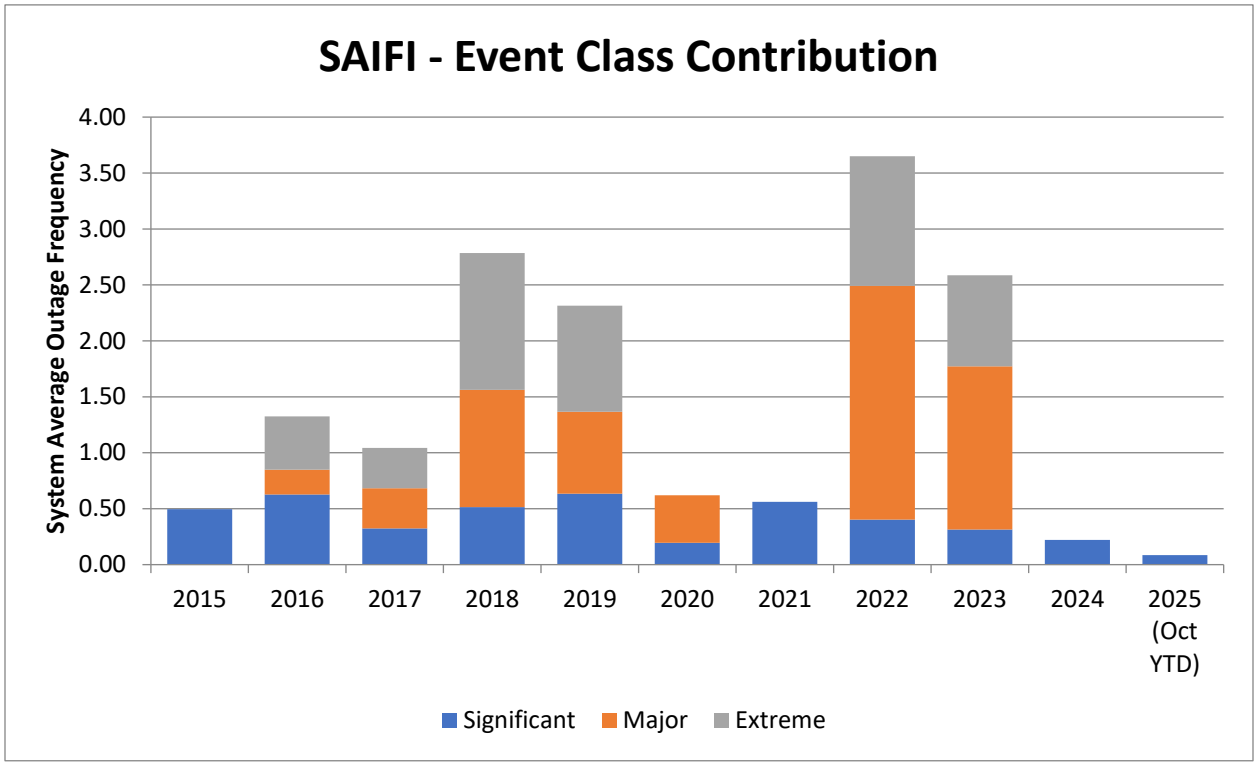


Figure 74: SAIDI – Event Class Contribution

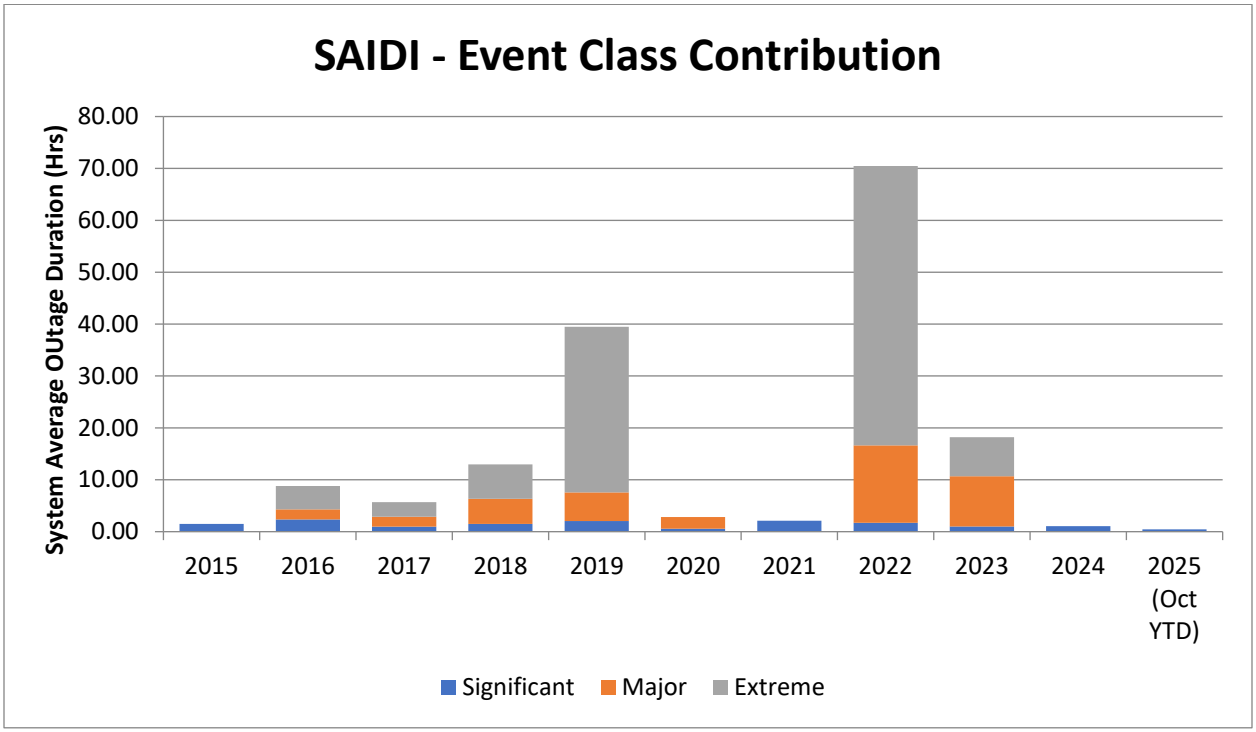


Figure 75 below provides detail on outage causes for the three event days experienced so far in 2025.

Figure 75: Detail on Outage Causes for identified Event Days

		Significant	Major	Extreme	
CEA Cause Code	**Description**	**Hours of Interruption**	**Hours of Interruption**	**Hours of Interruption**	**% of Hours**
0	Unknown/Other	614	0	0	0.25%
1	Scheduled Outage	11,601	0	0	4.64%
2	Loss of Supply	143,959	0	0	57.58%
3	Tree Contacts	58,419	0	0	23.37%
4	Lightning	0	0	0	0.00%
5	Failed Equipment	2,374	0	0	0.95%

		Significant	Major	Extreme	
CEA Cause Code	**Description**	**Hours of Interruption**	**Hours of Interruption**	**Hours of Interruption**	**% of Hours**
6	Adverse Weather	22,966	0	0	9.19%
7	Adverse Environment	7	0	0	0.00%
8	Human Element	0	0	0	0.00%
9	Foreign Interference	10,087	0	0	4.03%
	Total	250,026	0	0	

Over 20 percent of all identified event day outage hours in 2025 have been caused by tree contacts. Furthermore, a significant portion of events coded as adverse weather are likely related to tree contacts that may clear on their own or the tree may not be physically lying on the conductor once crews arrive. An additional portion of events coded as Loss of Supply are also related to tree contacts with transmission lines resulting in a customer outage. While NS Power always strives to minimize tree caused outages, the importance of this is further stressed in storm conditions. Continued investment in vegetation management and right-of-way widening will help minimize these outages in all weather conditions.

The following capital projects are identified to address vegetation management and right-of-way widening for 2026:

- CI C0080266 – New Distribution Rights-of-Way Phase 11
- D010 Distribution Right-of-Way Routine
- T010 Transmission Right-of-Way Routine

T010 and D010 Report

In the 2016 ACE Plan Order, the Board directed as follows:

> The Board approves the 2016 Routine capital expenditures, with the exception of the Distribution ROW widening (D010) which is reduced to $600,000. The Board directs that the Routine for Transmission widening be treated as a separate project, and not a routine, in future ACE Plan Applications. NSPI is to provide an annual progress report on the expenditure, works undertaken, results achieved and future plans as part of the annual ACE Plan submissions.[39]

In accordance with the Board's directive, NS Power provides its progress report on D010 and T010 below as of October 31, 2025.

In its 2017 ACE Plan Order, the Board directed as follows:

> The Board directs NSPI to update the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan (and future years) based on actual historical costs incurred for this project.[40]

NS Power confirms that the cost estimates for vegetation management and right-of-way widening projects in the 2026 ACE Plan are based on actual historical costs incurred.

Expenditures, Works Undertaken, and Results

The following progress was made on >69kV transmission widening under T010:

- 87 percent of planned 2025 work has been completed as of October 31, 2025
- 100 percent completion is forecast for year end 2025
- Forecast year end spend is approximately $3,000,000
- Substitutions have been made from the original plan, due to revised priorities:

[39] M07176, NS Power 2016 Annual Capital Expenditure Plan, Board Order, June 8, 2016.
[40] M07745, NS Power 2017 Annual Capital Expenditure Plan, Board Order, April 4, 2017.

- L-6511 was substituted by L-6002, L-6503

The following progress was made on distribution widening under D010:

- 62 percent of planned 2025 work has been completed as of October 31, 2025
- 80 percent completion is forecast for year end 2025
- Forecast year end spend is approximately $12,500,000

In the 2025 scope of work for D010, the actual costs of vegetation management per kilometer have been higher than originally forecast. This was driven by a combination of increases in traffic control, labour, and the continued enhancement of the scope of work for ROW widening. Additionally, through a large portion of the 2025 summer, a significant period of time was required for additional fire monitoring purposes in consideration of the extreme fire risk present due to the lack of precipitation. Forestry work sites required monitoring by the crew for one hour after work was complete to ensure no potential risk of fire was present. This led to a reduction in work efficiency due to the downtime at site. On the enhancement of scope, as discussed through the 2025 ACE Plan process, NS Power continued to further mitigate the effects of increasingly more frequent large wind events such as Fiona, and specific tree species were targeted, located beyond the defined ROW, that are prone to uprooting in major wind events. This activity would have been done in the past on trees that showed signs of poor health and therefore a higher likelihood of falling towards the power line. The improved approach now also assesses species type, to address certain species (such as poplar) that are more prone to uprooting during wind events. The increase in the time required to complete the additional tree removals combined with the cost increases with fuel, labor, and traffic control (compared to previous years used to create the original budget) has increased the average cost/kilometer. The result is that approximately 80 percent of kilometers originally targeted under D010 are ultimately expected to be completed within the 2025 ACE Plan budget amount. NS Power continues to explore opportunities to drive efficiencies in this routine and work collaboratively with its vegetation contractors to control costs.

Plans for Replacement of Aging Energy Delivery Equipment & Storm Performance

The 2015 ACE Plan Terms of Consensus included two commitments with respect to reliability:

> (4) As part of the reliability directive in future ACE Plans, NS Power will provide additional information regarding its plans for replacement of aging transmission and distribution equipment in accordance with the following recommendation on this matter made by the SBA's consultant, Mary Neal, at page 12 of her evidence in this proceeding dated January 16, 2015:
>
> > "I recommend NSPI provide more information regarding its plans for replacement of aging transmission and distribution equipment to better show how it justified the target investments. This should include (where possible):
> >
> > - Descriptions of assets to be replaced and their ages,
> > - Goals for strategic replacement programs, such as targets for age profiles of different asset classes,
> > - Expected improvements in asset age profiles due to each ACE Plan project involving replacement of transmission and distribution equipment considered at end-of-life,
> > - More detailed descriptions of how NSPI targets specific assets every year, whether based on age, performance degradation, or other factors, and
> > - Any recent, relevant inspection data"
>
> (5) As part of the reliability directive in future ACE Plans, NS Power will provide an update on its storm performance and related capital investment strategies to improve storm performance.[41]

The Terms of Consensus were approved by the Board on May 5, 2015. These two commitments are addressed below.

<u>Plans for Replacement of Aging Transmission and Distribution Equipment</u>

As part of its asset management practice, NS Power continually monitors outages and performance of transmission, substation, and distribution assets, with future investment plans developed at a

[41] M06514, NS Power 2015 Annual Capital Expenditure Plan, Terms of Consensus, February 18, 2015, page 2 of 5.

level aimed at providing safe and reliable service, while ensuring affordability. To sustain or improve reliability performance, NS Power follows its asset management principles to prioritize investments in Energy Delivery equipment in accordance with Section 6.2 of the CEJC. The project risk rating methodology found therein and described in **Section 3.0** utilizes condition and criticality to rate projects for the replacement or refurbishment of Energy Delivery assets. This reduces the overall risk for the associated asset classes.

Annual estimated replacement ranges are developed based on asset age profiles, and the Iowa Survivor curves for equipment failure are used as a guide in understanding the overall risk for each asset class. While the investments for a specific asset class may vary from year to year depending on asset condition and system performance, the estimated replacements analysis provides a working range in which to evaluate the appropriateness of proposed sustaining capital investments.

NS Power uses a variety of factors to determine the specific assets targeted for replacement as part of the annual capital investment program. Generally, targeted assets have experienced degradation in performance manifesting in decreased reliability, increased maintenance frequency and cost, or reduced functionality. These effects are identified through reliability tracking, field inspections, and test results of the impacted assets. Criticality of the asset to continued operations of NS Power's system and risks posed to people and the environment contribute to determining specific assets for replacement.

Asset age is a concern when the frequency of required maintenance is increased, the availability of replacement parts or critical spares is limited, or performance is negatively impacted. This information can be used to inform project prioritization. However, age profiles are used in concert with asset condition, performance, and legislated requirements; it is never the single determining element in an investment decision. Capital project justifications outline the specific reasoning behind a given replacement program considering all relevant elements.

In 2014, NS Power embarked on further formalizing the identification and prioritization of Energy Delivery assets for replacement by creating a regimented framework to determine the condition,

criticality, and evaluate the risks to NS Power's system imposed by individual assets within a given class. While an asset's risk rating alone does not determine its suitability for replacement, it can aid in identifying assets requiring more detailed investigation by technical experts and subsequent risk mitigation activities.

The target ranges for Energy Delivery assets covered by this analysis is provided in **Figure 76** below.

Figure 76: Age Based Replacement Ranges for Energy Delivery Assets

		High Range Replacements		Low Range Replacements	
Asset Classification	**Quantity on Grid**	**Estimated Useful Life (Years)**	**Annual Replacements**	**Estimated Useful Life (Years)**	**Annual Replacements**
Distribution Conductor (km)	44,076	45	979	55	801
Distribution Structure	373,703	50	7,474	60	6,228
Pole Top Transformer	139,138	35	3,975	45	3,092
Underground Conductor (km)	924	45	21	55	17
Padmount Transformers	4,468	35	128	45	99
Transmission Conductor (km)	5,528	55	101	65	85
Transmission Structure	32,185	55	585	65	495
Substation Breakers	455	45	10	55	8
Substation Transformer	445	50	9	60	7

Age demographics information is presently not available for all transmission and distribution asset classes. Substation transformers, substation breakers, transmission conductor, downline reclosers and padmount transformers are asset classes for which this information is currently available. As

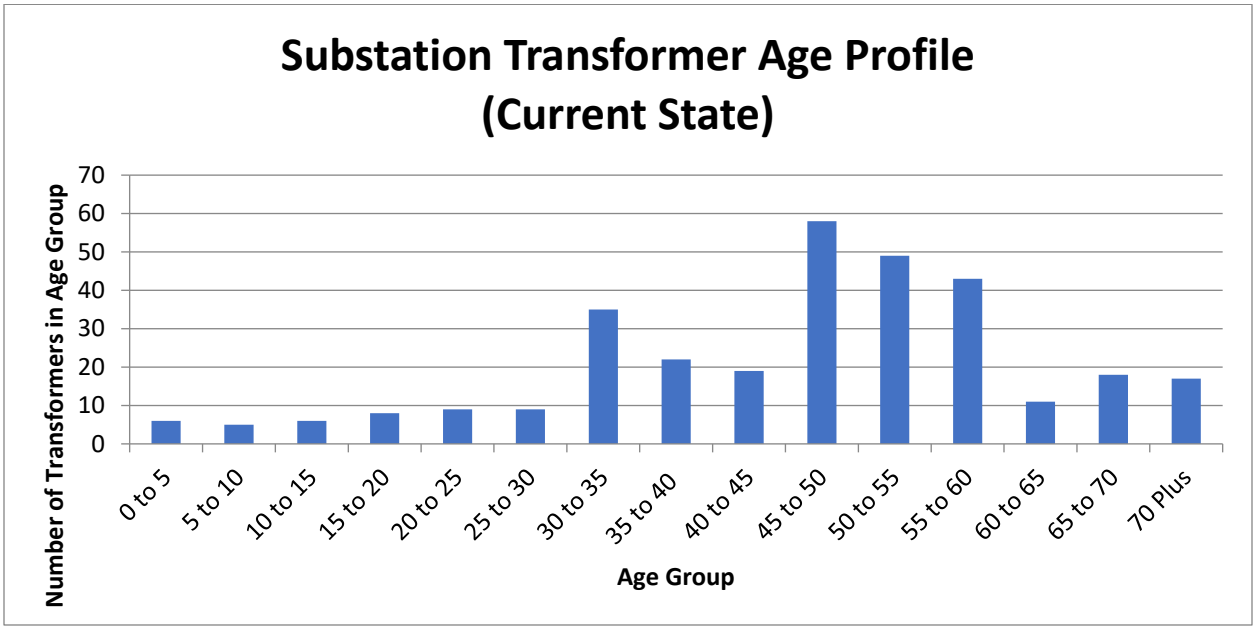
asset information improves for individual asset classes, their age profiles provide a more complete picture of the current state across the Energy Delivery system.

As Energy Delivery equipment reaches end-of-life, capital investments are used to mitigate impacts related to aging and unreliable infrastructure. It is important to recall here, and for context with the following sections (**Figure 77-Figure 86**), that age is not the only determinant of useful life and therefore an asset's reliability or risk. Older equipment may have lower risk ratings than newer equipment due to design, utilization, or other operating conditions and there continues to be advancements in technologies to enable re-validation of useful life. Therefore, in addition to age-driven identification and justification for capital replacements or upgrades, observed or calculated condition, reliability impact, and other factors are considered in determining a given asset class' capital program in any given year. The noted expected ranges of replacement per asset class per year serve as a guide or calibration range and are based on the age arithmetic. Actual replacement plans will vary depending on the assessment of the assets' conditions and priorities in the context of each year's overall plan.

Substation Transformers

Figure 77 below shows the substation transformer age profile (current state).

Figure 77: Substation Transformers Age Profile (Current State)



- Expected useful life of 50-60 years depending on the transformer type, utilization, and environmental conditions.

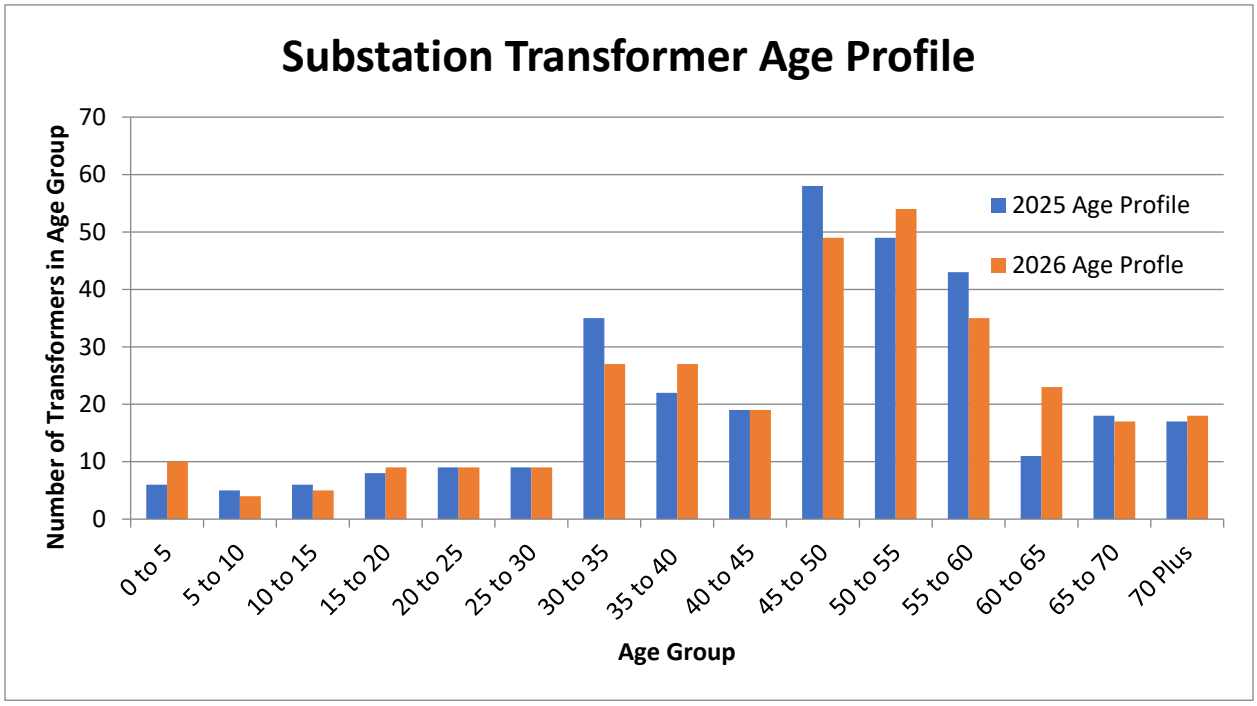
- Age Demographics – 43.8 percent of Transformers are beyond 50 years of service and 28.3 percent are beyond 60 years of service.

- Calculated range of annual replacement using the expected useful life only – 7-9 units per year.

- Changes to age demographics – As a result of the proposed 2026 capital investments in substation transformers, the age profile for this asset class will experience an increase of 2.9 percent in assets beyond 50 years of age and an increase of 1.3 percent above 60 years of age. Age is only one of multiple factors in determining targeted assets in a given year. To support mitigation of risk associated with this asset class, continuation of the strategic transformer spares program and mobile substation program is planned. Proactive transformer replacements in future years will again focus on the overall condition of each

unit and system criticality. **Figure 78** illustrates the overall change in asset age profile for Substation Transformers between 2025 and 2026.

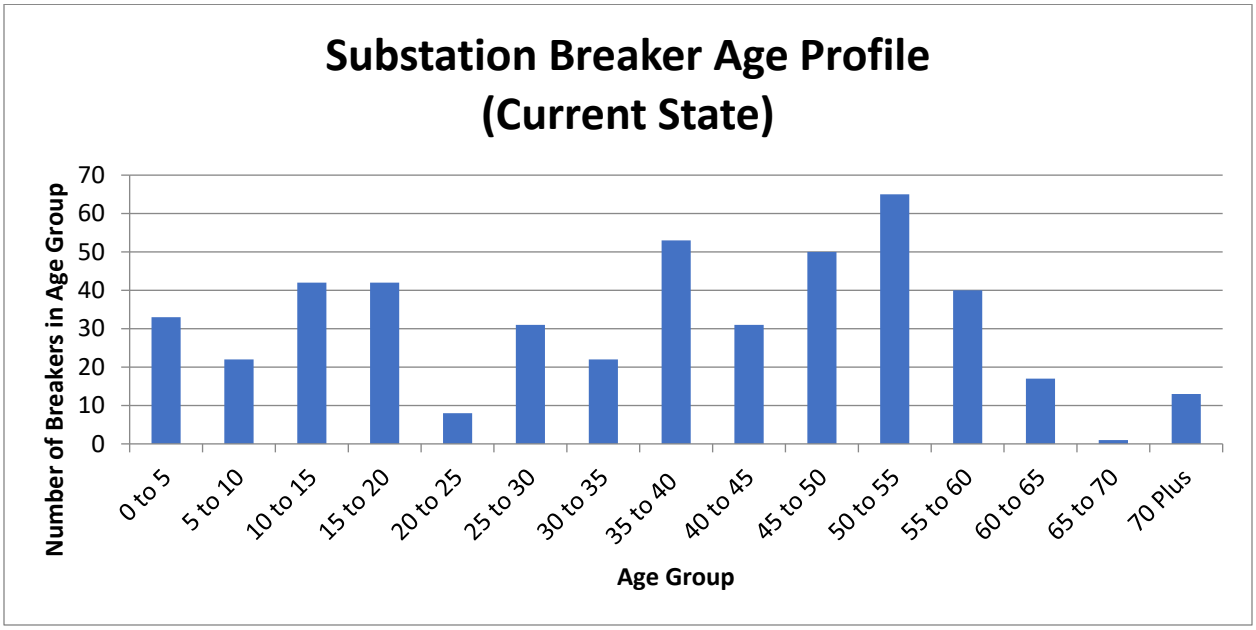
Figure 78: Substation Transformer Age Profile



Substation Breakers

Figure 79 below shows the substation breaker age profile (current state).

Figure 79: Substation Breakers Age Profile (Current State)



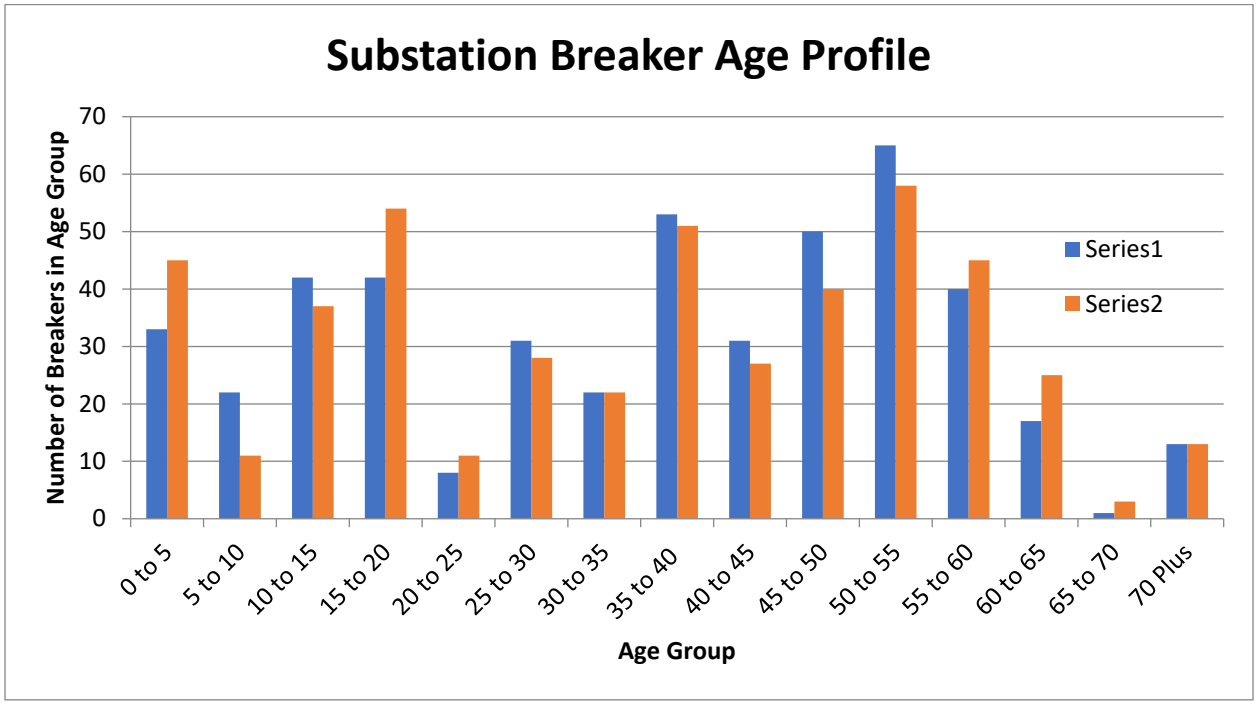
- Expected useful life of 45-55 years depending on the breaker type, operations count, and environmental conditions.

- Age Demographics – 39.1 percent of breakers are beyond 45 years of service and 15.0 percent are beyond 55 years of service.

- Calculated range of annual replacement using the expected useful life only – 8-10 units per year.

- Changes to age demographics – As a result of the proposed capital investments in Substation Breakers during 2026, the age profile for this asset class will experience a 0.43 percent decrease of assets beyond 45 years of age and 3.2 percent increase beyond 55 years of age. Age is only one of multiple factors in determining targeted assets in a given year. To support mitigation of risk associated with this asset class, continuation of the strategic breaker spares program is planned. **Figure 80** illustrates the overall change in asset age profile for Substation Breakers between 2025 and 2026.

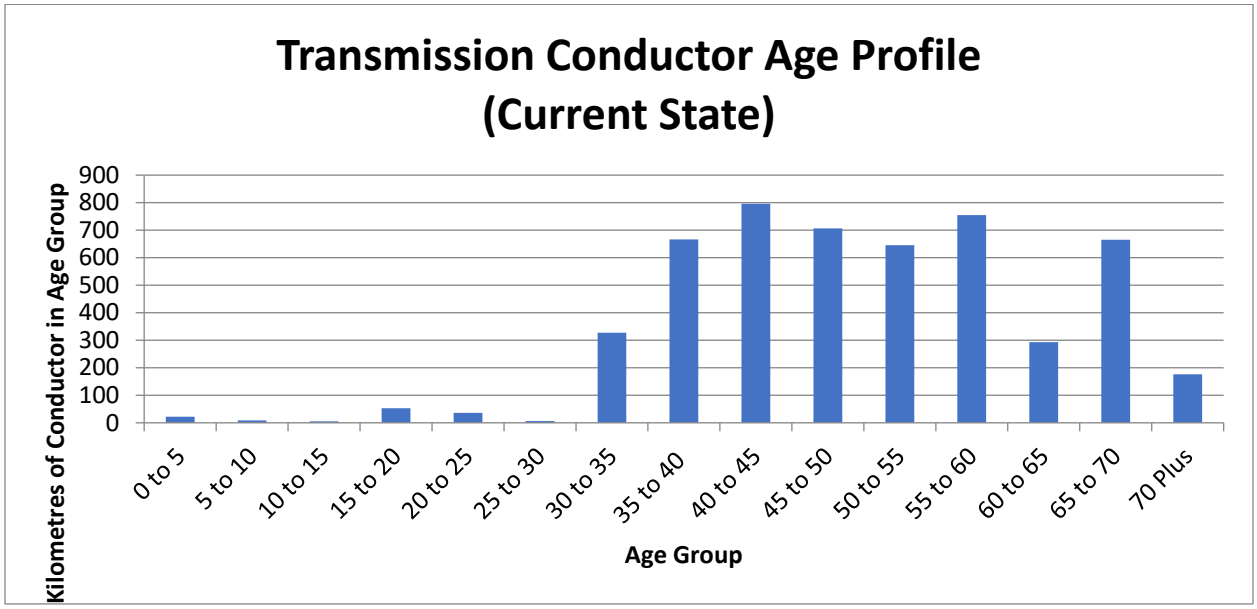
Figure 80: Substation Breaker Age Profile



Transmission Conductor

Figure 81 below shows the transmission conductor age profile (current state).

Figure 81: Transmission Conductor Age Profile (Current State)



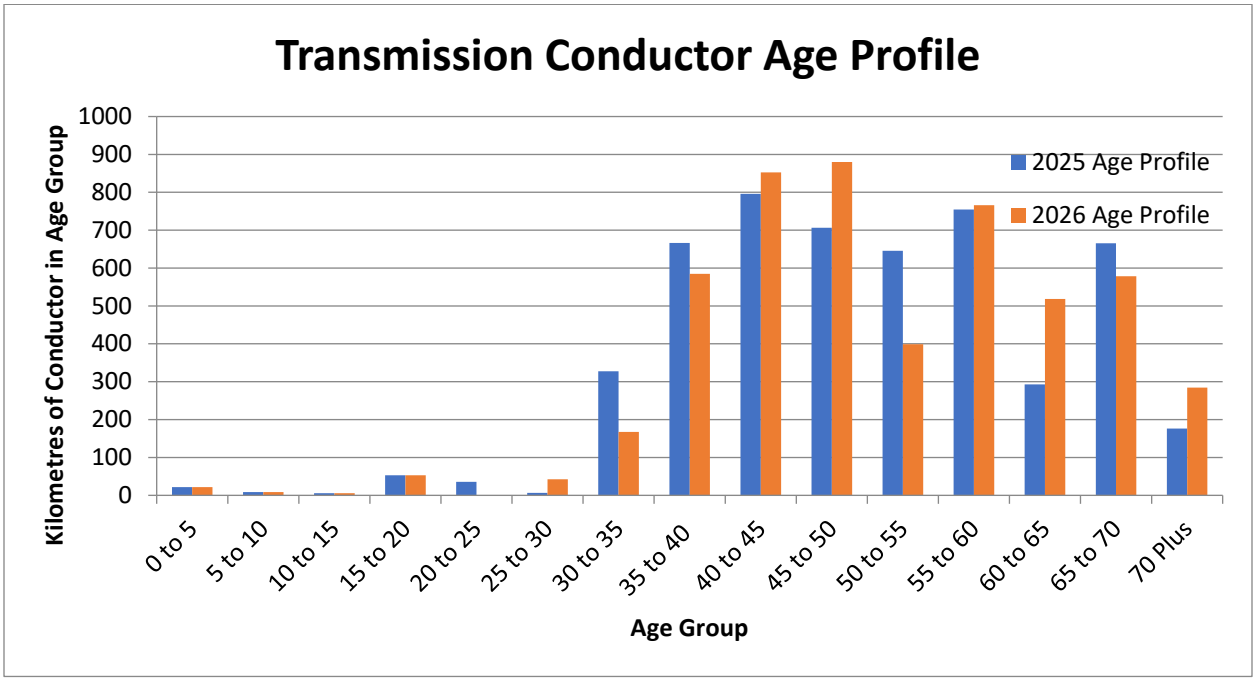
- Expected useful life of 55-65 years depending on the conductor design and environmental conditions.

- Age Demographics – 36.6 percent of conductor is beyond 55 years of service and 16.3 percent beyond 65 years of service.

- Calculated range of annual replacement using the expected useful life only – 85 to 100 km per year.

- Changes to age demographics – As a result of proposed capital investments in transmission conductor in 2026, the age profile for this asset class will experience an approximately 5.0 percent increase in assets beyond 55 years of age and 0.41 percent increase beyond 65 years of age. Age is only one of multiple factors in determining targeted assets in a given year. **Figure 82** illustrates the overall change in asset age profile for transmission conductor between 2025 and 2026.

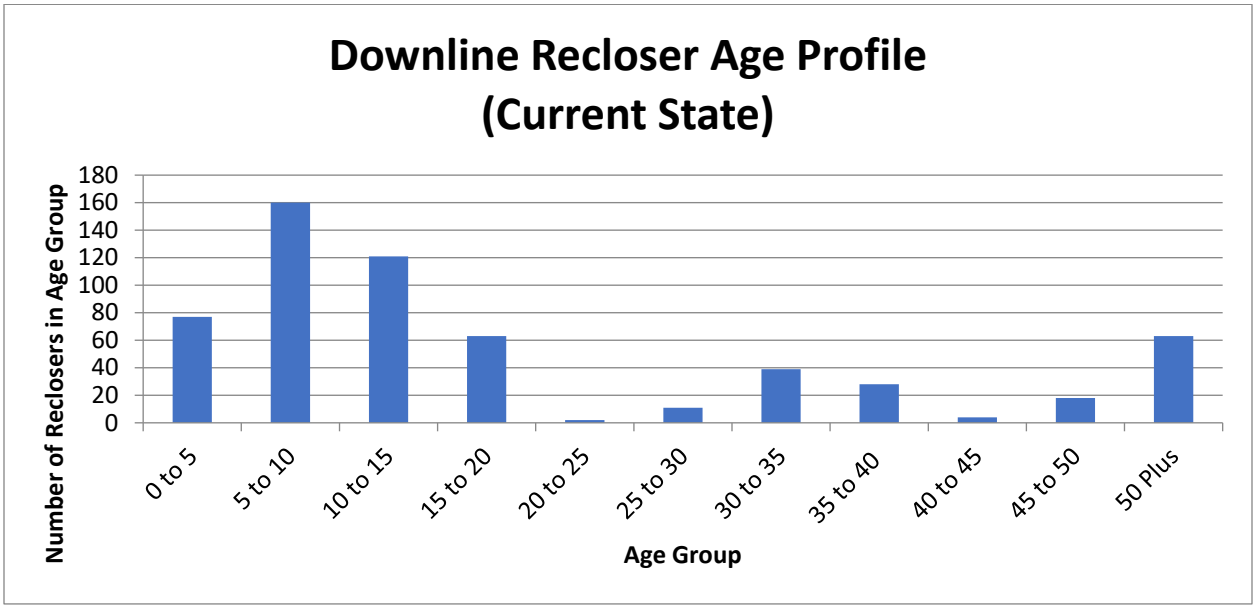
Figure 82: Transmission Conductor Age Profile



Downline Reclosers

Figure 83 below shows the downline reclosers age profile (current state).

Figure 83: Downline Reclosers Age Profile (Current State)



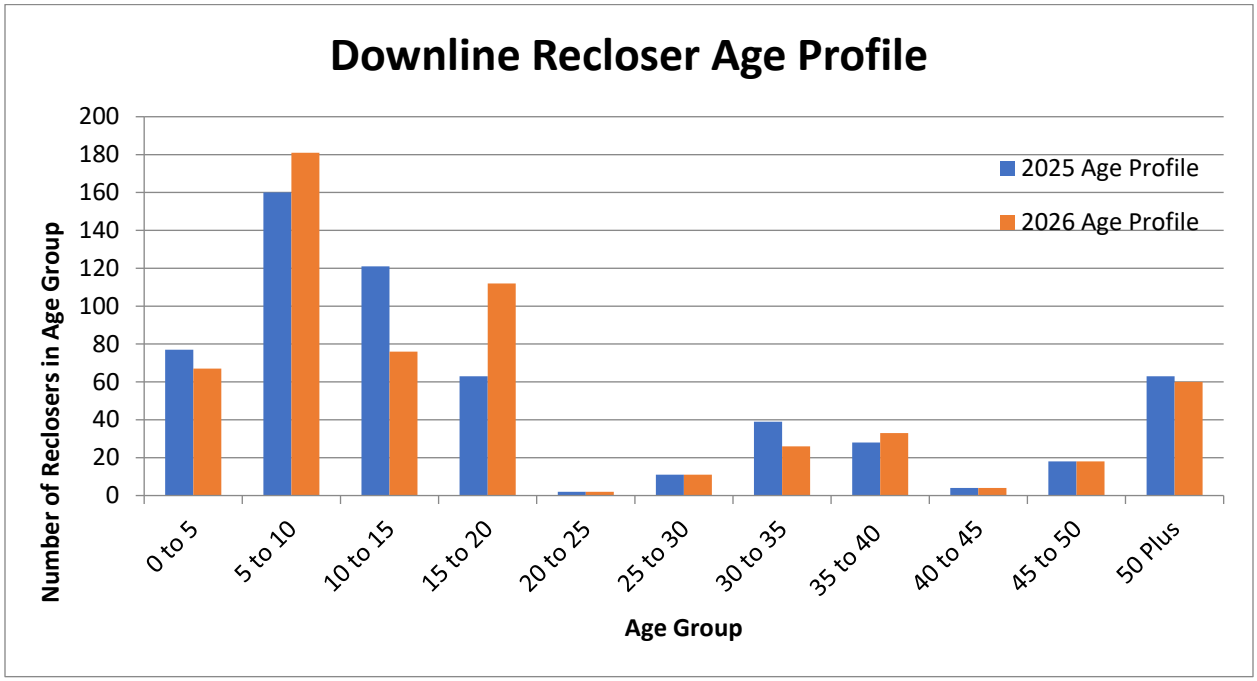
- Expected useful life of 30-40 years depending on the downline recloser design, loading, and environmental conditions.

- Age Demographics – 23.9 percent of Downline Reclosers are beyond 30 years of service and 13.9 percent are beyond 40 years of service.

- Calculated range of annual replacement using the expected useful life only – 15 to 20 units per year.

- Changes to age demographics – As a result of the proposed capital investments in Downline Reclosers during 2026, the age profile for this asset class will experience an approximately 0.43 percent decrease in assets beyond 30 years of age and 0.1 percent increase beyond 40 years of age. As noted above, age is only one of multiple factors in determining targeted assets in a given year. To support mitigation of risk associated with this asset class, continuation of the strategic Downline Recloser spares program is planned. **Figure 84** below illustrates the overall change in asset age profile for Downline Reclosers between 2025 and 2026.

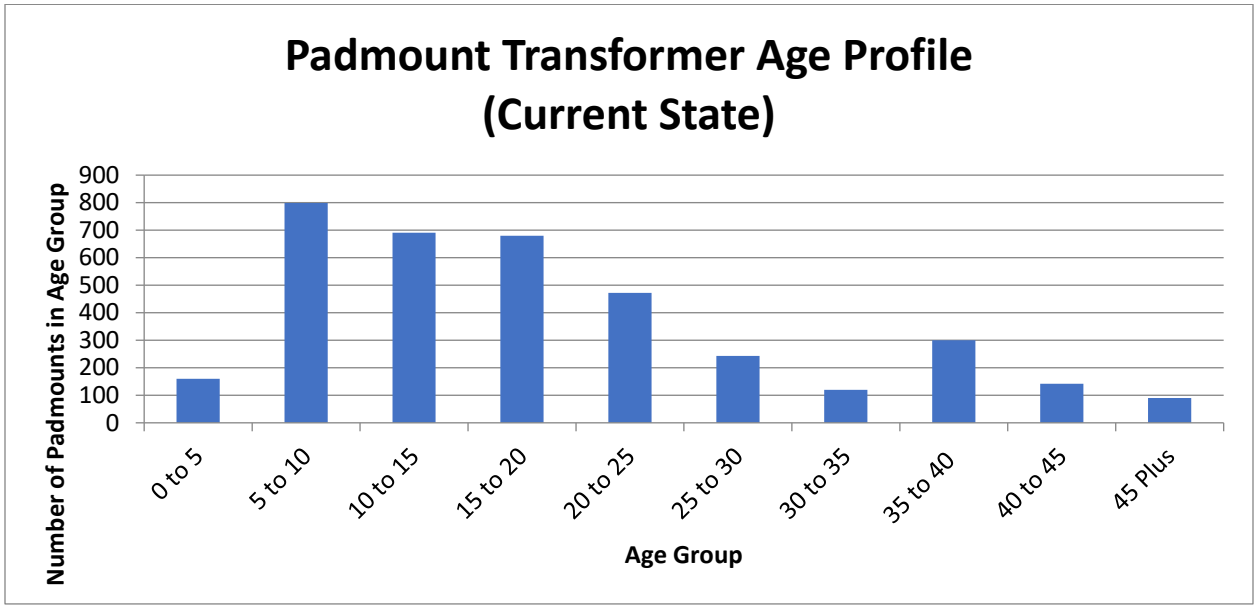
Figure 84: Downline Recloser Age Profile



Padmount Transformers

Figure 85 below shows the Padmount Transformer age profile (current state).

Figure 85: Padmount Transformers Age Profile (Current State)



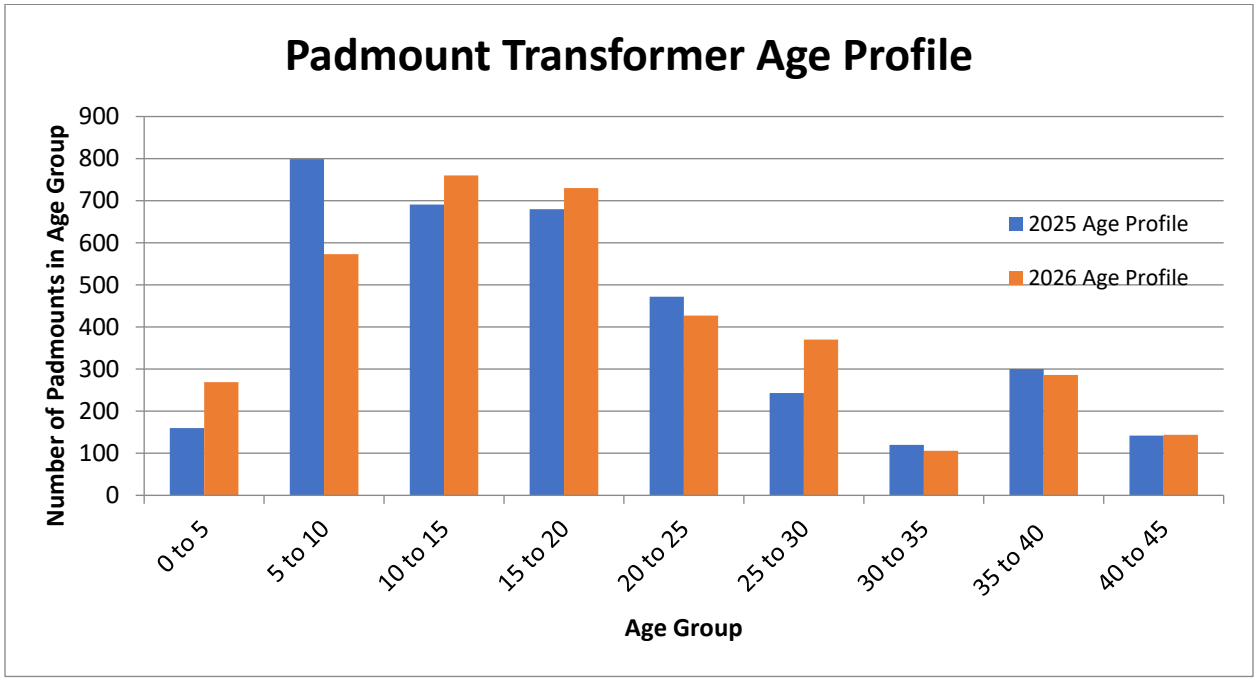
- Expected useful life of 35-45 years depending on the padmount design, loading, and environmental conditions.

- Age Demographics – 11.1 percent of padmounts are beyond 35 years of service and 2.4 percent beyond 45 years of service.

- Calculated range of annual replacement using the expected useful life only – 95 to 122 units per year.

- Changes to age demographics – As a result of the proposed capital investments in Padmount Transformers during 2026, the age profile for this asset class will experience an approximately 0.4 percent decrease in assets beyond 35 years of age and a 0.1 percent increase beyond 45 years of age. **Figure 86** below illustrates the overall change in asset age profile for Padmount Transformers between 2025 and 2026.

Figure 86: Padmount Transformer Age Profile



11.1.5 Strategic Asset Management Plan (SAMP)

The Board's letter dated July 8, 2025 pertaining to its inquiry into NS Power's Property and Assets provided the following directive:

> The Board directs NS Power to annually confirm in the ACE Plan filings whether any revisions were made to the SAMP (and, if so, to file any SAMP revisions) or if any revisions are anticipated. In addition, NS Power is directed to conduct a formal review of the SAMP by the end of the first five-year period, no later than December 31, 2029.[42]

NS Power expects to file a minor revision to the SAMP by December 31, 2026.

[42] M12022, Action Plan Update – Inquiry into NS Power's Property and Assets under s. 30(5)(a), Board Letter, July 8, 2025.

11.1.6 CIS Replacement Project – Status Update

The Board's letter dated October 1, 2025 pertaining to a customer DRO appeal provided the following directive:

> NS Power is directed to include specific updates about its Customer Information System Replacement project as part of its direct evidence in its Annual Capital Expenditure filings, until the project is completed.[43]

As outlined in NS Power's submissions under matter M11884, the Customer Information System (CIS) is the primary application for all of NS Power's customer processes and interactions. The current solution was installed in 1997. Over the last 28 years, the CIS has been customized to meet many customer, compliance, and operational requirements. This approach provided customers with a low-cost solution, and it continues to enable its supported functions in a secure and low-cost manner.

The CIS application is no longer under vendor support and has undergone significant changes and customizations over its lifespan. While investments have been made to remain on supported server infrastructure, operating system, and database technologies, the technology risk profile of this solution remains high. Upgrades to NS Power's CIS have been on the Company's long-term technology investment plan for several years as part of a strategic update to NS Power's core technology infrastructure. Capital Work Order C0021835 - IT – CIS Replacement was listed in the 2025 ACE Plan as a project for subsequent submittal with the following description:

> This project will replace Nova Scotia Power's Customer Information System (CIS). The CIS system is critical to delivering customer care, billing and communications to customers. CIS needs to be replaced in order to address the risks associated with the existing software and to continue to deliver bills and serve customers reliably.

In addition, NS Power anticipates the scope of the CIS Replacement project would also include enhancements to enable new tariff designs such as Time of Use (TOU), Critical Peak Pricing

[43] M11884, DRO Appeal, Board Letter, October 1, 2025.

(CPP), real-time pricing, and Time Varying Pricing (TVP), and accommodate new programs such as Green Choice.

Since the cyber incident was discovered on April 25, 2025, a dedicated team within NS Power, along with third-party cybersecurity experts, have been actively investigating the recent ransomware attack affecting both customers and the Company. While the CIS system itself was not impacted, the investigation into impacted systems may yield important considerations for future requirements to be included in the CIS Replacement project. As such, this investigation could impact the direction and timeline of the CIS Replacement project and work to advance the project which has been temporarily paused.

As provided in **Section 4.2** and **Section 5.3**, NS Power currently plans to file the CIS Replacement project application in 2026, with the launch of the new CIS system anticipated in 2029.

11.2 2026 Capital Spending by Justification Criteria

Items in the 2026 ACE Plan have been developed in accordance with the CEJC. Definitions of the various criteria referenced in **Figure 87** below are included in the CEJC.

Figure 87: Capital Expenditures by Justification Criteria

(Millions of dollars)

Justification Criteria	2026 Budget	Projects included for Approval	Routine Spend	Less than $1M	Items for Subsequent Submission	Carryover
Health & Safety	22.2	-	0.7	5.9	6.1	9.5
Environment	4.6	-	0.8	1.3	0.4	2.2
Land and Right-of-Way	0.1	-	0.1	-	-	-
Hydro, Wind and Biomass	37.3	-	3.2	6.5	10.2	17.3
Thermal	123.9	16.6	3.5	81.7	10.4	11.8
Transmission Plant	233.9	11.1	22.0	1.3	117.3	82.1
Distribution System	185.4	20.2	136.6	11.5	2.8	14.3
Metering Equipment	4.2	-	3.9	-	-	0.3
Work Support Facilities	22.5	1.2	9.1	1.6	1.2	9.4
Information Technology Application and Hardware System	45.0	-	4.3	7.1	26.2	7.4
Vehicles	23.2	-	23.2	-	-	-
Total	**$702.1**	**$49.0**	**$207.3**	**$116.9**	**$174.5**	**$154.3**

*Note: Details of justification sub-criteria are provided in the following section.
Note: Figures presented may include $0.1M in rounding differences on some line items.

11.3 2026 Capital Spending by Justification Sub-Criteria

Figure 88 below provides 2026 capital spending by justification sub-criteria.

Figure 88: 2026 Capital Spending by Justification Sub-Criteria

(Millions of dollars)

Justification Sub-Criteria	2026 Budget	Projects included for Approval	Routine Spend	Less than $1M	Items for Subsequent Submission	Carryover
Distribution System						
Requirement to Serve	117.9	-	117.4	-	-	0.5
Outage Performance	13.4	-	13.2	-	-	0.1
Joint Use Agreement	3.7	-	3.7	-	-	-
Other Distribution System	50.3	20.2	2.3	11.5	2.8	13.6
Total	**$185.4**	**$20.2**	**$136.6**	**$11.5**	**$2.8**	**$14.3**
Work Support Facilities						
Building Facilities/Furniture	5.8	-	4.9	0.9	-	-
Telecontrol & Telecommunications	6.4	0.9	1.5	0.5	-	3.5
Other Work Support Facilities	10.2	0.3	2.7	0.2	1.2	5.9
Total	**$22.5**	**$1.2**	**$9.1**	**$1.6**	**$1.2**	**$9.4**

Note: Figures presented may include $0.1M in rounding differences on some line items

11.4 Quick Reference Sheet

2025 AFUDC Rate for Capital 6.65%

In the Board's Weighted Average Cost of Capital (WACC) and Allowance for Funds Used During Construction (AFUDC) Order dated March 31, 2025, the Board directed NS Power as follows:

1. The WACC and AFUDC rates are set at 6.65%, effective April 1, 2025. [44]

Consistent with the Board's Order, the 2026 ACE Plan projects use the Board's approved AFUDC rate of 6.65 percent.

2026 O/H Rates

Generation		**Customer Operations**		**Shared Services**	
PP Regular	37.25%	Regular	53.98%	IT	56.12%
Hydro	88.84%	Contract	10.45%		
Contract	9.43%	Vehicle	32.18%		

[44] M11990, NS Power WACC/AFUDC Application, Board Order, March 31, 2025.

11.5 2026 Depreciation Rates

Figure 89: 2026 Depreciation Rates

	2026
Steam Production Plant	
Lingan	
Lingan 1-2	4.12%
Lingan 3-4	2.28%
Lingan – Common	4.48%
Total Lingan	3.35%
Point Aconi 1	2.27%
Point Tupper	
Point Tupper 1 (Common)	3.97%
Point Tupper 2	2.82%
Total Point Tupper	2.89%
Trenton	
Trenton 5	3.10%
Trenton 6	2.34%
Trenton – Common	0.47%
Total Trenton	2.47%
Tufts Cove	
Tufts Cove 1	4.24%
Tufts Cove 2	3.68%
Tufts Cove 3	2.33%
Tufts Cove – Common	3.44%
Total Tufts Cove	3.27%
Port Hawkesbury Biomass	2.50%
Point Tupper Marine Terminal	4.06%
International Coal Pier	2.60%
General	2.82%
Total Steam Production Plant	**2.82%**

2026 ACE Plan
CONFIDENTIAL (Attachments Only)

	2026
Hydro Production Plant	
Avon	3.02%
Bear River	1.80%
Black River	2.04%
Dickie Brook	3.16%
Fall River	1.82%
Harmony	4.55%
Lequille System	2.33%
Roseway	2.29%
Mersey	2.00%
St. Margaret's	2.85%
Sheet Harbour	3.38%
Tusket	2.64%
Wreck Cove System	1.67%
Annapolis Tidal	2.32%
General	2.10%
Total Hydro Production	**2.10%**
Other Production - Combustion Turbines	
Burnside	2.40%
Tusket	6.42%
Victoria Junction	3.17%
Tufts Cove Unit 4	2.55%
Tufts Cove Unit 5	2.77%
Tufts Cove Unit 6	3.03%
Wind Turbines	
Pre 2009 Wind	5.52%
Post 2009 Wind	4.00%

2026 ACE Plan
CONFIDENTIAL (Attachments Only)

	2026
Transmission Plant	
Land Rights - Easements	1.26%
Station Equipment	2.14%
Towers & Fixtures	1.26%
Poles & Fixtures	4.32%
Overhead Conductors & Devices	1.96%
Underground Conduit	1.53%
Underground Conductors & Devices	2.61%
Roads, Trails & Bridges	1.74%
Total Transmission Plant	**2.35%**
Distribution Plant	
Land Rights - Easements, Surveys & Clearing	1.56%
Structures & Improvements	5.31%
Station Equipment	1.28%
SCADA Equipment	9.68%
Remote Monitoring Equipment	10.32%
Station Equipment – Miscellaneous	12.49%
Poles, Towers & Fixtures	3.79%
Overhead Conductors & Devices	3.33%
Underground Conduit	1.51%
Underground Conductors & Devices	3.17%
Line Transformers	4.09%
Services	5.33%
Meters	6.87%
Street Lighting & Signal Systems	5.33%
Total Distribution Plant	**3.89%**

	2026
General Plant	
Land Rights - General Plant	1.93%
Structures & improvements	2.85%
Office Furniture & Equipment	9.26%
Office Furniture & Equip - Comp Hardware	20.00%
Office Furniture & Equip - Comp Software	10.00%
Transportation Equipment	9.55%
Stores Equipment	14.97%
Communication Equipment	4.38%
Communication Equipment - SCADA Eq	1.33%
Remote Monitoring Equipment	10.27%
Miscellaneous Equipment	5.02%
Roads, Bridges & Trails (Kelly Rock)	2.58%
Mining Equipment (Kelly Rock)	2.92%
Total General Plant	**8.16%**
Smart Grid Project	
Solar Generation	4.00%
Batteries	10.00%
EV Chargers	6.67%
Battery Energy Storage System (BESS) Project	
Battery Storage Systems	5.00%

1

CI Number: C0080206

Title: POA Boiler Refurbishment 2026

Start Date: 2026/08
In-Service Date: 2026/10
Final Cost Date: 2027/04
Function: Steam
Forecast Amount: $1,304,600

DESCRIPTION:

This project is for the refurbishment of the Point Aconi Boiler. The scope of work includes the inspection refurbishment and replacement of boiler components critical to environmental compliance and the safe, reliable, and efficient operation of the system. This includes tubing, headers, casing, ducting, insulation, cladding, tube shields, and other miscellaneous components identified as deficient. The final scope of this project will be determined based on the findings of the comprehensive inspections carried out during the 2026 planned shutdown, in accordance with established asset management practices and safety protocols. This effort includes evaluation and prioritization of activities to be undertaken during the annual outage. Boiler tubes and tube bends will be replaced in the areas where the thickness readings are below the minimum requirements specified by American Society of Mechanical Engineers specifications, and the Nova Scotia Labour and Advanced Education Regulations.

The Board provided the following Directive in its Decision pertaining to the Decarbonization Deferral Account (DDA) (M11220):

> NS Power must provide specific notice to all participants in this proceeding upon filing any future capital work order applications involving assets that are forecasted to be included in the DDA and to confirm this was done in its applications to the Board.

In accordance with the Board's directive, NS Power provided notice of this investment to participants in the DDA proceeding on December 3, 2025.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects includes "work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- 2024 – C0060250 POA Boiler Refurbishment 2024 - $1,121,251
- 2024 – C0060246 POA Boiler Arrowhead Replacements 2024 - $273,624
- 2024 – C0052438 POA BA Center Drain Valve Replacements 2024 - $118,768
- 2024 – C0071229 POA UU RH1 Refurbishment - $893,600
- 2025 – C0067947 POA SH3 Refurbishment 2025 - $659,405
- 2025 – C0067951 POA SH1 Refurbishment 2025 - $518,000
- 2025 – C0068028 POA Arrowhead Refurbishment 2025 - $271,606
- 2025 – C0068029 POA SUB Upgrades - $254,321
- 2025 – C0074768 POA UU RH1 Refurbishment - $238,855
- 2025 – C0067906 POA Boiler Refurbishment 2025 - $1,218,254
- 2026 – C0080205 POA Boiler Refractory Replacement 2026 - $1,022,040
- 2026 – TBD POA Arrowhead Refurbishment 2026 - $275,348
- 2027 – TBD POA Boiler Refractory Replacement 2027 - $TBD
- 2028 – TBD POA Boiler Refractory Replacement 2028 - $TBD

Depreciation Class: Steam Production Plant – Point Aconi

Estimated Life of the Asset: 8 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.15%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/ Refurbishment

Why do this project?

NS Power conducts condition and risk assessment and analysis based on the annual boiler inspection reports, boiler tube failure reports, root cause analyses, and boiler header inspection reports. The replacement of boiler components such as boiler tubes, tube shielding, and tube locks is essential to enhance the ongoing reliability of the boiler system and mitigate the risk of unplanned outages, particularly those resulting from tube leaks or failures. Operationally, the continued operation of the boiler with degraded components such as boiler tubes, tube bends, and tube shields significantly increases the likelihood of failures during operation, potentially leading to forced outages and production losses. From a safety perspective, tube leaks can lead to high-temperature steam releases and localized over-pressurization, posing safety hazards to personnel and damaging surrounding equipment. Financially, unplanned outages caused by component failures often incur significantly higher refurbishment costs, emergency labour premiums, and replacement energy costs compared to scheduled replacement during planned outages. Additionally, there is an asset integrity risk, as delaying the replacement of worn components accelerates damage to adjacent systems, leading to larger-scale refurbishment requirements and reducing the useful life of the boiler. Replacement of deteriorated components is therefore essential to ensure the continued safe, efficient, and cost-effective operation of the boiler, while supporting sustained asset integrity and reliability of the asset and maintaining the operating license compliance.

Why do this project now?

The inspection, refurbishment, and replacement of tubes and tube shields in the boiler can only be effectively conducted during a scheduled outage. These components operate under high temperatures, pressures, and abrasive conditions making it unsafe and impractical to access or service them during normal operation and requiring annual inspection and refurbishment. Carrying out this work annually during a planned outage significantly reduces the risk of unplanned downtime caused by tube leaks or component failures. Moreover, performing these activities as part of the outage schedule is essential to maintaining compliance with applicable industry standards and regulations such as Boiler and Pressure Equipment Regulations. This project is critical not only for operational safety but also for ensuring the ongoing efficiency and reliability of the boiler system.

Why do this project this way?

Replacing boiler tubes, tube bends, and shields is the most cost-effective way to significantly reduce the risk of tube leaks and minimize the likelihood of unplanned outages that could disrupt production and result in operational inefficiencies. This refurbishment is supported by detailed inspections, which have identified this work as essential to sustaining reliable boiler performance.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers) based on previous experience with these assets, and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 10 percent. Risks intended to be covered by this contingency include unforeseen price increases of materials (as a result of needing to expedite delivery) and additional scope that may be required during the refurbishment. While the refurbishment is planned, certain conditions of the boiler components cannot be fully assessed until the unit is opened up. If unexpected deterioration or damage is discovered at that stage, it may necessitate the urgent procurement of replacement materials to avoid schedule delays and minimize downtime.

Capital Project Detailed Estimate

Location: Steam
CI# : C0080206
Title: POA Boiler Refurbishment 2026
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	20	$ 466	$ 9,320		C0052294, C0060251
Maintenance Trades	PD	20	$ 427	$ 8,540		C0052294, C0060253
Power Engineer	PD	13	$ 457	$ 5,939		C0052294, C0060254
Power Plant Technician	PD	20	$ 439	$ 8,776		C0052294, C0060255
Utilityworker	PD	20	$ 297	$ 5,949		C0052294, C0060256
Technologists	PD	15	$ 377	$ 5,660		C0052294, C0060258
			Sub-Total	$ 44,184		
OT Labour						
Maintenance Trades	PD	10	$ 854	$ 8,540		C0052294, C0060250
Power Engineer	PD	5	$ 914	$ 4,568		C0052294, C0060250
Power Plant Technician	PD	10	$ 878	$ 8,776		C0052294, C0060250
Utilityworker	PD	10	$ 595	$ 5,949		C0052294, C0060250
			Sub-Total	$ 27,832		
Term Labour						
Maintenance Trades	PD	30	$ 427	$ 12,810		C0052294, C0060250
Power Plant Technician	PD	30	$ 439	$ 13,164		C0052294, C0060250
Utilityworker	PD	20	$ 297	$ 5,949		C0052294, C0060250
			Sub-Total	$ 31,923		
Materials						
Center Drain Components	lot	1	$ 80,000	$ 80,000		C0052294, C0060250
Boiler Tubes	lot	1	$ 50,000	$ 50,000		C0052294, C0060250
Tube Shields	lot	1	$ 50,000	$ 50,000		C0052294, C0060250
Bottom Screw Coolers	lot	1	$ 50,000	$ 50,000		C0052294, C0060250
Misc Consumables	lot	1	$ 20,000	$ 20,000		C0052294, C0060250
			Sub-Total	$ 250,000		
Contracts						
Scaffolding Services	lot	1	$ 115,000	$ 115,000		
Rescue Services	lot	1	$ 50,000	$ 50,000		
Blasting Services	lot	1	$ 200,000	$ 200,000		
Industrial Cleaning Services	lot	1	$ 150,000	$ 150,000		
Boilermakers	lot	1	$ 200,000	$ 200,000		
			Sub-Total	$ 715,000		
Rental/ Main of Equipment						
Equipment Rental Services	lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 20,000		
Other Goods & Services						
Contingency	%	10%	$ 1,088,939	$ 108,894		
			Sub-Total	$ 108,893.90		
Interest Capitalized						
AFUDC				$ 5,800		
			Sub-Total	$ 5,800		
Administrative Overhead						
Labour AO				$ 33,535		
Contractor AO				$ 67,432		
			Sub-Total	$ 100,967		
			SUB-TOTAL (no AO, AFUDC)	$ 1,197,833		
			TOTAL (AO, AFUDC included)	$ 1,304,600		
Original Cost				$ 866,970		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER An Emera Company

Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Process Industries	Required fields:	Estimate Classification				
Project Name: POA Boiler Refurbishment 2026	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Non-Process Facilities (Infrastructure, Ports, Pipeline, Power Transmission)	Defined (D)	P	P	D	D	D
Project Scope of Work Description	Preliminary (P)	P	P			
Byproduct and Waste Disposal	Defined (D)	NR	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Plant Production/Facility (includes power facilities)	Defined (D)	P	P	D	D	D
Electrical Power Requirements (when not the primary capacity driver)	Defined (D)	NR	P	D	D	D
C. Project Location						
Plant and Associated Facilities	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Communication Systems	Defined (D)	NR	P	D	D	D
Fire Protection and Life Safety	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Process Technology	Not Applicable (NA)					
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Preliminary (P)	NR	P			
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
H. Studies						
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Block Flow Diagrams	Not Applicable (NA)					
Equipment Data Sheets	Complete (C)	NR/S	P	C	C	C
Equipment Lists: Electrical	Complete (C)	NR/S	P	C	C	C
Equipment Lists: Process/Utility/Mechanical	Complete (C)	NR/S	P	C	C	C
Heat & Material Balances	Complete (C)	NR	C	C	C	C
Process Flow Diagrams (PFDs)	Complete (C)	NR	C	C	C	C
Utility Flow Diagrams (UFDs)	Complete (C)	NR	C	C	C	C
Design Specifications	Complete (C)	NR	S/P	C	C	C
Electrical One-Line Drawings	Not Applicable (NA)	NR				
General Equipment Arrangement Drawings	Complete (C)	NR	S/P	C	C	C
Instrument List	Complete (C)	NR	S/P	C	C	C
Piping & Instrumentation Diagrams	Complete (C)	NR	S/P	C	C	C
Plot Plans/Facility Layouts	Complete (C)	NR	S/P	C	C	C
Construction Permits	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Fire Protection & Life Safety Drawings & Details	Complete (C)	NR	S/P	P	C	C
Electrical Schedules	Preliminary (P)	NR	NR/S	P	P/C	
Instrument & Control Schedules	Preliminary (P)	NR	NR/S	P	P/C	
Instrument Data Sheets	Complete (C)	NR	NR/S	P	P/C	C
Piping Schedules	Preliminary (P)	NR	NR/S	P	P/C	
Piping Discipline Drawings	Complete (C)	NR	NR/S	S/P	C	C
Spare Parts Listings	Complete (C)	NR	NR	P	P/C	C
Electrical Discipline Drawings	Complete (C)	NR	NR	S/P	P/C	C
Facility Emergency Communication Plan & Drawings	Complete (C)	NR	NR	S/P	P/C	C
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Complete (C)	NR	NR	S/P	P/C	C
Mechanical Discipline Drawings	Complete (C)	NR	NR	S/P	P/C	C
	Total # Deliverables for this Project	5	33	38	36	33
	% Defined/Complete towards Class Estimate	100%	100%	88%	88%	84%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 88% of Class 3 deliverables are completed. A contingency value of 10% was selected to account for specific risks such as unforeseen material cost increases particularly resulting from expedited procurement timelines, as well as additional scope that may be required once refurbishment activities are underway and exisiting conditions are fully revealed.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *process industries* is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs), piping and instrument diagrams (P&IDs), and electrical one-line drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information. This RP applies to a variety of project delivery methods such as traditional design-bid-build (DBB), design-build (DB), construction management for fee (CM-fee), construction management at risk (CM-at risk), and private-public partnerships (PPP) contracting methods.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this recommended practice may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

Most plants also have significant electrical power equipment (e.g., transformers, switchgear, etc.) associated with them. As such, this RP also applies to electrical substation projects, either associated with the process plant, as part of power transmission or distribution infrastructure, or supporting the power needs of other facilities. This RP excludes power generating facilities and high-voltage transmission.

CI Number: C0080205

Title: POA Boiler Refractory Replacement 2026

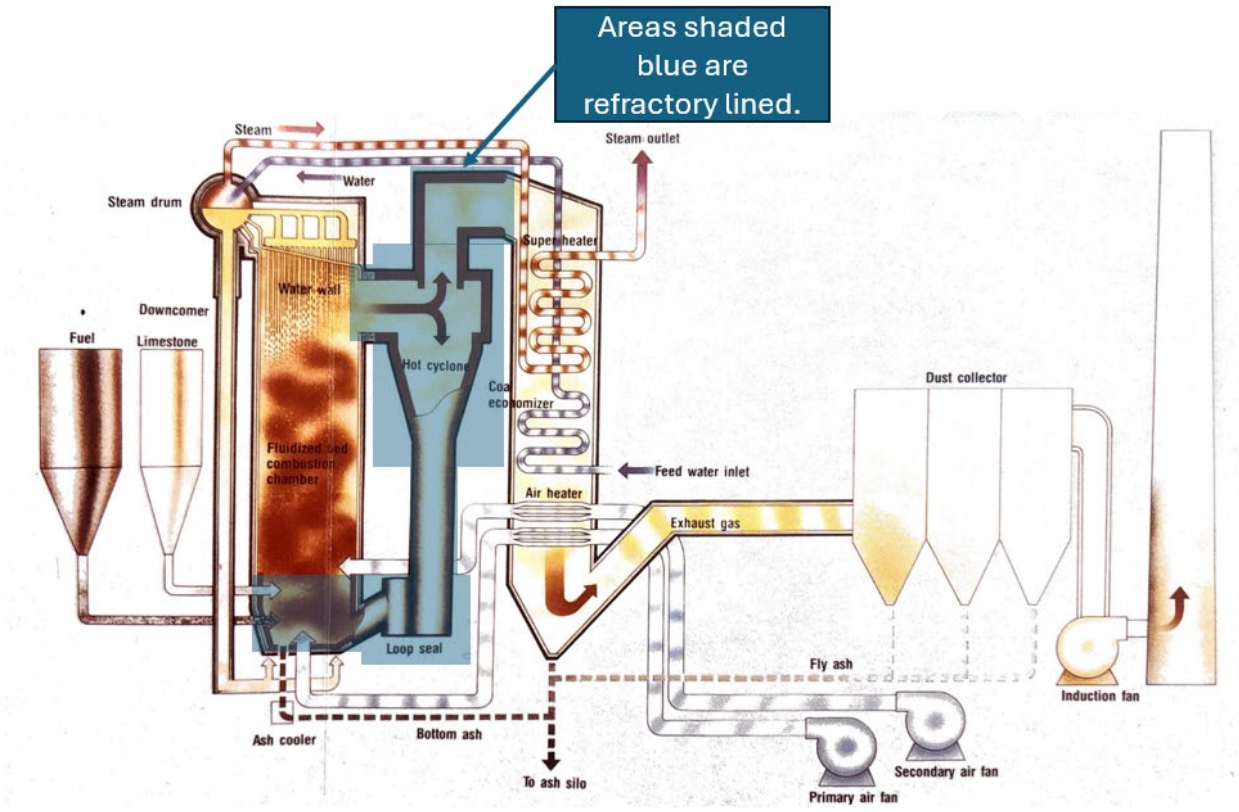
Start Date:	2026/08
In-Service Date:	2026/10
Final Cost Date:	2027/04
Function:	Steam
Forecast Amount:	$1,024,385

DESCRIPTION:

This project will replace refractory components in the Point Aconi boiler system, following inspection and verification to confirm its condition, and sustain system integrity. Refractory serves as a high-temperature wear liner and insulator, providing essential protection to the boiler casing and tubing. A well-functioning refractory is critical in protecting boiler components from high-temperature exposure, reducing thermal losses, and preventing accelerated degradation of pressure parts. This work is crucial to maintaining safe and efficient boiler operation and minimizing the risk of unplanned outages. Refractory materials are installed in the following key areas:

- Cyclones (two total)
- Combustor-to-cyclone crossover ducts (two total)
- Cyclone-to-back pass crossover ducts (two total)
- Loop seal cans (two total)
- Cyclone return legs (four total)
- Lower combustor

The boiler side view diagram below has blue shaded areas depicting the listed areas in the boiler that are refractory lined. For scale the height from the bottom of the loop seal to the top of the hot cyclone is approximately 115’.



The scope of this project includes the staging and preparation of both cyclones for internal inspection thorough visual and thermographic (if possible) inspection to identify the extent of refractory wear/damage. Planned replacement will be carried out for refractory material identified as worn or failing. Additional scope may be defined based on inspection findings. From the 2025 annual inspection it is anticipated that the target wall section of the south/right cyclone will require replacement along with one return refractory lining and combustor refractory refurbishment, however this is subject to change depending on thermal and abrasive damage assessed next year. In 2025 the south/right upper cyclone refractory adjacent to the target wall required replacement along with one return leg refractory lining, a section of the south wall on the right combustor to cyclone duct, and refurbishment of the combustor wear lining.

The Board provided the following Directive in its Decision pertaining to the Decarbonization Deferral Account (DDA) (M11220):

> NS Power must provide specific notice to all participants in this proceeding upon filing any future capital work order applications involving assets that are forecasted to be included in the DDA and to confirm this was done in its applications to the Board.

In accordance with the Board's directive, NS Power provided notice of this investment to participants in the DDA proceeding on December 3, 2025.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects includes "work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- 2024 C0060244 POA Boiler Refractory Replacement 2024 - $954,965
- 2025 C0067908 POA Boiler Refractory Replacement 2025 - $1,378,466
- 2027 TBD POA Boiler Refractory Replacement 2027 - $TBD
- 2028 TBD POA Boiler Refractory Replacement 2028 - $TBD

Depreciation Class: Steam Production Plant – Point Aconi

Estimated Life of the Asset: 8 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.12%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

A well-functioning refractory is critical in protecting boiler components from high-temperature exposure, reducing thermal losses, and preventing accelerated degradation of pressure parts. Routine inspection, refurbishment, and replacement are essential components of an effective refractory protection program. While improved unit performance and reduced boiler cycling have contributed to a slower rate of refractory deterioration, short-term repairs alone are insufficient to ensure long-term reliability of the boiler. To maintain optimal performance and prevent future unplanned outages, full replacement or refurbishment of degraded refractory components is required. This project is designed to ensure the refractory systems are in sound condition to support reliable boiler performance as well as identify and document any emerging issues or long-term replacement needs to inform future maintenance planning.

Why do this project now?

Refractory integrity is critical to safe and reliable boiler operation, and this work can only be performed during a planned outage due to the high-temperature and operational constraints of the system. This work can only be performed during a plant outage, making the scheduled 2026 planned outage window the ideal opportunity to execute a comprehensive refractory program. Refractory sections typically have a service life of 3–5 years, which makes it essential to stay ahead of degradation through annual inspections and proactive replacements. Recent inspections identified notable deterioration in key areas, including the south cyclone target wall and return leg sections, both of which require refurbishment to prevent escalation into more severe failures. The 2026 outage allows for a full refractory inspection, routine refurbishment, and targeted replacement of components identified as high-risk through Asset Management Methodology. This approach ensures continued reliability, mitigates the risk of unplanned failures, and supports long-term asset performance.

Why do this project this way?

The selection of refractory materials and installation methods for this project is based on both industry best practices and operational experience specific to the Point Aconi facility. High-erosion areas will be addressed using refractory brick, while castable refractory products will be utilized for refurbishment applications where appropriate. This approach ensures optimal durability, thermal performance, and resistance to mechanical wear.

Given the critical role refractory plays in boiler operation, there are no viable alternatives to the replacement of damaged or deteriorated refractory. Full replacement in affected areas is necessary to maintain system integrity, safety, and long-term performance.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers) based on previous experience with these assets, and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 10 percent. Risks intended to be covered by this contingency include market and pricing volatility related to materials and contract costs, as well as additional scope that may be required during the refurbishment; additional scope may be identified during demolition and inspection phases, when previously inaccessible areas of the boiler are exposed and assessed for unforeseen damage or deterioration.

Capital Project Detailed Estimate

Location: Steam
C# : C0080205
Title: POA Boiler Refractory Replacement 2026
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	20	$ 466	$ 9,320		C0040846, C0052274, C0060244, C0067908
Maintenance Trades	PD	13	$ 427	$ 5,551		C0040846, C0052274, C0060244, C0067908
Utilityworker	PD	30	$ 297	$ 8,923		C0040846, C0052274, C0060244, C0067908
			Sub-Total	$ 23,794		
OT Labour						
Utilityworker	PD	20	$ 595	$ 11,897		C0040846, C0052274, C0060244, C0067908
			Sub-Total	$ 11,897		
Term Labour						
Maintenance Trades	PD	10	$ 427	$ 4,270		C0040846, C0052274, C0060244, C0067908
Utilityworker	PD	25	$ 297	$ 7,436		C0040846, C0052274, C0060244, C0067908
			Sub-Total	$ 11,706		
Materials						
Refractory Materials	lot	1	$ 360,000	$ 360,000		C0040846, C0052274, C0060244, C0067908
Misc Consumables (Welding Consumables, consumables for refractory anchors etc.)	lot	1	$ 20,000	$ 20,000		C0040846, C0052274, C0060244, C0067908
			Sub-Total	$ 380,000		
Contracts						
Scaffolding Services	lot	1	$ 160,000	$ 160,000		C0067908
Rescue Services	lot	1	$ 50,000	$ 50,000		C0067908
Refractory Services	lot	1	$ 220,000	$ 220,000		C0067908
			Sub-Total	$ 430,000		
Rental/ Main of Equipment						
Trailer and Portable Toilet	lot	1	$ 20,000	$ 20,000		C0067908
			Sub-Total	$ 20,000		
Other Goods & Services						
Contingency	%	10%	$ 877,397	$ 87,740		
			Sub-Total	$ 87,740		
Interest Capitalized						
AFUDC				$ 3,254		
			Sub-Total	$ 3,254		
Administrative Overhead						
Labour AO				$ 15,440		
Contractor AO				$ 40,553		
			Sub-Total	$ 55,994		
			SUB-TOTAL (no AO, AFUDC)	$ 965,137		
			TOTAL (AO, AFUDC included)	$ 1,024,385		
Original Cost				$ 709,640		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Process Industries	Required fields:	Estimate Classification				
Project Name: POA Boiler Refractory Replacement 2026	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Non-Process Facilities (Infrastructure, Ports, Pipeline, Power Transmission)	Defined (D)	P	P	D	D	D
Project Scope of Work Description	Preliminary (P)	P	P			
Byproduct and Waste Disposal	Defined (D)	NR	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Plant Production/Facility (includes power facilities)	Defined (D)	P	P	D	D	D
Electrical Power Requirements (when not the primary capacity driver)	Defined (D)	NR	P	D	D	D
C. Project Location						
Plant and Associated Facilities	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Communication Systems	Not Applicable (NA)	NR				
Fire Protection and Life Safety	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Process Technology	Not Applicable (NA)					
F. Strategy						
Contracting/Sourcing	Preliminary (P)	NR	P			
Escalation	Not Applicable (NA)	NR				
G. Planning						
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Preliminary (P)	NR	P			
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
H. Studies						
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Block Flow Diagrams	Not Applicable (NA)					
Equipment Data Sheets	Not Applicable (NA)	NR/S				
Equipment Lists: Electrical	Not Applicable (NA)	NR/S				
Equipment Lists: Process/Utility/Mechanical	Complete (C)	NR/S	P	C	C	C
Heat & Material Balances	Complete (C)	NR	C	C	C	C
Process Flow Diagrams (PFDs)	Not Applicable (NA)	NR				
Utility Flow Diagrams (UFDs)	Not Applicable (NA)	NR				
Design Specifications	Complete (C)	NR	S/P	C	C	C
Electrical One-Line Drawings	Not Applicable (NA)	NR				
General Equipment Arrangement Drawings	Complete (C)	NR	S/P	C	C	C
Instrument List	Complete (C)	NR	S/P	C	C	C
Piping & Instrumentation Diagrams	Not Applicable (NA)	NR				
Plot Plans/Facility Layouts	Complete (C)	NR	S/P	C	C	C
Construction Permits	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Complete (C)	NR	S/P	P	C	C
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Fire Protection & Life Safety Drawings & Details	Complete (C)	NR	S/P	P	C	C
Electrical Schedules	Not Applicable (NA)	NR	NR/S			
Instrument & Control Schedules	Not Applicable (NA)	NR	NR/S			
Instrument Data Sheets	Not Applicable (NA)	NR	NR/S			
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listings	Complete (C)	NR	NR	P	P/C	C
Electrical Discipline Drawings	Not Applicable (NA)	NR	NR			
Facility Emergency Communication Plan & Drawings	Complete (C)	NR	NR	S/P	P/C	C
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Mechanical Discipline Drawings	Complete (C)	NR	NR	S/P	P/C	C
	Total # Deliverables for this Project	5	27	24	22	22
	% Defined/Complete towards Class Estimate	100%	100%	80%	80%	73%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 80% of Class 3 deliverables are completed. A contingency value of 10% was selected to account for specific risks such as market and pricing volatility related to materials and contract costs, as well as additional scope that may be required during the refurbishments.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *process industries* is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs), piping and instrument diagrams (P&IDs), and electrical one-line drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information. This RP applies to a variety of project delivery methods such as traditional design-bid-build (DBB), design-build (DB), construction management for fee (CM-fee), construction management at risk (CM-at risk), and private-public partnerships (PPP) contracting methods.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this recommended practice may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

Most plants also have significant electrical power equipment (e.g., transformers, switchgear, etc.) associated with them. As such, this RP also applies to electrical substation projects, either associated with the process plant, as part of power transmission or distribution infrastructure, or supporting the power needs of other facilities. This RP excludes power generating facilities and high-voltage transmission.

CI Number: C0021608

Title: TUC Shoreline Sheetpile Refurbishment

Start Date: 2022/10
In-Service Date: 2026/11
Final Cost Date: 2027/05
Function: Steam
Forecast Amount: $5,691,466

DESCRIPTION:

The scope of this project is to install an approximately 80-meter-long sloped rock revetment along the southwest shoreline of the Tufts Cove Generating Station (TUC). This work is to mitigate the deteriorated condition of the existing steel sheet pile structures that retain the plant shoreline. An extension will also be required for the unit 3 seawater cooling intake to accommodate the shoreline extension.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects include "Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- No other projects in 2024, 2025, 2026, 2027 or 2028

Depreciation Class: Steam Production Plant - Tufts Cove – Common

Estimated Life of the Asset: 50 years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool 0.52%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

This project is necessary due to the deteriorated condition of the existing sheet pile structures as identified by a third-party engineering consultant's condition assessment (please refer to Attachment 1). The shoreline sheet pile wall shows significant corrosion in the splash zone (i.e., above high water), with multiple cells exhibiting large areas of section loss. In the low water zone, the shoreline sheet piles were generally in a corroded condition, with the measured thickness losses ranging from 15% to 65%. The permanently submerged portion of the cells were also in a corroded condition, with thickness losses between 10% and 60%.

The condition assessment indicates that the shoreline sheet pile cells have no remaining capacity to support significant loading acting at the top of the cells where corrosion is the most severe, and the remainder of the cells below the mid-tide zone where capacity is compromised. Without intervention, the continued deterioration poses serious risks to structural stability and safety.

Why do this project now?

A condition assessment of the existing steel sheet pile structure was conducted in October 2022, confirming that remediation was required to maintain the structural integrity of the shoreline sheet pile (please refer to Attachment 1). The third-party consultant provided recommendations to complete remediation as soon as feasible to avoid a shoreline failure and to mitigate the potential of an environmental incident due to the presence of fuel lines located on top of the existing structures. A preliminary design option analysis to determine how to proceed with detailed design was completed by the same consultant in early 2023. Based on the chosen preliminary design option, an RFP for surveying and detailed engineering was awarded in late 2023. Surveying of the Harbor floor was completed in early 2024 as a

pre-requisite to the detailed design which was finalized in mid 2025. The detailed design was used as the basis of the construction RFP which is currently in the process of being awarded in late 2025.

Discussions with regulatory authorities regarding permitting requirements have been initiated. These permitting considerations are a key factor influencing the timing of the work, and early engagement is intended to streamline approvals and avoid delays during execution. Failing to refurbish this structure could result in a structural failure of the shoreline, resulting in risk of damage to adjacent shoreline infrastructure and assets.

Why do this project this way?

An options analysis study completed in 2023 evaluated various remediation strategies to protect the existing shoreline and critical infrastructure (please refer to Attachment 1). Two major constraints identified were the need to work around the existing steel sheet pile (which has lost its structural integrity) and to maintain operation of seawater cooling intake.

Three options were considered:

1. Rock revetment (armor stone).
2. New retaining wall/kingpins to be backfilled with granular materials.
3. Concrete retaining wall with partial cell encapsulation.

The rock revetment (option 1) was selected as it has the highest total score among the 3 design options in the chosen weighted criteria which included design criteria, operational impacts, regulatory considerations, and probable cost. In addition:

a. The design was the most simple and straightforward, meaning a lower chance of issues arising during execution (e.g. drilling kingpins into the bedrock, which required an extensive geotechnical investigation as part of the design).
b. The design had less intrusion and disruption to the existing infrastructure, shoreline and seabed.
    i. The new retaining wall option would extend the project footprint another 10m – this was not necessary for the objective and would have a larger impact on the existing marine habitat.
    ii. The concrete retaining wall requires extensive surface preparation on the entire existing sheet piles, creating debris and environmental risks during construction.
c. The rock revetment has a 50-year design service life expectancy and requires less maintenance. The maintenance which is required is less disruptive to the environment when compared to the retaining wall option (e.g. moving the armor stone around that has been shifted).
    i. The new retaining wall would have a 40 to 50-year lifespan and would require another large scale rehabilitation project. During that time, extensive maintenance on the retaining wall would still be required.
    ii. The concrete retaining wall was less footprint than the rock revetment option but had the potential to only last 15 to 20 years, requiring either major maintenance or full rehabilitation at that time.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers) and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 15 percent. Risks intended to be covered by the contingency include execution risks such as work delays due to environmental precautions and unknown conditions encountered. The contingency also covers any additional precautions that will need to be exercised based on feedback from governing authorities, such as the Department of Fisheries, or Transport Canada.

Capital Project Detailed Estimate

Location: Steam
CI# : C0021608
Title: TUC Shoreline Sheetpile Refurbishment
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	5	$ 420	2,101.02		
Engineering	PD	150	$ 466	$ 69,902		
Utilityworker	PD	55	$ 297	$ 16,359		
			Sub-Total	$ 88,361		
OT Labour						
Utilityworker	PD	20	$ 595	$ 11,898		
			Sub-Total	$ 11,898		
Materials						
Corestone & Leveling Course Layer at Intake Extension	lot	1	[redacted]		Attachment 2 #3-2	
Pre-Cast Box Culvert Install	lot	1			Attachment 2 #4-2	
Cast in Place Concrete Headwall	lot	1			Attachment 2 #5-2	
Corestone Layer	lot	1			Attachment 2 #6-2	
Filler Stone Layer	lot	1			Attachment 2 #7-2	
Armour Stone Layer	lot	1			Attachment 2 #8-2	
Offsetting Project Materials	lot	1	$ 65,000	$ 65,000		
			Sub-Total	[redacted]		
Contracts						
Mobilization/Demobilization	lot	1	[redacted]		Attachment 2 #1-1, #1-2	
Intake Extension & Underwater Excavation	lot	1			Attachment 2 #2-1, #2-3, #2-4	
Corestone & Leveling Course Layer at Intake Extension	lot	1			Attachment 2 #3-1, #3-3, #3-4	
Pre-Cast Box Culvert Install	lot	1			Attachment 2 #4-1, #4-3, #4-4	
Cast in Place Concrete Headwall	lot	1			Attachment 2 #5-1, #5-3, #5-4	
Corestone Layer	lot	1			Attachment 2 #6-1, #6-3, #6-4	
Filler Stone Layer	lot	1			Attachment 2 #7-1, #7-3, #7-4	
Armour Stone Layer	lot	1			Attachment 2 #8-1, #8-3, #8-4	
Project Closeout	lot	1			Attachment 2 #9-1, #9-2, #9-3, #9-4	
Offsetting Project Site Works	lot	1	$ 65,000	$ 65,000		
			Sub-Total	[redacted]		
Consulting						
Permitting	lot	1	$50,000	$ 50,000		
Design, Bathymetry, Surveying	lot	1	[redacted]			
Archaelogical Study - Offsetting Project	lot	1	$ 10,000	$ 10,000		
Borehole Drilling - Offsetting Project	lot	1	$ 50,000	$ 50,000		
Engineering Design & Consulting - Offsetting Project	lot	1	$ 35,000	$ 35,000		
			Sub-Total	[redacted]		
Meals						
Meals	lot	1	$ 58	$ 58		
			Sub-Total	$ 58		
Other Goods & Services						
Contingency	%	15%	$ 4,624,212	$ 693,632		
			Sub-Total	$ 693,632		
Interest Capitalized						
AFUDC				$ 69,955		
			Sub-Total	$ 69,955		
Administrative Overhead						
Labour AO				$ 31,082		
Contractor AO				$ 272,585		
			Sub-Total	$ 303,667		
			SUB-TOTAL (no AO, AFUDC)	$ 5,317,844		
			TOTAL (AO, AFUDC included)	5,691,466		
Original Cost				$ 561,708		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

General Construction	Required fields:	Estimate Classification				
Project Name: TUC Shoreline Sheetpile Refurbishment	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Functional Space - SF or m^2	Defined (D)	P	P	D	D	D
Electrical Power Requirements (when not the primary capacity driver)	Not Applicable (NA)	NR				
Mechanical Systems	Not Applicable (NA)	NR				
C. Project Location						
Building and/or Other Project Elements	Defined (D)	P	P	D	D	D
D. Requirements						
Anti-Terrorism Force Protection	Not Applicable (NA)					
No. of Building Floors	Not Applicable (NA)					
Security System	Not Applicable (NA)	NR/P				
LEED Certification Level	Not Applicable (NA)	NR/P				
Codes and/or Standards	Not Applicable (NA)	NR				
Communication Systems	Not Applicable (NA)	NR				
Exterior Closure Description	Not Applicable (NA)	NR				
Finishes Descriptions	Not Applicable (NA)	NR				
Fire Protection and Life Safety	Not Applicable (NA)	NR				
Environmental Monitoring	Preliminary (P)	NR	NR	P	P	
E. Technology Selection						
Not Applicable						
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
Logistics Plan	Not Applicable (NA)					
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Preliminary (P)	NR	P			
Work Breakdown Structure (WBS)	Preliminary (P)	NR	P			
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
Storm Water Management Plan	Not Applicable (NA)	NR				
H. Studies						
Environmental Impact/Sustainability Assessment	Preliminary (P)	NR	P			
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Soils & Hydrology	Defined (D)	NR	P	D	D	D
Technical Deliverables (Specifications and/or Drawings)						
Site Plan	Complete (C)	S	P	C	C	C
Design Specifications	Complete (C)	NR	S/P	C	C	C
Electrical One-Line Drawings	Not Applicable (NA)	NR				
General Equipment Arrangement Drawings	Complete (C)	NR	S/P	C	C	C
Plot Plans/Facility Layouts	Not Applicable (NA)	NR				
Room Classification Datasheet	Not Applicable (NA)	NR				
Room Layout Drawings	Not Applicable (NA)	NR				
Construction Permits	Preliminary (P)	NR	S/P	P/C		
Building Plan Views, Sections and Elevations	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Complete (C)	NR	S/P	P	C	C
Codes and Standards Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Complete (C)	NR	S/P	P	C	C
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Exterior Elevations	Complete (C)	NR	S/P	P	C	C
Finish Schedule	Not Applicable (NA)	NR				
Fire Protection and Life Safety Drawings and Details	Not Applicable (NA)	NR				
Furniture Plans, Schedules and Drawings	Not Applicable (NA)	NR				
Interior Section Views	Not Applicable (NA)	NR				
Landscaping Drawings	Complete (C)	NR	S/P	P	C	C
Plumbing Drawings	Not Applicable (NA)	NR				
Roof Plan, Drawing Details	Not Applicable (NA)	NR				
Storm Water Drawings	Not Applicable (NA)	NR				
Window Schedules	Not Applicable (NA)	NR				
Door Schedules	Not Applicable (NA)	NR				
Restroom Schedules	Not Applicable (NA)	NR				
Signage Drawings and Schedules	Not Applicable (NA)	NR				
Partition or Wall Types	Not Applicable (NA)	NR				
Electrical Schedules	Not Applicable (NA)	NR	NR/S			
Equipment Datasheets	Not Applicable (NA)	NR	NR/S			
Equipment Lists: Electrical	Not Applicable (NA)	NR	NR/S			
Equipment Lists: Process/Utility/Mechanical	Not Applicable (NA)	NR	NR/S			
Instrument and Control Schedules	Not Applicable (NA)	NR	NR/S			
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listing	Not Applicable (NA)	NR	NR			
Electrical Discipline drawings	Not Applicable (NA)	NR	NR			
Facility Emergency Communication Plan and Drawings	Not Applicable (NA)	NR	NR			
HVAC Drawings	Not Applicable (NA)	NR	NR			
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Mechanical Discipline Drawings	Not Applicable (NA)	NR	NR			
Room Discipline Drawings	Not Applicable (NA)	NR	NR			
Interior Lighting Plan and Drawings	Not Applicable (NA)	NR	NR			
Lighting Control Diagram	Not Applicable (NA)	NR	NR			
Lighting Schedules	Not Applicable (NA)	NR	NR			
Lightning Protection Drawings	Not Applicable (NA)	NR	NR			
Mechanical/HVAC Schedules	Not Applicable (NA)	NR	NR			
Motor Control Diagram	Not Applicable (NA)	NR	NR			
Plumbing Details	Not Applicable (NA)	NR	NR			
Security Plan and Drawings	Not Applicable (NA)	NR	NR			
Instrument List	Not Applicable (NA)	NR	NR			
Building Envelope/Moisture Protection/Flashing Details	Not Applicable (NA)	NR	NR			
Interior Elevations	Not Applicable (NA)	NR	NR			
Total Responses	**Total # Deliverables for this Project**	4	24	20	18	17
Percentage	**% Defined/Complete towards Class Estimate**	100%	100%	80%	72%	68%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 80% of Class 3 deliverables are completed. A contingency value of 15% was selected for this project. Risks intended to be covered by the contingency includes execution risks, and changes in market conditions that may impact costs; it also covers any additional precautions that will need to be exercised based on feedback from governing authorities, such as the Department of Fisheries, Transport Canada, etc. The contingency will also cover price changes if the contractor proposes changes to the work plan that will affect the cost of doing work based on site conditions.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required (NR):** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary (P):** Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined (D):** Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- **Not Required (NR):** Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *general construction* is assumed to include both new construction as well as renovation construction projects. It is intended to be used for building (vertical) construction, as well as site/civil projects. It is intended to cover projects which are repetitive and repeatable. Examples for buildings include: residential construction, commercial buildings, hotels, resorts, offices, retail, etc. This also includes site/civil projects. Examples for site/civil projects include: site development, utility infrastructure, telecommunications, water pipelines, sanitary sewer pipelines, storm water and water resources projects. The common thread among these industries for the purpose of estimate classification is their reliance on project definition documents (basis of design) and schematic drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information.

Estimates for buildings center on functional space requirements, structural requirements, site requirements, architectural elements, sustainability, and supporting mechanical, electrical, plumbing, and life-safety systems.

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October 2, 2025

Connor Lebans, P.Eng.
Mechanical Engineer – Tufts Cove and CTs
Tufts Cove Generating Station
315 Windmill Road
Dartmouth NS B3A 1H3
E-Mail: connor.lebans@nspower.ca

Dear Mr. Lebans:

RE: Tufts Cove SSP Wall Remediation

1 Introduction

CBCL Limited (CBCL) was engaged by Nova Scotia Power Inc. (NSPI) to complete a condition assessment of portions of the marine infrastructure and at the Tufts Cove Generating Station, and to develop conceptual options for repair / rehabilitation. The Tufts Cove Generating Station is comprised of six (6) generating units constructed since the 1970s. The site is built on infilled land that borders the northeastern shoreline of the Halifax Harbour and uses various retaining structures to delineate the edge of the site at the new shoreline (**Figure 1**).

This structure was constructed in the 1970s using steel sheet pile (SSP) circular cells built in a secant wall formation to retain infilled soil and increase the site footprint. There is a cold-water intake structure for each of these three units penetrating the SSP wall. This SSP wall originally extended from the North side of Unit 1 to the wharf access bridge is currently located (**Figure 2**). At some point, a rock revetment, complete with cold water intake extensions for TUC 1 and TUC2, was constructed in front of the wall directly in front of TUC1, TUC2 and TUC3. This new revetment retains the soil in that area and has made the SSP wall behind the rock revetement redundant. The portion of wall between the new rock revetment and the Wharf Access Bridge (**Figure 2**) is the specific focus of this project.

C. Lebans
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Figure 1 - Tufts Cove Generating Station Overall Site Layout

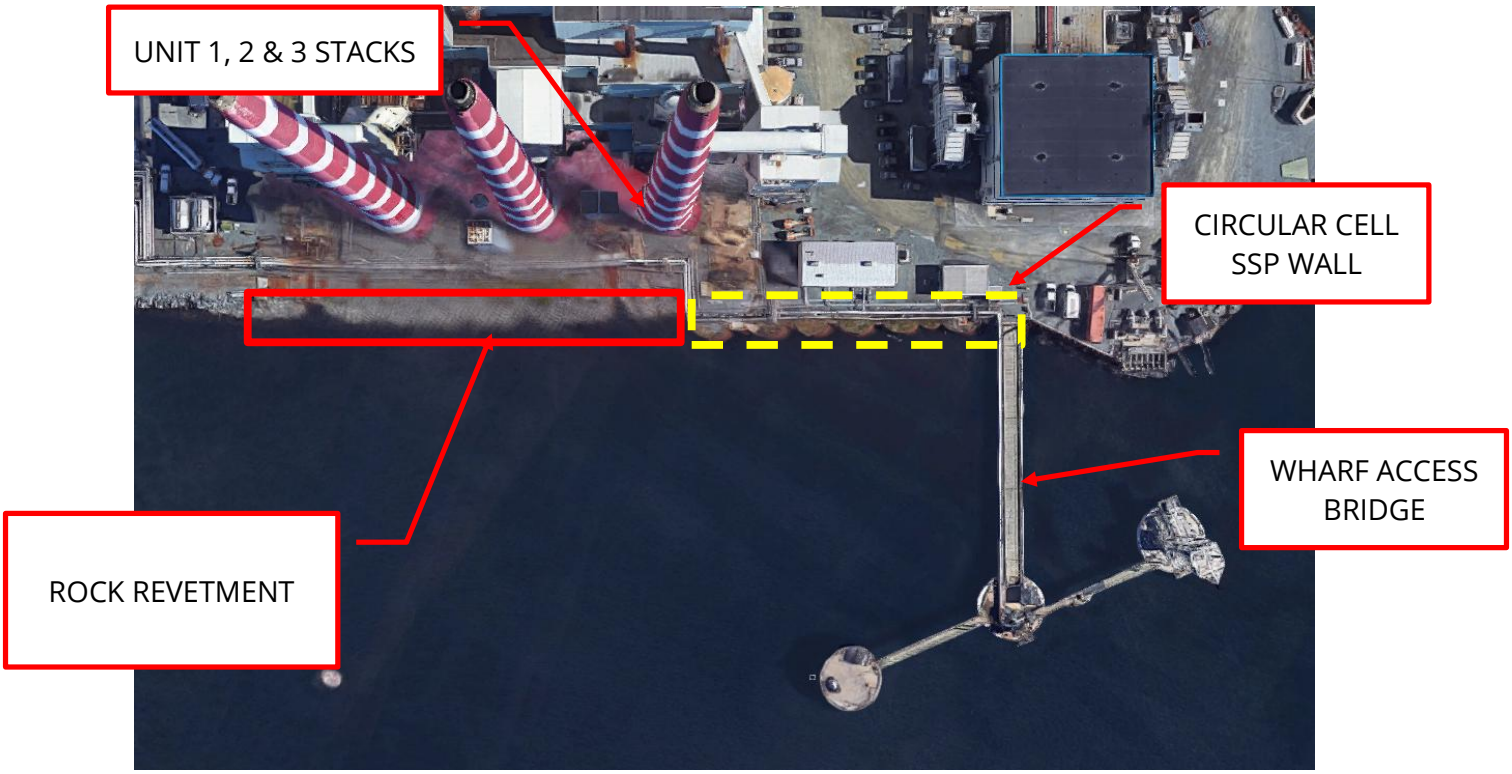

Figure 2 - Tufts Cove SSP Wall General Arrangement

The remainder of the SSP wall in this area has been largely untouched and was observed during a condition assessment in October 2022 to be in poor condition, and as such requires remediation to ensure the stability of the site at this location. The circular cells act as gravity-based structures, which use the weight of the structure to provide the resistance against the imposed soil retention and surcharge loads. The SSP's purpose in the circular cells is to create a formed area of fill (i.e., a skin of steel around granular fill), and it is this fill that the cells derive their weight. In containing this fill, the SSPs are subjected to significant hoop tension loads and it is important that sufficient steel thickness is maintained to prevent a tensile failure (i.e., "zipper" style failure).

2 Existing Structure

CBCL visited the site on October 11, 2022, to observe the existing condition of the SSP wall circular cells. NSPI engaged Connors Diving Services, to perform an underwater visual inspection and to take ultrasonic thickness (UT) measurements along the height of the wall to determine the extent of material loss due to corrosion.

2.1 Corrosion Background

Corrosion of steel is a significant issue in seawater environments and is typically far more severe than corrosion in freshwater due to higher electrical conductivity. The corrosion rates for steel structures exposed to seawater is highly dependent on the location of the area within the water column. The worst corrosion is usually seen in the splash zone (above high water) and around low water (**Figure 3**). Portions of structures that are permanently submerged or buried typically experience the lowest corrosion rates.

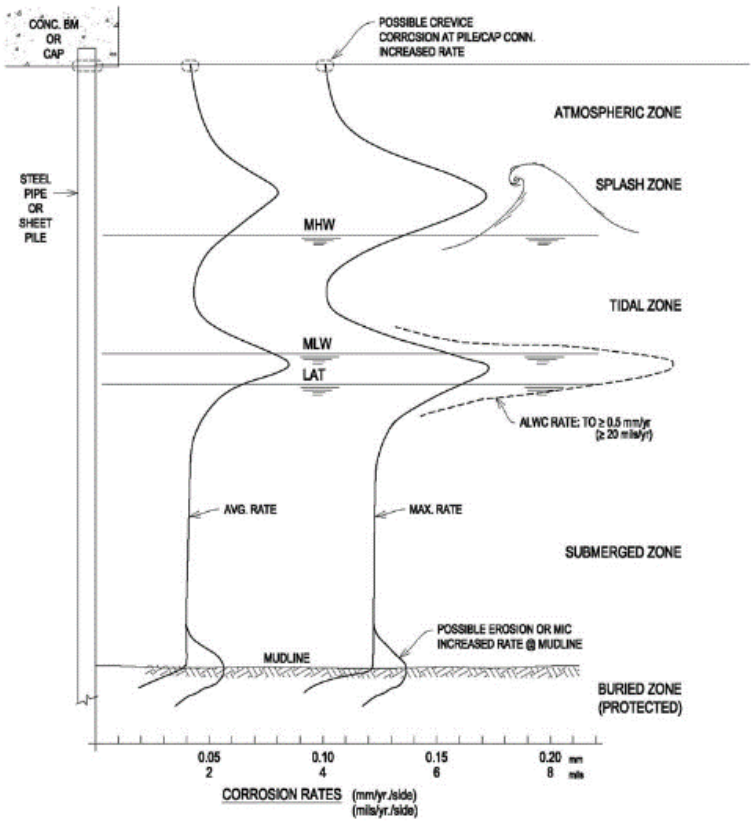

Figure 3 - Approximate General Corrosion Rates in Seawater (Gaythwaite, 2016)

Corrosion is a continuous process throughout the lifetime of the structure and is typically the parameter that governs the design life of the structure. For marine structures, this design life is typically between 40 – 50 years with regular maintenance. Once the structure exceeds the 50-year design life, there is the potential for maintenance and repair costs to become excessive when compared to replacing the structure.

To account for the effects of corrosion across the design life, marine structures are typically designed with a "corrosion allowance" which is additional steel that is expected to be lost through corrosion without causing structural deficiencies; protective coatings, usually epoxy paint systems or concrete cast against the steel; or with cathodic protection systems. The cathodic protection systems work by causing the steel structure to change from being an anode (the portion of the corrosion cell that loses material) to the cathode (the portion of the corrosion cell that is protected against corrosion). A type of cathodic protection called an Impressed Current Cathodic Protection system was noted to be installed at the SSP wall location which acts by energizing the wall with electrical current using a continuous power

supply. It should be noted that the structure is typically only protected while the impressed current is present, and if that current is interrupted, corrosion would proceed naturally.

Condition Assessment

The original design drawings (Dwg A-91H3-1-116-00-001 dated April 1973, refer **Figure 4** for excerpt - see Appendix A for original) indicate these cells were constructed with PS28 flat web sheet piles and had an original thickness of 3/8" (~9.5mm) (**Figure 5**). This was used as the
2.2 basis when calculating thickness losses.

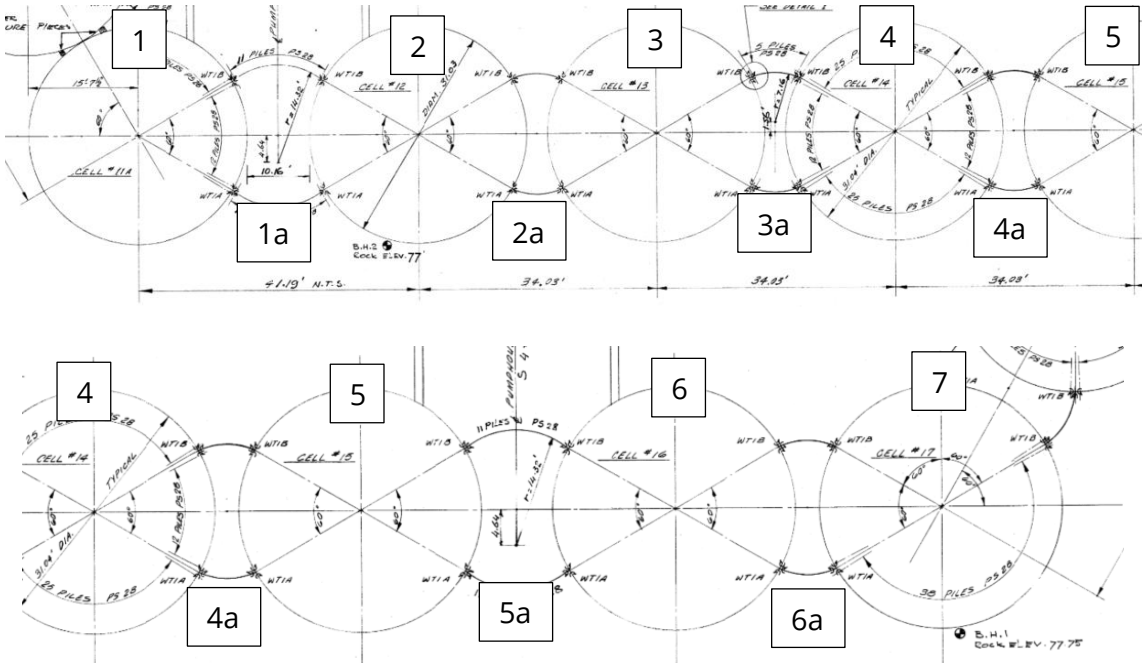

Figure 4 - Original Cell Layout (New Numbering in Boxes)

C. Lebans
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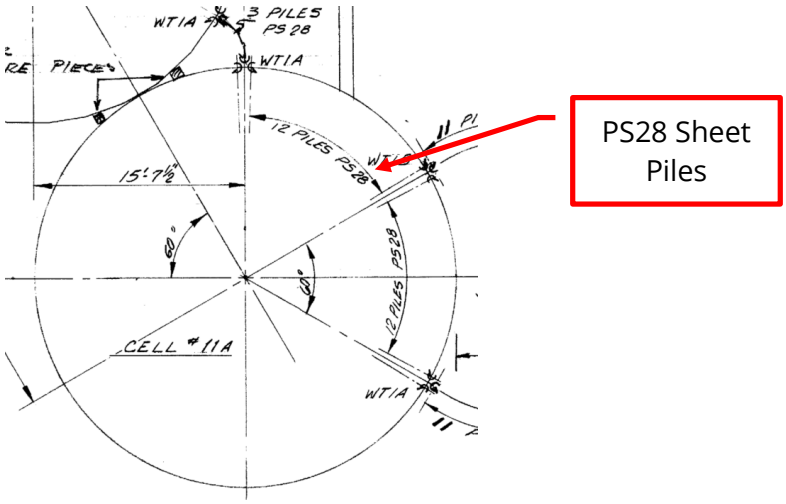


Figure 5 - Typical Cell Design Drawing

The SSP wall was generally observed to be in a critical condition, with severe corrosion noted in the splash zone (i.e., above high water) with multiple cells having large areas of complete section loss in this region (**Figure 6** & **Figure 7**).

In the mid-tide zone, the corrosion loss was noted to be in generally fair condition, with measured material loss in the range of 5% to 15%. This is less material loss than expected given the age of the structure. This may be due to presence of an impressed current cathodic protection system.

In the low water zone, the SSPs were generally in a critical condition, with the measured thickness losses in the range of 15% - 65%. The permanently submerged portion of the cells were also in a critical condition, with thickness losses measured in the range of 10% - 60%.

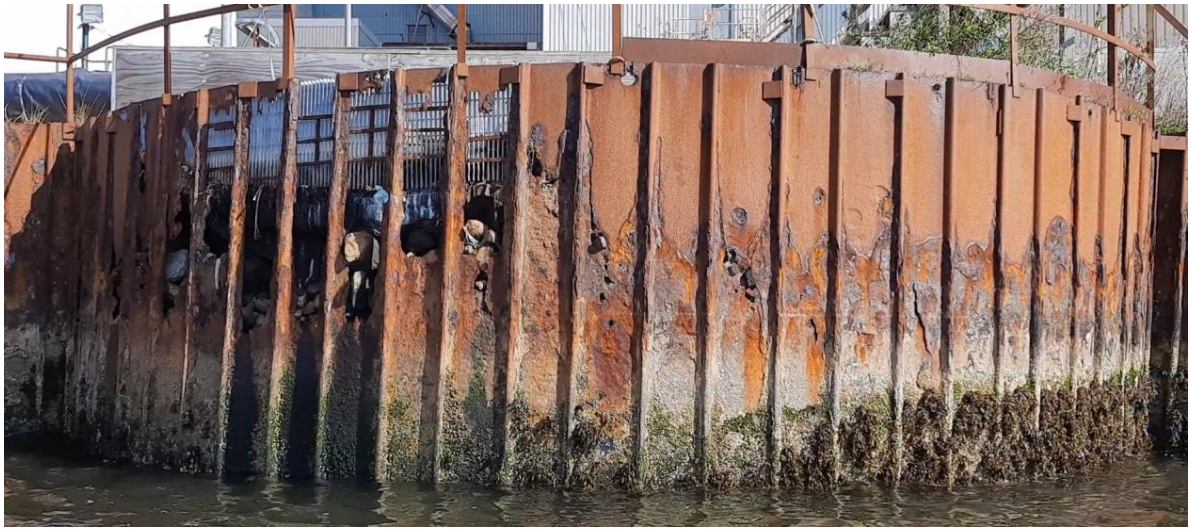


Figure 6 - Typical SSP Cell Condition

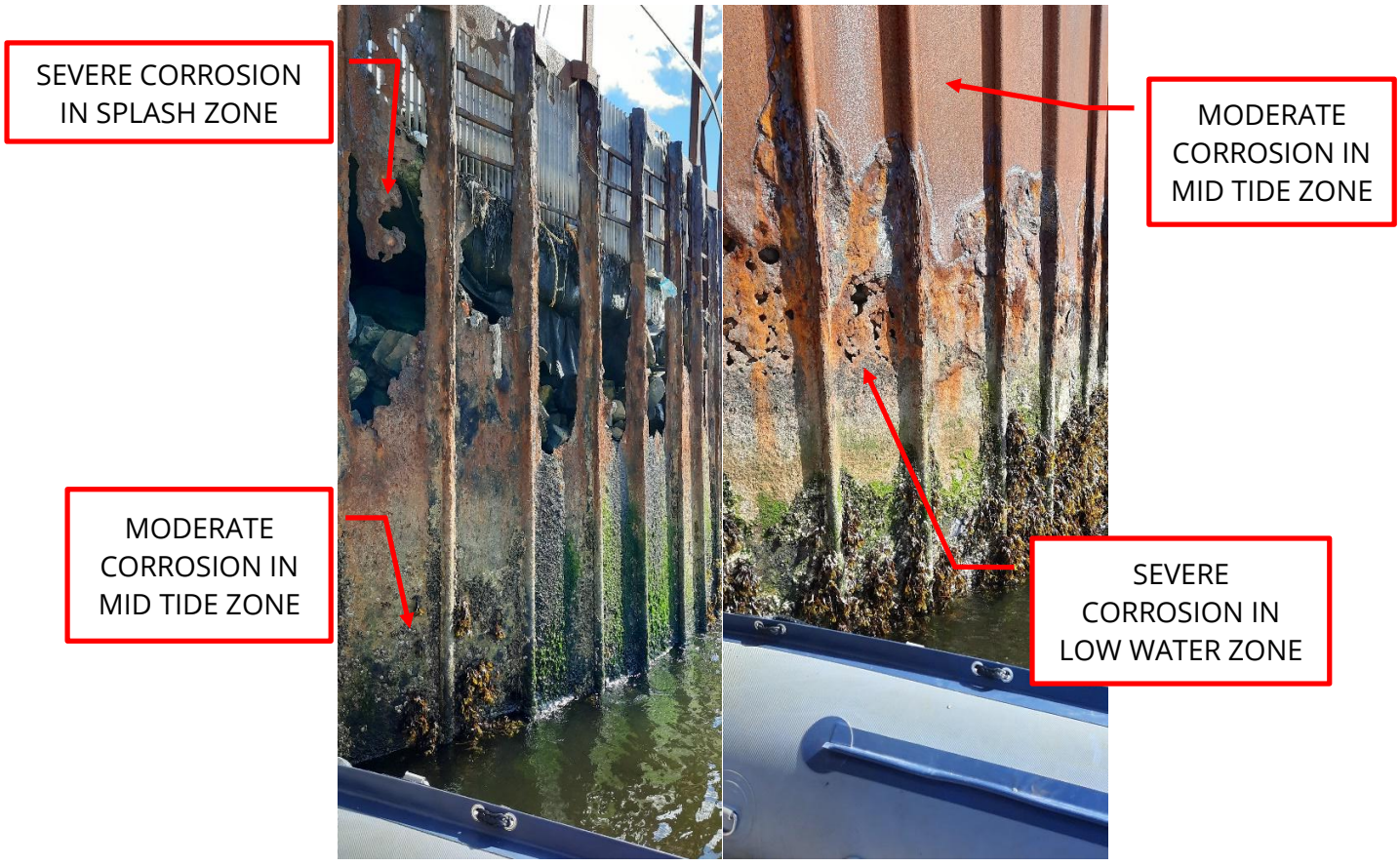


Figure 7 - Corrosion in the Intertidal Zone

The results of this condition assessment indicate that the SSP cells have no capacity for any significant loading acting on the top portion of the cells where the corrosion is the greatest, and the remainder of the cell below the mid tide zone has compromised capacity.

It should be noted that while most severe corrosion occurs on the seaward face of the SSP cells, the buried portion of the cells are also exposed to corrosion. It was not possible to view the buried portion of the SSP wall during the site visit, however, typically corrosion rates for steel in permanent contact with soil are approximately 0.05mm/year. Based on this corrosion rate, it is expected the total corrosion loss to be approximately 2.5mm (26%) over a 50-year design life. This corrosion loss is non-trivial and requires further investigation during detailed design.

3 Remediation Options

CBCL has developed three (3) design options to remediate the deteriorated SSP circular cell wall. These options, along with associated concept level drawings (**Appendix B**) and Class D Opinion of Probable Costs (OPC) are presented below

It is important to note that information on the site, such as existing geotechnical conditions, seabed bathymetry, and environmental conditions, is extremely limited. The options presented are based on assumptions that will have to be validated during detailed design. Within the OPC for each option, probable costs are given for the appropriate investigations to determine this critical information and confirm final configurations.

3.1 Design Criteria

To develop these options, CBCL has established the following design criteria, based on NPSI's requirements and typical designs of similar structures:

Table 1 - Proposed Design Criteria

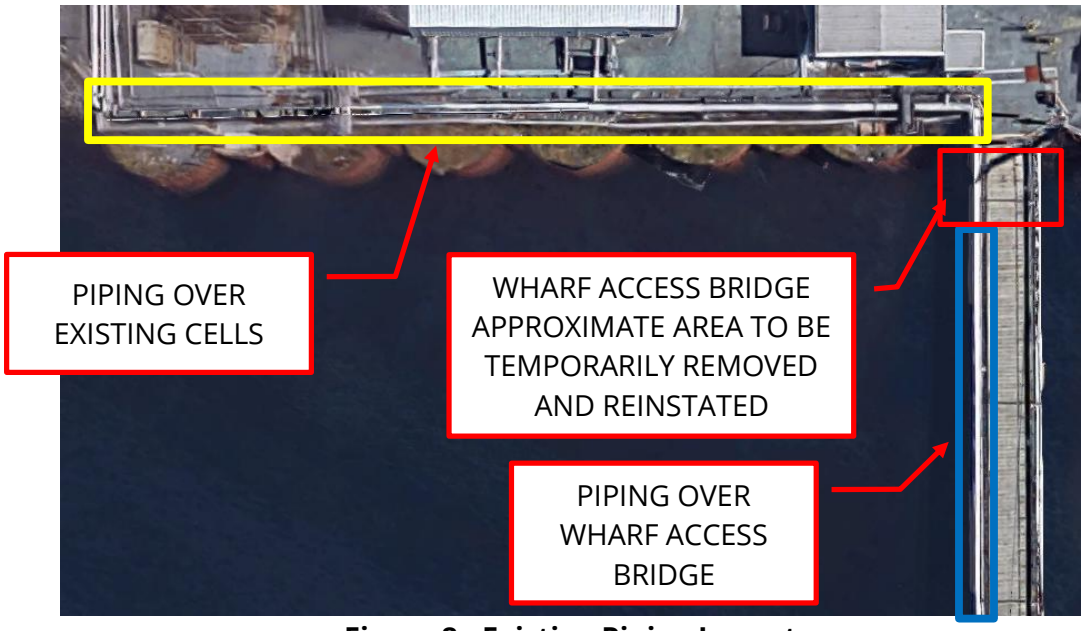
Criteria	Value
Design Life	50 years
Surcharge Loading	25 kPa
Concentrated Loading	MS200-77 Truck
Deck Elevation	+3.0m Chart Datum (CD)
Seabed Depth	-6.0m CD

It is our understanding that there is no requirement to berth vessels along the face of the SSP wall. It should be noted that the proposed deck elevation matches the current top of existing SSP wall and does not include any allowances for sea level rise projections. This should be considered during the detailed design phase and may have impacts on other areas of the site.

Demolition & Removals

The condition survey noted that the top portion of all SSP cells is highly deteriorated, and it is recommended that the cells be cut down to +0.00m CD regardless of chosen repair option. This will require temporary support of the existing piping currently located over the cells (**Figure 8**). Additionally, all options require the temporary removal of sections of the wharf access bridge and re-routing of the piping on the bridge **(Figure 8)**. It is expected that the wharf access bridge removals could be minimized by supporting a portion of the span on a temporary bent. This approach will avoid the need to remove the entire span. As an alternative, all impacted piping and the full wharf access bridge span could be temporarily removed while the repairs are being completed and reinstated upon completion of the repair work.

3.2



3.3

Figure 8 - Existing Piping Layout

Option 1 – Combi-Wall

This option will involve installation of a new anchored combi-wall in front of the existing SSP wall **(Figure 9)**. The combi-wall will consist of a series of king piles driven at approximately 2m apart and SSP sections driven in between the king piles to provide a continuous wall face. The new combi wall will encapsulate the existing SSP wall, making the SSP wall redundant.

It is expected that the king pile will be 457mm diameter king piles and will be drilled approximately 2m into bedrock. The king piles will be laterally supported by 64mm diameter steel tie rods that are drilled and grouted approximately 6m into bedrock We propose to

connect the king piles with a C310 waler and install the tie rods at every second king pile to reduce the amount of required drilling and grouting. It is expected that AZ24 sheet piles be driven to refusal in between the king piles. Once the combi-wall is fully installed, the area behind the combi-wall will be backfilled with granular material to create a trafficable area.

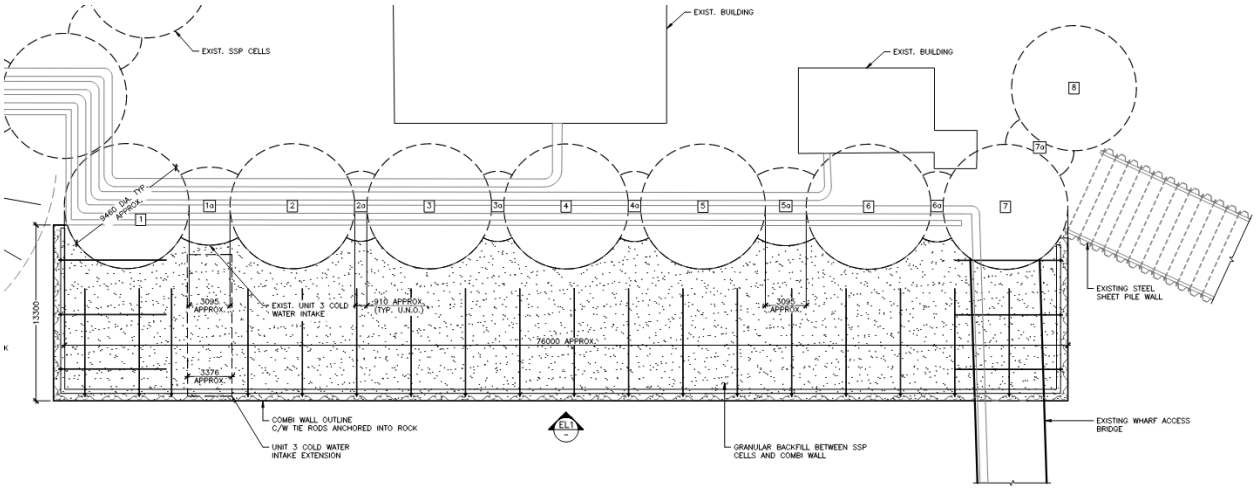


Figure 9 - Option 1 General Arrangement

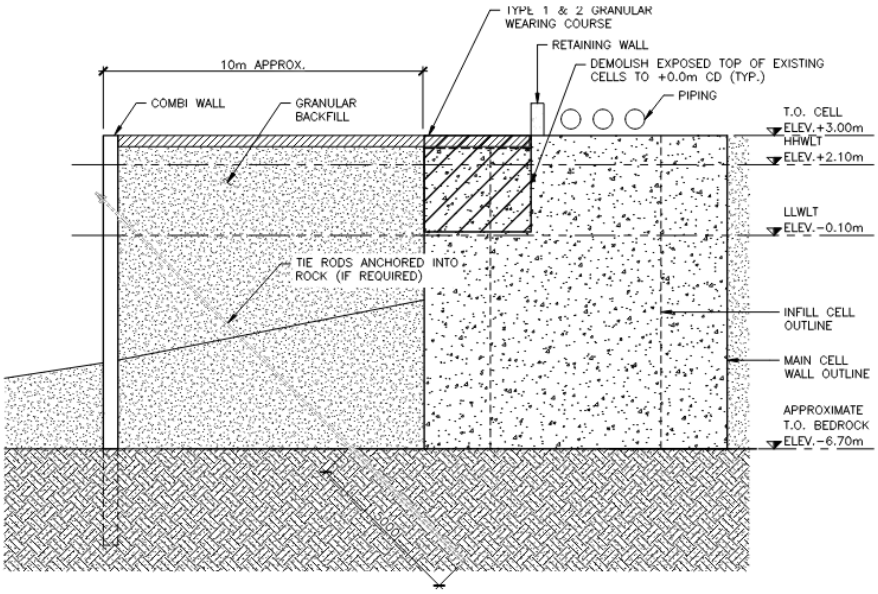


Figure 10 - Option 1 Typical Section

The combi-wall design is highly sensitive to geotechnical parameters such as the fill material properties and bedrock elevation. Since these soil parameters are currently unknown, some

conservative assumptions have been made in the conceptual design. It is recommended to complete a geotechnical investigation program during the detailed design phase to reduce the uncertainty of these soil parameters. As design progresses and the soil conditions are better understood, it is possible that these assumptions may be relaxed, resulting in lower overall project costs. These assumptions are described further below:

- The fill materials used to fill the SSP circular cells and behind the SSP wall are currently unknown. The combi-wall has been placed approximately 10m in front of the wall to ensure that the combi-wall and SSP walls are independent and that the combi-wall will not be negatively impacted by future deterioration of the existing SSP wall. It may be possible to reduce this offset based on the geotechnical program results, which will result in lower fill volumes and associated costs.

- Similarly, bedrock elevation and driving conditions for the proposed combi-wall are currently unknown. Based on preliminary data, CBCL is proposing a combi-wall configuration, which is cost-effective to install in areas with high bedrock. The proposed geotechnical investigation will provide a better understanding of the soil profiles and confirm suitability of the proposed combi-wall. If it is determined that driving conditions are more favorable, it may be possible to omit the king piles and construct the wall of SSP Z-panels, resulting in lower overall project costs.

To achieve a 50-year design life, it is expected that the combi wall would have a combination of sacrificial steel thickness and an impressed current system similar to existing to minimize corrosion and its effects on the strength of the wall.

CBCL proposes to install a concrete duct extension to extend the existing Unit 3 cold-water intake, at the same elevation and same size as the existing intake **(Figure 11)**. A trash rack and removable stoplog at the combi-wall face will be installed to allow for sealing and dewatering of the intake.

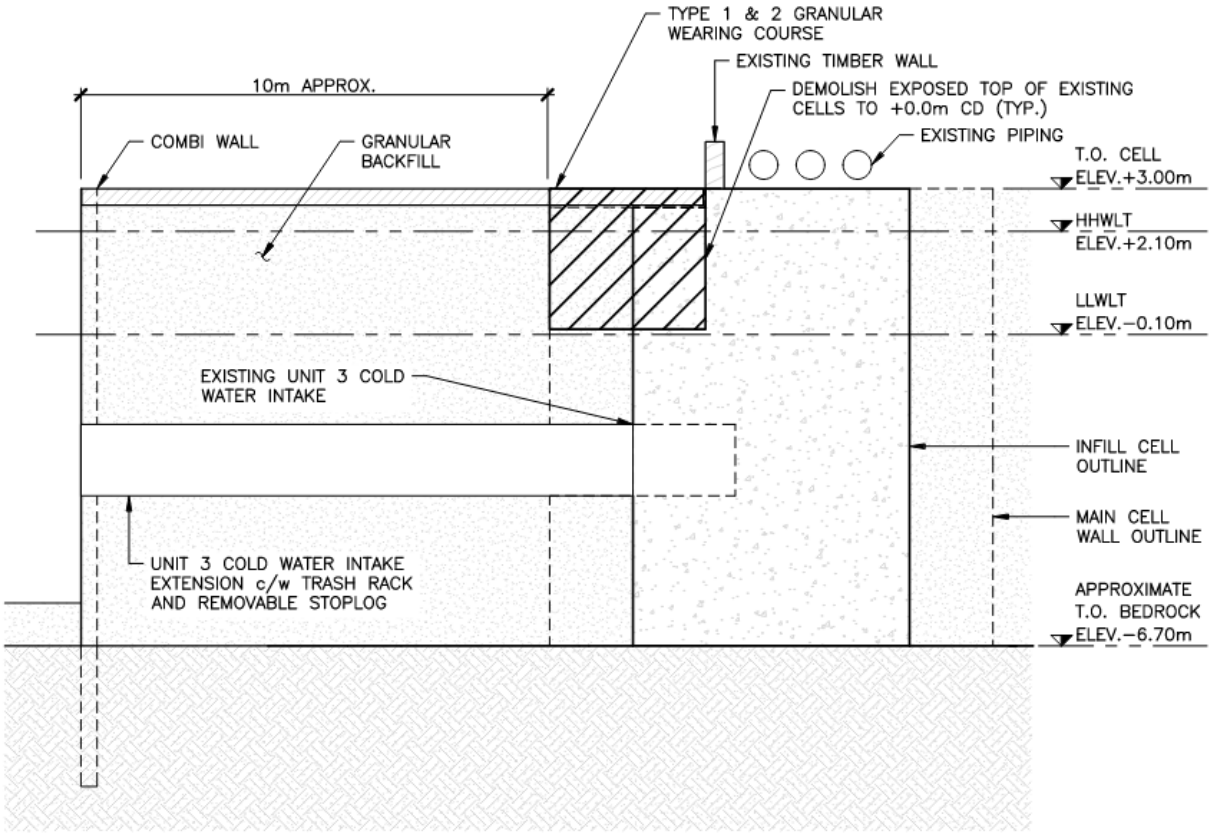


Figure 11 - Option 1 TUC3 Intake Extension

In summary, this option would provide a brand-new structure that will have a service life of 50 years, with minimal maintenance expected in the first 15 years. As it is a new structure, there is scope to increase the loads and service life from that stated in the design criteria noted in Table 1, in addition to designing the new reclaimed area for new structures / site expansion. It is important to note that this option would encroach on a significant portion of the seabed in front of the existing SSP wall, which may trigger additional regulatory requirements. While environmental regulatory scoping and the consultation process typically move in parallel with the engineering and detailed design phases, it is recommended to complete a regulatory roadmap early in the detailed design process to avoid project delays.

Option 2 – Concrete Retaining Wall & Partial Cell Encapsulation

This option involves encapsulating the exposed faces of the SSP cells with cast-in-place concrete and to install a new cast-in-place concrete retaining wall on the top of the cut-down SSP cells **(Figure 12)**. The proposed cantilevered retaining wall will be located on the top of the SSP cell. To reduce impact on operations, the front of the proposed cantilevered retaining wall will be located to provide sufficient working room around the existing piping.

3.4

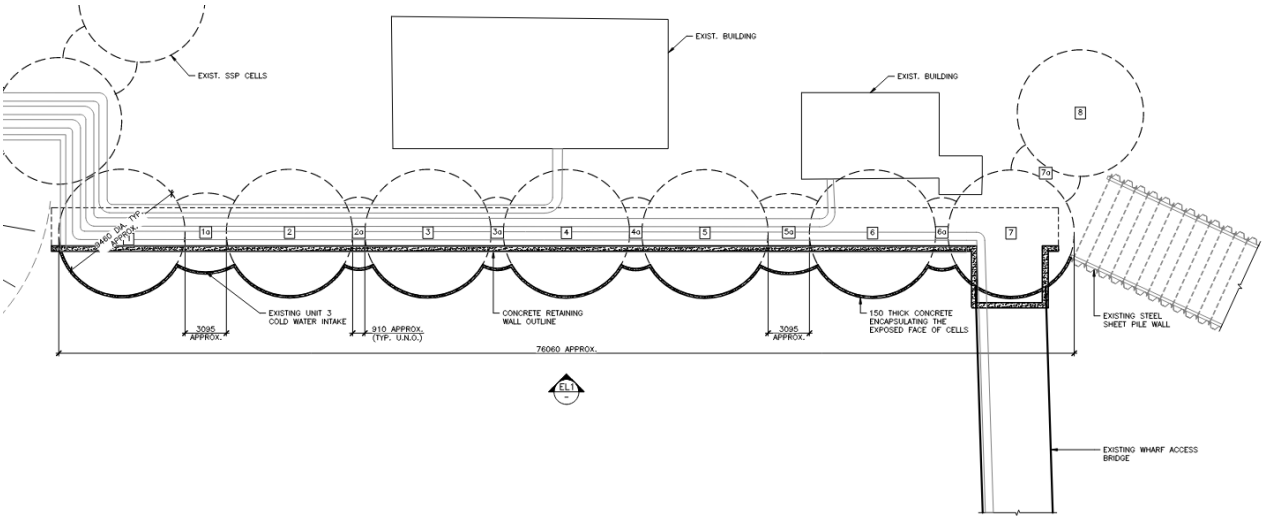


Figure 12 - Option 2 General Arrangement

The proposed concrete encapsulation will not provide any structural capacity to resist lateral loads and is intended to be a sacrificial coating to prevents further corrosion of the SSP cells. Consequently, this option continues to rely on the structural integrity of the SSP cells to resist the retained soil and surcharge loads. As such, a detailed analysis of the structural capacity of the SSP cell will need to be undertaken during detailed design to confirm the existing SSP cells have sufficient load carrying capacity. If this analysis determines the existing SSP cells are inadequate, it will be necessary to reinforce the existing SSP cells prior to concrete encapsulation.

Following this work, the encapsulation concrete will be installed using curved formwork attached to the cells. To develop a good bond between the encapsulating concrete and the SSP cells, reinforcing mesh will be welded to the face of the SSP cells prior to pouring. Diving services will be required to complete installation of the rebar and formwork; however, it is expected the concrete will be placed via tremie pipes. A penetration through encapsulation concrete, along with trash rack and removable stoplog, will be provided to accommodate the existing Unit 3 cold-water intake (**Figure 13**).

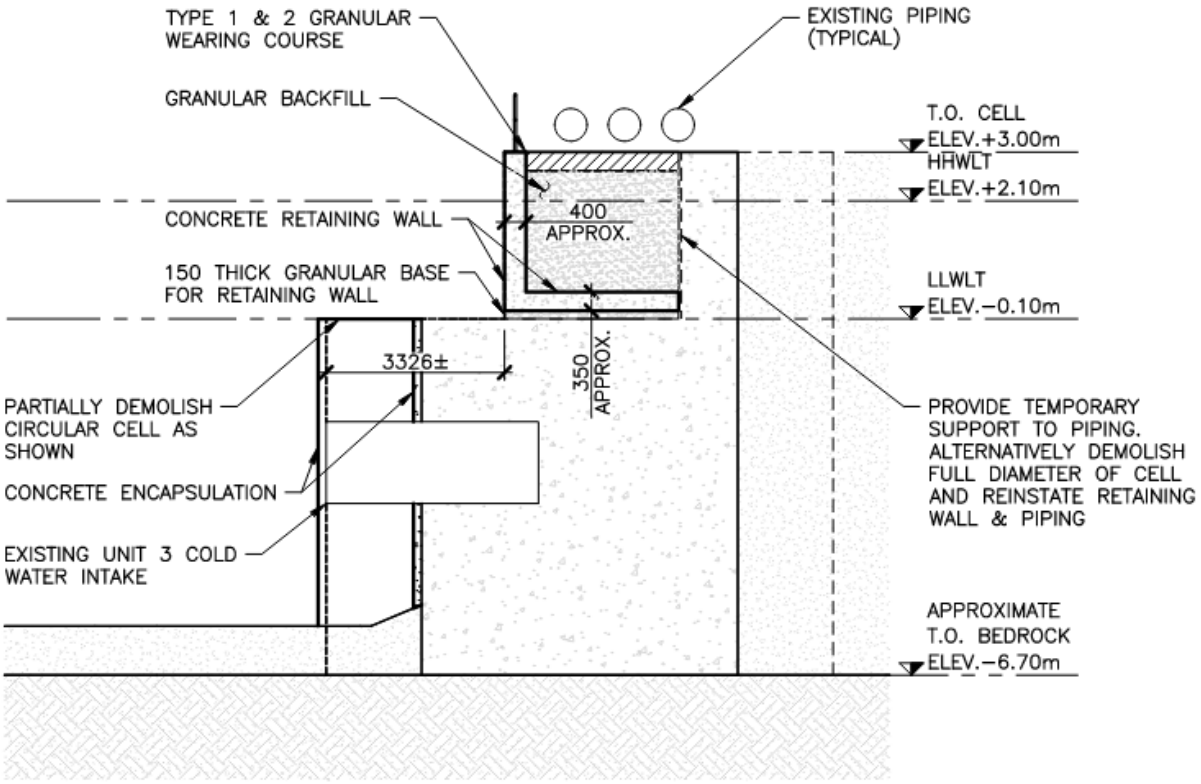


Figure 13 - Option 2 Typical Section

There is some uncertainty regarding the long-term viability of this option. The existing SSP cells rely on hoop tension to contain backfill. Encapsulation will protect seaside portion of cells from corrosion but will not provide protection to land side portion. Corrosion rate of buried structures is lower; however, the cells have been in place for approximately 50 years and the current condition of the buried portion is unknown. The SSP cells could remain vulnerable to failure post-encapsulation if the hoop tension capacity is compromised by corrosion loss in the buried portion to the cells. It is recommended to further investigate the existing condition of the buried portion of existing SSP walls before proceeding with detailed design of this option. It should be noted that this investigation may not be practical due to the presence of existing pipework, etc.

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Option 3 – Rock Revetment

This option is very similar to the existing rock revetment installed in front of TUC1, TUC2, and TUC3 with rock revetment being installed up to the edge of the working area for the existing piping **(Figure 14 & Figure 15)**. The preliminary armour rock median diameter is 700mm, which would be placed in two layers, placed at a 1V:2H slope. The filter stone median diameter
3.5 below these armour layers would be 300mm. A geotechnical field investigation and slope stability analysis will be required to confirm the geometry of the slope and if any dredging is required prior to installation. For the purposes of this study, we have assumed that the new material can be placed without dredging.

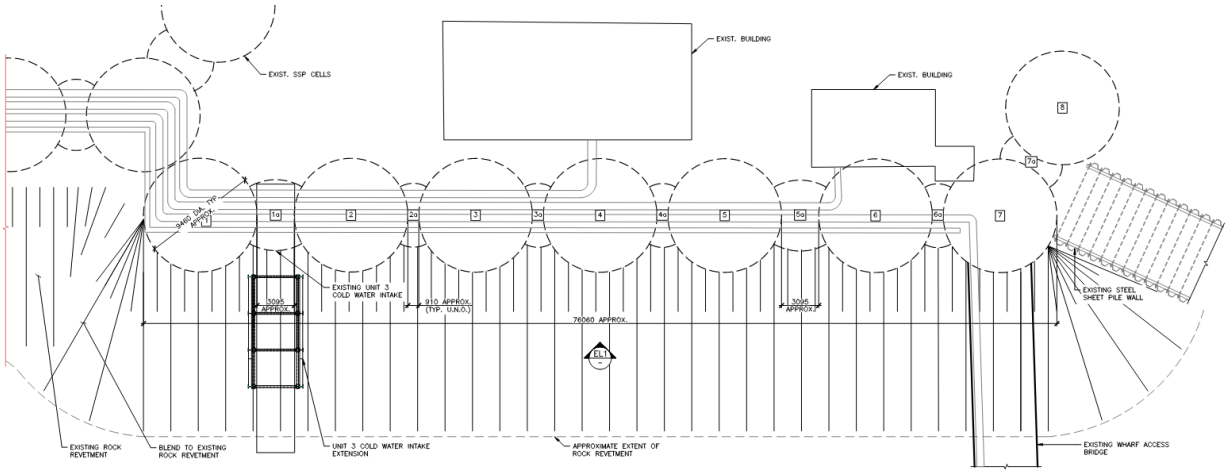

Figure 14 - Option 3 General Arrangement

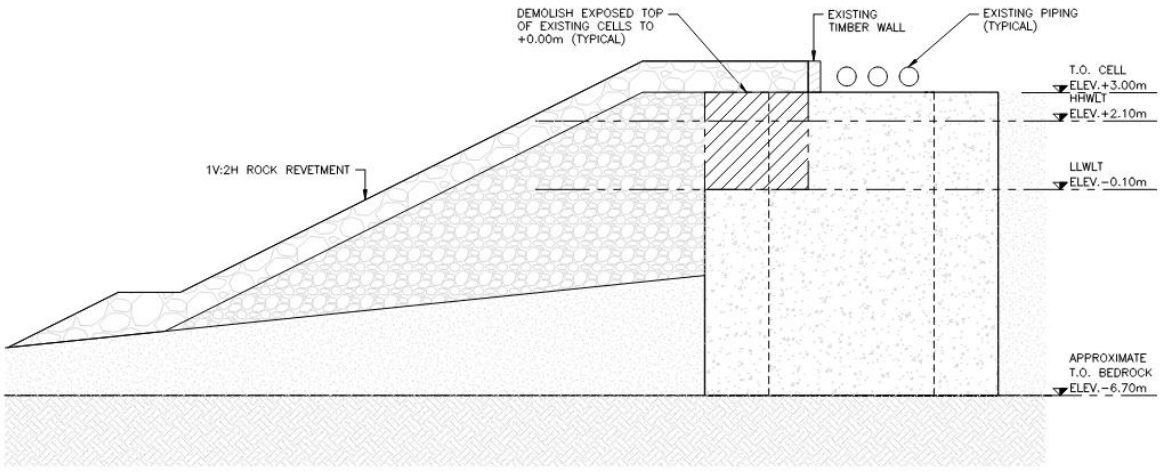

Figure 15 - Option 3 Typical Section

This rock revetment will retain the soil, making the existing SSP wall redundant. As detailed design progresses it is important to adequately size the rock material and to select durable rock types to meet these requirements. It is expected that the majority of required maintenance may involve "topping up" or replacing displaced rocks following storm events.

The TUC3 cold-water intake is extended using a similar design to the existing intake extensions (**Figure 16**). Where the existing extensions have individual stoplogs, the new extension is designed to have a single stoplog.

Similar to Option 1, this option encroaches onto a significant portion of seabed in front of the existing wall; however, this option will not provide any reclaimed trafficable land.

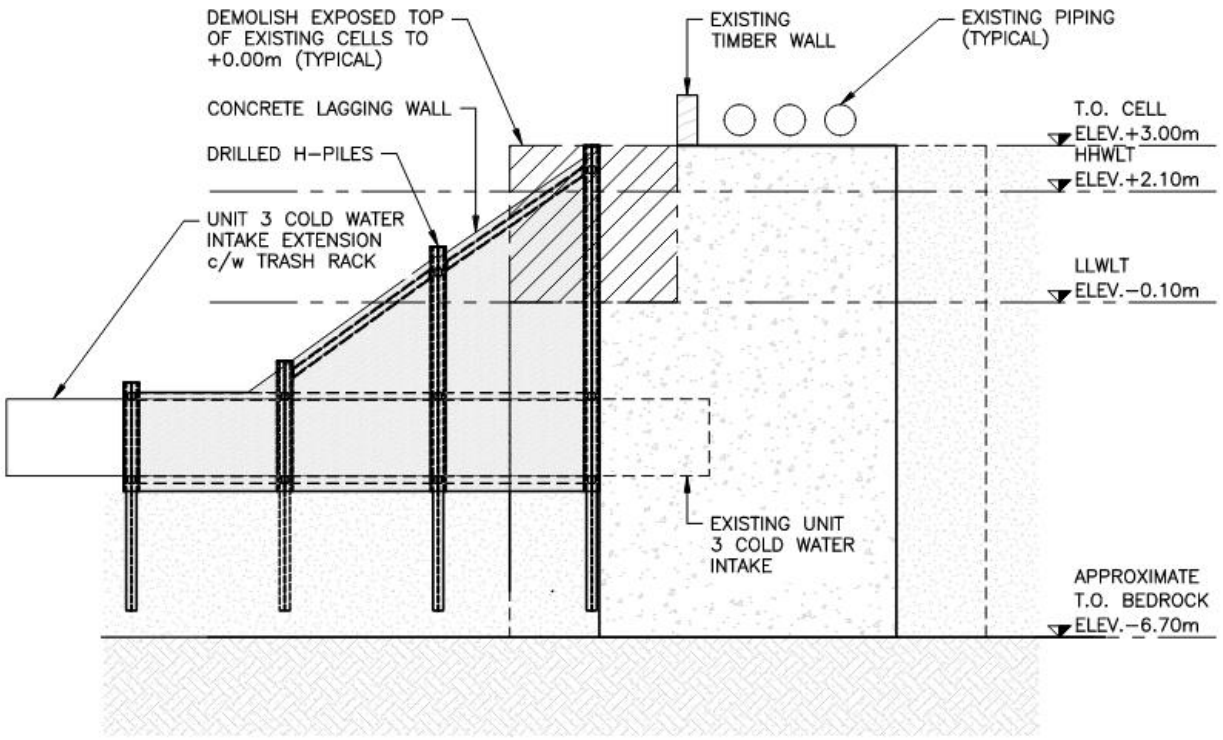

Figure 16 - Option 3 TUC3 Intake Extension

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Opinion of Probable Costs

Below is a table of the Class D OPC for each option. A breakdown of the cost items considered for each structure are found in Appendix C. It should be noted that the OPCs presented include a 40% Design Development Contingency and a 10% Construction Contingency.

3.6

Table 2 - Option Opinion of Probable Cost

Option	Cost (Excl. HST)
Option 1 – Combi-Wall	$6,260,000
Option 2 – Retaining Wall	$1,995,000
Option 3 – Rock Revetment	$1,730,000

4 Discussion and Recommendations

When considering the optimal solution for implementation, CBCL recommends applying four (4) weighted criteria to quantitatively assess option, which are detailed below:

- Meets Design Criteria (40%)
- Impact on Existing Operations (25%)
- Environmental / Permitting Considerations (15%)
- Probable Costs (20%)

The scoring methodology is to give each option score out of 3, with each score meaning detailed as follows:

- A score of 3 indicates that the option meets the criterion requirements.
- A score of 2 indicates that the option partially meets the criterion requirements.
- A score of 1 indicates that the option vaguely meets the criterion requirements.

The final scoring tables for each option are detailed below:

Table 3 - Option 1 Weighted Scoring

Option 1 – COMBI-WALL			
Criterion	Score	Weight (%)	Weighted Score
Meet Design Criteria	3	40	120
Operational Impacts	1	25	25
Regulatory Considerations	2	15	30
Probable Costs	1	20	20
Subtotal			195
Possible Max Score			300
		Total Score (%)	**65**

Table 4 - Option 2 Weighted Scoring

Option 2 – RETAINING WALL			
Criterion	Score	Weight (%)	Weighted Score
Meet Design Criteria	1	40	40
Operational Impacts	3	25	75
Regulatory Considerations	3	15	45
Probable Costs	2	20	40
Subtotal			200
Possible Max Score			300
		Total Score (%)	**67**

Table 5 - Option 3 Weighted Scoring

Option 3 – ROCK REVETMENT			
Criterion	Score	Weight (%)	Weighted Score
Meet Design Criteria	3	40	120
Operational Impacts	1	25	25
Regulatory Considerations	2	15	30
Probable Costs	3	20	60
Subtotal			235
Possible Max Score			300
		Total Score (%)	**78**

Option 1 scored strongly in “Meets Design Criteria”, however scored poorly in the remaining criteria, primarily due to the large amount of seabed area required and high capital costs.

Option 2 scored strongly in all but “Meets Design Criteria”. The main concern is that this option relies on keeping the existing SSP cells in service and it is unlikely that the existing SSP cells will remain in serviceable condition for the full 50-year design life, without an extensive maintenance over the design life of the structure. If the cells were kept in serviceable condition for the lifetime of the new retaining wall, then Option 2 would neither significantly encroach on the seabed (requiring more involved permitting processes) nor incur large capital expenditure costs to implement.

Option 3 – Rock Revetment scored the highest when considering the four (4) criteria. The key advantages for this option were that the probable costs are the lowest of the three (3) options and that it meets the design criteria (i.e., 50-year design life, soil retention, low maintenance). CBCL recommends proceeding with this option based on the preliminary design assumptions.

The next step is to gather information to develop a more detailed understanding of site conditions and to validate design assumptions. This work includes completion of geotechnical program, required surveys, development of a regulatory roadmap. It is also recommended to complete a coastal study to determine the projected sea level rise and associated impacts to the site. If study results differ from noted design assumptions, the gathered information will still be relevant and can be incorporated into detailed design of all proposed options.

In closing, CBCL is pleased to submit our Options Analysis report for the Tufts Cove SSP wall. We trust that this is considered sufficient, however if you have any queries or require further information, we respectfully ask that you contact the undersigned.

Yours very truly,

CBCL Limited

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File No: 220322.00

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APPENDIX A

Historical Drawings

Hughes-Owens 313 1102

REF. or DRAWING No. A 9 1 H 3 1 1 1 6 0 0 0 0 1

DETAILS TCC #3 - Coffer-dam Extension Arrangement
Units 3 & 4

DWG. NO. A 161-1-1110-001

EXISTING UNIT #1 | EXISTING UNIT #2 | PROPOSED UNIT #3 | PROPOSED UNIT #4

GENERAL ARRANGEMENT
SCALE: 1"=20'

SECTION B-B
SCALE: 1/8"=1'-0"

SECTION A-A
SCALE: 1"=20'

CELL LAYOUT
SCALE: 3/32"=1'-0"

DETAIL 1
(DETAIL OF WT1A & SHOWING POSITION OF INTERLOCKS)

NOTES:
1) CONTOUR LINES SHOWN THUS: —94—
2) ALL ELEVATIONS ARE TO TUFTS COVE DATUM (GEODETIC + 100.0')

APPROVED FOR CONSTRUCTION

REFERENCE DRAWINGS	DWG. NOS.
U.S. STEEL - PILING LAYOUT UNIT #1	P-3837
WHIT. BN. - PILING LAYOUT UNIT #1	5-B-789
COFFERDAM - PLAN & ELEVATION	10-P-2011
COFFER DAM EXTENSION ARRANGEMENT - TUFTS COVE UNIT #3	G-B-2002

REV. A — APPROVED FOR CONSTRUCTION; CELLS RE-NUMBERED; CELL 11A - RELOCATED; NO 5 OUTAGE RELOCATED — APRIL 17 '78

CHECKS: DIM

APPROVALS: MECH. CIVIL ELECT. APPROVED FOR CONSTRUCTION DATE

A 9 1 H 3 1 1 1 6 0 0 0 0 1

SCALE AS NOTED; DRAWN P.T.P.; DESIGNED; SURVEYED; PLOTTED; TRACED; JOB NO.

nova scotia power commission — HALIFAX, NOVA SCOTIA

TUFTS COVE GENERATING STATION UNIT # 3

COFFER-DAM EXTENSION ARRANGEMENT TUFTS COVE UNITS NO. 3 & 4

DATE FEB. 15/78 | DWG. NO. A 161-1-1110 001 | REV A

7-B-3001

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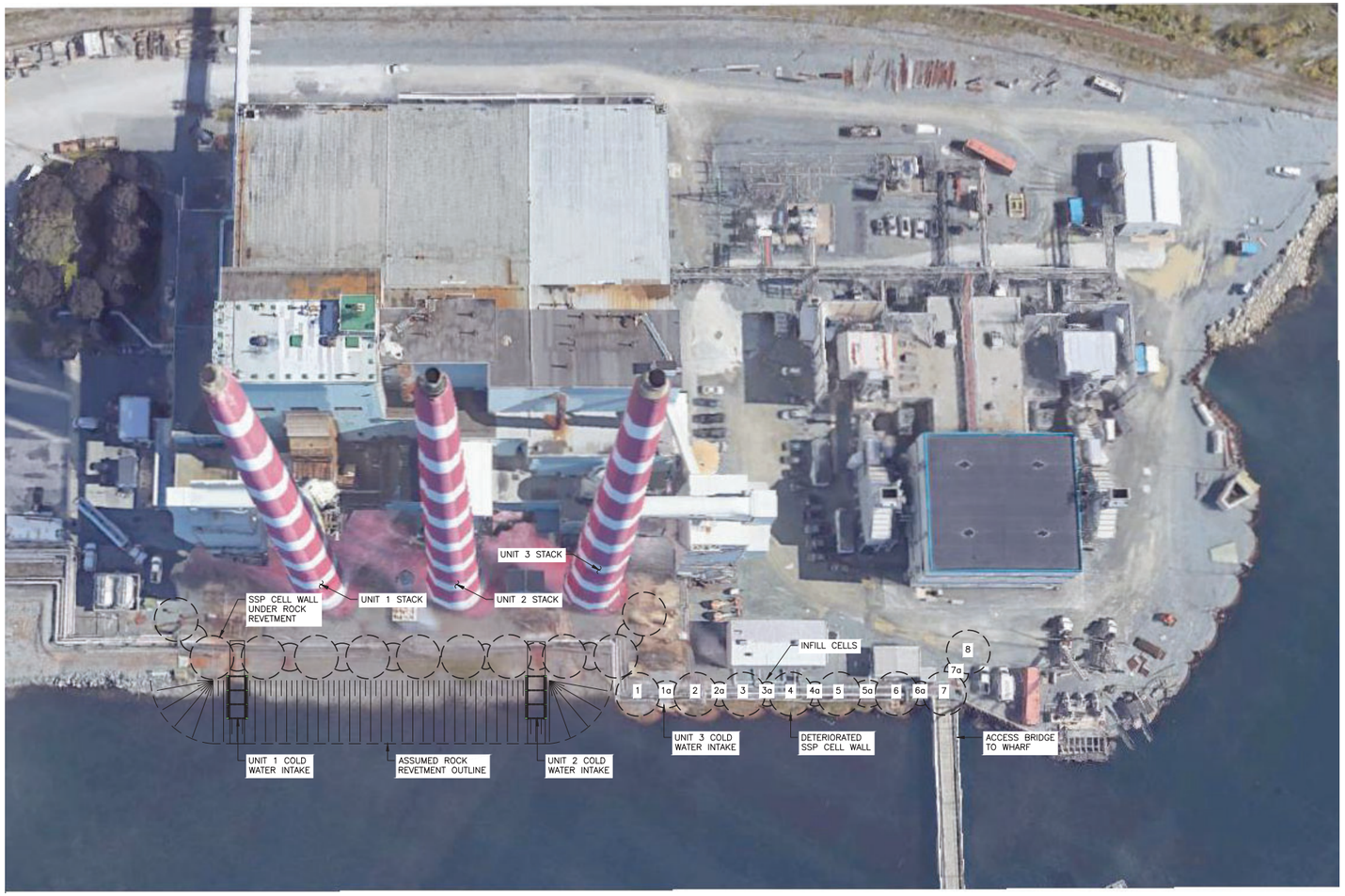
APPENDIX B

Concept Drawings

NORTH



PLAN– EXISTING CONDITIONS
1:500

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EXISTING CONDITIONS

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CBCL No 220322.00	Contract No
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Checked CPE	Approved JEF
Sheet No 1 of 7	
Drawing No MSK01	

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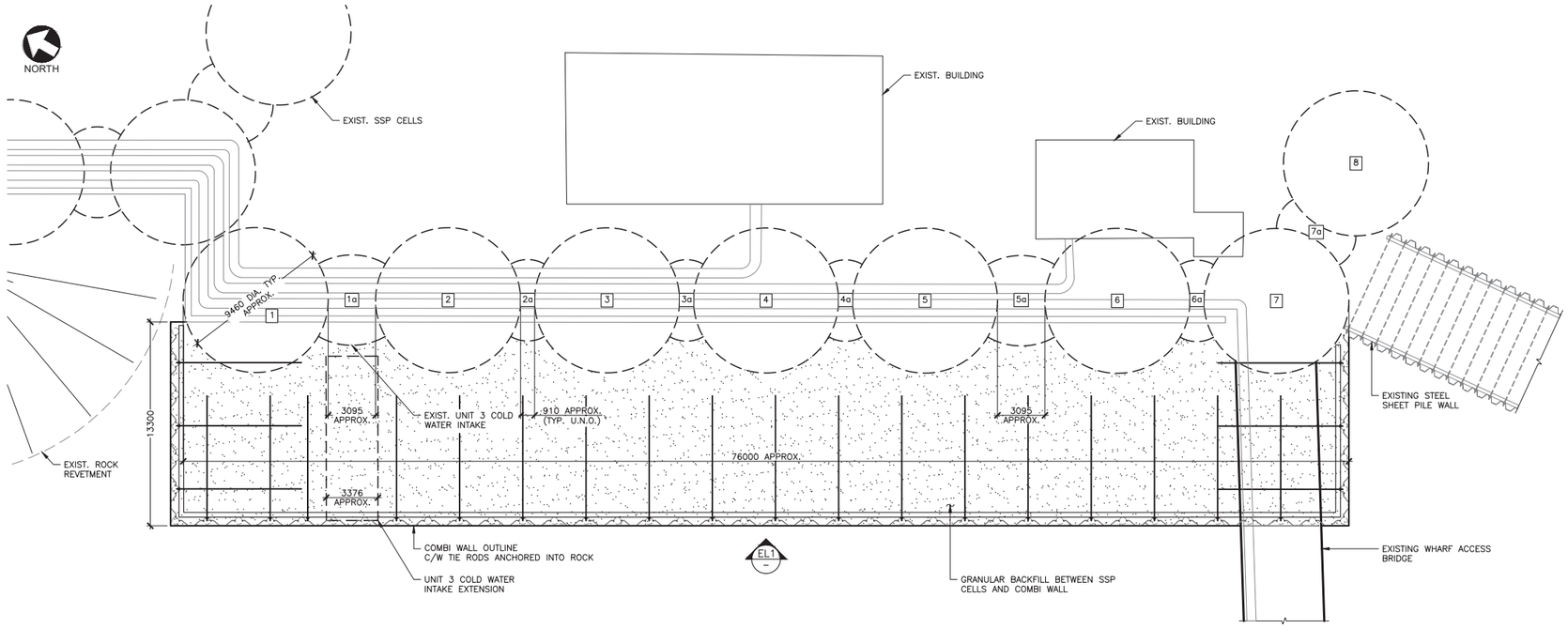

PLAN— GENERAL ARRANGEMENT
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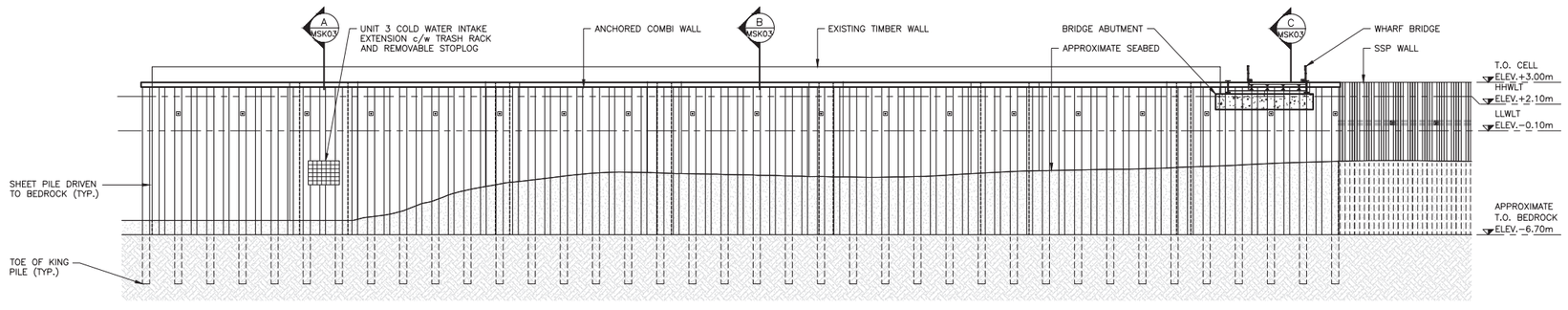

EL1 ELEVATION— COMBI WALL
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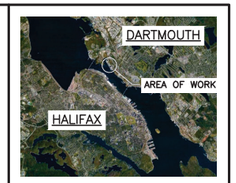

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XX DENOTES CELL NUMBER

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OPTION 1 - NEW COMBI WALL PLAN AND ELEVATION

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Checked CPE	Approved JEF
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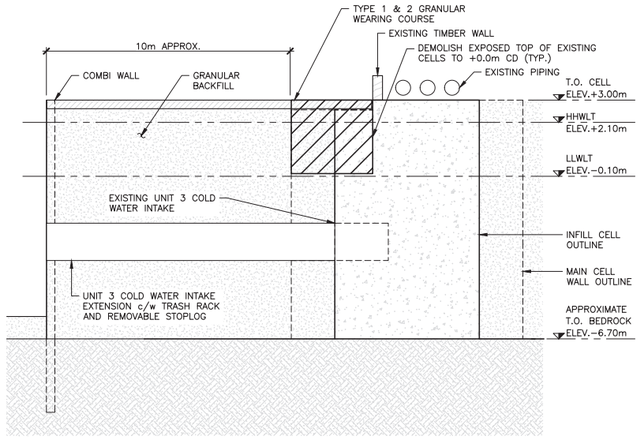

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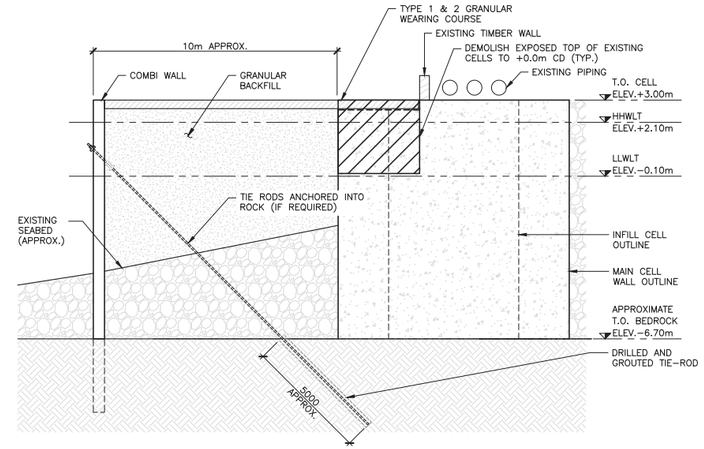

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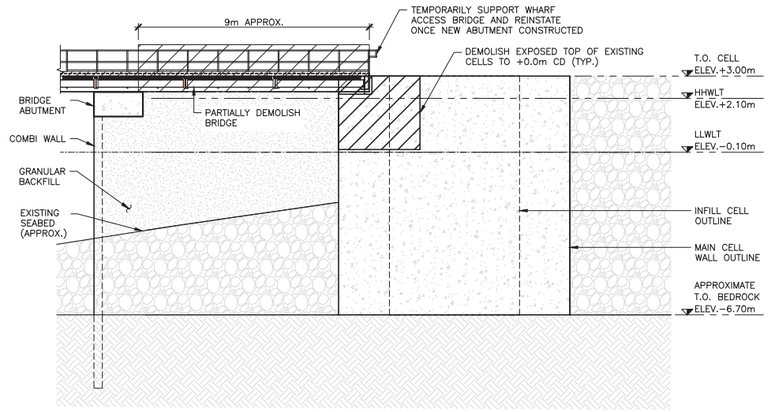

C MSK03 SECTION— WHARF ACCESS BRIDGE
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OPTION 1 - NEW COMBI WALL SECTIONS

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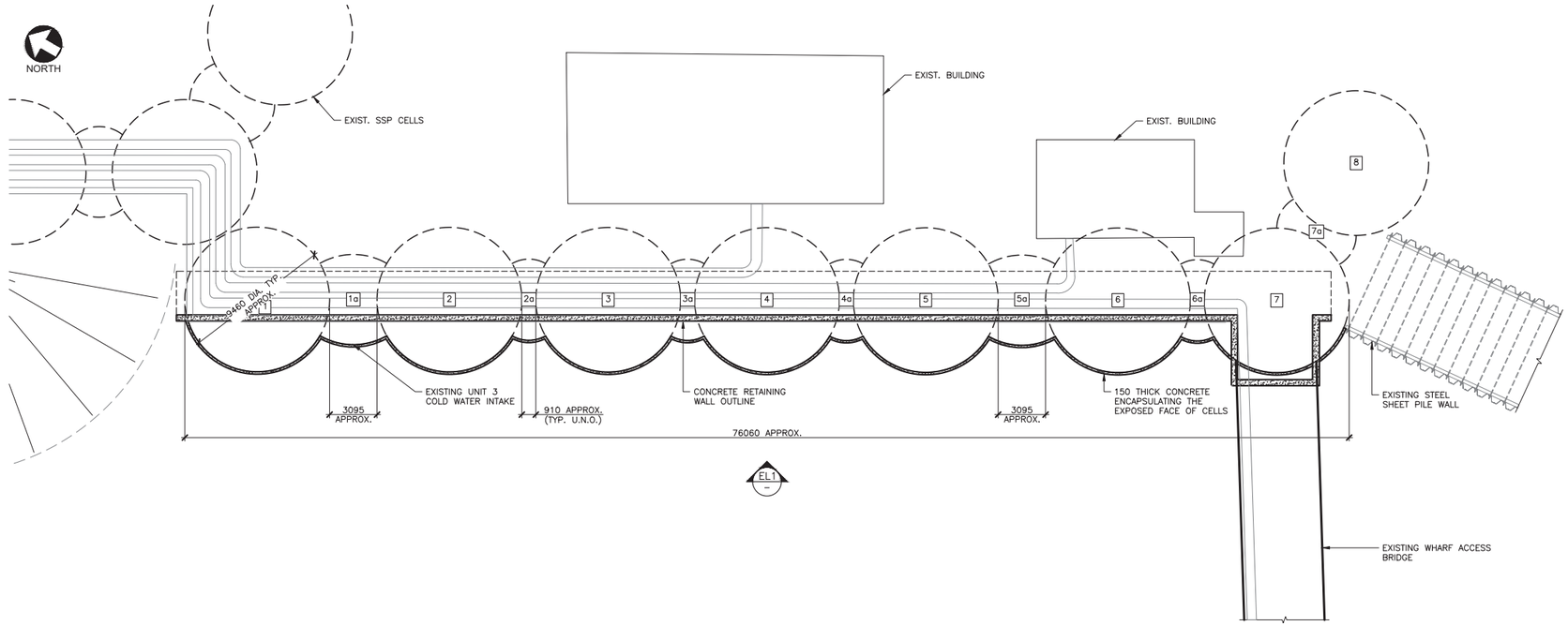

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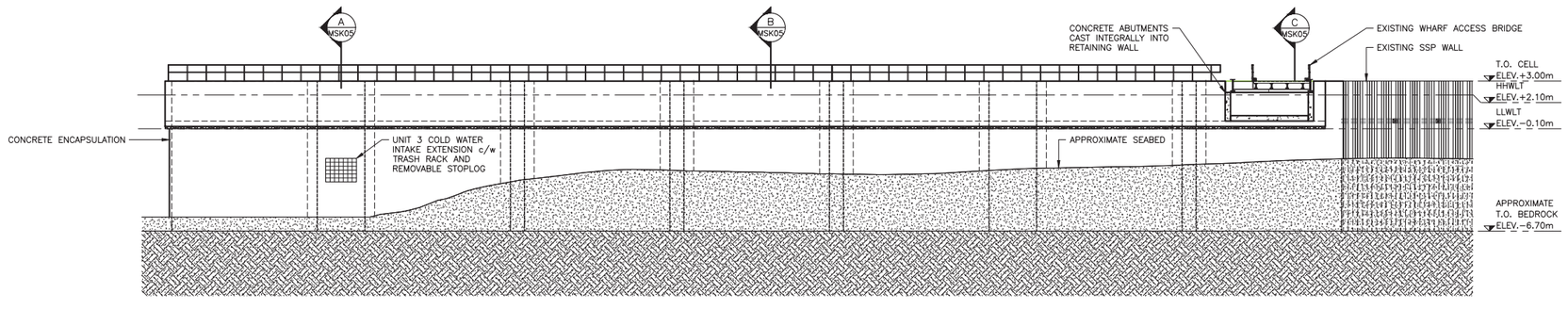

EL1 ELEVATION— RETAINING WALL
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OPTION 2 - NEW RETAINING WALL

CBCL

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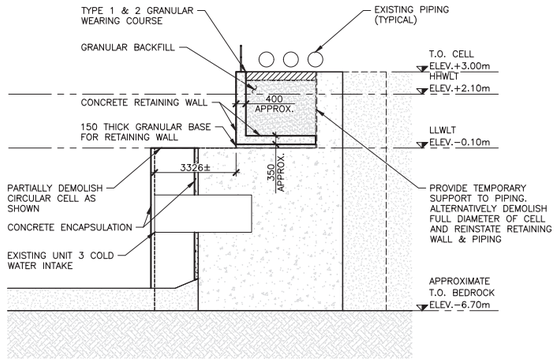

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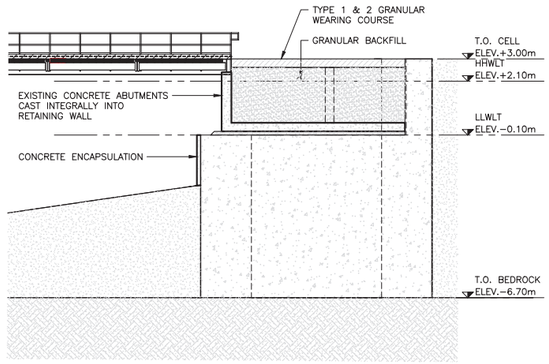

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OPTION 2 - ELEVATION AND SECTIONS

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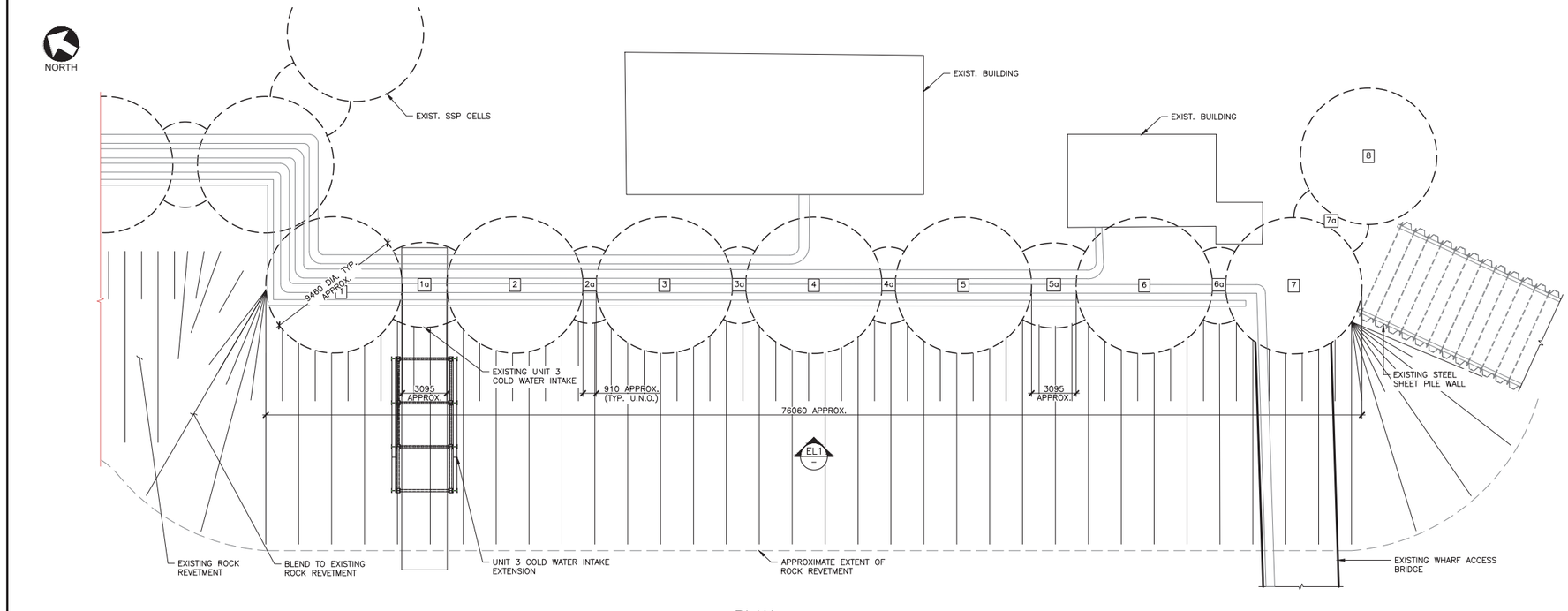

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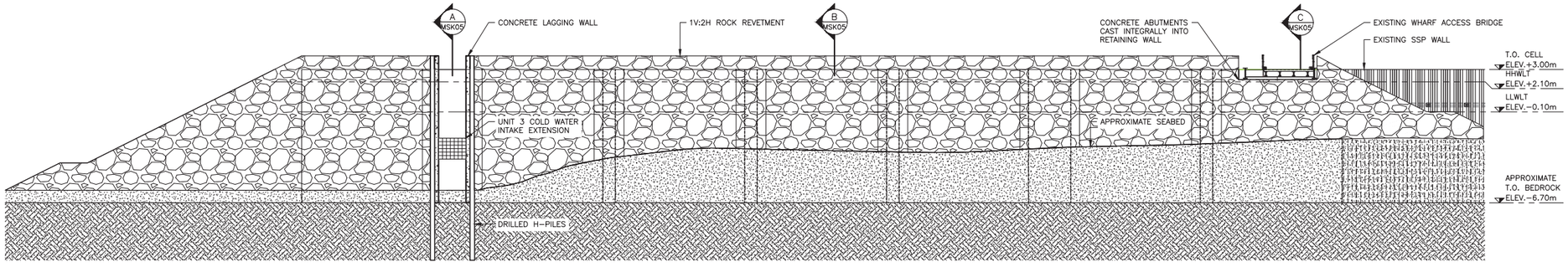

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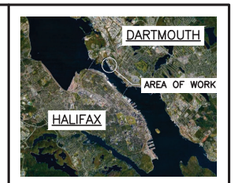

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OPTION 3 - NEW ROCK REVETMENT

CBCL

CBCL No 220322.00	Contract No
Date MAR 2023	Scale AS NOTED
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Checked CPE	Approved JEF
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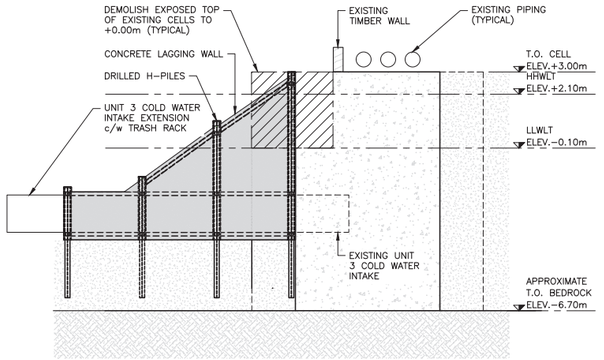

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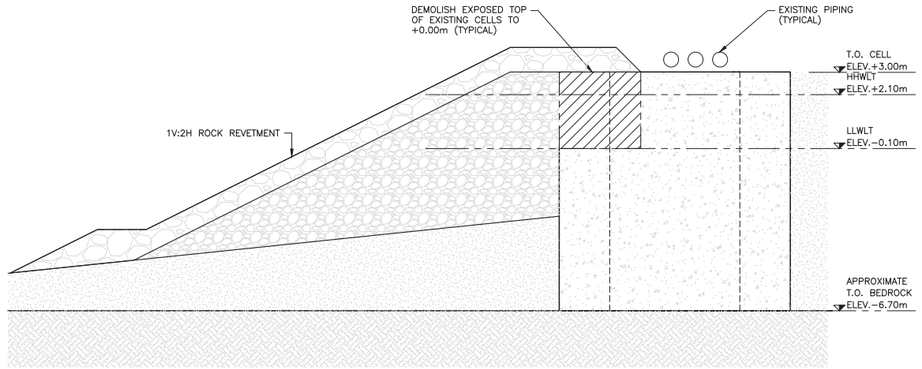

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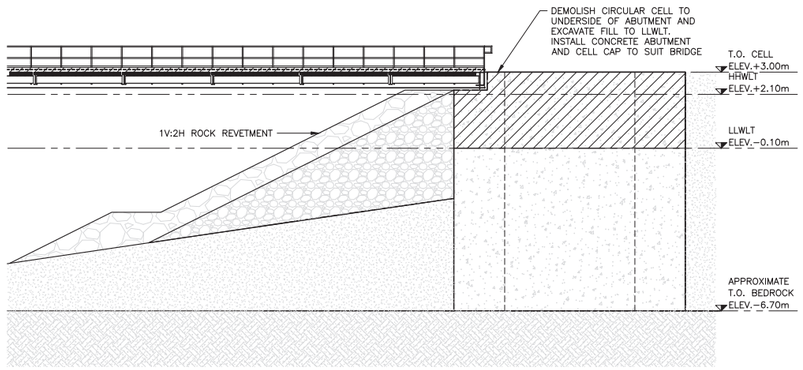

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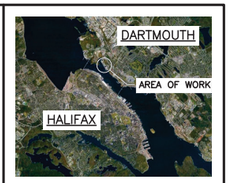

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TUFTS COVE SSP WALL REPAIR

MARINE

OPTION 3 - ELEVATION AND SECTIONS

CBCL

CBCL No 220322.00	Contract No
Date MAR 2023	Scale AS NOTED
Designed CPE	Drawn MEG
Checked CPE	Approved JEF
Sheet No 7 of 7	
Drawing No MSK07	

DRAWING NAME: Y:\HALIFAX\DATA\PROJECTS\2022\220322.00 NSPI TUFTS COVE SSP WALL\44 CAD\03 STRUCT\220322.00-MSK07.DWG LAYOUT NAME: OPTION 3 - ELEVATION AND SECTIONS PLOT DATE: Thursday, March 9, 2023 11:12:28 AM CAD OPERATOR: LULI

CBCL-610x914 TITLE SHEET (ARCH D)

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APPENDIX C

Opinion of Probable Costs

OPINION OF PROBABLE CONSTRUCTION COST
TUFTS COVE SSP WALL REPAIR
Nova Scotia Power

DATE:	03 09 2023
CBCL FILE No.:	220322.00
PREPARED BY:	CE
REVIEWED BY:	JF / GP
EST. DESCRIPTION :	Class D

No.	DESCRIPTION	UoM	Qty	Unit Price	Sub Totals	Totals
1.0	**MOBILIZATION, DEMOBILIZATION, BONDS, INSURANCE, PCM**	**LS**	**1**			**$ 500,000**
a.	Mobilization, Insurance, Bonds, Permits, Pre-Construction Management	LS	1	$ 500,000	$ 500,000	-
2.0	**DEMOLITION & TEMPORARY SUPPORTS**	**LS**	**1**			**$ 170,000**
a.	Remove Top of Cells & Temporarily Support Piping	LS	1	$ 110,000	$ 110,000	
b.	Temporarily Support Bridge and Partially Demolish	LS	1	$ 60,000	$ 60,000	
c.	Temporary Rerouting of Bridge Piping	LS			*Not Included*	
3.0	**COMBI-WALL**	**LS**	**1**			**$ 2,890,000**
a.	Supply of Pipe and Sheet Piles	T	190	$ 3,100	$ 589,000	
b.	Supply of Tie-Rods & Walers	T	12	$ 3,000	$ 36,000	
c.	Install of Combi-Wall	LM	100	$ 16,000	$ 1,600,000	
d.	Drilling & Grouting of Tie-Rods	EA	28	$ 15,000	$ 420,000	
e.	Supply & Install of Granular Fill	T	12000	$ 20	$ 240,000	
4.0	**SEABED OFFSET FEES**			***Not Included***		
5.0	**DESIGN DEVELOPMENT CONTINGENCY ALLOWANCE - *Note 1***	**LS**		40%		**$ 1,500,000**
	SUB-TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS					**$ 5,060,000**
6.0	**ENGINEERING, INVESTIGATION AND CONSTRUCTION ALLOWANCES**					
a.	Engineering, Project Management and Construction Oversight			10%	$ 510,000	
b.	Surveys (Topographical & Bathymetry)	Ea.	1	$ 40,000	$ 40,000	
c.	Environmental Surveys & Permits	Ea.	1	$ 50,000	$ 50,000	
d.	Geotechnical Investigations	Ea.	1	$ 100,000	$ 100,000	
7.0	Construction Contingency - ***Note 2***			10%	$ 500,000	
8.0	Escalation (Based on 2023 Dollars) - ***Note 3***			0%	***Not Included***	
9.0	Location Factor - ***Note 4***			0%	***Included in Units***	
	TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS with CONSTRUCTION CONTINGENCY					**$ 6,260,000**

THIS OPINION OF PROBABLE COSTS IS PRESENTED ON THE BASIS OF EXPERIENCE, QUALIFICATIONS, AND BEST JUDGEMENT. IT HAS BEEN PREPARED IN ACCORDANCE WITH ACCEPTABLE PRINCIPLES AND PRACTICES. MARKET TRENDS, NON-COMPETITIVE BIDDING SITUATIONS, UNFORESEEN LABOUR AND MATERIAL ADJUSTMENTS AND THE LIKE ARE BEYOND THE CONTROL OF CBCL LIMITED. AS SUCH WE CANNOT WARRANT OR GUARANTEE THAT ACTUAL COSTS WILL NOT VARY FROM THE OPINION PROVIDED.

Note 1	A Design Development Contingency is to allow for necessary growth of quantities, increase constructiion costs as the work is better defined
Note 2	A Construction Contingency is to allow for the cost of additional work that is over and above the original tendered construction contract price
Note 3	The Escalation/Inflation allowance is for increases in construction costs from the time budget is prepared until the time of Tender submissions
Note 4	The Location Factor is provided variances between construction costs at the location of the project & historical cost data used to prepare budget

Budget Definitions

A **Class "D" Budget** is an order of magnitude conceptual budget to screen various alternative solutions. Project documents are in the initial conceptual stages but sufficient information is available to provide an rough indication of probable cost and allow ranking of the various options being considered. Design development is typically in the preliminary concept stage.

A **Class "C" Budget** is based on a full description of the preferred option, construction/design experience and market conditions. This estimate should be sufficient for making correct investment decisions and obtaining preliminary project approval. Design development is typically in the order of 25% complete.

A **Class "B" Budget** is based on preliminary design drawings and outline specifications or performance criteria, which includes design of all major systems and subsystems. The result of all site/installation investigations have been incorporated. This budget should provide for the establishment of realistic prediction of cost and be sufficient to obtain effective project approval. Design development is typically in the order of 65% complete.

A **Class "A" Budget** is based on complete or substantially complete working drawings and specifications prior to calling for competitive bids. This estimate should be sufficient to allow a detailed reconciliation/negotiation with bidding contractors after tender. This estimate will contain only those cash allowances called for in the tender documents and will not allow for design contingencies, but include a post award construction contingency. Design development is typically in the order of 95% to 100% .

OPINION OF PROBABLE CONSTRUCTION COST
TUFTS COVE SSP WALL REPAIR
Nova Scotia Power

DATE:	03 09 2023
CBCL FILE No.:	220322.00
PREPARED BY:	CE
REVIEWED BY:	JF / GP
EST. DESCRIPTION :	Class D

No.	DESCRIPTION	UoM	Qty	Unit Price	Sub Totals	Totals
1.0	**MOBILIZATION, DEMOBILIZATION, BONDS, INSURANCE, PCM**	**LS**	**1**	0		**$ 160,000**
a.	Mobilization, Insurance, Bonds, Permits, Pre-Construction Management	LS	1	$ 160,000	$ 160,000	-
2.0	**DEMOLITION & TEMPORARY SUPPORTS**	**LS**	**1**			**$ 170,000**
a.	Remove Top of Cells & Temporarily Support Piping	LS	1	$ 110,000	$ 110,000	
b.	Temporarily Support Bridge and Partially Demolish	LS	1	$ 60,000	$ 60,000	
c.	Temporary Rerouting of Bridge Piping	LS	*Not Included*			
3.0	**RETAINING WALL**	**LS**	**1**			**$ 770,000**
a.	Encapsulating Concrete	LS	1	$ 200,000	$ 200,000	
b.	Retaining Wall Footing	LS	1	$ 170,000	$ 170,000	
c.	Retaining Wall	LS	1	$ 400,000	$ 400,000	
4.0	**DESIGN DEVELOPMENT CONTINGENCY ALLOWANCE - *Note 1***			40%		**$ 440,000**
	SUB-TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS					**$ 1,540,000**
5.0	**ENGINEERING, INVESTIGATION AND CONSTRUCTION ALLOWANCES**					
a.	Engineering, Project Management and Construction Oversight			10%	$ 150,000	
b.	Surveys (Topographical & Bathymetry)	Ea.	1	$ 40,000	$ 40,000	
c.	Environmental Surveys & Permits	Ea.	1	$ 15,000	$ 15,000	
d.	Geotechnical Investigations	Ea.	1	$ 50,000	$ 50,000	
6.0	Construction Contingency - ***Note 2***			10%	$ 200,000	
7.0	Escalation (Based on 2023 Dollars) - ***Note 3***			0%	***Not Included***	
8.0	Location Factor - ***Note 4***			0%	***Included in Units***	
	TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS with CONSTRUCTION CONTINGENCY					**$ 1,995,000**

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OPINION OF PROBABLE CONSTRUCTION COST
TUFTS COVE SSP WALL REPAIR
Nova Scotia Power

DATE:	03 09 2023
CBCL FILE No.:	220322.00
PREPARED BY:	CE
REVIEWED BY:	JF / GP
EST. DESCRIPTION :	Class D

No.	DESCRIPTION	UoM	Qty	Unit Price	Sub Totals	Totals
1.0	**MOBILIZATION, DEMOBILIZATION, BONDS, INSURANCE, PCM**	**LS**	**1**			**$ 130,000**
a.	Mobilization, Insurance, Bonds, Permits, Pre-Construction Management	LS	1	$ 130,000.00	$ 130,000	
2.0	**DEMOLITION & TEMPORARY SUPPORTS**	**LS**	**1**			**$ 170,000**
a.	Remove Top of Cells & Temporarily Support Piping	LS	1	$ 110,000	$ 110,000	
b.	Remove Bridge Section and Temporarily Support Bridge	LS	1	$ 60,000	$ 60,000	
c.	Temporary Rerouting of Bridge Piping	LS	*Not Included*			
3.0	**ROCK REVETMENT**	**LS**	**1**			**$ 610,000**
a.	Supply & Install of Rock Revetment	T	11000	$ 35	$ 385,000	
b	Unit 3 Intake Extension	LS	1	$ 225,000	$ 225,000	
4.0	**SEABED OFFSET FEES**	***Not Included***				
5.0	**DESIGN DEVELOPMENT CONTINGENCY ALLOWANCE - *Note 1***			40%		**$ 400,000**
	SUB-TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS					**$ 1,310,000**
6.0	**ENGINEERING, INVESTIGATION AND CONSTRUCTION ALLOWANCES**					
a.	Engineering, Project Management and Construction Oversight			10%	$ 130,000	
b.	Surveys (Topographical & Bathymetry)	Ea.	1	$ 40,000	$ 40,000	
c.	Environmental Surveys & Permits	Ea.	1	$ 50,000	$ 50,000	
d.	Geotechnical Investigations	Ea.	1	$ 100,000	$ 100,000	
7.0	Construction Contingency - ***Note 2***			10%	$ 100,000	
8.0	Escalation (Based on 2023 Dollars) - ***Note 3***			0%	***Not Included***	
9.0	Location Factor - ***Note 4***			0%	***Included in Units***	
	TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS with CONSTRUCTION CONTINGENCY					**$ 1,730,000**

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A **Class "B" Budget** is based on preliminary design drawings and outline specifications or performance criteria, which includes design of all major systems and subsystems. The result of all site/installation investigations have been incorporated. This budget should provide for the establishment of realistic prediction of cost and be sufficient to obtain effective project approval. Design development is typically in the order of 65% complete.

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2026 ACE Plan C0021608 Attachment 2 has been removed due to confidentiality.

CI Number: C0068898

Title: TUC1 IP LP Last Stage Blade Replacement

Start Date: 2025/05
In-Service Date: 2026/06
Final Cost Date: 2026/12
Function: Steam
Forecast Amount: $5,215,861

DESCRIPTION:

This project is for the removal and replacement of L-0 blades with original lacing wire design on the Tufts Cove Unit 1 Intermittent-Low Pressure (IP-LP) Turbine (LPT1) and Tufts Cove Unit 1 Dual Flow Low Pressure (DFLP) Turbine (LPT2 and LPT3) to allow for the continued safe and reliable operation of the unit.

The energy in the steam is converted to mechanical (rotary) energy by the low-pressure turbine blades, which further results in the rotation of the turbine and generator shafts to generate electricity. These L-0 blades are susceptible to erosion and fatigue due to their location in the turbine from normal operation over time. The L-0 blades are the last blades before the steam is condensed in the condenser.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects include "Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- 2023 C0055376 TUC1 LP Blade Refurbishment $2,025,440

Depreciation Class: Steam Production Plant – Tufts Cove 1

Estimated Life of the Asset: 25 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 – Retirement and disposal of Capital Assets
- Percentage of Asset Pool: 5.33%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Refurbishment/Replacement

Why do this project?

During the planned inspection of the Tufts Cove Unit 1 L-0 blades on the IP-LP and DFLP turbine in March 2025, it was discovered that some of the L-0 blades were found to have developed cracks developed from normal operation over time. Failure of these blades in service could result in catastrophic damage to the turbine and condenser, leading to extended unavailability and significant safety risks.

Why do this project now?

Cracks in the L-0 blades were identified during a planned inspection in March 2025. Following this discovery, NS Power initiated procurement of replacement blades, which were ordered in May 2025 and are scheduled to be delivered to the service shop in November 2025. The blades are currently being manufactured in preparation for replacement in 2026. Completing this replacement will mitigate the risk of blade failure, and associated collateral damage to both the interior and possibly exterior of the machine. Currently this risk is being mitigated through Enhanced monitoring in the form of increased inspections.

Executing the blade replacement during the planned outage window ensures the unit is restored to full operational readiness, while avoiding the risk of unplanned outages and extended downtime.

Why do this project this way?

Replacement of the Tufts Cove Unit 1 L-0 blades is the best option for continued reliability of Tufts Cove Unit 1 as the existing blades were found to have developed cracks. It was determined that individual blade replacement or refurbishment would not significantly reduce the risk of blade failure and would increase the likelihood of repeated work scope in the future. A full replacement ensures long-term reliability and aligns with the turbine's lifecycle planning.

Contingency Statement

Contingency for this project was determined using a combination of internal subject matter expert judgement (professional engineers) and previous experience in Turbine Blade projects like C0055376 TUC1 LP Blade Replacement. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 10 percent. Risks intended to be covered by the contingency are potential additional scope found during inspections of the rotor or blades not being replaced that require minor refurbishments.

Capital Project Detailed Estimate

Location: Steam
CI# : C0068898
Title: TUC1 IP LP Last Stage Blade Replacement
Execution Year: 2025-2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	50	$ 466	$ 23,301		
Maintenance Trades	PD	160	$ 427	$ 68,323		
			Sub-Total	$ 91,624		
OT Labour						
Maintenance Trades	PD	160	$ 854	$ 136,646		
			Sub-Total	$ 136,646		
Travel Expense						
Travel Expenses - Factory Acceptance Testing & Shop Inspection	lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 25,000		
Materials						
LP1 Half Set, LP2 Full Set, LP3 Full Set	lot	1	[redacted]		Attachment 2 - Page 8, 3.1	
L-0 Blade Installation Kit for 3 Rows	lot	1			Attachment 2 - Page 8, 3.2	
IP/LP & DFLP Rotor Inspections Remove & Replace 3 Rows L-0 Blades Ethos Shop Work	lot	1			Attachment 2 - Page 8, 3.3-3.4	
USD to CAD	%	40%				
Gaskets	lot	1	$ 10,000	$ 10,000		
Consumables	lot	1	$ 12,500	$ 12,500		
			Sub-Total	$ 3,241,708		
Contracts						
Pre-Planning	lot	1	[redacted]		Attachment 1, 2.1 - Item 1	
Technical Field Advisor (TFA) Onsite	lot	1			Attachment 1, 2.1 - Item 2	
Startup Balancing (Onsite Engineer + Mobilization + Tooling)	lot	1			Attachment 1, 2.1 - Item 3	
Cradle 30T Rental	lot	1			Attachment 1, 2.1 - Item 4	
Non-Destruction Examination (NDE) of Blades	lot	1	$ 70,000	$ 70,000		
Sand Blasting	lot	1	$ 30,000	$ 30,000		
Machining Support	lot	1	$ 50,000	$ 50,000		
Borescope	lot	1	$ 10,000	$ 10,000		
Rigging	lot	1	$ 7,500	$ 7,500		
Bolt Heating	lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 739,085		
Freight Postage Delivery						
Freight Blades & Rotor	lot	1	[redacted]			
Transportation of 30T Cradle	lot	1			Attachment 1, 2.1 - Item 5	
			Sub-Total	$ 155,750		
Consulting						
3rd Party Consulting & Planning	lot	1	$ 75,000	$ 75,000		
			Sub-Total	$ 75,000		
Meals						
Overtime Meals	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Rentals						
Office Trailers	lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 15,000		
Other Goods & Services						
Contingency	10%		$ 4,484,813	$ 448,481		
			Sub-Total	$ 448,481.27		
Interest Capitalized						
AFUDC				$ 153,272		
			Sub-Total	$ 153,272		
Administrative Overhead						
Labour AO				$ 59,592		
Contractor AO				$ 69,703		
			Sub-Total	$ 129,295		
			SUB-TOTAL (no AO, AFUDC)	$ 4,933,294		
			TOTAL (AO, AFUDC included)	$ 5,215,861		
Original Cost				$ 2,932,854		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER An Emera Company

Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Process Industries	Required fields:	Estimate Classification				
Project Name: TUC1 IP LP Last Stage Blade Replacement	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Non-Process Facilities (Infrastructure, Ports, Pipeline, Power Transmission)	Not Applicable (NA)					
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Byproduct and Waste Disposal	Not Applicable (NA)	NR				
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Plant Production/Facility (includes power facilities)	Not Applicable (NA)					
Electrical Power Requirements (when not the primary capacity driver)	Not Applicable (NA)	NR				
C. Project Location						
Plant and Associated Facilities	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Communication Systems	Not Applicable (NA)	NR				
Fire Protection and Life Safety	Not Applicable (NA)	NR				
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Process Technology	Not Applicable (NA)					
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Not Applicable (NA)	NR				
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Block Flow Diagrams	Not Applicable (NA)					
Equipment Data Sheets	Not Applicable (NA)	NR/S				
Equipment Lists: Electrical	Not Applicable (NA)	NR/S				
Equipment Lists: Process/Utility/Mechanical	Complete (C)	NR/S	P	C	C	C
Heat & Material Balances	Not Applicable (NA)	NR				
Process Flow Diagrams (PFDs)	Not Applicable (NA)	NR				
Utility Flow Diagrams (UFDs)	Not Applicable (NA)	NR				
Design Specifications	Complete (C)	NR	S/P	C	C	C
Electrical One-Line Drawings	Not Applicable (NA)	NR				
General Equipment Arrangement Drawings	Complete (C)	NR	S/P	C	C	C
Instrument List	Not Applicable (NA)	NR				
Piping & Instrumentation Diagrams	Not Applicable (NA)	NR				
Plot Plans/Facility Layouts	Complete (C)	NR	S/P	C	C	C
Construction Permits	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Fire Protection & Life Safety Drawings & Details	Not Applicable (NA)	NR				
Electrical Schedules	Not Applicable (NA)	NR	NR/S			
Instrument & Control Schedules	Not Applicable (NA)	NR	NR/S			
Instrument Data Sheets	Not Applicable (NA)	NR	NR/S			
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listings	Not Applicable (NA)	NR	NR			
Electrical Discipline Drawings	Not Applicable (NA)	NR	NR			
Facility Emergency Communication Plan & Drawings	Not Applicable (NA)	NR	NR			
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Mechanical Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	3	15	13	12	12
	% Defined/Complete towards Class Estimate	100%	100%	87%	87%	80%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project inidcate that 87% of the Class 3 deliverables have been completed. A contingency value of 10% was selected to account for specific execution risks, including technical field advisor & startup engineering costs, labor costs, and supporting contract costs being based on estimates.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *process industries* is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs), piping and instrument diagrams (P&IDs), and electrical one-line drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information. This RP applies to a variety of project delivery methods such as traditional design-bid-build (DBB), design-build (DB), construction management for fee (CM-fee), construction management at risk (CM-at risk), and private-public partnerships (PPP) contracting methods.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this recommended practice may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

Most plants also have significant electrical power equipment (e.g., transformers, switchgear, etc.) associated with them. As such, this RP also applies to electrical substation projects, either associated with the process plant, as part of power transmission or distribution infrastructure, or supporting the power needs of other facilities. This RP excludes power generating facilities and high-voltage transmission.

Proposal

Siemens Energy Reference Number SF252455369

Customer	Nova Scotia Power
Proposal Description	2026 TUC1 IP-LP Outage Support
Submission Date	September 16, 2025
Prepared By	Ricky Chauhan Service Sales Leader

Siemens Energy Canada Limited
Power Generation Services
1577 North Service Road East
Oakville, Ontario L6H 0H6

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September 16, 2025

Nova Scotia Power Inc.
315 Windmill Road
Dartmouth, NS B3A 1H3

Subject: 2026 TUC1 IP-LP Outage Support
Siemens Energy Reference Number SF252455369

Dear Nova Scotia Power Inc.,

Siemens Energy Canada Limited (hereinafter, "Siemens Energy") appreciates the opportunity to present this proposal to Nova Scotia Power for the services described therein.

A review of this proposal will demonstrate the overall value of working with Siemens Energy on your unit and our significant value-added benefits to customers. We are confident of our ability to deliver the highest quality service.

The information contained in this proposal and all related documents is proprietary and confidential information that belongs to Siemens Energy. This information is being disclosed to you for the specific purpose of your evaluation of Siemens Energy as a contractor for a particular project. By reviewing the information contained in these documents, you agree to be bound to a confidentiality obligation with respect to this information. Specifically, you hereby agree that (1) you will treat this information with the same level of care as you treat your own proprietary information; (2) you will not disclose this information to third parties without the prior written consent of Siemens Energy; and (3) you will not use this information for any purpose beyond evaluating Siemens Energy as a contractor and/or contracting with Siemens Energy for the particular project quoted herein.

The above terms supersede any click-wrap or other terms not expressly set forth in a signed agreement between the parties covering the proposal. All such click-wrap or other terms are expressly rejected by Siemens Energy.

Thank you for considering Siemens Energy to perform this service. We look forward to working on Nova Scotia Power's unit. Siemens Energy will be pleased to discuss this proposal, at your convenience, or any questions about our experience or capabilities. Please feel free to contact me if you have any questions regarding this proposal.

With best regards,

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SIEMENS energy

Nova Scotia Power
2026 TUC1 IP-LP Outage Support

Chris Holloway

Siemens Energy Canada Limited
Siemens Energy Gas Services
Mobile: +1 (709) 727-2526
mailto:chris.holloway@siemens-energy.com

EBA Technical	EBA Commercial
Dan Fearn Digitally signed by Dan Fearn DN: cn=Dan Fearn, o=SECL, ou=GS, email=dan.fearn@siemens-energy.com Date: 2025.09.17 18:10:49 -03'00'	Rachel denBak Digitally signed by Den Bak Rachel DN: cn=Den Bak Rachel, o=Siemens, email=rachel.denbak@siemens-energy.com Date: 2025.09.17 16:04:24 -04'00'

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SIEMENS energy

Nova Scotia Power
2026 TUC1 IP-LP Outage Support

Revision History

Date	Rev	Summary	Issued By
September 16, 2025	0	Original Issue	C. Holloway

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1.0 Executive Summary

SECL offers to provide the following Scope(s) of Services below in support of the Tufts Cove Unit 1 Outage. All services are based on a time and material basis with tooling on a monthly rental charge.

1.1 Pre-Planning

Siemens Energy to provide the following resources for pre-planning:

- One (1) Service Engineer to support remote development of work packages for IP / LP. Duration (pending confirmation of scope), would be estimated up to 160 hrs of support.

1.2 Onsite Execution

Siemens Energy to provide the following resources for onsite execution:

- One (1) TFA and One (1) Third Party TFA to support onsite execution working a shift schedule of 1x6x10 for twelve (12) weeks (estimated dates: TBD pending NSP review).
- One (1) Machinery Dynamics Engineer for start-up support working a shift schedule of 1x6x10 for a duration of one (1) week (estimated).

1.3 Site Safety Discussion

Nova Scotia Power to provide site specific safety orientation for Siemens Energy personnel. Siemens Energy will work under the Nova Scotia Power Health and Safety Manual as well as the SECL Health and Safety Manual. Nova Scotia Power will provide site specific (safety) related coverage during the outage. Fatigue management should be discussed as the outage is scheduled for greater than seven (7) days.

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2.0 Commercial Considerations / Pricing

2.1 Pricing

Siemens Energy is pleased to offer the following pricing to Nova Scotia Power to perform the scopes of work as detailed in Section 1 of this proposal.

Item	Work Scope Description	Price Basis	Price (1-4)
1	Preplanning	T&M	[redacted]
2	TFA Onsite (SECL TFA and Third Party Contractor TFA)	T&M	[redacted]
3	Startup Balancing (Onsite Engineer + Mobilization + Tooling)	T&M	[redacted]
4	Cradle 30T – 30 Day Rental	T&M	[redacted]
5	Transportation	T&M	[redacted]
		Total	[redacted]

(1) All prices are quoted in 2025 Canadian dollars and do not include any sales tax. Applicable taxes will be added at time of invoice.

(2) T&M invoices will be billed according to the MSA. The 2026 MSA rates and tooling charges will apply at the time of execution. While the 2026 rates are currently known, the proposal pricing reflects the current 2025 rates.

(3) All offsite support scope (Bearings, Specialty Machining; etc.) will require separate Purchase Order(s) outside of the SDIR process and will not be executed as part of the Service PO.

(4) The rental period for the 30T Cradle is structured in increments of 30 days. Should the rental duration exceed the initial 30-day period, SECL reserves the right to impose charges for an additional 30-day term.

2.2 Quality Program

This offer is based on a Quality Program in accordance with ISO 9001:2015.

2.3 Environmental, Health & Safety

This offer is based on Siemens Energy "Zero Harm" program and in accordance with COR Certification Requirements.

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2.4 Terms and Conditions

Terms and Conditions as defined and agreed upon in the Master Services Agreement (MSA), between Nova Scotia Power Inc. and Siemens Energy Canada Ltd., shall apply to the work scope in this proposal.

2.5 Tariff Clause

The offered price does not include any taxes, duties, tariffs, or equivalent measures (including by way of executive order, legislation, regulation or order in council) by any local or foreign governmental authority (including to any components or raw materials, contained in or any part of the goods) imposed, enacted or announced after January 1, 2025 ("Tariffs") on imports or exports affecting the delivery and manufacturing of the offered good or its components including at any tier of a sub-supplier. Siemens Energy will issue an additional invoice for the cost of the Tariffs once the impact is known and calculated.

In addition, should the cost or time of performing the Work increase due to (i) any new or modified Tariffs, on any portion of the Work supplied under this Agreement (ii) changes made to the sourcing plan in order to mitigate the impact of Tariffs, (iii) demonstratable market price increases attributable to the application of such Tariffs or (iv) any rules, regulations or processes for persons entering the Canadian border are imposed, modified or changed, then, in each case, to the extent any of the same impacts Siemens Energy's price, schedule, obligations or performance under this Contract, Siemens Energy shall be entitled to a change order for an equitable adjustment in prices and times for performance to fully compensate Siemens Energy for the increased costs of, or time to perform, the Work.

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PROPOSAL FOR

Tufts Cove Unit 1 L-0 Blade Replacement

Nova Scotia Power

Proposal Ref: 24-007942R1 14 May 2025 1 / 11

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Nova Scotia Power ("NSP")

Tufts Cove Thermal Generating Station

315 Windmill Rd.
Dartmouth, NS B2Y 1G0
Canada

Attn: Banpreet Singh Shaney

Subject: Proposal 24-007942 Rev. 1; Tufts Cove U1 L-0 Blade Replacement

Dear Banpreet,

EthosEnergy Canada, Ltd is pleased to present this proposal to Nova Scotia Power to remove and replace blading for LP1, LP2, and LP3 with original (lacing wire) design for Tufts Cove Unit 1 at the EthosEnergy Houston Service Center, as requested.

The scope coverage presented in this proposal provides Nova Scotia Power a partner with proven capabilities and experience on the requested work scope to meet the requirements outlined.

We are excited about the opportunity to work on this project with Nova Scotia Power and look forward to discussing this proposal in greater depth. Please contact me if you have any questions or require further information.

Respectfully submitted for your review and consideration,

Best regards,

David Sinay

David Sinay
Sales Account Manager
david.sinay@ethosenergy.com
M: +1 (609)-850-0209

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1 Confidentiality

This entire commercial and technical proposal and the correspondence and communications concerning this proposal, collectively the "Proposal" developed by EthosEnergy, are the property of EthosEnergy.

This Proposal is furnished in confidence solely for the purpose of considering its merits in relation to the subject scope of work and for no other direct or indirect use. By accepting this document from EthosEnergy, **Nova Scotia Power** agrees:

- Not to use this document, and the information it contains, for any purpose other than the purpose stated above.
- Not to use the information included in the Proposal for the performance of the scope of work by the recipient or any third parties.
- Not to disclose the information contained in this Proposal to, or allow use by, competitors of EthosEnergy.
- Not to publish or in any other way disclose this document or the information it contains unless otherwise required by law, regulations or judicial or regulatory order.
- Not to make copies of any part of this Proposal without the prior written permission of EthosEnergy.
- To return this document when it is no longer needed for the purpose for which it is submitted, or upon request of EthosEnergy.

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2 Value Statement

For over 25 years, EthosEnergy' s unique approach to risk management and contracting flexibility has provided owners and operators with value-based solutions for their Turbines, (Steam and Gas) as well as Generators and Centrifugal Compressors. Transparency of process and alignment of goals around what's important to our customers is what makes us different.

2.1 Why Buy from EthosEnergy?

- **EthosEnergy is Backed by a Values-Based, Financially Strong, and Experienced Company**
  - EthosEnergy' s Core Values are at the heart of our business because they define who we are, how we work, what we believe in and what we stand for. For you, our customer, this means that you have a partner that values safety and integrity like you do and that seeks to provide you with innovative, socially responsible solutions that deliver to you long-term value as part of a mutually beneficial relationship
  - 24/7 worldwide engineering and back-office support
  - 80+ engineers with robust industry and machine specific expertise creating and supporting EthosEnergy provided solutions
  - Industry-leading Engineering team
  - Extensive experience operating & maintaining over 80 power plants totaling over 22GW of generation under long-term O&M or term maintenance agreements

- **EthosEnergy Has a Proven Track Record**
  - Over 20 years of experience providing our own developed / designed and manufactured components
  - EthosEnergy upgraded steam path in most OEM steam turbines globally
  - Provide upgrades and performance guarantees
  - Improvement over existing OEM designs

- **EthosEnergy Parts are High Quality, Intentionally**
  - ISO 9001 / 14001 certified
  - Rigorous quality and supply chain management control through ISO and EFQM certified processes
  - Robustness of quality processes are driven by the fact that our customers have zero tolerance towards non-OEM quality issues
  - Open book policy – on-site review or audit by our clients, or designated third party inspections of any specification, manufacturing drawing, or quality record, without restriction
  - Gated manufacturing process with "source inspectors" assigned to each production facility as "stamp-holders"
  - Post design verification to ensure product integrity

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3 Scope of Work

3.1 Manufacture New L-0 Blades for LP1, LP2, LP3

Part #	Location	Quantity	Hardware Included
AETTC04	L-0 Blades w/ Installation Hardware	114 (106 base + 8 spares)	Stellite, pins, tiewire

- EthosEnergy assumes NSP has a ½ set of L-0 blades for LP1 in inventory. EthosEnergy's scope of supply will include for one L-0 set each for LP2 & LP3, and a ½ set for LP1.
- Expedited Manufacturing lead time for two and a half sets is estimated to be **15 – 16 Weeks**, after receipt of purchase order*, and all information required to manufacture.

  A purchase order should be received no later than May 19, 2025 in order to meet August 31, 2025 delivery.
- Pricing offered below includes a moment weigh of the mismatch set for LP1
- The standard NDE performed on these blades is a Magnetic Particle Inspection (MPI – wet flourescent method) of the prep cut prior to brazing, followed by a Liquid Penetrant Inspection (LPI – visible red dye process) of the brazed Stellite shields. A final MPI is then performed on the entire, finish-machined blade. Any additional testing beyond our standard will be quoted separately and billed at cost plus 15%.

3.2 Blade Installation Kit

- Provide three (3) sets of installation kits including Pins, Reamers and Bushings

3.3 Remove & Replace L-0 Blades (IP/LP Turbine Rotor)

- Receive IP/LP turbine rotor at EthosEnergy Houston.
- Prior to any work being performed, a receiving rotor check balance will be performed.
- Protect shaft ends, grit blast clean rotor 220 grit aluminum oxide blast media.
- Visually inspect rotor for damage, take ample pictures of any damage.
- MT inspect rotor.
- Set-up rotor and perform a rotor TIR on critical areas.
- Check and record the probe areas ERO.
- Check and record journal diameters.
- Dimensionally inspect the rotor critical areas, record.

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- Check integral coupling hub face for flatness and runout, check and record rabbit diameter and runout.
- Remove one (1) row of L-0 blades by normal means, clean, visual and MT inspect, install new blades, drill & ream locking pins, install & peen locking pins, inspect, braze lancing wires, inspect.
    - Grit blast and boresonic inspection to be performed following removal of L-0 blades.
    - Borescope: Includes removal of one (1) plug, fabrication and reinstallation of new bore plug, pre-hone and post-hone incremental measurement will be taken and recorded every 4.0 inches, visual and WFMT examination of the rotor bore, Eddy Current Testing (ET), Ultrasonic examination (UT), and final report documenting examinations and results of deterministic life assessment
- Low-speed balance rotor to 4W/N after all work is completed.
- Perform a rotor shipping inspection after all work has been completed.
- Prepare the rotor for shipment back to the customer's site, light oil applied, protect journals and thrust collar areas, protect blade tips as needed, heat seal wrap rotor, put rotor in shipping skid and secure.

3.4 Remove & Replace L-0 Blades (DFLP Turbine Rotor)

- Receive DFLP turbine rotor and stub shaft at EthosEnergy Houston.
- Prior to any work being performed, a receiving rotor check balance will be performed.
- Protect shaft ends, grit blast clean rotor 220 grit aluminum oxide blast media.
- Visually inspect rotor for damage, take ample pictures of any damage.
- MT inspect rotor.
- Set-up rotor and perform a rotor TIR on critical areas.
- Check and record the probe areas ERO.
- Check and record journal diameters.
- Dimensionally inspect the rotor critical areas, record.
- Check integral coupling hub face for flatness and runout, check and record rabbit diameter and runout.
- Solvent clean and inspect customer-supplied stub shaft and hardware
- Remove two (2) rows of L-0 blades by normal means, clean, visual and MT inspect, install new blades, drill & ream locking pins, install & peen locking pins, inspect, braze lancing wires, inspect.

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- Grit blast and boresonic inspection to be performed following removal of L-0 blades.
- Borescope: Includes removal of one (1) plug, fabrication and reinstallation of new bore plug, pre-hone and post-hone incremental measurement will be taken and recorded every 4.0 inches, visual and WFMT examination of the rotor bore, Eddy Current Testing (ET), Ultrasonic examination (UT), and final report documenting examinations and results of deterministic life assessment

- Set-up rotor and install customer-supplied stub shaft.
- Low-speed balance rotor to 4W/N after all work is completed. Remove stub shaft and hardware.
- Perform a rotor shipping inspection after all work has been completed.
- Prepare the rotors and customer-supplied stub shaft for shipment back to the customer's site, light oil applied, protect journals and thrust collar areas, protect blade tips as needed, heat seal wrap rotor, put rotor in shipping skid and secure.

4 Pricing

Scope of Work	Total Price*	Delivery
(3.1) Manufacture New L-0 Blades & Hardware - LP2 Full Set, LP3 Full Set, LP1 Half Set	[redacted]	**15 – 16 Weeks**
(3.2) L-0 Blade Installation Kit for Three Rows	[redacted]	**10 – 12 Weeks**
(3.3- 3.4) IP/LP & DFLP Rotor Inspections; Remove & Replace Three Rows L-0 Blades	[redacted]	**46 – 50 Days**

Unless otherwise stated, prices provided herein are exclusive of any tariffs, duties or other similar taxes related to cross-border sales and/or sourcing of components and raw materials ("Cross-Border Taxes"). Any applicable Cross-Border Taxes will be paid directly by Buyer or passed-through to Buyer at EthosEnergy's cost.

5 Assumptions and Clarifications

- Due to the current extreme volatility surrounding metal pricing and supply, pricing on all quotes must be reconfirmed at time of order placement, and all metal is subject to prior sale. This quote is valid for thirty (30) days.
- Our proposal is based upon information supplied at the time of proposal preparation. Any deviations may affect price and delivery time. Estimated price and delivery are based on undivided and uninterrupted performance of the work.
- Proposal is only for work within the above presented scope. All other works, parts and services are to be performed by others.

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- Any modification to scope outlined above is subject to additional cost and schedule change.
- If metallurgical inconsistencies are encountered in the base metal during inspection, welding, grinding, machining, or any other operation, the cost and duration may increase potentially causing extra work to remove the anomalies.
- Pricing is based on normal blast cleaning using 220 grit Aluminum Oxide. If rotor cannot be cleaned by normal blasting due to excessive particle build up, etc., extra time required for cleaning is considered extra work and will be quoted separately upon discovery.
- Removal of the finger root type pins is by "NORMAL MEANS". If the pins cannot be removed or are difficult to remove in the allotted time, then additional cost will be quoted as extra work upon discovery. No more than 3 attempts with a Hilti-gun shall be made. Drilling to remove will be quoted as extra work upon discovery.
- EthosEnergy assumes the blades are finger root type blades with 3 locking pins, segmented tie wire, brazed to air foil, free standing.
- EthosEnergy assumes that the customer supplied stub shaft will have all necessary installation hardware needed to install the stub shaft. If any additional hardware is needed to install the stub shaft, it will be quoted as extra work upon discovery.
- EthosEnergy assumes that the customers supplied stub shaft is balanced and is ready to install and that no additional work will be needed to insure proper installation and runout. Any additional work on the stub shaft will be quoted as extra work upon discovery.
- The standard NDE performed on these blades is a Magnetic Particle Inspection (MPI – wet flourescent method) of the prep cut prior to brazing, followed by a Liquid Penetrant Inspection (LPI – visible red dye process) of the brazed Stellite shields. A final MPI is then performed on the entire, finish-machined blade. Any additional testing beyond our standard will be quoted separately and billed at cost plus 15%.
- COVID -19
    - The Coronavirus (COVID-19) pandemic is unprecedented and is having dramatic impacts around the world. Within EthosEnergy, the impact to our people and our global businesses varies considerably by location and is fluid for many reasons. We are continuing to closely monitor the pandemic and its potential impact to our people, our customers, and businesses daily. EthosEnergy's offering in this proposal reflects our best assessment on our ability to deliver the scope of services within this proposal at this time. If our ability to deliver on any or all commercial aspects of this proposal is adversely impacted due to events caused by COVID-19, adjustments to this offering may be required.
    - Estimate provided in this proposal does not account for possible quarantine costs, COVID-19 testing of our employees, local regulations or specific Protocols regarding COVID 19.
    - EthosEnergy follows the CDC recommended guidelines as well as local health department guidelines. EthosEnergy employees wear masks unless the work task is hindered by wearing masks. EthosEnergy employees further maintain 6’ of social distancing as much as feasible. Further, each crew member receives temperature checks prior to the start of each shift. Any employee showing a fever of 100 degrees or more is not allowed to work and must isolate. This may include COVID testing depending upon all of the factors. In the case that an employee does test positive, their spot on the crew would be replaced. In some cases, customers have requested EthosEnergy quarantine for 14 days prior to beginning the work but typically have not accepted this as the price to put an entire crew on standby time for 14 days is expensive. EthosEnergy can provide pricing for this if the customer would like.

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6 Commercial Summary

6.1 Pricing and Payment Terms

Pricing is based on the Scope of Work provided, Assumptions and Clarifications, and Terms and Conditions contained in this proposal.

Pricing is based in 2025 USD.

Payment Terms: Net 30

- The following are the applicable payment terms:

#	Milestone	% of Selling Price
1	Upon Contract Award / Authority to Proceed	50%
3	Upon Notification of Readiness to Ship	Balance

6.2 Taxes, duties and fees

All direct and indirect taxes, duties or levies, including but not limited to VAT, WHT import and export duties, are excluded.

6.3 Validity

This quotation shall remain valid for 30 days from the date of this proposal.

6.4 Delivery

Delivery of work is estimated and Is after the receipt of the following: 1) an acceptable purchase order; 2) first payment or down payment; 3) all required components delivered to the EthosEnergy Repair Facility; and 4) all other information required by EthosEnergy to perform its work under this Proposal. All delivery estimates are made subject to prior sale.

Any unscheduled delays due to customer holds points stemming from witness, questions, or requests for customer input, may result in day-for-day slippage to the final delivery date.

Unless otherwise specified above, pricing does not include shipping, and delivery is ex-works EthosEnergy facility.

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6.4.1 Freight and insurance

All equipment and parts are supplied Ex-Works Contractor's facilities. If the Company requests the Contractor to arrange shipping, all freight costs will be billed to the Company at cost plus 15%. The Company will sign and deliver to Contractor, on a timely basis, an insurance waiver relinquishing any and all claims against Contractor for any liability relative to Company's equipment, including loss or damage thereto. Any good(s) left in EthosEnergy's facilities more than thirty (30) days after either completion of the work, or after initial inspection without an acceptable purchase order, will be considered stored good(s) subject to a monthly storage fee unless otherwise agreed between the parties.

6.5 Warranty

Per agreed terms and conditions.

6.6 Contracting Entity

Purchase order shall be issued to:

EthosEnergy Canada, Ltd.
3100 South Sam Houston Parkway East
Houston, TX 77047

www.ethosenergy.com

6.7 Terms and Conditions

EthosEnergy has attached a copy of our standard terms and conditions to the end of this document. Any modifications to these terms will be subject to mutual agreement and EthosEnergy Management approval.

If Nova Scotia Power enters into Master Terms and Conditions ('Master Terms') with EthosEnergy or any of EthosEnergy's Affiliates that applies to the purchase of Goods and Services, then the terms and conditions of such Master Terms shall govern this work.

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CI Number: C0080134

Title: TUC2 Stack Coating and Structural Refurbishment

Start Date: 2026/05
In-Service Date: 2026/10
Final Cost Date: 2027/04
Function: Steam
Forecast Amount: $4,256,511

DESCRIPTION:

This project is for the removal of existing protective coatings, completing concrete crack refurbishments on the external stack column, and the application of a two-layer epoxy coating system to Unit 2 of the Tufts Cove Generating Station (TUC) concrete chimney stack to restore integrity and extend asset life.

The stacks at Tufts Cove Generating Station are critical to the plant and its operation to push flue gasses from the boilers up to a defined height dictated by the Nova Scotia Department of Environment and Climate Change (NSECC) to ensure the concentration of ground level flue gasses are within the allowable limits.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects include "Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- 2024 C0066791 TUC2 Stack Refurbishment 2024 $303,012
- 2025 C0074291 TUC2 Stack Protective Envelope $491,698

Depreciation Class: Steam Production Plant – Tufts Cove 2

Estimated Life of the Asset: 25 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 3.99%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

In 2024, a third-party conducted multiple inspections of the TUC 2 stack column through a regularly planned condition assessment in accordance with internal NS Power quality practices. The exhaust stacks are inspected to map out cracking, inspect condition of coatings and monitor condition of hardware as the environment adjacent to saltwater is known to be corrosive. Core sample analysis revealed extensive multi-dimensional cracking, with some extending through the full thickness of the stack.

The inspection report (please refer to Attachment 1) identified the freeze-thaw cycling as the dominant root cause of the cracking. The stacks at Tufts Cove have significant surface area that is subjected to water ingress through any minor or major crack. A key recommendation was to apply new protective coatings to the stack column to prevent future water ingress into the concrete and cold joints. Additionally, the report advised that while the stack is stripped of its existing coating for this work, it would be an ideal opportunity to complete localized refurbishment on any major cracks identified.

Why do this project now?

The last time TUC2 stack had major coating work completed was in 2008 with an expected life of approximately 15 years. The 2024 TUC2 stack inspection identified the stack coating as a deficiency that should be addressed within two years. Similarly, the localized cracking observed in the stack was recommended for refurbishment as soon as feasible. Delaying this work beyond 2026 could negatively impact the long-term asset life of the stack, pose structural integrity risks, and present safety concerns, particularly the potential for material to spall from the stack column at height.

Why do this project this way?

Removal of existing coatings, targeted concrete refurbishment, and application of a two-coat epoxy system represents a common industry practice for restoring chimney stacks. This method ensures optimal adhesion of new coatings, addresses structural vulnerabilities, and provides long-term protection against environmental exposure. It balances cost-effectiveness with durability, minimizing future maintenance needs and aligning with best practices for asset preservation.

All work will be carried out by contractors specialized in stack maintenance and high-angle/swing-stage work. A coating capture system will be employed during coating to prevent environmental contamination, as trace amounts of lead have been identified in the existing coating material.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers and third-party consultants) and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a 20 percent contingency. Risks intended to be covered by the contingency are related to the contractor costs; specifically, increases in cost due to adverse weather conditions such as wind, rain, and excess humidity. If it is too windy, access to the stack is prohibited due to safety regulations. Coating and concrete work requires a dry space to complete the work; therefore, rain introduces either a delay to the work or increased costs from constructing a dry space to complete. Weather conditions that are not ideal for coating the stack or completing concrete refurbishment work could also lead to increased costs due to rework. Delays due to weather will also increase the cost of equipment rentals.

Capital Project Detailed Estimate

Location: Steam
CI# : C0080134
Title: TUC2 Stack Coating and Structural Refurbishment
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	20	$ 420	$ 8,403		
Engineering	PD	40	$ 466	$ 18,640		
Maintenance Trades	PD	10	$ 427	$ 4,270		
Utilityworker	PD	95	$ 297	$ 28,256		
			Sub-Total	$ 59,570		
OT Labour						
Utilityworker	PD	[redacted]				
			Sub-Total	[redacted]		
Materials						
Coating & Structural Refurbishment Materials	lot	1	[redacted]		Attachment 2, Page 3, 35% of "PRICE"	
			Sub-Total	[redacted]		
Contracts						
Contractor Coating & Structural Refurbishment	lot	1	[redacted]		Attachment 2, Page 3, 65% of "PRICE"	
			Sub-Total	[redacted]		
Other Goods & Services						
Contingency	20%	1	$ 3,313,959	$ 662,792		
			Sub-Total	$ 662,792		
Interest Capitalized						
AFUDC				$ 55,023		
			Sub-Total	$ 55,023		
Administrative Overhead						
Labour AO				$ 26,734		
Contractor AO				$ 198,004		
			Sub-Total	$ 224,737		
			SUB-TOTAL (no AO, AFUDC)	$ 3,976,751		
			TOTAL (AO, AFUDC included)	$ 4,256,511		
Original Cost				$ 2,748,772		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

General Construction	Required fields:	Estimate Classification				
Project Name: TUC2 Stack Coating and Structural Refurbishment	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Functional Space - SF or m^2	Not Applicable (NA)					
Electrical Power Requirements (when not the primary capacity driver)	Not Applicable (NA)	NR				
Mechanical Systems	Not Applicable (NA)	NR				
C. Project Location						
Building and/or Other Project Elements	Defined (D)	P	P	D	D	D
D. Requirements						
Anti-Terrorism Force Protection	Not Applicable (NA)					
No. of Building Floors	Not Applicable (NA)					
Security System	Not Applicable (NA)	NR/P				
LEED Certification Level	Not Applicable (NA)	NR/P				
Codes and/or Standards	Not Applicable (NA)	NR				
Communication Systems	Not Applicable (NA)	NR				
Exterior Closure Description	Not Applicable (NA)	NR				
Finishes Descriptions	Preliminary (P)	NR	P			
Fire Protection and Life Safety	Not Applicable (NA)	NR				
Environmental Monitoring	Preliminary (P)	NR	NR	P	P	
E. Technology Selection						
Not Applicable						
F. Strategy						
Contracting/Sourcing	Preliminary (P)	NR	P			
Escalation	Not Applicable (NA)	NR				
G. Planning						
Logistics Plan	Not Applicable (NA)					
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Defined (D)	NR	P	D	D	D
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
Storm Water Management Plan	Not Applicable (NA)	NR				
H. Studies						
Environmental Impact/Sustainability Assessment	Preliminary (P)	NR	P			
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Site Plan	Not Applicable (NA)					
Design Specifications	Preliminary (P)	NR	S/P			
Electrical One-Line Drawings	Not Applicable (NA)	NR				
General Equipment Arrangement Drawings	Not Applicable (NA)	NR				
Plot Plans/Facility Layouts	Not Applicable (NA)	NR				
Room Classification Datasheet	Not Applicable (NA)	NR				
Room Layout Drawings	Not Applicable (NA)	NR				
Construction Permits	Not Applicable (NA)	NR				
Building Plan Views, Sections and Elevations	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Codes and Standards Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Exterior Elevations	Complete (C)	NR	S/P	P	C	C
Finish Schedule	Complete (C)	NR	S/P	P	C	C
Fire Protection and Life Safety Drawings and Details	Not Applicable (NA)	NR				
Furniture Plans, Schedules and Drawings	Not Applicable (NA)	NR				
Interior Section Views	Not Applicable (NA)	NR				
Landscaping Drawings	Not Applicable (NA)	NR				
Plumbing Drawings	Not Applicable (NA)	NR				
Roof Plan, Drawing Details	Not Applicable (NA)	NR				
Storm Water Drawings	Not Applicable (NA)	NR				
Window Schedules	Not Applicable (NA)	NR				
Door Schedules	Not Applicable (NA)	NR				
Restroom Schedules	Not Applicable (NA)	NR				
Signage Drawings and Schedules	Not Applicable (NA)	NR				
Partition or Wall Types	Not Applicable (NA)	NR				
Electrical Schedules	Not Applicable (NA)	NR	NR/S			
Equipment Datasheets	Not Applicable (NA)	NR	NR/S			
Equipment Lists: Electrical	Not Applicable (NA)	NR	NR/S			
Equipment Lists: Process/Utility/Mechanical	Not Applicable (NA)	NR	NR/S			
Instrument and Control Schedules	Not Applicable (NA)	NR	NR/S			
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listing	Not Applicable (NA)	NR	NR			
Electrical Discipline drawings	Not Applicable (NA)	NR	NR			
Facility Emergency Communication Plan and Drawings	Not Applicable (NA)	NR	NR			
HVAC Drawings	Not Applicable (NA)	NR	NR			
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Mechanical Discipline Drawings	Not Applicable (NA)	NR	NR			
Room Discipline Drawings	Not Applicable (NA)	NR	NR			
Interior Lighting Plan and Drawings	Not Applicable (NA)	NR	NR			
Lighting Control Diagram	Not Applicable (NA)	NR	NR			
Lighting Schedules	Not Applicable (NA)	NR	NR			
Lightning Protection Drawings	Not Applicable (NA)	NR	NR			
Mechanical/HVAC Schedules	Not Applicable (NA)	NR	NR			
Motor Control Diagram	Not Applicable (NA)	NR	NR			
Plumbing Details	Not Applicable (NA)	NR	NR			
Security Plan and Drawings	Not Applicable (NA)	NR	NR			
Instrument List	Not Applicable (NA)	NR	NR			
Building Envelope/Moisture Protection/Flashing Details	Preliminary (P)	NR	NR	S	P	
Interior Elevations	Not Applicable (NA)	NR	NR			
Total Responses	**Total # Deliverables for this Project**	2	16	13	13	11
Percentage	**% Defined/Complete towards Class Estimate**	100%	100%	72%	72%	61%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 72% of Class 3 deliverables are completed. A contingency value of 20% was selected as per the budgetary pricing received. Risks intended to be covered by the contingency are related to the contractor costs.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required (NR):** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary (P):** Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined (D):** Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- **Not Required (NR):** Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *general construction* is assumed to include both new construction as well as renovation construction projects. It is intended to be used for building (vertical) construction, as well as site/civil projects. It is intended to cover projects which are repetitive and repeatable. Examples for buildings include: residential construction, commercial buildings, hotels, resorts, offices, retail, etc. This also includes site/civil projects. Examples for site/civil projects include: site development, utility infrastructure, telecommunications, water pipelines, sanitary sewer pipelines, storm water and water resources projects. The common thread among these industries for the purpose of estimate classification is their reliance on project definition documents (basis of design) and schematic drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information.

Estimates for buildings center on functional space requirements, structural requirements, site requirements, architectural elements, sustainability, and supporting mechanical, electrical, plumbing, and life-safety systems.

COMMONWEALTH CANADA

NOVA SCOTIA POWER INC
TUFTS COVE GENERATING STATION
UNIT # 2

INSPECTION REPORT
Project 2924
November 2024

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I. INTRODUCTION

Commonwealth Dynamics Limited was contracted by Nova Scotia Power Inc to conduct a concrete column analysis of the TUC # 2 chimney. Three (3) inspection/core extraction drops were conducted of the 492' reinforced concrete chimney at 120° intervals via a power climber cage. The condition of the concrete wall was the focus of the inspection with special attention paid to column cracking and all areas of delamination. Given the known fallout within the chimney annulus observations were noted with respect to the column construction joints and have been commented on. Six (6) core samples were taken from the concrete column at various locations

The project # 2924 has been assigned to this inspection.

II. DESCRIPTION

Construction: 492'-0" x 14'-8" Top OD, reinforced concrete column with one independent refractory brick liner. The concrete column is 492'-0" with a base OD of 40'-6" and a top OD of 14'-8". A 316L stainless steel liner cap rests on the concrete column. The exterior of the column has been painted with two (2) coats of Sealcoat protective coating, in an alternating bands of International orange and white throughout the entire height of the chimney. The top 50'-0" of the interior of the column was originally painted with one (1) coat of coal tar epoxy.

Liner: Independent, brick liner 500'-0" x 8'-0" top ID. Base of the liner is located at elevation 0'-0" with a 16-0" bottom ID. Test port penetrations are located at the 130'-0" elevation. A combination of carbon steel and stainless steel bands encircle the liner at 5'-0" intervals throughout the entire height of the structure. Wall reductions can be found at 110'-0" and 310'-0" decreasing the thickness of the brick liner. The brick liner protrudes 8'-0" above the top of the reinforced concrete shell and accommodates a 316L stainless steel weather hood supported by two (2), 4" stainless steel bands.

Ladder: The annular contains a permanent, column mounted, carbon steel ladder with a ⅜ safety cable from elevation 0'-0" to elevation 492'-0"

Platforms: Four (4) interior platforms (annular space) locations. One (1) 360° CEMS platform at elevation 125'-0"; one (1) partial 180° AOL balcony at elevation 240'-0"; One (1) partial 180° balcony at elevation 365'-0"; One (1) 360° AOL balcony at elevation 485'-0"

Breeching Ducts: One (1) 20'-8" x 7'-6" breeching duct located on the east side, with a bottom sill at an elevation of 21'.

LPS: Two (2) interior (annular space) copper downlead cables, north & south. Top 50'-0" consists of a lead incased copper cable, while the remaining 440'-0" is comprised of a bare ⅝ bare copper cable.

AOL: Eight solid red LED obstruction lights throughout the entire height of the chimney. A pair of (2) obstruction lights are located at each AOL platform, 180° apart, staggered at 90° at each balcony elevation.

Access Doors: 6'-6" x 3'-0" man door in column base, elevation 0'-0" on the south side. A 4'-6" x 2'-6" liner access door is located at the 16'-6" elevation on the west side.

III Inspection Findings & Recommendations:

Exterior Concrete Column North, East, Southwest Inspection Drops:

Based on observations from the exterior inspection drops, the overall condition of the concrete column is less than fair, with extensive vertical and horizontal cracks. The cold joints were also noted as poor with extensive cracking, honeycomb, rock pockets and spalling along the joints throughout the full height of the chimney on all three inspection drops.

A series of 4" core samples were taken at varying elevations mostly in cracks to document the condition of the concrete and the severity of the cracking and water migration. These holes were packed with none shrink grout after the samples were taken.

The cold joints (construction joints) located through the full height of the chimney were noted as poor with horizontal cracks running through the cold joint with hollow soft concrete noted.

Concrete deficiencies were noted throughout the height of the stack with a few of the worst noted here. A major vertical crack on the north side begins at approximately elevation 85' has been trowel patched through it's full length. At elevation 308' a large spall was noted at the cold joint with hollow concrete around the spall. At elevation 322' a spall was noted at the cold joint with exposed concrete aggregate. Another vertical crack was noted running parallel to the major repaired crack. At elevation 330' horizontal cracking at the cold joint and vertical cracks and hollow concrete. Elevation 338' horizontal cracking at the cold joint, concrete is hollow sounding and damp. Elevation 398' the major repaired crack stops but the area at this elevation has horizontal cracking vertical cracks and hollow sounding concrete. At elevation 405' large horizontal cracks at the cold joint spalled concrete exposed reinforcing steel. At elevation 413' a large horizontal crack at the cold joint was noted with hollow soft concrete. At elevation 442' exposed reinforcing steel and spalled concrete. Elevation 450' large spalled concrete loose concrete aggregate at the cold joint with exposed rusted reinforcing steel. Elevation 465' at the cold joint a spall was detected along with vertical cracking spalled concrete and exposed rusted reinforcing steel. Elevation 475' hairline spider web cracks and paint delamination. A hairline vertical running up the concrete column beginning at approximately just above the breeching duct at elevation 80'. At elevation 120' the access hatch was showing cracked poor concrete with unpainted concrete. At elevation 135' the vertical crack continues up the column. At elevation 165' spalled concrete at the cold joint was noted with exposed rusted reinforcing steel. Elevation 180' exposed rusted reinforcing steel curtain was observed with spalled loose concrete. Elevation 195' vertical cracks continue poor paint coating. Elevation 218' large spalled area exposed reinforcing steel. Elevation 293' open cold joint spalled loose concrete. Elevations 345' and 360' cold joint cracking and spalls with holes to the column evident. Elevations 382' & 403' vertical cracks and spalled concrete. Elevations 418' & 440' spalled concrete at cold joint vertical crack continues horizontal cracking evident. Elevation 445' cold joints cracked and concrete is testing hollow. Elevation 53' the southwest inspection drop revealed exposed shallow rebar, spalled concrete and vertical and horizontal cracking. Elevation 190' large spalled area at cold joint. Elevations 334'/338' exposed reinforcing steel spalls cracks open cold joints, elevation 356' open cold joint and exposed reinforcing steel.

III Inspection Findings & Recommendations:

Exterior Concrete Column North, East, Southwest Inspection Drops:

Elevation 372’ horizontal crack runs 15’+ feet, elevation 380’ horizontal crack approximately 10’+. Elevation 387’ horizontal crack runs 15’+. Elevations 410’ & 425’ large horizontal cracks at cold joints hollow sounding concrete. Elevation 445’ a large spalled area of concrete was removed as a safety precaution with the void going through to the annular space. Elevation 453’ open cold joint loose aggregate paint coating is poor. Elevation 459’ shallow reinforced reinforcing steel spalled concrete. Elevation 460’ honeycombing to the concrete at the cold joint paint delamination continues.

It must be noted that Paint coating was noted as poor throughout all the inspection drops with delamination, peeling, cracking & weathering to the coating.

At elevation 130’ north one of the aircraft obstruction lights is not working and should be replaced. Elevation 235’ the AOL assembly the conduit has become loose at the connection nut.

The fabric expansion joints on the breeching duct was noted as satisfactory. The top of the breeching duct is allowing rain water to penetrate the cladding via open seams where the caulk sealant has failed. Numerous backer bar nuts were missing holding the breeching duct canvas fabric joint in place.

Core samples:

Elevation 120’ a core sample was taken at this location and filled in afterwards with none shrink grout.

Elevation 230’ north through the crack, observed going through the wall as seen in the open hole.

Elevation 356’ core sample taken and hole filled with grout.

Elevation 370’ core sample taken and hole is filled with none shrink grout.

Elevation 430 southwest a core sample was taken with the hole filled with none shrink grout.

Elevation 452’ core sample, please note that the sample was cracked throughout its full length.

III. Repair Recommendations

Recommendations for repair were made and the various items were assigned to a category based on the severity of the damage. The categories are as follows:

Category 1 - Damage which presently compromises the structural integrity or create a safety concern and therefore demands immediate attention; on an emergency basis (scheduled at first available opportunity).

Category 2 -Damage which requires attention; repairs should be made in a timely fashion. (Short term repairs scheduled within two (2) years.)

Category 3 -Damage which is not threatening to the structural integrity, nor would we anticipate deterioration to rapidly accelerate and therefore affect the structural integrity or substantially increase repair costs. (Long term repairs- scheduled within five (5) years.)

Category 1:

1. Repair all of the horizontal cracks and vertical cracks through the full height of the concrete column. Particular emphasis on all of the cold joints. These areas to be fully excavated with all cracks ground out using diamond saw blades & exposed reinforcing steel coated with rust inhibiting paint coating. The excavated prepared areas of the column should be then filled with a non shrink or flexible concrete patch material suitable for all weather conditions. Please see photographs: 1, 2, 7-10, 12-14, 16 ,18, 23, 36-38, 43-44, 53, 55-60, 63-64, 66 for further information
2. Thoroughly excavate all spalled areas located throughout the concrete column exterior. Note some of these areas penetrate the annular space at certain points. Apply rust inhibiting paint coating to all exposed reinforcing steel. Fill all voids in the concrete column with a non shrink concrete repair material suitable for all weather conditions. Please see photographs: 8-10, 16-17, 19-20, 24, 31, 33-34, 36, 40, 42, 47, 50-52, 62, 65 for further information.
3. Replace the non-working AOL Light located at the 130’ elevation with new LED units replace in pairs. Repair the loose conduit at the locking nut to the AOL light at the 265’ elevation. please see photo graphs # 3, 37 for further information.

Category 2:

1. Remove replace the damaged/missing caulk sealant to the top of the breeching duct cladding joints. Please see photograph 28 for further information.
2. Thoroughly prepare the exterior concrete column for painting after all crack, cold joints & spall and void repairs have been completed throughout the entire concrete column. Apply one (1) base coat of a elastomeric primer & one (1) top coat of elastomeric coating. Please refer to the photos through out this report for further information.
3. We would recommend that each of the stacks at the station be inspected internally/externally on a three year cycle.

Commonwealth Dynamics Limited can perform any or all of the recommended repairs, pricing for the repairs will be submitted separately. For questions about any of the repairs listed please feel free to contact us at any time.

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Trevor Grondin: Phone (250) 213-2834 trevor.grondin@icc-commonwealth.com

IV. PHOTO LOG AND COMMENTARY

NSPI
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

1. Major crack starts at approximately 85’ north

2. Large open crack at cold joint concrete is hollow along open joint

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

3. LED obstruction light only one unit working

4. Major crack continues up the concrete column. The crack has been patched in the past.

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Job number 2924

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5. Core sample hole at elevation 230’ note crack goes all the way through the shell.

6. Core sample hole at elevation 230’ was filled with grout after the core was extracted.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

7. Elevation 247'-6" north, horizontal crack at cold joint approx. 14' in length

8. Elevation 308' exposed damp concrete at cold joint which is cracked. Spall areas where moisture is getting into the column.

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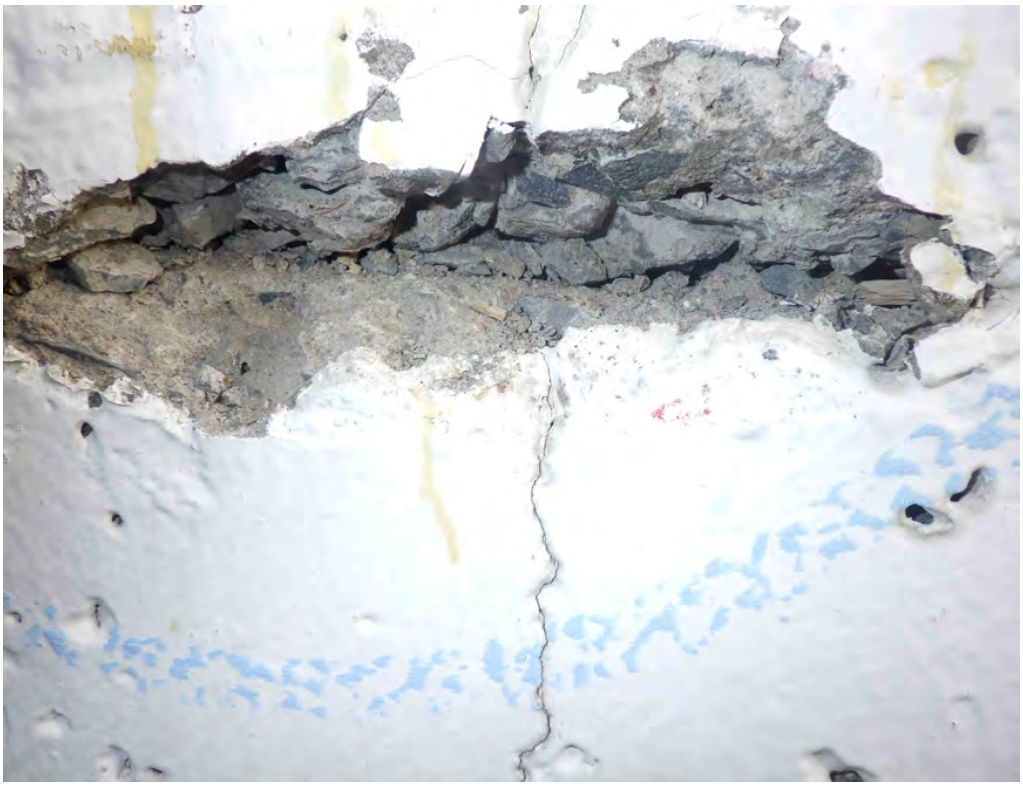
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA



9. Elevation 322’ deep spall at cold joint exposed concrete and aggregate.

10. Vertical hairline crake runs parallel to the larger crack, horizontal crack follows the cold joint, spalled area at cold joint should be repaired.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

11. Elevation 330’ horizontal cracking at the cold joint vertical cracks continue up the column, concrete is hollow sounding.

12. Elevation 338’ horizontal crack at cold joint open joints are hollow and concrete is damp.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

13. Elevation 390' open pocket along the seam at cold joint, likely from original construction, concrete hammer tests hollow and is damp.

14. Elevation 390' cold joint is cracked and open joint continues concrete is hollow and damp.

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Tufts Cove Generating station. Unit # 2
Job number 2924

15. Elevation 398’ major crack stops at this elevation multiple smaller cracks and hollow concrete either side of large, patched crack

16. Elevation 405’ large crack at cold joint exposed loose aggregate and poor mix and adhesion of original construction.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

17. Elevation 405' spalled concrete exposed reinforcing steel that is extremely close to the surface.

18. Elevation 413' large horizontal crack at cold joint concrete is hollow and soft.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

19. Elevation 442’ exposed reinforcing steel spalled concrete

20. Elevation 450’ loose spalled concrete removed as a safety precaution exposed rusting rebar is visible.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

21. Core sample taken at elevation 452’ showing the crack and inside coating.

22. Core sample shows center rebar in fair condition, please note the crack in the sample.

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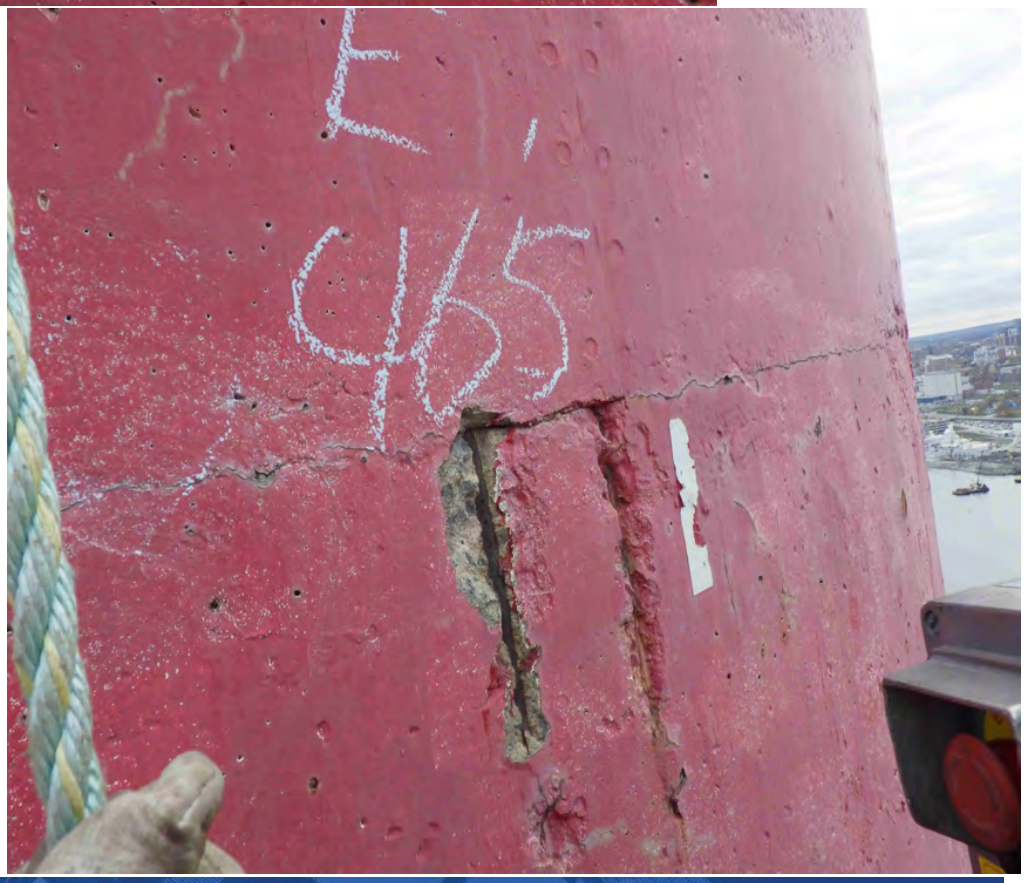
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

23. Elevation 465' horizontal crack and soft spalled concrete.



24. Elevation 465' exposed reinforcing steel due to rusting and spalls, one old and one new. The horizontal crack follows the cold joint.

NSPI
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

25. Elevation 475' numerous horizontal and vertical cracks evident to the top portion of the concrete column

26. 21' elevation, underside of breeching duct expansion joint fabric was satisfactory lower paint is very poor.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

27. Elevation 40’ missing connection hardware at expansion joint fabric back-er bar is broken.

28. Top of breeching duct rain-water is pooling on top of the duct, the sealant at the cladding is cracked allowing rainwater to get to the duct insulation and plate.

NSPI
Tufts Cove Generating station. Unit # 2
Job number 2924

29. Elevation 80’ vertical crack continues from base of column, cracked flaking paint and rust bleed through are evident.

30. The column coating is in poor condition exposing the concrete throughout this area.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

31. Elevation 120' the access hatch has a rusted steel frame, exposed bare concrete and rebar should be coated and sealed.

32. 135' vertical crack continues through this area.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

33. Elevation 165’ loose concrete spall at construction joint removed for safety purposes.

34. Elevation 180’ loose concrete removed exposed reinforcing steel curtain

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Tufts Cove Generating station. Unit # 2
Job number 2924

35. Elevation 195’ vertical crack continues with spalled concrete paint is missing.

36. Elevation 218’ exposed reinforcing curtain loose spalled concrete.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

37. Conduit is loose at locking nut on AOL

38. Elevation 293’ hollow cracked concrete at cold joint

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

39. Open crack at cold joint hollow soft concrete found by hammer testing.

40. Elevation 360’ open pocket at cold joint.

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

41. Elevation 382’ vertical crack continues with hairline horizontal cracks

42. Elevation 403’ another spalled area of concrete.

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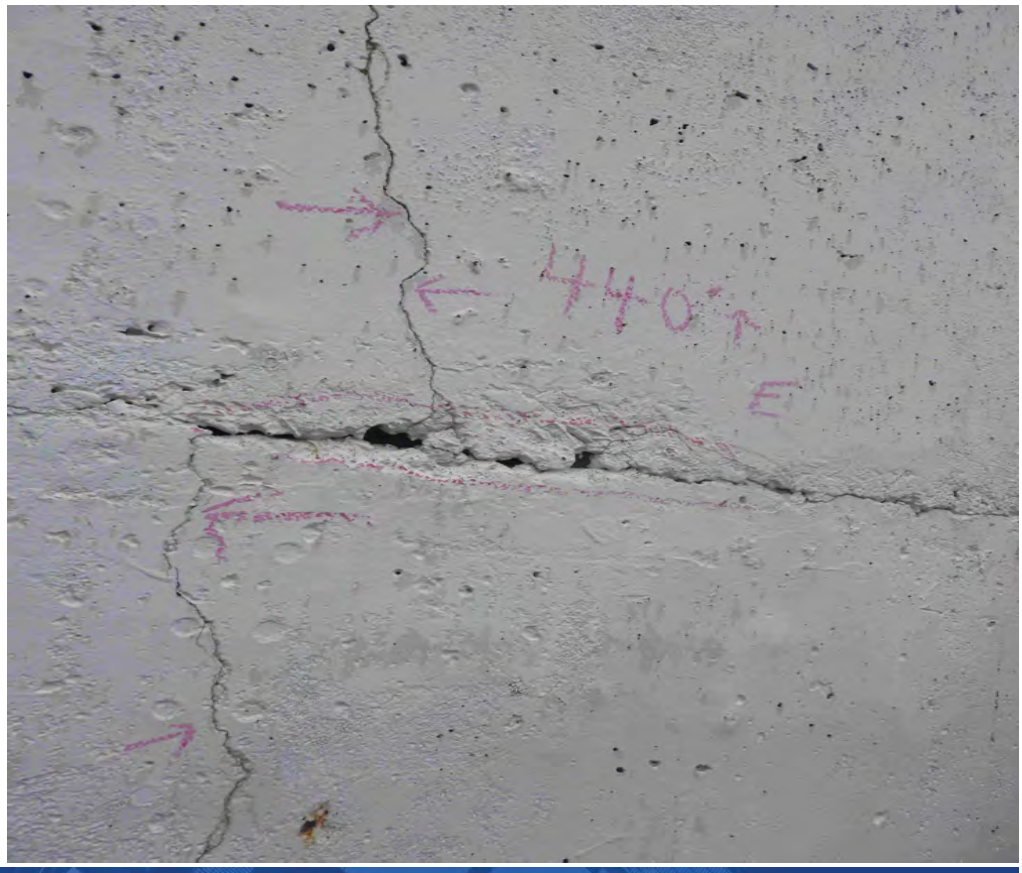
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

43. Elevation 418' large open void at cold joint exposing the rebar and allowing water into the concrete.



44. Elevation 440' vertical crack continues horizontal crack at cold joint

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Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

45. Elevation 455’ hollow concrete at cold joint delaminated paint coating

46. Looking toward the top of the column paint is delaminated cold joints are cracked and open

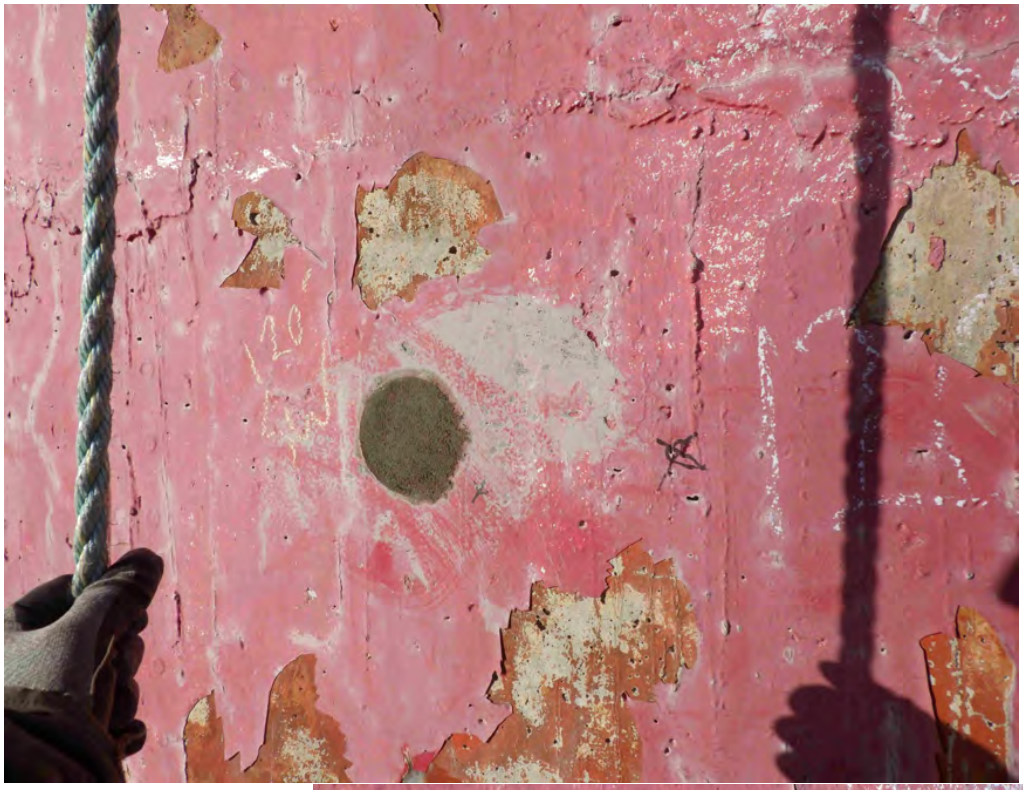
NSPI
Tufts Cove Generating station. Unit # 2
Job number 2924

47. Elevation 53’ old open voids exposed shallow reinforcing steel paint is faded and worn.

48. Looking up the concrete column the paint is delaminated and in poor condition throughout the height of the column.

NSPI
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA



49. Elevation 120’ a core sample was taken at this elevation and was filled in with none shrink grout note condition of paint coating is poor.

50. Elevation 190’ large spall exposed reinforcing steel paint coating is very poor

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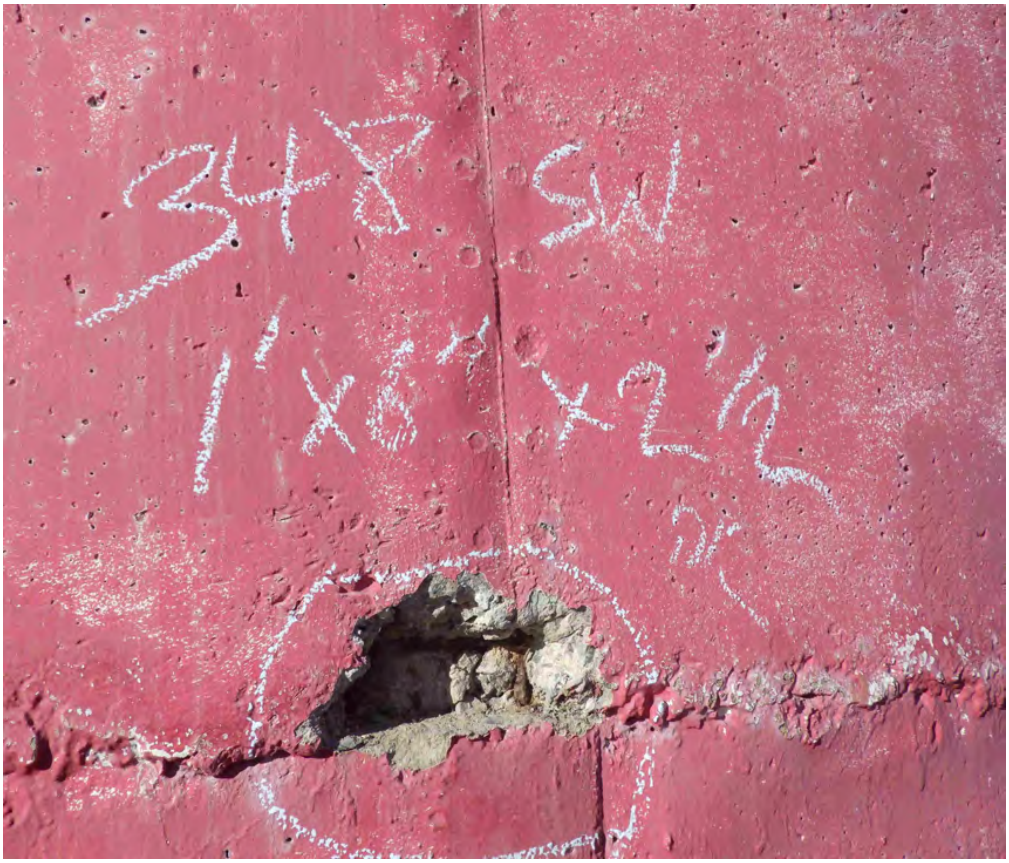
Tufts Cove Generating station. Unit # 2
Job number 2924

COMMONWEALTH CANADA

51. Elevation 334’ very shallow, exposed rebar has spalled out through the concrete.



52. Elevation 348’ exposed reinforcing steel spalled loose concrete at the cold joint.

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Job number 2924

COMMONWEALTH CANADA

53. Elevation 356’ open cold joint spalled loose concrete exposed reinforcing steel.

54. Elevation 370’ repaired core hole AOL was noted as satisfactory.

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Job number 2924

COMMONWEALTH CANADA

55. Elevation 372 ‘ horizontal crack runs through the cold joint for 15’ plus open to 3/4”

56. Elevation 380’ horizontal crack 10’ plus.

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Job number 2924

COMMONWEALTH CANADA

57. Elevation 387’ horizontal crack running 15’ plus

58. Elevation 387’ horizontal crack continues 15’ around the column.

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Job number 2924

COMMONWEALTH CANADA

59. Elevation 410’ large crack and void at the cold joint.

60. Elevation 425’ large hollow area of concrete at cold joint.

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Job number 2924

COMMONWEALTH CANADA

61. Elevation 430’ core sample taken in the horizontal crack then the hole was filled with none shrink grout .

62. Elevation 445’ large spalled concrete areas at cold joint excavated hole runs through to annular space.

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Job number 2924

COMMONWEALTH CANADA

63’ Elevation 453’ large open void at cold joint

64. Elevation 453’ horizontal crack at cold joint poor paint coating

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Job number 2924

COMMONWEALTH CANADA

65. Exposed shallow rebar flaking paint coating

66. Honeycombing to the concrete at the cold joint hollow concrete paint is thin and delaminated.

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Job number 2924

COMMONWEALTH CANADA

67. Honeycombing to the concrete and flaking paint, coating is thin and warn.

68. Weathered worn delaminated paint coating

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Job number 2924

COMMONWEALTH CANADA

69. Paint coating is weathered and delaminated

NSPI
Tufts Cove Generating station. Unit # 2
Job number 2924

45

COMMONWEALTH CANADA

August 6, 2025

NOVA SCOTIA POWER INC.
Tufts Cove Generating Station – Chimney Column Paint Removal, Concrete Repairs & Coating Application

TO: Connor Lebans, P. Eng.
Mechanical Engineer – Tufts Cove and CTs
Nova Scotia Power Inc. – Tufts Cove Generating Station
315 Windmill Rd.
Dartmouth, Nova Scotia B3A 3C5

CDL Proposal #: 25-6026

Dear Mr. Lebans;

Further to your verbal request, dated Apr. 17th 2025, Commonwealth Dynamics Limited is pleased to submit to you our budgetary proposal to remove existing coatings on a single TUC chimney column, repair concrete deficiencies and apply two coats of an epoxy paint system, in an effort to seal the exterior shell from future moisture infiltration. CDL has quoted this work, with the intent to conduct paint removal using our water blast and paint capture system. Our methodology offers maximum capture performance, with a high efficiency water filtration and recycling system. For the purpose of this proposal, it has been assumed that the first column recoating scope will occur in the Spring and Summer of 2026.

At Commonwealth Dynamics, we pride ourselves on the professionalism and quality of service that we provide to our customers. We appreciate the opportunity to offer you our assistance in this scope of work and look forward to being of further service. If you have any questions or comments concerning this proposal, please contact me at (250) 213-2834, or by e-mail; trevor.grondin@icc-commonwealth.com.

PROPOSED WORK SCOPE:

Crew Mobilization/Demobilization

A base crew of [redacted] employees will be required to mobilize tools and equipment at the Tufts Cove Generating Station in Dartmouth, NS. Further crew requirements will be supplemented by local trades (Labourers/Painters). All employees shall be required to complete the facility site specific and environmental training before starting work on the property. Mandatory training for workers includes; supervisor competency training (for supervisor only), first aid and CPR, working at heights, [redacted] high angle rope rescue and confined space entry training.

Phase 1 – Coating(s) Removal

[redacted] CDL will implement a water blast and capture system to remove the existing coating. This system has been used successfully on numerous projects, to ensure a full capture result, in environmentally sensitive locations. Water used to remove paint will be captured in vacuums and pumped through an industrial filter. Water will be reused, while solid materials will be retained in storage cylinders for client disposal. Crew members will begin at the top of the column and work systematically towards grade, removing 100% of the coating(s). The goal of this phase is to expose the bare concrete wall for further deficiency assessment.

Phase 2 – Concrete Repairs

Prior to applying the new coating system, it will be necessary to assess the concrete column and apply concrete repair strategies to seal cracks measuring [redacted] in width and any spall areas which are observed. Areas of severe delamination should be removed and properly repaired. Given that the quantity of concrete repairs is currently unknown, we have allotted [redacted] devoted to repairing [redacted] of cracking and [redacted] of spall repair. Repairs will be carefully mapped for future reference.

Phase 3 – Coating Application

Per manufacturers recommendations (International Paints), two (2) coats of paint will be applied to the prepared concrete surface. The primer coat (Interseal 670HS) will consist of two colours (International Orange and White) and will be applied in identical height, interchanging bands, per design specifications. The top coat (Interthane 990) will again be two separate colours and will be applied by roller and brush. [redacted]

TOTAL PRICE:

As part of our budgetary proposal, we have included a preliminary schedule for scope activities. It is expected that [redacted] shifts will be necessary to complete the entire scope outlined above. Our budgetary price to address a single column is:

PRICE: [redacted] **– CAD.**
Complete for Mob/Demob, Equipment, Labour, Materials Supervision & Engineering.
HST: Not included.

CLARIFICATIONS:

Our pricing for the proposed inspection work is based on the following clarifications:

- Quote is to be considered budgetary ±20%.
- Performing work during normal working hours [redacted] (7:00A – 7:00P).
- Pricing for entire scope is predicated on working [redacted]
- Does not include disposal of any solid waste.
- [redacted]
- [redacted]
- Owner must provide pretest of source water to ensure no lead in the source water.
- [redacted]
- Unobstructed access to the structure, no other contractors or personnel working near the structure.
- CDL to establish a 50’ exclusion zone around the perimeter of the chimney while exterior work is transpiring.
- Owner to provide adequate area for set-up, equipment and materials staging near base of chimneys.
- Owner to provide suitable washroom facilities.
- Owner to supply adequate source of electricity for lighting and tools (110v/220v) near base of chimney at no cost to COMMONWEALTH.
- No provision for exposure to or disturbance of hazardous material or related permits is contemplated or included in our price.
- CDL disclaims any liability for damage due to paint or concrete spatter, drift or droplets. No provision for protection of equipment or vehicles has been included. CDL will notify the plant on days when such work will take place and it is the responsibility of the plant to move or protect company or personal equipment or vehicles from the area around or down wind of the stack.

- Mutually agreed Terms and Conditions.
- All sales, use and other taxes such as GST & HST have not been included and will be invoices as a separate line item.
- All invoices are due net 30 days.

We wish to thank you for giving us the opportunity to be of service and if there are any questions feel free to contact us. We look forward to working with you.

Please visit us at: https://www.icc-commonwealth.com

Sincerely,
Trevor Grondin
Sales/ Construction
Commonwealth Dynamics Limited
1 Centre Street / Unit #116
Scarborough, On. M1J 3B4
Canada
250-213-2834
Trevor.grondin@ICC-Commonwealth.com

CI Number: C0080133

Title: TUC3 IP Turbine Refurbishment

Start Date: 2026/06
In-Service Date: 2027/11
Final Cost Date: 2028/05
Function: Steam
Forecast Amount: $2,588,734

DESCRIPTION:

This project is for component inspection, and refurbishment or replacement of components within the Intermediate Pressure (IP) turbine (such as rotor, casings, steam path, seals, bearings fasteners) on Tufts Cove Unit 3 to allow for the continued safe and reliable operation of the steam turbine.

The Tufts Cove Unit 3 turbine includes an Intermediate Pressure (IP) turbine, which converts the energy from the high-pressure, high-temperature steam received from the TUC3 boiler into mechanical energy which rotates the TUC3 generator, resulting in the production of electrical energy. The IP turbine sections are subjected to high temperature and pressure conditions and are subject to degradation over time by solid particle erosion (due to particles in the steam) and creep damage (due to continuous operation at high temperature, increased cycling and ramping of the unit).

This project is being filed at this time to allow for long lead turbine materials to be ordered in 2026 and arrive in 2027 for project execution.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects include "Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- No other projects in 2024, 2025, 2026, 2027 or 2028

Depreciation Class: Steam Production Plant – Tufts Cove 3

Estimated Life of the Asset: 30 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 1.42%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Refurbishment/Replacement

Why do this project?

The TUC3 steam turbine is forecast to accumulate over 314,000 operating hours and over 1985 start/stop cycles at the time of the next TUC3 planned 2027 major outage when this project will be completed. Unit utilization, the number of start/stop cycles and the risk profile of the assets at TUC3 have been used to identify the requirement for a turbine refurbishment. This project will provide current condition information to allow appropriate maintenance planning and risk assessment targeted to maintain the near-term and long-term safe reliable operation of the TUC3 turbine and mitigate the risk of unplanned outages.

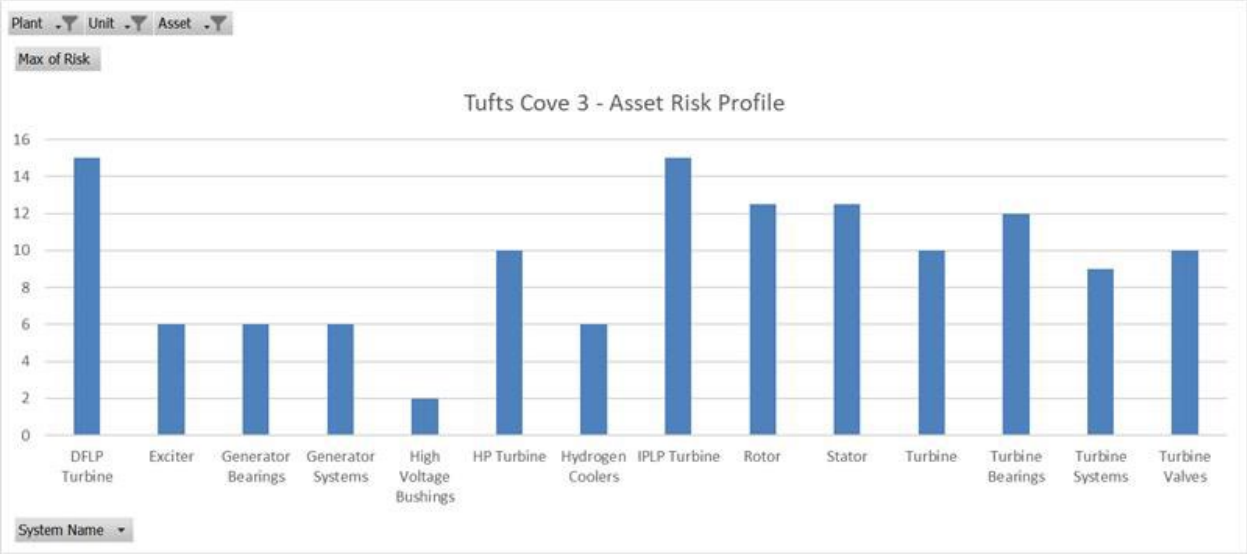
Why do this project now?

The TUC3 steam turbine is forecast to accumulate over 314,000 operating hours and over 1985 start/stop cycles at the time of the next TUC3 planned 2027 major outage when this project will be completed. This project is being filed at this time to allow for long lead turbine materials to be ordered in 2026 and arrive in 2027 for project execution. The last major inspection of these components occurred in 2017 at 258,000 hours of operation. The IP turbine will have operated in

excess of 50,000 hours since its last major inspection and will be due for overhaul in 2027 based on NS Power's asset management strategy.

Completing this project in a planned manner, assessing current conditions, and mitigating against the risks of unplanned failure is the preferred approach to complete this work. Completing the IP turbine refurbishment during the 2027 outage ensures TUC3 remains available to meet firm capacity requirements through 2030 and beyond, mitigating risks of unplanned outages and supporting system reliability during a critical transition period for the generation fleet.

Steam turbine overhauls are scheduled based on unit utilization (accumulated operating hours and cycles) and by known conditions within each unit. Below is a risk profile of Tufts Cove 3 steam turbine Intermediate Pressure (IP) Turbine components that shows risks associated within each. The risk profile shows that while the machine is due for inspection there are also components that require refurbishment or replacement in the IP sections to reduce operational risk including the IPLP and DFLP sections, which have been identified as high-risk areas likely requiring attention during this refurbishment.



Why do this project this way?

Inspection and refurbishment of the IP turbine components within appropriate time intervals and Original Equipment Manufacturer recommendations versus complete replacement of the turbine is the most cost-effective approach. This approach also ensures the continued safe and reliable operation of the steam turbine. In addition to maintaining the safe and reliable operation of the turbine, completing the IP turbine refurbishment during the 2027 planned outage will allow for efficient operation of the unit in alignment with NS Power's asset management strategy.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers and third-party consultants), previous experience with IP Turbine Refurbishment and the non-binding contingency guidelines. Consistent with maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 15 percent. The contingency will account for potential additional work scope from unexpected deterioration of components within the Turbine sections which is currently unknown without the inspections completed. Currently, the project scope is preliminary and is derived from the expected findings based on run hours, asset age, and previous similar project experience.

Capital Project Detailed Estimate

Location: Steam
CI# : C0080133
Title: TUC3 IP Turbine Refurbishment
Execution Year: 2026-2027

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	20	$ 420	$ 8,403		C0051136
Engineering	PD	100	$ 466	$ 46,601		C0051136
Maintenance Trades	PD	270	$ 427	$ 115,295		C0051136
Power Engineer	PD	20	$ 457	$ 9,136		C0051136
Power Plant Technician	PD	20	$ 439	$ 8,776		C0051136
Utilityworker	PD	90	$ 297	$ 26,769		C0051136
			Sub-Total	$ 214,980		
OT Labour						
Electrician	PD	10	$ 840	$ 8,403		C0051136
Maintenance Trades	PD	100	$ 854	$ 85,404		C0051136
Power Engineer	PD	10	$ 914	$ 9,136		C0051136
Power Plant Technician	PD	10	$ 878	$ 8,776		C0051136
Utilityworker	PD	45	$ 595	$ 26,769		C0051136
			Sub-Total	$ 138,488		
Materials						
TUC3 Turbine Outage Materials	lot	1	[redacted]		Attachment 1 , Page 8	
Consumables	lot	1	$ 10,000	$ 10,000		
Scaffolding/Insulation	lot	1	[redacted]			
			Sub-Total	[redacted]		
Contracts						
Pre-Planning and Scope Execution	lot	1	[redacted]		Attachment 2, Section 2.1	
Standard Blading Scope	lot	1	[redacted]		Attachment 2, Section 2.1	
Balancing and Machinery Dynamics	lot	1	[redacted]		Attachment 2, Section 2.1	
Scaffolding	lot	1	$ 75,000	$ 75,000		
Insulation	lot	1	$ 25,000	$ 25,000		
Grit Blasting Enclosure	lot	1	$ 10,000	$ 10,000		
Grit Blasting Services	lot	1	$ 25,000	$ 25,000		
Engineering - Metallurgy	lot	1	$ 25,000	$ 25,000		
Inspection - NDE Services	lot	1	$ 40,000	$ 40,000		
Borescope / FME Services	lot	1	$ 10,000	$ 10,000		
			Sub-Total	[redacted]		
Consulting						
Technical Advising Consultants	lot	1	$ 100,000	$ 100,000		
			Sub-Total	$ 100,000		
Other Goods & Services						
Contingency	%	15%	$ 2,068,960	$ 310,344		
			Sub-Total	$ 310,344		
Interest Capitalized						
AFUDC				$ 13,154		
			Sub-Total	$ 13,154		
Administrative Overhead						
Labour AO				$ 105,879		
Contractor AO				$ 90,397		
			Sub-Total	$ 196,277		
			SUB-TOTAL (no AO, AFUDC)	$ 2,379,304		
			TOTAL (AO, AFUDC included)	$ 2,588,734		
Original Cost				$ 1,326,571		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER An Emera Company

Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Process Industries	Required fields:	Estimate Classification				
Project Name: TUC3 IP Turbine Refurbishment	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Non-Process Facilities (Infrastructure, Ports, Pipeline, Power Transmission)	Not Applicable (NA)					
Project Scope of Work Description	Preliminary (P)	P	P			
Byproduct and Waste Disposal	Not Applicable (NA)	NR				
Site Infrastructure (Access, Construction Power, Camp, etc.)	Not Applicable (NA)	NR				
B. Capacity						
Plant Production/Facility (includes power facilities)	Not Applicable (NA)					
Electrical Power Requirements (when not the primary capacity driver)	Not Applicable (NA)	NR				
C. Project Location						
Plant and Associated Facilities	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Communication Systems	Not Applicable (NA)	NR				
Fire Protection and Life Safety	Not Applicable (NA)	NR				
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Process Technology	Not Applicable (NA)					
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
Logistics Plan	Not Applicable (NA)					
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Not Applicable (NA)	NR				
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Not Applicable (NA)	NR				
Risk Register	Not Applicable (NA)	NR				
Stakeholder Consultation/Engagement/Management Plan	Not Applicable (NA)	NR				
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Block Flow Diagrams	Not Applicable (NA)					
Equipment Data Sheets	Complete (C)	NR/S	P	C	C	C
Equipment Lists: Electrical	Not Applicable (NA)	NR/S				
Equipment Lists: Process/Utility/Mechanical	Complete (C)	NR/S	P	C	C	C
Heat & Material Balances	Not Applicable (NA)	NR				
Process Flow Diagrams (PFDs)	Not Applicable (NA)	NR				
Utility Flow Diagrams (UFDs)	Not Applicable (NA)	NR				
Design Specifications	Complete (C)	NR	S/P	C	C	C
Electrical One-Line Drawings	Not Applicable (NA)	NR				
General Equipment Arrangement Drawings	Not Applicable (NA)	NR				
Instrument List	Not Applicable (NA)	NR				
Piping & Instrumentation Diagrams	Complete (C)	NR	S/P	C	C	C
Plot Plans/Facility Layouts	Complete (C)	NR	S/P	C	C	C
Construction Permits	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Fire Protection & Life Safety Drawings & Details	Not Applicable (NA)	NR				
Electrical Schedules	Not Applicable (NA)	NR	NR/S			
Instrument & Control Schedules	Not Applicable (NA)	NR	NR/S			
Instrument Data Sheets	Not Applicable (NA)	NR	NR/S			
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listings	Preliminary (P)	NR	NR	P	P/C	
Electrical Discipline Drawings	Not Applicable (NA)	NR	NR			
Facility Emergency Communication Plan & Drawings	Not Applicable (NA)	NR	NR			
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Mechanical Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	2	11	11	11	10
	% Defined/Complete towards Class Estimate	100%	100%	92%	92%	92%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 92% of Class 3 deliverables have been completed. A contingency value of 15% was selected to account for risks related to project scope. Currently, the project scope is preliminary and is derived from the expected findings based on run hours, asset age, and previous similar project experience.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *process industries* is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs), piping and instrument diagrams (P&IDs), and electrical one-line drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information. This RP applies to a variety of project delivery methods such as traditional design-bid-build (DBB), design-build (DB), construction management for fee (CM-fee), construction management at risk (CM-at risk), and private-public partnerships (PPP) contracting methods.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this recommended practice may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

Most plants also have significant electrical power equipment (e.g., transformers, switchgear, etc.) associated with them. As such, this RP also applies to electrical substation projects, either associated with the process plant, as part of power transmission or distribution infrastructure, or supporting the power needs of other facilities. This RP excludes power generating facilities and high-voltage transmission.

SIEMENS energy

Siemens Energy Canada Limited
Gas Services
1577 North Service Road East,Floor 3
Oakville, Ontario, L6H 0H6/Canada

QUOTATION

SIEMENS QUOTATION NO.	DOCUMENT DATE
20081872	17-Jun-2025

Authorized Signature

SOLD TO: (635927)
NOVA SCOTIA POWER INC
PO Box 910
HALIFAX NS B3J 2A8

BILL TO: (635927)
NOVA SCOTIA POWER INC
PO Box 910
HALIFAX NS B3J 2A8

SHIP TO: (635927)
NOVA SCOTIA POWER INC, AN EMER
TUFTS COVE GENERATING STN
315 WINDMILL RD
DARTMOUTH NS B3A 1H3

VALID TO DATE
20-Jul-2025
CUSTOMER DOCUMENT NO.
Email
SALES CONTACT
CONTACT TEL NO.
GST#/QST#
GST# 77231 0736 RT0004 * QST# 1226918872 TQ0004

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
	SECL REFERENCE #: SF252403687 ATTN: GREG CARLIN				
0010	SMC64367.005 GLAND RING-9/16" Pit ch-9 Contacts GLAND RING 9/16" Pitch (9 contacts) [1 Ring = 6 Segs] Assy Drawing No.: SMC64367 ITEM 5 Detail Drawing No.: 22MC61617	1 EA	[redacted]	36 Weeks	[redacted]
0020	SMC64367.006 GLAND RING-9/16" Pit ch-5 Contacts	3 EA	[redacted]	36 Weeks	[redacted]

Siemens Energy Canada Ltd obligation to fulfill this agreement is subject to the proviso that the fulfillment is not prevented by any impediments arising out of national and international foreign trade and customs requirements or any embargos [or other sanctions].
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QUOTATION

SIEMENS QUOTATION NO.	DOCUMENT DATE
20081872	17-Jun-2025

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
	. GLAND RING 9/16" Pitch (5 contacts) [3 Rings = 18 Segs] Assembly Drawing No.: SMC64367 ITEM 6 Detail Drawing No.: 22MC61618				
0030	JZZ:GENS SPRING FOR MK5	36 EA	[redacted]	18 Weeks	[redacted]
	. SPRING No 206 Assembly Drawing No.: SMC64367 ITEM 9 Detail Drawing No.: 38611-643				
0040	JZZ:GENS SPRING FOR MK6	90 EA	[redacted]	18 Weeks	[redacted]
	. SPRING NO 208 Assembly Drawing No.: SMC64367 ITEM 10 Detail Drawing No.: 38611-625				
0050	JZZ:GENS GLAND RING	10 EA	[redacted]	52 Weeks	[redacted]
	. STEAM PIPE GLAND RING Assembly Drawing No.: SMC64000 ITEM 3 Detail Drawing No.: 83UC61502				
0060	JZZ:GENS METAFLEX JOINT	2 EA	[redacted]	16 Weeks	[redacted]
	. METAFLEX GASKET - TYPE 'C' Assembly Drawing No.: SMC64000 ITEM 4				

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QUOTATION

SIEMENS QUOTATION NO.	DOCUMENT DATE
20081872	17-Jun-2025

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
0070	JZZ:GENS Stud Bolts 1-1/4"UN8 , A=7-1/2" for MK 1 --- . 1.1/4" UN8 RELIEVED STUDBOLT A = 7.5" Assembly Drawing No.: SLC64550 ITEM 14 Detail Drawing No.: CTU051-01	24 EA	[redacted]	20 Weeks	[redacted]
0080	JZZ:GENS Stud Bolts for MK 3 (3/4" UNF) --- . 5/8" UNF STUDBOLT A = 5 Assembly Drawing No.: SLC64550 ITEM 15 Detail Drawing No.: CTU030-01	16 EA	[redacted]	18 Weeks	[redacted]
0090	JZZ:GENS Cap Nut for MK 14 --- . 1.1/4" UN8 CAP NUT (STANDARD) Assembly Drawing No.: SLC64550 ITEM 17 Detail Drawing No.: CTU250-05	48 EA	[redacted]	20 Weeks	[redacted]
0100	JZZ:GENS 3/4" UNF Nuts for MK 15 --- . 3/4" UNF NUTS Assembly Drawing No.: SLC64550 ITEM 18	4 EA	[redacted]	16 Weeks	[redacted]
0110	SMC64036.002 DIAPHRAGM --- .	2 EA	[redacted]	16 Weeks	[redacted]

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QUOTATION

SIEMENS QUOTATION NO.	DOCUMENT DATE
20081872	17-Jun-2025

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
	DIAPHRAGM Assembly Drawing No.: SMC64036 ITEM 2 Detail Drawing No.: 28UC61501				
0120	SMC64036.003 Sealing Ring (5/8" S ection Dia) --- . O' RING 14.5" I/D x 5/8" DIA. SECTION Assembly Drawing No.: SMC64036 ITEM 3	2 EA	[redacted]	18 Weeks	[redacted]
0130	JZZ:GENS SPECIAL STUD BOLTS 2 .1/4"UN --- . 2.1/4"UN SPECIAL STUD A=13.13/16" Assembly Drawing No.: 20MC61646 ITEM 17 Detail Drawing No.: CTU190-03	2 EA	[redacted]	20 Weeks	[redacted]
0140	JZZ:GENS STUD BOLT 2.3/4"UN --- . 2.3/4" UN STUDBOLT A = 24" Assembly Drawing No.: 20MC61646 ITEM 18 Detail Drawing No.: CTU195-02	4 EA	[redacted]	20 Weeks	[redacted]
0150	JZZ:GENS FITTING STUD BOLT 2. 3/4"UN --- . 2.3/4" UN FITTING STUDBOLT A = 24.1/2" Assembly Drawing No.: 20MC61646 ITEM 19 Detail Drawing No.: CTU068-02	2 EA	[redacted]	20 Weeks	[redacted]

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ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
0160	JZZ:GENS STUDBOLT A - 19" --- . 2.1/2" UN STUDBOLT A = 19" Assembly Drawing No.: 20MC61646 ITEM 20 Detail Drawing No.: CTU195-01	2 EA	[redacted]	20 Weeks	[redacted]
0170	JZZ:GENS STUD A-13.1/4 --- . 2.1/2" UN STUD A=13.1/4" Assembly Drawing No.: 20MC61646 ITEM 21 Detail Drawing No.: CTU191-01	2 EA	[redacted]	20 Weeks	[redacted]
0180	JZZ:GENS STUD A-7.1/2" --- . 1.1/2" UN STUD A=7.1/2" Assembly Drawing No.: 20MC61646 ITEM 22 Detail Drawing No.: CTU038-03	2 EA	[redacted]	20 Weeks	[redacted]
0190	JZZ:GENS SPECIAL STUD A-801/2 " --- . 2" UN8 SPECIAL STUD A=8.1/2" Assembly Drawing No.: 20MC61646 ITEM 23 Detail Drawing No.: CTU190-02	2 EA	[redacted]	20 Weeks	[redacted]
0200	JZZ:GENS STUDBOLT A - 11.5/8" --- . 2" UN8 SPEC. STUDBOLT A=11.5/8"	4 EA	[redacted]	20 Weeks	[redacted]

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20081872	17-Jun-2025

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
	Assembly Drawing No.: 20MC61646 ITEM 24 Detail Drawing No.: CTU194-02				
0210	JZZ:GENS FITTING STUD BOLT A-12.1/8" . 2" UN FITTING STUDBOLT A=12.1/8" Assembly Drawing No.: 20MC61646.025 Detail Drawing No.: CTU067-02	2 EA	[redacted]	20 Weeks	[redacted]
0220	JZZ:GENS RELIEVED STUD A-7" . 1.1/2" UN8 RELIEVED STUD A=7" Assembly Drawing No.: 20MC61646 ITEM 28 Detail Drawing No.: CTU038-03	6 EA	[redacted]	20 Weeks	[redacted]
0230	JZZ:GENS SPECIAL SCREWS L-1.7/8" . 1" UNF SPECIAL SCREWS L=1.7/8" Assembly Drawing No.: 20MC61646.041 Detail Drawing No.: 20AU1586	2 EA	[redacted]	18 Weeks	[redacted]
0240	JZZ:GENS SPECIAL SCREWS L-3.7/8" . 3/4" UNF SPECIAL SCREWS L=3.7/8" Assembly Drawing No.: 20MC61646.042 Detail Drawing No.: 20AU1586	2 EA	[redacted]	18 Weeks	[redacted]

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20081872	17-Jun-2025

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
0250	JZZ:GENS STUDBOLT A-19.1/2" --- . 2.3/4" UN STUDBOLT A = 19.1/2" Assembly Drawing No.: 20MC61646.043 Detail Drawing No.: CTU195-02	2 EA	[redacted]	20 Weeks	[redacted]
0260	JZZ:GENS STUDBOLT A-13.1/2" --- . 2" UN8 SPEC. STUDBOLT A=13.1/2" Assembly Drawing No.: 20MC61646.055 Detail Drawing No.: CTU194-02	2 EA	[redacted]	20 Weeks	[redacted]
0270	JZZ:GENS STUD A-11.3/16" --- . 2.1/4" UN6 STUD A=11.3/16" Assembly Drawing No.: 20MC61646.056 Detail Drawing No.: CTU190-03	2 EA	[redacted]	20 Weeks	[redacted]
0280	SMC64367.007 Gland Ring 11/16" Pi tch (11 contacts) --- . GLAND RING 11/16" Pitch (11 contacts) [1 Ring = 6 Segs) Assembly Drawing No.: SMC64367 ITEM 7 Detail Drawing No.: 22MC61622	1 EA	[redacted]	36 Weeks	[redacted]
0290	SMC64367.008 Gland Ring 11/16" Pi tch (5 contacts) ---	3 EA	[redacted]	36 Weeks	[redacted]

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20081872	17-Jun-2025

ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE
	. GLAND RING 11/16" Pitch (5 contacts) [3 Rings = 18 Segs) Assembly Drawing No.: SMC64367 ITEM 8 Detail Drawing No.: 22MC61621				
HST		14.000 %	[redacted]		[redacted]
		Final Net Amount:			[redacted]

Currency	CAD
Terms of Payment	Within 35 days Due net
Terms of Delivery	DDP -
Terms and Conditions	Siemens Energy Canada Ltd Standard terms and conditions apply unless otherwise noted. If you have any questions or concerns, please contact your Siemens Energy Canada Ltd. representative.

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QA REQUIREMENTS

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ISO 9001 2015

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TERMS & CONDITIONS

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SPARE REFERENCE:

Detail Drawing Numbers followed by "SPARE" denotes that the item is being supplied, with additional material on the mating surface or oversized, for final site sizing to ensure fit is as per original design intent.

Please ensure the Purchase Order includes the quoted drawing number followed by SPARE to capture this condition.

.

PRICE:

A minimum order value of $750 Cdn applies.

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ITEM	MATERIAL	QTY	PRICE	LEAD TIME	EXT PRICE

Price shown includes any import duties that may be applicable, DDP TUFTS COVE, NSPI, but do not include any taxes or tariffs.

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Price shown is based on the items AND quantities quoted. Should the number of items and/or order quantities differ from the those quoted, we reserve the right to amend the prices accordingly.

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Siemens Energy's pricing is subject to adjustment for the impact of any new or modified taxes, duties, tariffs or equivalent measures imposed by any local or foreign governmental authority which is applicable to our offering, including any portions or components contained within the offering.

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VALIDITY:

This proposal is valid for a period of 30 days from date of submission, unless extended, modified or withdrawn by Siemens Energy Canada Limited and limits acceptance to the terms set forth herein.

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However, Siemens Energy reserves the right to revise pricing or lead time during this validity period in response to market conditions.

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PAYMENT TERMS:

Net 30 days

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TARIFFS:

The offered price does not include any taxes, or tariffs, or equivalent measures (including by way of executive order, legislation, regulation or order in council) by any local or foreign governmental authority (including to any components or raw materials, contained in or any part of the goods) imposed, enacted or announced after January 1, 2025 ("Tariffs") on imports or exports affecting the delivery and manufacturing of the offered good or its components including at any tier of a sub-supplier. Siemens Energy will issue an additional invoice for the cost of the Tariffs once the impact is known and calculated.

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In addition, should the cost or time of performing the Work increase due to (i) any new or modified Tariffs, on any portion of the Work supplied under this Agreement (ii) changes made to the sourcing plan in order to mitigate the impact of Tariffs, (iii) demonstratable market price increases attributable to the application of such Tariffs or (iv) any rules, regulations or processes for persons entering the Canadian border are imposed, modified or changed, then, in each case, to the extent any of the same impacts Siemens Energy's price, schedule, obligations or performance under this Contract, Siemens Energy shall be entitled to a change

QUOTATION

SIEMENS QUOTATION NO.	DOCUMENT DATE
20081872	17-Jun-2025

ITEM	MATERIAL	QTY	LEAD TIME PRICE	EXT PRICE

order for an equitable adjustment in prices and times for performance to fully compensate Siemens Energy for the increased costs of, or time to perform the Work.

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CONDITIONS OF SALE:

Terms and Conditions as defined and agreed upon in the Master Services Agreement (MSA), between Nova Scotia Power Inc. and Siemens Canada Ltd. effective April 2, 2019 shall apply, except as modified in this proposal.

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The Parties acknowledge that there is an uncertain political and security situation in the world, in particular due to the invasion of Ukraine (""Uncertain Situation""), for which effects are difficult to foresee at the time of Contract signing and which can directly and indirectly affect the execution of this Contract including but not limited to the availability of certain equipment, commodities, metals, and materials as well as the availability of transportation means and services. In the light of the above, and in case of any public health event, contagion, pandemic, epidemic, endemic, outbreak (whether known or unknown) or quarantine, the Parties agree that Siemens Energy shall be entitled to reasonable adjustments of the delivery term(s) and/or the Contract price(s) to the extent any delay and costs are caused directly or indirectly by the above-mentioned Uncertain Situation and/or any related consequences.

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Notwithstanding anything to the contrary in any other agreements between the parties, if (i) any new or change to any law, rule, regulation, code, standard, order, judgement, or requirement, (including the interpretation of the same); (ii) any new or modified taxes, duties, tariffs, or equivalent measures (including by way of executive order) are imposed by any local or foreign governmental authority (including to any components contained in or any part of the goods); (iii) any rules, regulations or processes for persons entering the Canadian border are imposed, modified or changed, then, in each case, to the extent the same impacts Siemens Energy Canada Limited's (SECL) price, schedule, obligations or performance under this Contract SECL shall be entitled to a change order for an equitable adjustment in prices and times for performance.

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Feel free to contact us should you have any questions. We look forward to receiving your instructions to proceed.

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Regards,

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Singh Hemlata

Digitally signed by Singh Hemlata
DN: cn=Singh Hemlata, o=Siemens, email=hemlata.singh@siemens-energy.com
Date: 2025.06.23 08:37:26 -04'00'

Sokoloski Nikolas

Digitally signed by Sokoloski Nikolas
DN: c=DE, st=Bayern, o=Siemens, 2.5.4.97=NTRDE-HRB 6684, email=nikolas.sokoloski@siemens-energy.com, serialNumber=Z003MFYS, givenName=Nikolas, sn=Sokoloski, cn=Sokoloski Nikolas
Date: 2025.06.23 09:09:04 -04'00'

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Hemlata Singh

Parts Business Leader | hemlata.singh@siemens-energy.com

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Customer	Nova Scotia Power
Proposal Description	2026 TUC3 IP Major
Submission Date	April 3, 2025
Prepared By	Luca Del Sordo Bid Management Specialist

Siemens Energy Canada Limited
Power Generation Services
1577 North Service Road East
Oakville, Ontario L6H 0H6

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April 3, 2025

Neil Gallant
Nova Scotia Power Inc.
Capital Projects Manager
neil.Gallant@nspower.ca

Subject: **2026 TUC3 IP Major**
Siemens Energy Reference Number SF252356064

Dear Neil Gallant,

Siemens Energy Canada Limited (hereinafter, "Siemens Energy") appreciates the opportunity to present this proposal to Nova Scotia Power for the services described therein.

A review of this proposal will demonstrate the overall value of working with Siemens Energy on your unit and our significant value-added benefits to customers. As the original equipment manufacturer (OEM) of these units, Siemens Energy possesses all the original design and baseline information, which enable us to recommend the most appropriate maintenance and service offerings that will yield the highest unit availability and reliability. Our field engineers and technicians are fully trained and qualified on Siemens Energy generating equipment and represent the best personnel in the industry for servicing and maintaining that equipment. We are confident of our ability to deliver the highest quality service.

The information contained in this proposal and all related documents is proprietary and confidential information that belongs to Siemens Energy. This information is being disclosed to you for the specific purpose of your evaluation of Siemens Energy as a contractor for a particular project. By reviewing the information contained in these documents, you agree to be bound to a confidentiality obligation with respect to this information. Specifically, you hereby agree that (1) you will treat this information with the same level of care as you treat your own proprietary information; (2) you will not disclose this information to third parties without the prior written consent of Siemens Energy; and (3) you will not use this information for any purpose beyond evaluating Siemens Energy as a contractor and/or contracting with Siemens Energy for the particular project quoted herein.

The above terms supersede any click-wrap or other terms not expressly set forth in a signed agreement between the parties covering the proposal. All such click-wrap or other terms are expressly rejected by Siemens Energy.

Thank you for considering Siemens Energy to perform this service. We look forward to working on Nova Scotia Power's unit. Siemens Energy will be pleased to discuss this proposal, at your convenience, or any questions about our experience or capabilities. Please feel free to contact me if you have any questions regarding this proposal.

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With best regards,
Chris Holloway

Siemens Energy Canada Limited
Siemens Energy Gas Services
Mobile: +1 (709) 727-2526
mailto:chris.holloway@siemens-energy.com

EBA Technical	EBA Commercial
Luca Del Sordo Digitally signed by Luca Del Sordo DN: cn=Luca Del Sordo, c=CA, email=luca.del-sordo@siemens-energy.com Date: 2025.04.03 11:07:45 -04'00'	Rachel denBak Digitally signed by Den Bak Rachel DN: cn=Den Bak Rachel, c=DE, o=Siemens, email=rachel.denbak@siemens-energy.com Date: 2025.04.04 11:08:20 -04'00'

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Revision History

Date	Rev	Summary	Issued By
April 3, 2025	0	Original Issue	C. Holloway

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1.0 Executive Summary

Siemens Energy will be offering the following scope of services for the Nova Scotia Power 2026 Tufts Cove 3 IP Major outage:

1.1 Pre-Planning

Siemens Energy to provide the following resources for pre-planning:

- One (1) Remote Project Manager working a shift schedule of 1x8x5 for five (5) days.
- One (1) Engineer working a shift schedule of 1x8x5 for four (4) weeks.

Pre-Planning Deliverables

- Schedule (including for base scope activities)
- Work Plans for Base Scope
- Contingency (planning / unplanned) can be added as specified by NSP.
- Work Plan (issued for customer review – IFR) to be issued no less than 2 months prior to breaker open.
- Preliminary schedule (Level 1) to be issued with IFR work plans

1.2 Outage Base Scope

Bearings

- Clean, inspect, and replace if needed
    - Replacement with station spares

NSP to advise if bearings are available and machined to 80%

Casing Elevation

- Clean, inspect and laser elevation checks

SECL to advise impact to support laser elevation checks

Rotor Bore Inspection

- Clean, inspect, and Phased Array Ultrasonic testing (PAUT) of Blade Grooves

SECL to advise if boresonic is required for spindle with approximately 60K hours.

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Spindle

- Clean and conduct blade Inspection
- Clean, inspect - Low Speed Balance

SECL to advise impact to support blader scope (weld repair and/or replacement) pending blade visual inspection

SECL to advise impact to support low speed balance of the spindle.

1.3 Site Safety Discussion

NSPI to provide site specific safety orientation for Siemens Energy personnel. Siemens Energy will work under the NSPI Health and Safety Manual as well as the SECL Health and Safety Manual. NSPI will provide site specific (safety) related coverage during the outage. Fatigue management should be discussed as the outage is scheduled for greater than seven (7) days.

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2.0 Commercial Considerations / Pricing

2.1 Pricing

Siemens Energy is pleased to offer the following pricing to Nova Scotia Power to perform the scopes of work as detailed in Section 1 of this proposal.

Item	Work Scope Description	Price Basis	Price (1-2)
1	Pre-planning and Base Scope Execution	T&M	$[redacted]
2	Standard Blading Scope	T&M	$[redacted]
3	Balancing and Machinery Dynamics	T&M	$[redacted]
		Total	**$[redacted]**

(1) Price is quoted in 2025 CAD as per 2025 MSA Rates. MSA Rates in effect at the time of execution shall apply.
(2) T&M invoices will be invoiced per the MSA.

2.2 Quality Program

This offer is based on a Quality Program in accordance with ISO 9001:2015.

2.3 Environmental, Health & Safety

This offer is based on Siemens Energy "Zero Harm" program and in accordance with COR Certification Requirements.

2.4 Terms and Conditions

Terms and Conditions as defined and agreed upon in the Master Services Agreement (MSA), between Nova Scotia Power Inc. and Siemens Energy Canada Ltd., shall apply to the work scope in this proposal.

2.5 Tariff Clause

Notwithstanding anything to the contrary in any other agreements between the parties, if (i) any new or change to any law, rule, regulation, code, standard, order, judgement, or requirement, (including the interpretation of the same); (ii) any new or modified taxes, duties, tariffs, or equivalent measures (including by way of executive order) are imposed by any local or foreign governmental authority (including to any components contained in or any part of the goods); (iii) any rules, regulations or processes for persons entering the Canadian border are imposed, modified or changed, then, in each case, to the extent the same impacts Siemens Energy Canada Limited's (SECL) price, schedule, obligations or performance under this Contract SECL shall be entitled to a change order for an equitable adjustment in prices and times for performance.

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CI Number: C0068888

Title: TUC3 Continuous Ash Hauling System

Start Date: 2026/01
In-Service Date: 2026/09
Final Cost Date: 2027/03
Function: Steam
Forecast Amount: $1,359,984

DESCRIPTION:

The scope of this project is to install a drag chain conveyor system on the TUC 3 Electrostatic Precipitator (ESP) unit to facilitate continuous extraction of oil fly ash. The TUC 3 ESP's function is to remove fly ash particulate from the gas expelled by the boiler. This change will provide a new internal ash collection process using live bottom trailers for collection and transportation.

The current design of the ESP hoppers is to store collected fly ash for a short term only. Fly ash should be removed on a daily basis to avoid potential ash pluggage and handling issues. The current system requires an external vacuum truck to be mobilized to site daily (when TUC 3 is using Heavy Fuel Oil) to collect ash manually. This truck is then connected to the ESP hoppers and hauls ash to an external metal bin.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Steam projects include "Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example)."

- No other projects in 2024, 2025, 2026, 2027 or 2028

Depreciation Class: Steam Production Plant – Tufts Cove 3

Estimated Life of the Asset: 25 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.19%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement /Refurbishment

Why do this project?

This project is required as the current method of handling fly ash downstream of the hoppers poses risk to the reliability of the precipitator system and incurs high operational and maintenance costs.

The current ash collection process involves allowing the ash hoppers to fill with ash for 12-16 hours and then having a contractor come to site with a vacuum truck to pull ash from the hoppers into an external collection bin. Ash hoppers are not designed to store ash for a long period of time – this can cause bridging, clogging, ignition of ash, etc. Bridging and clogging can lead to inoperable ash hauling conditions which in turn can cause heat damage to the internals of the precipitator. Timely removal of ash from the hoppers is imperative.

In recent years, the seasonal use of heavy fuel oil has increased, and the operating costs associated with the manual process and contractor services have increased significantly. This project has been developed to reduce the use of contractor services and simplify the removal and transportation of heavy oil fly ash collected in Unit 3 ESP. Ongoing constraints and price volatility in natural gas imports have made HFO a critical alternative. During extended periods of elevated natural gas prices or supply disruptions, HFO may be used continuously, making the ash collection and removal system essential for maintaining fleet capacity.

Why do this project now?

This project is necessary at this time due to the increasing reliance on heavy fuel oil (HFO) at Tufts Cove, driven by ongoing volatility in natural gas prices and availability. HFO has become a critical alternative fuel to ensure fleet capacity is maintained. However, the existing fly ash hauling system is designed for intermittent use and cannot efficiently support the sustained demands associated with higher HFO consumption. Expanding the use of vacuum trucks to manage the increased ash volume would result in significantly higher operational costs and introduce additional safety risks associated with increased operator exposure to fly ash. Installing a dedicated ash conveyance and collection system will allow the facility to more efficiently manage the increased ash output by reducing operating cost and reducing safety risks of operation by minimizing exposure to fly ash.

Why do this project this way?

The alternatives that NS Power considered were a pneumatic system and a mechanical drag chain system. In discussion with industry experts, it was advised that NS Power proceed with a mechanical drag chain system as damp fly ash would quicky compromise the functionality of a pneumatic ash conveyance system. A conveyor system can handle potentially damp ash and has a lower likelihood of plugging. The mechanical drag conveyor was recommended over other conveyors, such as a screw conveyor or belt conveyor, because drag conveyors are relatively compact, fully sealed, capable of handling high heat, and allow for long spans. Belt conveyors will not handle higher heat materials and are not sealed. Screw conveyors are limited on length without the use of hanger bearings which should be avoided due to high maintenance requirements and low operational reliability. Drag chain systems are mechanically simpler than other options, therefore reducing maintenance requirements.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers and third-party consultants) and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 15 percent. The contingency addresses risks related to the scope as some modifications may be required during the detailed design phase of the project; however, the pricing in place is a fixed cost awarded via request for proposal (RFP) through a design/build contract. Multiple vendors were engaged during the RFP to ensure best pricing and solution quality

Capital Project Detailed Estimate

Location: Steam
CI# : C0068888
Title: TUC3 Continuous Ash Hauling System
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	60	$ 420	$ 25,210		
Engineering	PD	60	$ 466	$ 27,961		
Maintenance Trades	PD	5	$ 427	$ 2,135		
Utilityworker	PD	25	$ 297	$ 7,436		
			Sub-Total	$ 62,741		
Materials						
Conveyance System	lot	1	[redacted]		Attachment 1, Page 6	
Electrical Materials	lot	1	$ 100,000	$ 100,000		
Platform Materials	lot	1	$ 15,000	$ 15,000		
			Sub-Total	[redacted]		
Contracts						
Precipitator Conveyor Installation	lot	1	[redacted]		Attachment 2, Page 2	
Concrete Modifications estimate	lot	1	$ 20,000	$ 20,000		
Platform Install	lot	1	$ 15,000	$ 15,000		
			Sub-Total	[redacted]		
Consulting						
Third Party Project Support	lot	1	$ 10,000	$ 10,000		
Engineering of Conveyance System	lot	1	[redacted]		Attachment 3, Page 1	
			Sub-Total	[redacted]		
Other Goods & Services						
Contingency	15%	1	$ 1,114,469	$ 167,170		
			Sub-Total	$ 167,170		
Interest Capitalized						
AFUDC				$ 23,379		
			Sub-Total	$ 23,379		
Administrative Overhead						
Labour AO				$ 23,372		
Contractor AO				$ 31,594		
			Sub-Total	$ 54,966		
			SUB-TOTAL (no AO, AFUDC)	$ 1,281,639		
			TOTAL (AO, AFUDC included)	$ 1,359,984		
Original Cost				$ 178,623		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER An Emera Company

Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

General Construction	Required fields:	Estimate Classification				
Project Name: TUC3 Continuous Ash Hauling System	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Functional Space - SF or m^2	Not Applicable (NA)					
Electrical Power Requirements (when not the primary capacity driver)	Defined (D)	NR	P	D	D	D
Mechanical Systems	Defined (D)	NR	P	D	D	D
C. Project Location						
Building and/or Other Project Elements	Defined (D)	P	P	D	D	D
D. Requirements						
Anti-Terrorism Force Protection	Not Applicable (NA)					
No. of Building Floors	Not Applicable (NA)					
Security System	Not Applicable (NA)	NR/P				
LEED Certification Level	Not Applicable (NA)	NR/P				
Codes and/or Standards	Not Applicable (NA)	NR				
Communication Systems	Not Applicable (NA)	NR				
Exterior Closure Description	Not Applicable (NA)	NR				
Finishes Descriptions	Not Applicable (NA)	NR				
Fire Protection and Life Safety	Not Applicable (NA)	NR				
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Not Applicable						
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
Logistics Plan	Not Applicable (NA)					
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Not Applicable (NA)	NR				
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
Storm Water Management Plan	Not Applicable (NA)	NR				
H. Studies						
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Site Plan	Complete (C)	S	P	C	C	C
Design Specifications	Complete (C)	NR	S/P	C	C	C
Electrical One-Line Drawings	Complete (C)	NR	S/P	C	C	C
General Equipment Arrangement Drawings	Preliminary (P)	NR	S/P			
Plot Plans/Facility Layouts	Complete (C)	NR	S/P	C	C	C
Room Classification Datasheet	Not Applicable (NA)	NR				
Room Layout Drawings	Not Applicable (NA)	NR				
Construction Permits	Not Applicable (NA)	NR				
Building Plan Views, Sections and Elevations	Preliminary (P)	NR	S/P	P		
Civil/Site/Structural/Architectural Discipline Drawings	Preliminary (P)	NR	S/P	P		
Codes and Standards Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Preliminary (P)	NR	S/P	P		
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Exterior Elevations	Preliminary (P)	NR	S/P	P		
Finish Schedule	Not Applicable (NA)	NR				
Fire Protection and Life Safety Drawings and Details	Not Applicable (NA)	NR				
Furniture Plans, Schedules and Drawings	Not Applicable (NA)	NR				
Interior Section Views	Not Applicable (NA)	NR				
Landscaping Drawings	Not Applicable (NA)	NR				
Plumbing Drawings	Not Applicable (NA)	NR				
Roof Plan, Drawing Details	Not Applicable (NA)	NR				
Storm Water Drawings	Not Applicable (NA)	NR				
Window Schedules	Not Applicable (NA)	NR				
Door Schedules	Not Applicable (NA)	NR				
Restroom Schedules	Not Applicable (NA)	NR				
Signage Drawings and Schedules	Preliminary (P)	NR	S/P	P		
Partition or Wall Types	Not Applicable (NA)	NR				
Electrical Schedules	Not Applicable (NA)	NR	NR/S			
Equipment Datasheets	Not Applicable (NA)	NR	NR/S			
Equipment Lists: Electrical	Not Applicable (NA)	NR	NR/S			
Equipment Lists: Process/Utility/Mechanical	Not Applicable (NA)	NR	NR/S			
Instrument and Control Schedules	Not Applicable (NA)	NR	NR/S			
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listing	Preliminary (P)	NR	NR	P	P/C	
Electrical Discipline drawings	Preliminary (P)	NR	NR	S/P	P/C	
Facility Emergency Communication Plan and Drawings	Preliminary (P)	NR	NR	S/P	P/C	
HVAC Drawings	Not Applicable (NA)	NR	NR			
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
Mechanical Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
Room Discipline Drawings	Not Applicable (NA)	NR	NR			
Interior Lighting Plan and Drawings	Not Applicable (NA)	NR	NR			
Lighting Control Diagram	Not Applicable (NA)	NR	NR			
Lighting Schedules	Not Applicable (NA)	NR	NR			
Lightning Protection Drawings	Not Applicable (NA)	NR	NR			
Mechanical/HVAC Schedules	Not Applicable (NA)	NR	NR			
Motor Control Diagram	Not Applicable (NA)	NR	NR			
Plumbing Details	Not Applicable (NA)	NR	NR			
Security Plan and Drawings	Not Applicable (NA)	NR	NR			
Instrument List	Started (S)	NR	NR			
Building Envelope/Moisture Protection/Flashing Details	Not Applicable (NA)	NR	NR			
Interior Elevations	Not Applicable (NA)	NR	NR			
Total Responses	**Total # Deliverables for this Project**	3	21	23	17	12
Percentage	**% Defined/Complete towards Class Estimate**	100%	100%	85%	63%	44%

Comments:

This project is being submitted as a Class 3 estimate. The defined deliverables for this project indicate that 85% of Class 3 deliverables are completed. A contingency value of 15% was selected to account for specific risks such as risks related to the scope as it is not fully defined due to the conceptual design. The contingency also accounts for changes in electrical supplies estimates, and potential unforeseen impacts from import tariffs affecting the material supply chain.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required (NR):** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary (P):** Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined (D):** Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- **Not Required (NR):** Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *general construction* is assumed to include both new construction as well as renovation construction projects. It is intended to be used for building (vertical) construction, as well as site/civil projects. It is intended to cover projects which are repetitive and repeatable. Examples for buildings include: residential construction, commercial buildings, hotels, resorts, offices, retail, etc. This also includes site/civil projects. Examples for site/civil projects include: site development, utility infrastructure, telecommunications, water pipelines, sanitary sewer pipelines, storm water and water resources projects. The common thread among these industries for the purpose of estimate classification is their reliance on project definition documents (basis of design) and schematic drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information.

Estimates for buildings center on functional space requirements, structural requirements, site requirements, architectural elements, sustainability, and supporting mechanical, electrical, plumbing, and life-safety systems.

TUC3 Continuous Ash Hauling System
Summary of Alternatives

Nova Scotia POWER An Emera Company

Division :		**Date :**	**4-Dec-25**
Department :		**CI Number:**	C0068888
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Continuous Ash Hauling System	5.77%	3,245,613	-2,528,869	1	#NUM!	0.0 years
B	Do Nothing	5.77%	4,435,140	-3,419,061	2	#NUM!	0.0 years
	0	NA	NA	NA	NA	#VALUE!	#VALUE!
	0	NA	NA	NA	NA	#VALUE!	#VALUE!

Recommendation :

Based on the results it is recommended to install the continuous ash hauling system for TUC3.

Notes/Comments :

Continuous Ash Hauling System

The scope of this project is to install a drag chain conveyor system on the TUC 3 Electrostatic Precipitator (ESP) unit to facilitate continuous extraction of oil fly ash. The TUC 3 ESP's function is to remove fly ash particulate from the gas expelled by the boiler. This change will provide a new internal ash collection process using live bottom trailers for collection and transportation.

Do Nothing

The current design of the ESP hoppers is to store collected fly ash for a short term only. Fly ash should be removed on a daily basis to avoid potential ash pluggage and handling issues. The current system requires an external vacuum truck to be mobilized to site daily (when TUC 3 is using Heavy Fuel Oil) to collect ash manually. This truck is then connected to the ESP hoppers and hauls ash to an external metal bin.

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TUC3 Continuous Ash Hauling System
Summary of Sensitivities

Nova Scotia POWE An Emera Compar

Division :		**Date :**	**4-Dec-25**
Department :		**CI Number:**	C0068888
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Continuous Ash Hauling System	5.77%	3,245,613	-2,528,869	1	#NUM!	0.0 years
B	Do Nothing	5.77%	4,435,140	-3,419,061	2	#NUM!	0.0 years
	0	NA	NA	NA	NA	#VALUE!	#VALUE!
	0	NA	NA	NA	NA	#VALUE!	#VALUE!

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Continuous Ash Hauling System	30%	3,626,861	-2,834,482	1	#NUM!	0.0 years
B	Do Nothing	30%	4,435,140	-3,419,062	2	#NUM!	0.0 years
	0	30%	NA	NA	NA	#VALUE!	#VALUE!
	0	30%	NA	NA	NA	#VALUE!	#VALUE!
Change:	**A**		381,249	-305,612	0	#NUM!	0.0 years
	B		0	0	0	#NUM!	0.0 years
			NA	NA	NA	#VALUE!	#VALUE!
			NA	NA	NA	#VALUE!	#VALUE!

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Continuous Ash Hauling System	-10%	3,245,613	-2,528,869	1	#NUM!	0.0 years
B	Do Nothing	-10%	4,435,140	-3,419,061	2	#NUM!	0.0 years
	0	-10%	NA	NA	NA	#VALUE!	#VALUE!
	0	-10%	NA	NA	NA	#VALUE!	#VALUE!
Change:	**A**		0	0	0	#NUM!	0.0 years
	B		0	0	0	#NUM!	0.0 years
			NA	NA	NA	#VALUE!	#VALUE!
			NA	NA	NA	#VALUE!	#VALUE!

TUC3 Continuous Ash Hauling System
Continuous Ash Hauling System

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2025	-	(227,519.0)	-	-	-	-	(227,519.0)	65,980.5	(161,538.5)	(161,538.5)	1.00	(161,538.5)
2026	-	(229,015.3)	-	(1,305,018.0)	102,531.1	1,192,959.3	(1,534,033.3)	96,148.5	(1,437,884.9)	(1,359,444.9)	0.95	(1,520,983.4)
2027	-	(230,568.0)	-	-	94,328.6	1,096,203.4	(230,568.0)	94,220.0	(136,348.0)	(121,877.5)	0.89	(1,642,860.9)
2028	-	(69,217.1)	-	-	86,782.3	1,007,187.9	(69,217.1)	45,239.8	(23,977.3)	(20,263.4)	0.85	(1,663,124.3)
2029	-	(70,401.5)	-	-	79,839.8	925,293.7	(70,401.5)	43,570.0	(26,831.5)	(21,438.5)	0.80	(1,684,562.9)
2030	-	(71,609.5)	-	-	73,452.6	849,951.0	(71,609.5)	42,068.0	(29,541.5)	(22,316.2)	0.76	(1,706,879.1)
2031	-	(72,841.7)	-	-	67,576.4	780,635.8	(72,841.7)	40,721.2	(32,120.5)	(22,940.7)	0.71	(1,729,819.8)
2032	-	(74,098.5)	-	-	62,170.3	716,865.7	(74,098.5)	39,517.9	(34,580.6)	(23,350.4)	0.68	(1,753,170.2)
2033	-	(75,380.5)	-	-	57,196.6	658,197.3	(75,380.5)	38,447.4	(36,933.1)	(23,578.5)	0.64	(1,776,748.7)
2034	-	(280,258.0)	-	-	52,620.9	604,222.3	(280,258.0)	96,534.9	(183,723.1)	(110,892.3)	0.60	(1,887,640.9)
2035	-	(281,591.7)	-	-	48,411.2	554,565.3	(281,591.7)	95,700.9	(185,890.9)	(106,079.9)	0.57	(1,993,720.8)
2036	-	(282,952.2)	-	-	44,538.3	508,880.9	(282,952.2)	94,972.2	(187,979.9)	(101,420.1)	0.54	(2,095,140.9)
2037	-	(80,769.9)	-	-	40,975.3	466,851.3	(80,769.9)	35,306.1	(45,463.8)	(23,190.8)	0.51	(2,118,331.7)
2038	-	(82,185.3)	-	-	37,697.2	428,184.0	(82,185.3)	34,766.0	(47,419.4)	(22,868.8)	0.48	(2,141,200.5)
2039	-	(83,629.1)	-	-	34,681.5	392,610.1	(83,629.1)	34,310.1	(49,319.0)	(22,487.4)	0.46	(2,163,687.9)
2040	-	(85,101.6)	-	-	31,906.9	359,882.1	(85,101.6)	33,932.5	(51,169.1)	(22,058.2)	0.43	(2,185,746.1)
2041	-	(86,603.7)	-	-	29,354.4	329,772.3	(86,603.7)	33,627.8	(52,975.8)	(21,591.2)	0.41	(2,207,337.4)
2042	-	(88,135.7)	-	-	27,006.0	302,071.4	(88,135.7)	33,391.1	(54,744.6)	(21,095.0)	0.39	(2,228,432.3)
2043	-	(104,698.5)	-	-	24,845.6	276,586.5	(104,698.5)	37,567.8	(67,130.7)	(24,456.6)	0.36	(2,252,888.9)
2044	-	(345,649.2)	-	-	22,857.9	253,140.4	(345,649.2)	106,867.1	(238,782.1)	(82,245.9)	0.34	(2,335,134.8)
2045	-	(347,275.0)	-	-	21,029.3	231,570.0	(347,275.0)	106,808.3	(240,466.8)	(78,307.8)	0.33	(2,413,442.6)
2046	-	(348,933.4)	-	-	19,346.9	211,725.2	(348,933.4)	106,801.3	(242,132.1)	(74,548.7)	0.31	(2,487,991.3)
2047	-	(86,268.2)	-	-	17,799.2	193,468.0	(86,268.2)	30,179.5	(56,088.6)	(16,326.8)	0.29	(2,504,318.0)
2048	-	(87,993.5)	-	-	16,375.2	176,671.4	(87,993.5)	30,266.9	(57,726.6)	(15,886.9)	0.28	(2,520,204.9)
2049	-	(89,753.4)	-	-	15,065.2	161,218.5	(89,753.4)	30,397.4	(59,356.0)	(15,444.2)	0.26	(2,535,649.1)
2050	-	-	-	-	13,860.0	147,001.8	-	4,019.4	4,019.4	988.8	0.25	(2,534,660.3)
2051	-	-	-	-	12,751.2	133,922.5	-	3,697.9	3,697.9	860.1	0.23	(2,533,800.2)
2052	-	-	-	-	11,731.1	121,889.5	-	3,402.0	3,402.0	748.1	0.22	(2,533,052.2)
2053	-	-	-	-	10,792.6	110,819.2	-	3,129.9	3,129.9	650.7	0.21	(2,532,401.5)
2054	-	-	-	-	9,929.2	100,634.4	-	2,879.5	2,879.5	566.0	0.20	(2,531,835.5)
2055	-	-	-	-	9,134.9	91,264.5	-	2,649.1	2,649.1	492.3	0.19	(2,531,343.2)
2056	-	-	-	-	8,404.1	82,644.2	-	2,437.2	2,437.2	428.2	0.18	(2,530,915.0)
2057	-	-	-	-	7,731.8	74,713.4	-	2,242.2	2,242.2	372.5	0.17	(2,530,542.5)
2058	-	-	-	-	7,113.2	67,417.2	-	2,062.8	2,062.8	324.0	0.16	(2,530,218.6)
2059	-	-	-	-	6,544.2	60,704.6	-	1,897.8	1,897.8	281.8	0.15	(2,529,936.8)
2060	-	-	-	-	6,020.6	54,529.1	-	1,746.0	1,746.0	245.1	0.14	(2,529,691.7)
2061	-	-	-	-	5,539.0	48,847.6	-	1,606.3	1,606.3	213.2	0.13	(2,529,478.5)
2062	-	-	-	-	5,095.9	43,620.6	-	1,477.8	1,477.8	185.4	0.13	(2,529,293.0)
2063	-	-	-	-	4,688.2	38,811.7	-	1,359.6	1,359.6	161.3	0.12	(2,529,131.7)
2064	-	-	-	-	4,313.1	34,387.6	-	1,250.8	1,250.8	140.3	0.11	(2,528,991.4)
2065	-	-	-	-	3,968.1	30,317.4	-	1,150.7	1,150.7	122.0	0.11	(2,528,869.4)
Total	**-**	**(3,882,449.6)**	**-**	**(1,305,018.0)**	**1,236,006.0**		**(5,187,467.6)**	**1,484,352.1**	**(3,703,115.5)**	**(2,528,869.4)**		

TUC3 Continuous Ash Hauling System
Do Nothing

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2025	-	(287,795.0)	-	-	-	-	(287,795.0)	83,460.6	(204,334.5)	(204,334.5)	1.00	(204,334.5)
2026	-	(293,550.9)	-	(1.0)	-	-	(293,551.9)	85,129.8	(208,422.1)	(197,052.2)	0.95	(401,386.7)
2027	-	(299,421.9)	-	-	-	-	(299,421.9)	86,832.4	(212,589.6)	(190,027.7)	0.89	(591,414.4)
2028	-	(305,410.4)	-	-	-	-	(305,410.4)	88,569.0	(216,841.4)	(183,254.5)	0.85	(774,668.9)
2029	-	(311,518.6)	-	-	-	-	(311,518.6)	90,340.4	(221,178.2)	(176,722.7)	0.80	(951,391.5)
2030	-	(317,748.9)	-	-	-	-	(317,748.9)	92,147.2	(225,601.7)	(170,423.7)	0.76	(1,121,815.2)
2031	-	(324,103.9)	-	-	0.0	1.0	(324,103.9)	93,990.1	(230,113.8)	(164,349.2)	0.71	(1,286,164.4)
2032	-	(330,586.0)	-	-	0.1	0.9	(330,586.0)	95,870.0	(234,716.0)	(158,491.2)	0.68	(1,444,655.6)
2033	-	(337,197.7)	-	-	0.1	0.8	(337,197.7)	97,787.4	(239,410.4)	(152,842.1)	0.64	(1,597,497.7)
2034	-	(343,941.7)	-	-	0.1	0.7	(343,941.7)	99,743.1	(244,198.6)	(147,394.3)	0.60	(1,744,891.9)
2035	-	(350,820.5)	-	-	0.1	0.7	(350,820.5)	101,738.0	(249,082.5)	(142,140.6)	0.57	(1,887,032.6)
2036	-	(357,836.9)	-	-	0.1	0.6	(357,836.9)	103,772.7	(254,064.2)	(137,074.3)	0.54	(2,024,106.8)
2037	-	(364,993.6)	-	-	0.1	0.6	(364,993.6)	105,848.2	(259,145.5)	(132,188.5)	0.51	(2,156,295.3)
2038	-	(372,293.5)	-	-	0.0	0.5	(372,293.5)	107,965.1	(264,328.4)	(127,476.8)	0.48	(2,283,772.1)
2039	-	(379,739.4)	-	-	0.0	0.5	(379,739.4)	110,124.4	(269,615.0)	(122,933.1)	0.46	(2,406,705.3)
2040	-	(387,334.2)	-	-	0.0	0.5	(387,334.2)	112,326.9	(275,007.3)	(118,551.4)	0.43	(2,525,256.6)
2041	-	(395,080.9)	-	-	0.0	0.4	(395,080.9)	114,573.5	(280,507.4)	(114,325.8)	0.41	(2,639,582.4)
2042	-	(402,982.5)	-	-	0.0	0.4	(402,982.5)	116,864.9	(286,117.6)	(110,250.8)	0.39	(2,749,833.3)
2043	-	(411,042.1)	-	-	0.0	0.4	(411,042.1)	119,202.2	(291,839.9)	(106,321.1)	0.36	(2,856,154.4)
2044	-	(419,263.0)	-	-	0.0	0.3	(419,263.0)	121,586.3	(297,676.7)	(102,531.5)	0.34	(2,958,685.9)
2045	-	(427,648.2)	-	-	0.0	0.3	(427,648.2)	124,018.0	(303,630.2)	(98,876.9)	0.33	(3,057,562.8)
2046	-	(436,201.2)	-	-	0.0	0.3	(436,201.2)	126,498.4	(309,702.8)	(95,352.6)	0.31	(3,152,915.4)
2047	-	(444,925.2)	-	-	0.0	0.3	(444,925.2)	129,028.3	(315,896.9)	(91,953.9)	0.29	(3,244,869.4)
2048	-	(453,823.7)	-	-	0.0	0.2	(453,823.7)	131,608.9	(322,214.8)	(88,676.4)	0.28	(3,333,545.7)
2049	-	(462,900.2)	-	-	0.0	0.2	(462,900.2)	134,241.1	(328,659.1)	(85,515.7)	0.26	(3,419,061.4)
2050	-	-	-	-	0.0	0.2	-	0.0	0.0	0.0	0.25	(3,419,061.4)
2051	-	-	-	-	0.0	0.2	-	0.0	0.0	0.0	0.23	(3,419,061.4)
2052	-	-	-	-	0.0	0.2	-	0.0	0.0	0.0	0.22	(3,419,061.4)
2053	-	-	-	-	0.0	0.2	-	0.0	0.0	0.0	0.21	(3,419,061.4)
2054	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.20	(3,419,061.4)
2055	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.19	(3,419,061.4)
2056	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.18	(3,419,061.4)
2057	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.17	(3,419,061.4)
2058	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.16	(3,419,061.4)
2059	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.15	(3,419,061.4)
2060	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.14	(3,419,061.4)
2061	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.13	(3,419,061.4)
2062	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.13	(3,419,061.4)
2063	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.12	(3,419,061.4)
2064	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.11	(3,419,061.4)
2065	-	-	-	-	0.0	0.1	-	0.0	0.0	0.0	0.11	(3,419,061.4)
	-	**(9,218,160.1)**	**-**	**(1.0)**	**0.9**		**(9,218,161.1)**	**2,673,266.7**	**(6,544,894.4)**	**(3,419,061.4)**		

TUC3 Continuous Ash Hauling System
Avoided Cost Calculations

Nova Scotia POWER An Emera Company

Division :		Date :	4-Dec-25
Department :		CI Number:	C0068888
		Project No. :	

Continuous Ash Hauling System

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	2026	2027	2026	2027	2026	2027
Replacement Energy Cost ($/MWh)	0.00	0.00				
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	100%	50%				
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative $1,359,984

Do Nothing

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	2026	2027	2026	2027	2026	2027
Replacement Energy Cost ($/MWh)	0.00	0.00				
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	100%	50%				
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative $1

0

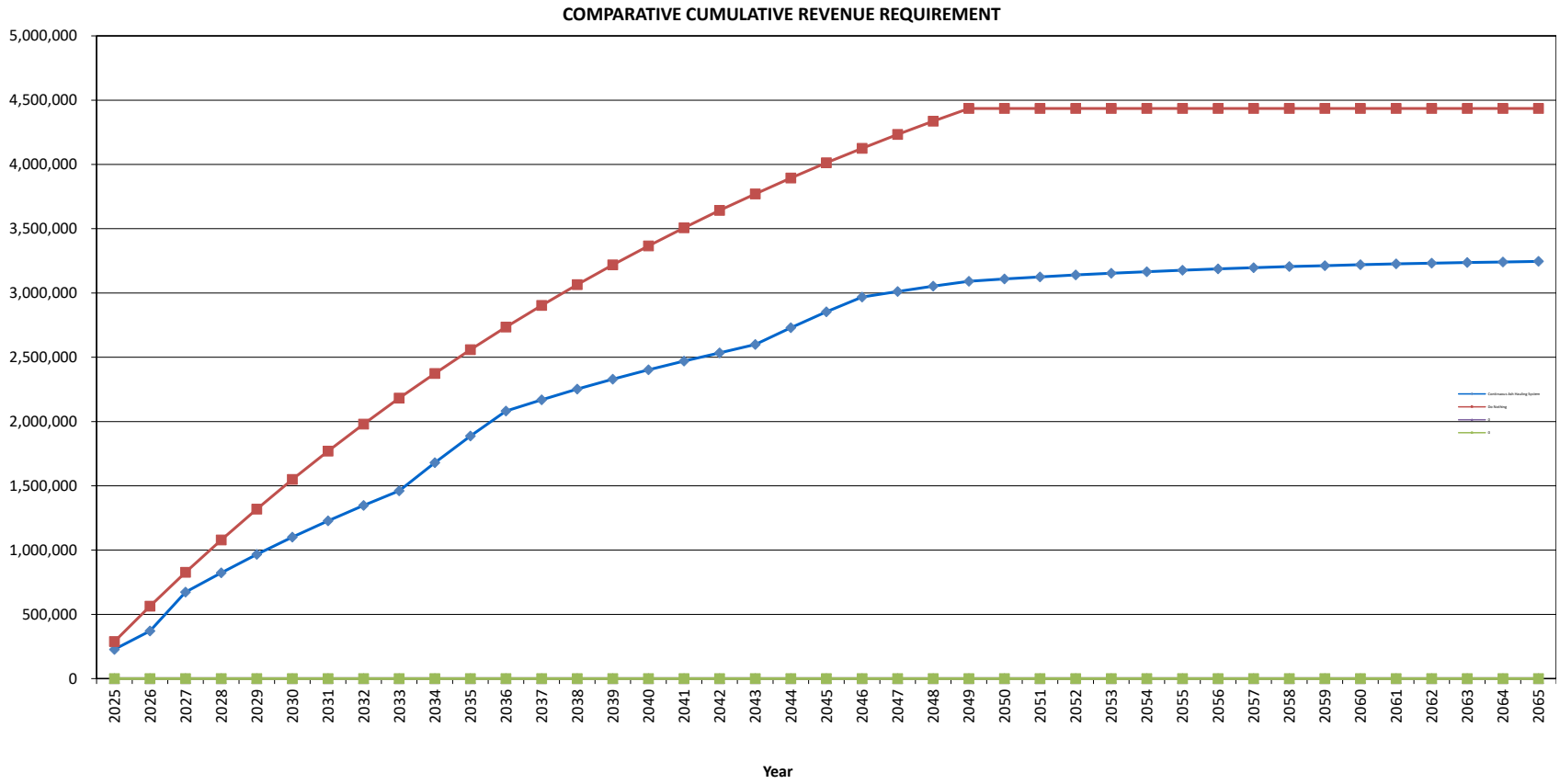
	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	2026	2027	2026	2027	2026	2027
Replacement Energy Cost ($/MWh)	0.00	0.00				
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	100%	50%				
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative $0

0

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	2026	2027	2026	2027	2026	2027
Replacement Energy Cost ($/MWh)	0.00	0.00				
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	100%	50%				
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative $0


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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DATE	QUOTATION
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ProcessBarron - Southern Field Canada, Inc.
P.O Box 94090 / Bedford PO | Toronto, ON M4N 3R1
Phone: (205) 663-5330 | Fax: (205) 663-6037
http://www.processbarron.com

New Fans	Solid Fuel Feed Systems	Mechanical Dust Collectors
Fan Repair & Service	Mechanical Ash Handling Systems	Boiler Air Heater
Dampers	New & Replacement Screw Conveyors	Boiler Retrofit & Conveyors
Expansion Joints	Breeching, Stacks, & Ductwork	Turnkey Projects

Quotation For:
GAVIN MCINNIS
NOVA SCOTIA POWER - TUFT'S COVE

315 WINDMILL ROAD
DARTMOUTH NS B3A 3C5
Canada

Phone: (800) 428-6230
Email:

Description: ASH COLLECTION SYSTEM

Quote Expires: 03/07/2025
Payment Terms: See Quotation Comments
Shipping: FOB ORIG PP&ADD
Sales Mgr: Brian Buchanan
bbuchanan@processbarron.com
(205) 613-4920
Sales Rep: STAN LORENOWICH
stanleyc@videotron.ca
(514) 799-9929
RFQ No: R-10935

Line	Description	Quantity	Unit	Unit Price	Extended Price
1	Investigation of Precipitator System	1	EA	[redacted]	

Product Estimator: Jamie Pate jpate@processbarron.com (205) 663-5330
MHP-OTHER-SERVICE

Testing will being conducted to determine the existing precipitator inlet particulate loading, particle size distribution, physical properties, and chemical properties testing. The following testing will be conducted at the proposed test locations:

[redacted]

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[redacted]

Personnel
Testing will be conducted utilizing one project managers and one test analyst.

[redacted]

Line	Description	Quantity	Unit	Unit Price	Extended Price
2	Fly Ash Handling System	1	EA		[redacted]

Product Estimator: John Riley jriley@processbarron.com (205) 663-5330
MHP-SYSTEM ENGINEERING

[redacted]

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[redacted]

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NOVA SCOTIA POWER - TUFT'S COVE

[redacted]

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[redacted]

Grand Total: [redacted]

Quotation Comments:

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All pricing is in Canadian dollars. Current rate (02/25/2025) = $1 USD to $1.4254 CAD.

Freight Terms: Unless shipping instruction are provided by the buyer, PB-SF-EEC will ship, F.O.B. Shipping Point, PP&A on invoice. Pricing does NOT include off-loading, unless otherwise noted.

Taxes: Sales & Use taxes are not included in the pricing offered. No Duties or Tariffs are included in the pricing offered. Sales & Use Tax etc., if applicable, are to be submitted by the Purchaser direct to the State taxing authority.

Terms: All invoices are due and payable in CAD Dollar, Net Thirty (30) days from invoice date. A 1.5% per month finance charge will apply to all invoices over thirty (30) days old. Not applicable if alternative terms have been previously negotiated.

Restocking: There will be a 15% restocking charge plus the cost of freight for stock items. Custom items are not refundable/returnable.

Installation: Costs associated with installation of items quoted herein is excluded from the pricing offered.

Equipment will be designed and fabricated in a manner to allow for the most economic shipping method and efficient assembly of equipment.

Pricing does NOT include:

- Civil EngineeringConstruction or Materials for Foundations (concrete, steel, anchor bolts, grout, etc)
- Electrical Engineering
- Electrical wiring, components, or controls (except where noted)
- Modifications to existing structural steel or equipment
- New access steel
- Ash Bin
- Re-routing or supply of any water lines, pneumatic piping, or electrical cables
- Installation
- Equipment will comply with all required standards and codes; however, field testing or labeling, such as CSA labeling, is not included.

Preliminary Delivery Schedule (Negotiable)

- Approval Drawings: 6-8 weeks ARO
- Approval Drawings Returned: 1-2 weeks from receipt
- Certified Drawings: 1 week after return of approval drawings
- Equipment Ready to Ship: 16-22 weeks after return of approval drawings

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GAVIN MCINNIS
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS

Unless otherwise indicated within the details of this quotation/proposal, the following General Terms & Conditions shall apply:

1. GENERAL

A. These general terms and conditions of sale (these "Terms") are the only terms which govern the sale of the goods and equipment ("Goods") and services ("Services") by Processbarron - Southern Field Canada Inc. ("Seller") to the buyer named on the reverse side of these Terms ("Buyer"). Notwithstanding anything herein to the contrary, if a written contract signed by both parties is in existence covering the sale of the Goods and Services covered hereby, the terms and conditions of said contract shall prevail to the extent they are inconsistent with these Terms.

B. The accompanying quotation/proposal (the "**Proposal**") and these Terms (collectively, this "**Agreement**") comprise the entire agreement between the parties, and supersede all prior or contemporaneous understandings, agreements, negotiations, representations and warranties, and communications, both written and oral. These Terms prevail over any of Buyer's general terms and conditions of purchase regardless of whether or when Buyer has submitted its purchase order or such terms. Fulfilment of Buyer's order does not constitute acceptance of any of Buyer's terms and conditions and does not serve to modify or amend these Terms and/or the Agreement.

C. Notwithstanding anything to the contrary contained in this Agreement, Seller may, from time to time change the Services without the consent of Buyer *provided that* such changes do not materially affect the nature or scope of the Services, or the fees or any performance dates set forth in the Proposal.

2. **PRICING NOTE -** If the material price varies between the date of the Proposal and the date the purchase order (the "**Order**") is placed, Seller reserves the right to adjust pricing to reflect such price changes. Seller will provide Buyer with prompt written notice in the event of any such price change.

3. PROPOSAL ACCEPTANCE - This Proposal is offered for acceptance within thirty (30) days from the date of the Proposal, after which it is subject to confirmation by Seller, and made with the understanding that if accepted by Buyer these Terms are agreed to.

4. **DELIVERY OF GOOD AND PERFORMANCE OF SERVICES -**

A.The Goods will be delivered within a reasonable time after the receipt of Buyer's Order, subject to availability of finished Goods. Seller shall not be liable for any delays, loss or damage in transit.

B. Unless otherwise agreed in writing by the parties, the Goods shall be delivered to the delivery point as indicated on the Proposal (the "**Delivery Point**"). Buyer shall be responsible for all loading costs and provide equipment and labour reasonably suited for receipt of the Goods at the Delivery Point.

C. Seller may, in its sole discretion, without liability or penalty, make partial shipments of Goods to Buyer. Each shipment will constitute a separate sale, and Buyer shall pay for the units shipped whether such shipment is in whole or partial fulfilment of Buyer's Order.

D. With respect to the Services, Buyer shall (i) cooperate with Seller in all matters relating to the Services and provide such access to Buyer's premises, and such office accommodation and other facilities as may reasonably be requested by Seller, for the purposes of performing the Services; (ii) respond promptly to any Seller request to provide direction, information, approvals, authorizations or decisions that are reasonably necessary for Seller to perform Services in accordance with the requirements of this Agreement; (iii) provide such customer materials or information as Seller may request to carry out the Services in a timely manner and ensure that such customer materials or information are complete and accurate in all material respects; and (iv) obtain and maintain all necessary licenses and consents and comply with all applicable laws in relation to the Services before the date on which the Services are to start.

5. RESPONSIBILITY -

a. Seller shall not be liable or responsible to Buyer, nor be deemed to have defaulted under or breached this Agreement, for any failure or delay in fulfilling or performing any term of this Agreement when and to the extent Seller's failure or delay is caused by or results from the following force majeure events ("**Force Majeure Event(s)**"): (a) acts of God; (b) flood, tsunami, fire, earthquake, explosion; (c) epidemics, pandemics, including the 2019 novel coronavirus pandemic (COVID-19); (d) war, invasion, hostilities (whether war is declared or not), terrorist threats or acts, riot, or other civil unrest; (e) government order, law or actions; (f) embargoes or blockades in effect on or after the date of this Agreement; (g) national or regional emergency; (h) strikes, lockouts, labour stoppages or slowdowns, labour disputes, or other industrial disturbances; (i) shortage of adequate power or telecommunications or transportation facilities; (j) failure of any governmental or public authority to grant a necessary licence or consent; and (k) other events beyond the reasonable control of Seller.

B. Authorization by Buyer to ship the Goods shall constitute a waiver of all claims for loss and damage due to delay.

C. Buyer will assume full responsibility for any loss or damage resulting from operation of the Goods. Seller assumes no responsibility for any auxiliary apparatus or work in connection with the Goods furnished hereunder, notwithstanding that Seller may have submitted recommendations pertaining hereto.

6. INSPECTION - Buyer shall inspect the Goods within five (5) business days of receipt ("**Inspection Period**"). Buyer will be deemed to have accepted the Goods unless it notifies Seller in writing of any Non-Conforming Goods during the Inspection Period and furnishes such written evidence or other documentation as required by Seller. "Non-Conforming Goods" means only the following: (i) product shipped is different than identified in Buyer's Order; or (ii) product's label or packaging incorrectly identifies its contents.

7. **DEFECTIVE GOODS -**

A. If any Goods, as furnished by Seller are alleged by Buyer to be defective or not manufactured in accordance with Buyer's specifications and are rejected by Buyer within the warranty period, Buyer shall promptly notify Seller and Seller shall have the option of replacing or correcting, within a reasonable time, any defective Goods, at Seller's own expense, or reimbursing Buyer the agreed cost of such replacement or correction. Buyer shall not furnish any material or do any work for Seller's account without specific authorization and a definitive written agreement from Seller as to the consideration, and in no case shall the Seller be liable for more than the price charged for such material as may prove defective, and no payments shall be withheld by Buyer pending adjustment of liability or amount of cost of alleged errors.

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GAVIN MCINNIS
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS (cont'd)

B. Buyer acknowledges and agrees that the remedies set forth in Section 7(A) are Buyer's exclusive remedies for the delivery of Non-Conforming Goods. Except as provided under Section 7(A), all sales of Goods to Buyer are made on a one-way basis and Buyer has no right to return Goods purchased under this Agreement to Seller.

8. WARRANTIES -

A. Seller warrants to Buyer that for a period of twelve (12) months after installation or eighteen (18) months after shipment of the Goods, whichever comes first (the "**Warranty Period**"), that such Goods will be free from defects in material and workmanship. Subject to the below, with respect to any such Goods during the Warranty Period, Seller shall, in its sole discretion, either (i) repair or replace such Goods (or the defective part) or (ii) credit or refund the price of such Goods at the pro rata contract rate *provided that,* if Seller so requests, Buyer shall, at Seller's expenses, return such Goods to Seller.

B. EXCEPT FOR THE EXPRESS WARRANTY SET FORTH ABOVE, SELLER MAKES NO WARRANTY OR REPRESENTATION OF ANY KIND WITH RESPECT TO THE GOODS, WHETHER EXPRESS, IMPLIED, OR STATUTORY, INCLUDING BUT NOT LIMITED TO (A) ANY WARRANTY OR CONDITION OF MERCHANTABILITY. MERCHANTABLE QUALITY, OR FITNESS FOR A PARTICULAR PURPOSE OR (B) ANY WARRANTY ARISING AS A RESULT OF USAGE IN THE TRADE OR BY COURSE OF DEALING. BUYER ACKNOWLEDGES THAT IT HAS NOT RELIED UPON ANY REPRESENTATION, CONDITION OR WARRANTY MADE BY SELLER, OR ANY OTHER PERSON ON SELLER'S BEHALF, EXCEPT AS SPECIFICALLY PROVIDED ABOVE.

C. The Seller shall not be liable for a breach of warranty set forth above unless (i) Buyer gives written notice of the defect to Seller within sixty (60) days from when Buyer discovers or ought to have discovered the defect; and (ii) Seller reasonably verifies Buyer's claim that the Goods are defective. Deterioration or wear occasioned by chemical, abrasive or excessive heat shall not constitute defects. Seller shall, at its option, repair or replace such Goods (or defective part), without charge at FOB point of shipment, provided that such warranty excludes the cost to remove and re-install such Goods, and all transportation costs.

D. Goods not manufactured by Seller are warranted only to the extent they are warranted by their manufacturer. This warranty does not cover any Goods which, in the judgment of Seller, have (i) been subject to misuse, neglect, improper maintenance, improper storage, improper installation, abnormal environmental conditions or use contrary to any instructions issued by Seller; (ii) been repaired or altered outside Seller's plant in any way that may have impaired its safety, operation, or efficiency; nor any product which has been subject to accident or operated in excess of design limitations.

9. INSURANCE - During the term of this Agreement, Buyer shall, at its own expense, maintain and carry insurance in full force and effect which includes, but is not limited to, commercial general liability (including product liability) in a sum no less than two (2) times the aggregate purchase order amount with financially sound and reputable insurers. Upon Seller's request, Buyer shall provide Seller with a certificate of insurance from Buyer's insurer evidencing the insurance coverage specified in these Terms. Buyer shall provide Seller with thirty (30) days' advance written notice in the event of a cancellation or material change in Buyer's insurance policy. Except where prohibited by law, Buyer shall require its insurer to waive all rights of subrogation against Seller's insurers and Seller.

10. TITLE AND RISK OF LOSS - Title and risk of loss passes to Buyer upon delivery of the Goods at the Delivery Point. As collateral security for the payment of the purchase price of the Goods, Buyer hereby grants to Seller a lien on and security interest in and to all of the right, title and interest of Buyer in, to and under the Goods, wherever located, and whether now existing or hereafter arising or acquired from time to time, and in all accessions thereto and replacements or modifications thereof, as well as all proceeds (including insurance proceeds) of the foregoing. The security interest granted under this provision constitutes a purchase money security interest under the applicable Provincial Personal Property Security Act.

11. ACCESS - Authorized representatives of Seller acceptable to Buyer acting reasonably shall have access at all reasonable times to the installation of the Goods for the purpose of observing and adjusting the operation thereof.

12. TIME OF SHIPMENT - Statements as to expected dates of shipment represent Seller's best judgment, but shipment on those dates is not guaranteed. The time of shipment shall be determined from date of receipt by Seller of all information necessary to enable Seller to proceed with its work.

13. SUBCONTRACTING - Seller reserves as its prerogative the option to subcontract all or any portion of work under contract.

14. TAXES - The prices shown do not include any taxes (sales, excise, use, etc.) or any other governmental charges. Any charges or taxes applicable to the order will be paid by Buyer except where specifically exempt by a certificate.

15. TERMS OF PAYMENT -

A. Unless other terms of payment are specified in this Proposal or shown on the Order, payment shall become due thirty (30) days from the date of Seller's invoice. If shipment is delayed by Buyer, payment shall become due thirty (30) days from date Seller is ready to ship. If manufacturing is delayed by Buyer, partial shipment is to be made based on the acknowledged price and a percentage of completion at time of notification of delay.

B. If in the judgment of Seller the financial condition of Buyer is changed and at the time of construction or shipment does not warrant the terms shown on the Order, Seller may require full or partial payment in advance of construction and shipment of the Order.

C. Should Buyer delay payment beyond limits defined in Seller's Proposal and Buyer's Order, then interest will be charged on any unpaid portion of the purchase price at the rate of 1.5% per month (being 19.6% per annum), calculated daily and compounded monthly.

16. CANCELLATION - Buyer may only cancel their Order by written notice to Seller. Such cancellation will be subject to charges incurred by Seller up through the date of cancellation based on engineering, manufacturing, or outside purchasing completed or irrevocably incurred at the time the notice of cancellation is received in writing.

17. FIELD WORK - Unless otherwise noted, the following terms apply to all work to be performed at Buyer or third party sites:

A. All work will be performed by open shop labor. Any union dispute will be the responsibility of Buyer. Any standby time resulting from such disputes will be billed at full rates;

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NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS (cont'd)

B. Pricing only includes safety orientation meetings of no more than one (1) hour duration scheduled on the first work day. Attendance at meetings of greater than one (1) hour duration or not scheduled on the first work day will be invoiced at full rates. Any safety orientation that must be attended by a Seller representative prior to the beginning of outage work will be billed at full rates;
C. It is the responsibility of Buyer to inform Seller of any flammable coating, residue, contaminants, hazardous materials, etc. that may be present within or around the housings, ductwork or any area where Seller work is to be performed or where Seller personnel may be present. It is the responsibility of Buyer to remove and/or clean up any hazardous materials prior to Seller beginning work;
D. Field installation pricing presumes that all necessary access will be made available to Seller crews as needed to complete work as detailed herein; impediments such as, but not limited to, scaffolding, contractor tools, and/or cranes set in place by others that prevent or slow Seller field crews from completing their tasks will result in additional charges in the amount of time lost;
E. In performing the removal and installation of equipment, Seller crews will be following Seller's normal industry accepted rigging and lifting procedures. Seller's standard procedures are also governed by Seller's company safety regulations and procedures. The pricing and scheduling of this project is based on the Seller crews utilizing Seller's standard procedures and policies to safely complete this project. Should Buyer (Safety Group, Engineering, EPC or other contracted third party) require Seller's crews follow other policies, procedures, lifting or rigging plans (and/or require engineering certified lifting plans & additional equipment), then the additional man-hours and other associated costs will be performed on a time and materials basis and will be invoiced based on the actual hours and expense required by these changes in procedures; and
F. It is Buyer's responsibility to supply the required lubrication for all rotary equipment. Seller can recommend the lubrication type if needed, and Seller will install customer-supplied lubrication upon request if Seller crews are onsite installing/maintaining equipment. Nevertheless, it is ultimately Buyer's responsibility to supply and ensure proper lubrication levels prior to running the equipment.

18. REPLACEMENT PARTS - If these Terms are for replacement parts, Buyer warrants that the original components in which such replacement parts will be placed are in satisfactory working condition, and when such replacement parts are installed, the resultant installation will operate in a safe manner, at speeds and temperatures for which the original equipment was purchased.

19. SAFETY ACCESSORIES- Buyer understands that Seller manufactures multifunctional goods that may or may not require safety devices, depending on the use and location of the goods. Buyer warrants that it has determined what safety devices, including warning devices and notices of danger, should be placed on the Goods sold hereunder, and further warrants that it has either purchased these from Seller or from another source.

20. LIMITATION OF LIABILITY - IN NO EVENT SHALL SELLER BE LIABLE FOR ANY CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, OR PUNITIVE DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF OR RELATING TO ANY BREACH OF THESE TERMS AND/OR THE AGREEMENT, WHETHER OR NOT THE POSSIBILITY OF SUCH DAMAGES HAS BEEN DISCLOSED IN ADVANCE BY BUYER OR COULD HAVE BEEN REASONABLY FORESEEN BY BUYER, REGARDLESS OF THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED, AND NOTWITHSTANDING THE FAILURE OF ANY AGREED OR OTHER REMEDY OF ITS ESSENTIAL PURPOSE. IN NO EVENT SHALL SELLER'S AGGREGATE LIABILITY ARISING OUT OF OR RELATED TO THIS AGREEMENT, WHETHER ARISING OUT OF OR RELATED TO BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, EXCEED THE TOTAL OF THE AMOUNTS PAID TO SELLER FOR THE GOODS AND SERVICES SOLD HEREUNDER.

21. WAIVER - No waiver by Seller of any of the provisions of this Agreement is effective unless explicitly set forth in writing and signed by Seller. No failure to exercise, or delay in exercising, any right, remedy, power or privilege arising from this Agreement operates, or may be construed, as a waiver thereof. No single or partial exercise of any right, remedy, power or privilege hereunder precludes any other or further exercise thereof or the exercise of any other right, remedy, power or privilege.

22. RELATIONSHIP OF PARTIES - The relationship between the parties is that of independent contractors. Nothing contained in this Agreement shall be construed as creating any agency, partnership, joint venture or other form of joint enterprise, employment or fiduciary relationship between the parties, and neither party shall have authority to contract for or bind the other party in any manner whatsoever.

23. GOVERNING Law - This Agreement shall be governed by and interpreted under the laws of the Province of Ontario and the federal laws of Canada applicable therein. Any litigation with respect to the provisions of this Agreement may be brought in provincial or federal courts located in the Province of Ontario.

24. NOTICE - All notices, request, consents, claims, demands, waivers and other communications hereunder (each, a "**Notice**") shall be in writing and addressed to the parties at the addresses set forth on the face of the Proposal or to such other address that may be designated by the receiving party in writing. Notices sent in accordance with this Section will be deemed effectively given: (a) when received, if delivered by hand, with signed confirmation of receipt; (b) when received, if sent by a nationally recognized overnight courier, signature required; (c) when sent, if by facsimile or email (**in** each case, with confirmation of transmission) if sent during the addressee's normal business hours, and on the next business day if sent after the addressee's normal business hours; and (d) on the seventh day after the date mailed by certified or registered mail by the Canada Post Corporation, return receipt requested, postage prepaid.

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DATE	QUOTATION
02/25/2025	CQT02974-0005

GAVIN MCINNIS
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS (cont'd)

25. SEVERABILITY - Should any provision of this Agreement be declared invalid, void or unenforceable for any reason, the remaining provisions of this Agreement shall be unaffected and shall continue in full force and effect, and such invalid, void or unenforceable provision shall be interpreted as closely as possible to the manner in which it was written.

26. COMPLIANCE WITH LAW - Buyer shall comply with all applicable laws, regulations and ordinances. Buyer shall maintain in effect all the licenses, permissions, authorizations, consents and permits that it needs to carry out its obligations under this Agreement. Buyer shall comply with all export and import laws of all countries involved in the sale of the Goods under this Agreement or any resale of the Goods by Buyer. Buyer assumes all responsibility for shipments of Goods requiring any government import clearance. Seller may terminate this Agreement if any governmental authority imposes antidumping or countervailing duties or any other penalties on Goods.

27. TERMINATION - In addition to any remedies that may be provided under these Terms, Seller may terminate this Agreement with immediate effect upon written notice to Buyer, if Buyer: (a) fails to pay any amount when due under this Agreement; (b) has not otherwise performed or complied with any of these Terms, in whole or in part; or (c) becomes insolvent, files a petition for bankruptcy or commences or has commenced against it proceedings relating to bankruptcy, receivership, reorganization or assignment for the benefit of creditors.

28. CONFIDENTIAL INFORMATION - All non-public, confidential or proprietary information of Seller, including but not limited to, specifications, samples, patterns, designs, plans, drawings, documents, data, business operations, customer lists, pricing, discounts or rebates, disclosed by Seller to Buyer, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as “confidential” in connection with this Agreement is confidential, solely for the use of performing this Agreement and may not be disclosed or copied unless authorized in advance by Seller in writing. Seller shall be entitled to injunctive relief for any violation of this Section. This Section does not apply to information that is: (a) in the public domain; (b) known to Buyer at the time of disclosure; or (c) rightfully obtained by Buyer on a non-confidential basis from a third party.

29. ASSIGNMENT - Buyer shall not assign any of its rights or delegate any of its obligations under this Agreement without the prior written consent of Seller. Any purported assignment or delegation in violation of this Section is null and void. No assignment or delegation relieves Buyer of any of its obligations under this Agreement. Seller shall be entitled to assign its rights and obligations hereunder in its sole discretion. Subject to the foregoing, this Agreement shall be binding upon and inure to the benefit of and be enforceable by the parties and their respective successors, assigns, heirs and legal representatives and no other person or entity shall have any right, benefit or obligation hereunder.

30. LANGUAGE - The parties acknowledge and agree that they have required that this Agreement be prepared in the English language. Les parties reconnaissent avoir exigé que les présentes soient rédigées en langue anglaise.

31. SURVIVAL - Provisions of these Terms which by their nature should apply beyond their terms will remain in force after any termination or expiration of this Agreement including, but not limited to, the following provisions: Section 9 (Insurance), Section 20 (Limitation of Liability), Section 23 (Governing Law), Section 28 (Confidential Information) and this Section 31 (Survival).

ProcessBarron – Southern Field Canada Inc.
P.O. Box 94090, Bedford PO
Toronto, Ontario M4N 3R1
CSD005 – Proposal Document Rev.2

July 10, 2025

Nova Scotia Power
Tufts Cove Generating Station
315 Windmill Road,
Dartmouth, Nova Scotia

Attention: Gavin McInnis Via E-mail: gavin.mcinnis@nspower.ca

Reference: NS Power Tufts Cove TUC3 Precipitator Ash Handling
Budgetary Quote for Mechanical Installation
PBSF Reference: CBT480

Dear Gavin,

ProcessBarron – Southern Field Canada (PBSF) is pleased to provide this Budgetary Proposal for the installation of ash handling equipment as described in ProcessBarron proposal CQT02974.

The scope of work included in our budgetary estimate consists of mechanical installation of the following:

[redacted]

The scope of work associated with this project also includes:

- Planning, coordination, engineering (if required), procurement and mobilization of necessary resources.
- The supply, set up, and orientation of all tools and equipment for the removal and installation of replacement components.
- The cleanup, close out and demobilization from the site
- Capital tools and rental equipment such as welding machines, light towers, etc. as needed to perform the work.

Excluded from our quote are the following:

- Installation or removal of any insulation and lagging
- Hazardous materials abatement, if required
- Installation of any permanent access platforms
- Provision of scaffolding or elevated work platforms
- Crane, if required
- Fire protection, first aid, emergency showers, and spill cleanup
- Permits for hot/cold work, lockouts, tagouts, blinding, and de-energizing of equipment
- Site access, vehicle parking, laydown and temporary storage for tools, equipment, and materials
- Washrooms, lunchrooms, office space, supplies, waste disposal and cleaning services
- Utilities including power, heat, ventilation, potable & plant water, waste bins, compressed air & fuel
- Gas testing & monitoring, confined space & fire watch attendants, emergency responders, high angle rescue & medical transportation
- Onsite transportation, handling and storage of construction materials and disposal of all waste materials
- Specialized services such as PWHT, field machining, and other 3rd party service and testing representatives

ProcessBarron – Southern Field Canada Inc.
P.O. Box 94090, Bedford PO
Toronto, Ontario M4N 3R1

The estimated timeline for completing the installation work is approximately 2-4 weeks, depending on the preferred schedule and manpower loading. The work would require approximately 1000 hours of direct labour, with an additional 300 hours of supervision and project management. The work would be completed on a time and material basis in accordance with our standard rates, found at the end of this document.

[redacted]

Thank you for the opportunity to provide you with this proposal. Should you have any question or require clarifications or additional information, please contact the undersigned or our Regional Sales Manager.

Sincerely,

Ivan Sretenović

Ivan Sretenović
Managing Director
ProcessBarron - Southern Field Canada Inc.

The information contained within this document and related attachments is confidential and proprietary to PBSF and is intended to remain Confidential. Disclosing, duplicating, sharing or distributing the content either in whole or in segments is strictly prohibited.

ProcessBarron - Southern Field Canada, Inc.
PO Box 94090 | Bedford PO
Toronto, Ontario | M4N 3R1

2024-2025 ProcessBarron – Southern Field Standard Field Service Labour and Equipment Rates:

[redacted]

ProcessBarron - Southern Field Canada, Inc.
PO Box 94090 | Bedford PO
Toronto, Ontario | M4N 3R1

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SouthernField | EnvironmentalElements

DATE	QUOTATION
07/10/2025	CQT03259-0001

ProcessBarron - Southern Field Canada, Inc.
P.O Box 94090 / Bedford PO | Toronto, ON M4N 3R1
Phone: (205) 663-5330 | Fax: (205) 663-6037
http://www.processbarron.com

New Fans	Solid Fuel Feed Systems	Mechanical Dust Collectors
Fan Repair & Service	Mechanical Ash Handling Systems	Boiler Air Heater
Dampers	New & Replacement Screw Conveyors	Boiler Retrofit & Conveyors
Expansion Joints	Breeching, Stacks, & Ductwork	Turnkey Projects

Quotation For:
Gavin McInnis
NOVA SCOTIA POWER - TUFT'S COVE
315 WINDMILL ROAD
DARTMOUTH NS B3A 3C5
Canada

Phone:
(902) 292-5515

Email:

Quote Expires: 08/02/2025
Payment Terms: See Quotation Comments
Shipping: FOB ORIG PP&ADD
Sales Mgr: Brian Buchanan
bbuchanan@processbarron.com
(205) 613-4920
Sales Rep: STAN LORENOWICH
stanleyc@videotron.ca
(514) 799-9929

Description: Measuring Trip/Pre-engineering

Line	Description	Quantity	Unit	Unit Price	Extended Price
1	Measuring Trip/Pre-engineering	1	EA	[redacted]	

[redacted]

Grand Total: [redacted]

Quotation Comments:

ProcessBarron
SouthernField | EnvironmentalElements

DATE	QUOTATION
07/10/2025	CQT03259-0001

Gavin McInnis
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS

Unless otherwise indicated within the details of this quotation/proposal, the following General Terms & Conditions shall apply:

1. GENERAL

A. These general terms and conditions of sale (these "Terms") are the only terms which govern the sale of the goods and equipment ("Goods") and services ("Services") by Processbarron - Southern Field Canada Inc. ("Seller") to the buyer named on the reverse side of these Terms ("Buyer"). Notwithstanding anything herein to the contrary, if a written contract signed by both parties is in existence covering the sale of the Goods and Services covered hereby, the terms and conditions of said contract shall prevail to the extent they are inconsistent with these Terms.

B. The accompanying quotation/proposal (the "**Proposal**") and these Terms (collectively, this "**Agreement**") comprise the entire agreement between the parties, and supersede all prior or contemporaneous understandings, agreements, negotiations, representations and warranties, and communications, both written and oral. These Terms prevail over any of Buyer's general terms and conditions of purchase regardless of whether or when Buyer has submitted its purchase order or such terms. Fulfilment of Buyer's order does not constitute acceptance of any of Buyer's terms and conditions and does not serve to modify or amend these Terms and/or the Agreement.

C. Notwithstanding anything to the contrary contained in this Agreement, Seller may, from time to time change the Services without the consent of Buyer *provided that* such changes do not materially affect the nature or scope of the Services, or the fees or any performance dates set forth in the Proposal.

2. **PRICING NOTE -** If the material price varies between the date of the Proposal and the date the purchase order (the "**Order**") is placed, Seller reserves the right to adjust pricing to reflect such price changes. Seller will provide Buyer with prompt written notice in the event of any such price change.

3. PROPOSAL ACCEPTANCE - This Proposal is offered for acceptance within thirty (30) days from the date of the Proposal, after which it is subject to confirmation by Seller, and made with the understanding that if accepted by Buyer these Terms are agreed to.

4. **DELIVERY OF GOOD AND PERFORMANCE OF SERVICES -**

A.The Goods will be delivered within a reasonable time after the receipt of Buyer's Order, subject to availability of finished Goods. Seller shall not be liable for any delays, loss or damage in transit.

B. Unless otherwise agreed in writing by the parties, the Goods shall be delivered to the delivery point as indicated on the Proposal (the "**Delivery Point**"). Buyer shall be responsible for all loading costs and provide equipment and labour reasonably suited for receipt of the Goods at the Delivery Point.

C. Seller may, in its sole discretion, without liability or penalty, make partial shipments of Goods to Buyer. Each shipment will constitute a separate sale, and Buyer shall pay for the units shipped whether such shipment is in whole or partial fulfilment of Buyer's Order.

D. With respect to the Services, Buyer shall (i) cooperate with Seller in all matters relating to the Services and provide such access to Buyer's premises, and such office accommodation and other facilities as may reasonably be requested by Seller, for the purposes of performing the Services; (ii) respond promptly to any Seller request to provide direction, information, approvals, authorizations or decisions that are reasonably necessary for Seller to perform Services in accordance with the requirements of this Agreement; (iii) provide such customer materials or information as Seller may request to carry out the Services in a timely manner and ensure that such customer materials or information are complete and accurate in all material respects; and (iv) obtain and maintain all necessary licenses and consents and comply with all applicable laws in relation to the Services before the date on which the Services are to start.

5. RESPONSIBILITY -

a. Seller shall not be liable or responsible to Buyer, nor be deemed to have defaulted under or breached this Agreement, for any failure or delay in fulfilling or performing any term of this Agreement when and to the extent Seller's failure or delay is caused by or results from the following force majeure events ("**Force Majeure Event(s)**"): (a) acts of God; (b) flood, tsunami, fire, earthquake, explosion; (c) epidemics, pandemics, including the 2019 novel coronavirus pandemic (COVID-19); (d) war, invasion, hostilities (whether war is declared or not), terrorist threats or acts, riot, or other civil unrest; (e) government order, law or actions; (f) embargoes or blockades in effect on or after the date of this Agreement; (g) national or regional emergency; (h) strikes, lockouts, labour stoppages or slowdowns, labour disputes, or other industrial disturbances; (i) shortage of adequate power or telecommunications or transportation facilities; (j) failure of any governmental or public authority to grant a necessary licence or consent; and (k) other events beyond the reasonable control of Seller.

B. Authorization by Buyer to ship the Goods shall constitute a waiver of all claims for loss and damage due to delay.

C. Buyer will assume full responsibility for any loss or damage resulting from operation of the Goods. Seller assumes no responsibility for any auxiliary apparatus or work in connection with the Goods furnished hereunder, notwithstanding that Seller may have submitted recommendations pertaining hereto.

6. INSPECTION - Buyer shall inspect the Goods within five (5) business days of receipt ("**Inspection Period**"). Buyer will be deemed to have accepted the Goods unless it notifies Seller in writing of any Non-Conforming Goods during the Inspection Period and furnishes such written evidence or other documentation as required by Seller. "Non-Conforming Goods" means only the following: (i) product shipped is different than identified in Buyer's Order; or (ii) product's label or packaging incorrectly identifies its contents.

7. **DEFECTIVE GOODS -**

A. If any Goods, as furnished by Seller are alleged by Buyer to be defective or not manufactured in accordance with Buyer's specifications and are rejected by Buyer within the warranty period, Buyer shall promptly notify Seller and Seller shall have the option of replacing or correcting, within a reasonable time, any defective Goods, at Seller's own expense, or reimbursing Buyer the agreed cost of such replacement or correction. Buyer shall not furnish any material or do any work for Seller's account without specific authorization and a definitive written agreement from Seller as to the consideration, and in no case shall the Seller be liable for more than the price charged for such material as may prove defective, and no payments shall be withheld by Buyer pending adjustment of liability or amount of cost of alleged errors.

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DATE	QUOTATION
07/10/2025	CQT03259-0001

Gavin McInnis
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS (cont'd)

B. Buyer acknowledges and agrees that the remedies set forth in Section 7(A) are Buyer's exclusive remedies for the delivery of Non-Conforming Goods. Except as provided under Section 7(A), all sales of Goods to Buyer are made on a one-way basis and Buyer has no right to return Goods purchased under this Agreement to Seller.

8. WARRANTIES -

A. Seller warrants to Buyer that for a period of twelve (12) months after installation or eighteen (18) months after shipment of the Goods, whichever comes first (the "**Warranty Period**"), that such Goods will be free from defects in material and workmanship. Subject to the below, with respect to any such Goods during the Warranty Period, Seller shall, in its sole discretion, either (i) repair or replace such Goods (or the defective part) or (ii) credit or refund the price of such Goods at the pro rata contract rate *provided that,* if Seller so requests, Buyer shall, at Seller's expenses, return such Goods to Seller.

B. EXCEPT FOR THE EXPRESS WARRANTY SET FORTH ABOVE, SELLER MAKES NO WARRANTY OR REPRESENTATION OF ANY KIND WITH RESPECT TO THE GOODS, WHETHER EXPRESS, IMPLIED, OR STATUTORY, INCLUDING BUT NOT LIMITED TO (A) ANY WARRANTY OR CONDITION OF MERCHANTABILITY. MERCHANTABLE QUALITY, OR FITNESS FOR A PARTICULAR PURPOSE OR (B) ANY WARRANTY ARISING AS A RESULT OF USAGE IN THE TRADE OR BY COURSE OF DEALING. BUYER ACKNOWLEDGES THAT IT HAS NOT RELIED UPON ANY REPRESENTATION, CONDITION OR WARRANTY MADE BY SELLER, OR ANY OTHER PERSON ON SELLER'S BEHALF, EXCEPT AS SPECIFICALLY PROVIDED ABOVE.

C. The Seller shall not be liable for a breach of warranty set forth above unless (i) Buyer gives written notice of the defect to Seller within sixty (60) days from when Buyer discovers or ought to have discovered the defect; and (ii) Seller reasonably verifies Buyer's claim that the Goods are defective. Deterioration or wear occasioned by chemical, abrasive or excessive heat shall not constitute defects. Seller shall, at its option, repair or replace such Goods (or defective part), without charge at FOB point of shipment, provided that such warranty excludes the cost to remove and re-install such Goods, and all transportation costs.

D. Goods not manufactured by Seller are warranted only to the extent they are warranted by their manufacturer. This warranty does not cover any Goods which, in the judgment of Seller, have (i) been subject to misuse, neglect, improper maintenance, improper storage, improper installation, abnormal environmental conditions or use contrary to any instructions issued by Seller; (ii) been repaired or altered outside Seller's plant in any way that may have impaired its safety, operation, or efficiency; nor any product which has been subject to accident or operated in excess of design limitations.

9. INSURANCE - During the term of this Agreement, Buyer shall, at its own expense, maintain and carry insurance in full force and effect which includes, but is not limited to, commercial general liability (including product liability) in a sum no less than two (2) times the aggregate purchase order amount with financially sound and reputable insurers. Upon Seller's request, Buyer shall provide Seller with a certificate of insurance from Buyer's insurer evidencing the insurance coverage specified in these Terms. Buyer shall provide Seller with thirty (30) days' advance written notice in the event of a cancellation or material change in Buyer's insurance policy. Except where prohibited by law, Buyer shall require its insurer to waive all rights of subrogation against Seller's insurers and Seller.

10. TITLE AND RISK OF LOSS - Title and risk of loss passes to Buyer upon delivery of the Goods at the Delivery Point. As collateral security for the payment of the purchase price of the Goods, Buyer hereby grants to Seller a lien on and security interest in and to all of the right, title and interest of Buyer in, to and under the Goods, wherever located, and whether now existing or hereafter arising or acquired from time to time, and in all accessions thereto and replacements or modifications thereof, as well as all proceeds (including insurance proceeds) of the foregoing. The security interest granted under this provision constitutes a purchase money security interest under the applicable Provincial Personal Property Security Act.

11. ACCESS - Authorized representatives of Seller acceptable to Buyer acting reasonably shall have access at all reasonable times to the installation of the Goods for the purpose of observing and adjusting the operation thereof.

12. TIME OF SHIPMENT - Statements as to expected dates of shipment represent Seller's best judgment, but shipment on those dates is not guaranteed. The time of shipment shall be determined from date of receipt by Seller of all information necessary to enable Seller to proceed with its work.

13. SUBCONTRACTING - Seller reserves as its prerogative the option to subcontract all or any portion of work under contract.

14. TAXES - The prices shown do not include any taxes (sales, excise, use, etc.) or any other governmental charges. Any charges or taxes applicable to the order will be paid by Buyer except where specifically exempt by a certificate.

15. TERMS OF PAYMENT -

A. Unless other terms of payment are specified in this Proposal or shown on the Order, payment shall become due thirty (30) days from the date of Seller's invoice. If shipment is delayed by Buyer, payment shall become due thirty (30) days from date Seller is ready to ship. If manufacturing is delayed by Buyer, partial shipment is to be made based on the acknowledged price and a percentage of completion at time of notification of delay.

B. If in the judgment of Seller the financial condition of Buyer is changed and at the time of construction or shipment does not warrant the terms shown on the Order, Seller may require full or partial payment in advance of construction and shipment of the Order.

C. Should Buyer delay payment beyond limits defined in Seller's Proposal and Buyer's Order, then interest will be charged on any unpaid portion of the purchase price at the rate of 1.5% per month (being 19.6% per annum), calculated daily and compounded monthly.

16. CANCELLATION - Buyer may only cancel their Order by written notice to Seller. Such cancellation will be subject to charges incurred by Seller up through the date of cancellation based on engineering, manufacturing, or outside purchasing completed or irrevocably incurred at the time the notice of cancellation is received in writing.

17. FIELD WORK - Unless otherwise noted, the following terms apply to all work to be performed at Buyer or third party sites:

A. All work will be performed by open shop labor. Any union dispute will be the responsibility of Buyer. Any standby time resulting from such disputes will be billed at full rates;

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Gavin McInnis
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS (cont'd)

B. Pricing only includes safety orientation meetings of no more than one (1) hour duration scheduled on the first work day. Attendance at meetings of greater than one (1) hour duration or not scheduled on the first work day will be invoiced at full rates. Any safety orientation that must be attended by a Seller representative prior to the beginning of outage work will be billed at full rates;
C. It is the responsibility of Buyer to inform Seller of any flammable coating, residue, contaminants, hazardous materials, etc. that may be present within or around the housings, ductwork or any area where Seller work is to be performed or where Seller personnel may be present. It is the responsibility of Buyer to remove and/or clean up any hazardous materials prior to Seller beginning work;
D. Field installation pricing presumes that all necessary access will be made available to Seller crews as needed to complete work as detailed herein; impediments such as, but not limited to, scaffolding, contractor tools, and/or cranes set in place by others that prevent or slow Seller field crews from completing their tasks will result in additional charges in the amount of time lost;
E. In performing the removal and installation of equipment, Seller crews will be following Seller's normal industry accepted rigging and lifting procedures. Seller's standard procedures are also governed by Seller's company safety regulations and procedures. The pricing and scheduling of this project is based on the Seller crews utilizing Seller's standard procedures and policies to safely complete this project. Should Buyer (Safety Group, Engineering, EPC or other contracted third party) require Seller's crews follow other policies, procedures, lifting or rigging plans (and/or require engineering certified lifting plans & additional equipment), then the additional man-hours and other associated costs will be performed on a time and materials basis and will be invoiced based on the actual hours and expense required by these changes in procedures; and
F. It is Buyer's responsibility to supply the required lubrication for all rotary equipment. Seller can recommend the lubrication type if needed, and Seller will install customer-supplied lubrication upon request if Seller crews are onsite installing/maintaining equipment. Nevertheless, it is ultimately Buyer's responsibility to supply and ensure proper lubrication levels prior to running the equipment.

18. REPLACEMENT PARTS - If these Terms are for replacement parts, Buyer warrants that the original components in which such replacement parts will be placed are in satisfactory working condition, and when such replacement parts are installed, the resultant installation will operate in a safe manner, at speeds and temperatures for which the original equipment was purchased.

19. SAFETY ACCESSORIES- Buyer understands that Seller manufactures multifunctional goods that may or may not require safety devices, depending on the use and location of the goods. Buyer warrants that it has determined what safety devices, including warning devices and notices of danger, should be placed on the Goods sold hereunder, and further warrants that it has either purchased these from Seller or from another source.

20. LIMITATION OF LIABILITY - IN NO EVENT SHALL SELLER BE LIABLE FOR ANY CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, OR PUNITIVE DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF OR RELATING TO ANY BREACH OF THESE TERMS AND/OR THE AGREEMENT, WHETHER OR NOT THE POSSIBILITY OF SUCH DAMAGES HAS BEEN DISCLOSED IN ADVANCE BY BUYER OR COULD HAVE BEEN REASONABLY FORESEEN BY BUYER, REGARDLESS OF THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED, AND NOTWITHSTANDING THE FAILURE OF ANY AGREED OR OTHER REMEDY OF ITS ESSENTIAL PURPOSE. IN NO EVENT SHALL SELLER'S AGGREGATE LIABILITY ARISING OUT OF OR RELATED TO THIS AGREEMENT, WHETHER ARISING OUT OF OR RELATED TO BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, EXCEED THE TOTAL OF THE AMOUNTS PAID TO SELLER FOR THE GOODS AND SERVICES SOLD HEREUNDER.

21. WAIVER - No waiver by Seller of any of the provisions of this Agreement is effective unless explicitly set forth in writing and signed by Seller. No failure to exercise, or delay in exercising, any right, remedy, power or privilege arising from this Agreement operates, or may be construed, as a waiver thereof. No single or partial exercise of any right, remedy, power or privilege hereunder precludes any other or further exercise thereof or the exercise of any other right, remedy, power or privilege.

22. RELATIONSHIP OF PARTIES - The relationship between the parties is that of independent contractors. Nothing contained in this Agreement shall be construed as creating any agency, partnership, joint venture or other form of joint enterprise, employment or fiduciary relationship between the parties, and neither party shall have authority to contract for or bind the other party in any manner whatsoever.

23. GOVERNING Law - This Agreement shall be governed by and interpreted under the laws of the Province of Ontario and the federal laws of Canada applicable therein. Any litigation with respect to the provisions of this Agreement may be brought in provincial or federal courts located in the Province of Ontario.

24. NOTICE - All notices, request, consents, claims, demands, waivers and other communications hereunder (each, a "**Notice**") shall be in writing and addressed to the parties at the addresses set forth on the face of the Proposal or to such other address that may be designated by the receiving party in writing. Notices sent in accordance with this Section will be deemed effectively given: (a) when received, if delivered by hand, with signed confirmation of receipt; (b) when received, if sent by a nationally recognized overnight courier, signature required; (c) when sent, if by facsimile or email (**in** each case, with confirmation of transmission) if sent during the addressee's normal business hours, and on the next business day if sent after the addressee's normal business hours; and (d) on the seventh day after the date mailed by certified or registered mail by the Canada Post Corporation, return receipt requested, postage prepaid.

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07/10/2025	CQT03259-0001

Gavin McInnis
NOVA SCOTIA POWER - TUFT'S COVE

GENERAL TERMS & CONDITIONS (cont'd)

25. SEVERABILITY - Should any provision of this Agreement be declared invalid, void or unenforceable for any reason, the remaining provisions of this Agreement shall be unaffected and shall continue in full force and effect, and such invalid, void or unenforceable provision shall be interpreted as closely as possible to the manner in which it was written.

26. COMPLIANCE WITH LAW - Buyer shall comply with all applicable laws, regulations and ordinances. Buyer shall maintain in effect all the licenses, permissions, authorizations, consents and permits that it needs to carry out its obligations under this Agreement. Buyer shall comply with all export and import laws of all countries involved in the sale of the Goods under this Agreement or any resale of the Goods by Buyer. Buyer assumes all responsibility for shipments of Goods requiring any government import clearance. Seller may terminate this Agreement if any governmental authority imposes antidumping or countervailing duties or any other penalties on Goods.

27. TERMINATION - In addition to any remedies that may be provided under these Terms, Seller may terminate this Agreement with immediate effect upon written notice to Buyer, if Buyer: (a) fails to pay any amount when due under this Agreement; (b) has not otherwise performed or complied with any of these Terms, in whole or in part; or (c) becomes insolvent, files a petition for bankruptcy or commences or has commenced against it proceedings relating to bankruptcy, receivership, reorganization or assignment for the benefit of creditors.

28. CONFIDENTIAL INFORMATION - All non-public, confidential or proprietary information of Seller, including but not limited to, specifications, samples, patterns, designs, plans, drawings, documents, data, business operations, customer lists, pricing, discounts or rebates, disclosed by Seller to Buyer, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as “confidential” in connection with this Agreement is confidential, solely for the use of performing this Agreement and may not be disclosed or copied unless authorized in advance by Seller in writing. Seller shall be entitled to injunctive relief for any violation of this Section. This Section does not apply to information that is: (a) in the public domain; (b) known to Buyer at the time of disclosure; or (c) rightfully obtained by Buyer on a non-confidential basis from a third party.

29. ASSIGNMENT - Buyer shall not assign any of its rights or delegate any of its obligations under this Agreement without the prior written consent of Seller. Any purported assignment or delegation in violation of this Section is null and void. No assignment or delegation relieves Buyer of any of its obligations under this Agreement. Seller shall be entitled to assign its rights and obligations hereunder in its sole discretion. Subject to the foregoing, this Agreement shall be binding upon and inure to the benefit of and be enforceable by the parties and their respective successors, assigns, heirs and legal representatives and no other person or entity shall have any right, benefit or obligation hereunder.

30. LANGUAGE - The parties acknowledge and agree that they have required that this Agreement be prepared in the English language. Les parties reconnaissent avoir exigé que les présentes soient rédigées en langue anglaise.

31. SURVIVAL - Provisions of these Terms which by their nature should apply beyond their terms will remain in force after any termination or expiration of this Agreement including, but not limited to, the following provisions: Section 9 (Insurance), Section 20 (Limitation of Liability), Section 23 (Governing Law), Section 28 (Confidential Information) and this Section 31 (Survival).

CI Number: C0080135

Title: CT-BGT2 Engine Refurbishment

Start Date: 2026/07
In-Service Date: 2026/10
Final Cost Date: 2027/04
Function: Gas Turbine
Forecast Amount: $2,462,664

DESCRIPTION:

This project is for the refurbishment of the Burnside Unit #2 Combustion Turbine engine. This includes a full tear down, inspection, and refurbishment or replacement of all engine components per the OEM service guidelines and inspection findings. NS Power performs major shop inspections/refurbishment (MSIs) at the refurbishment depot based on routine thorough internal borescope inspections that are conducted annually by NS Power to determine engine condition over time. Please refer to Attachment 1 for the most recent annual routine inspection conducted in March 2025. This inspection revealed the need for a shop-level tear down, particularly due to damage observed on the stage 9 blades—a compressor stage that NS Power has previously experienced two unplanned failures.

Burnside Unit #2 is a 33MW combustion turbine located in the Burnside Industrial Park in Dartmouth. It provides black start capability, 10-minute reserve, Volt-Ampere Reactive support and additional firm energy capacity to the NS Power electrical system. The unit was originally commissioned by NS Power in 1976

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Gas Turbine projects include "work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example).

- No other projects in 2024, 2025, 2026, 2027 or 2028

Depreciation Class: Other Production – Gas Turbines - Burnside

Estimated Life of the Asset: 10 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 4.22%

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

Please refer to Attachment 1 for the most recent borescope inspection (BSI) report from March 2025 which has identified signs of increased wear and damage in the engine. NS Power has established a condition-based approach via routine internal borescope inspections and major shop inspections. Major shop inspects are done to proactively address hidden failure modes, such as excess blade root wear – a condition that can lead to blade liberation and only detectable through depot-level teardown. This preventative strategy significantly reduces the risk of unplanned forced outages.

Refurbishing this engine will allow Burnside to maintain all four operating units, which provide multiple benefits to NS Power and its customers. This unit, along with all the other combustion turbines, provides essential ancillary services to the system such as:

- Peaking capacity – generation used to serve peak customer demand
- Black start capability – first-start generation used to start other generating assets following a widespread power system blackout

- 10-minute and 30-minute operating reserve – fast-acting generation that can be operational within 10 and 30 minutes

Fast-acting generation assets like Burnside Unit #2 are critical tools for system operators managing elevated levels of variable generation—such as wind—and responding to system disturbances to maintain system reliability. When energy output from wind or other sources unexpectedly declines, having generation available within 10 minutes helps mitigate the risk of a potential generation shortfall.

Additionally, the metro-based combustion turbines located in Burnside can provide Metro Dynamic Reactive Reserve (MDRR) to the electrical grid, operating either in generation mode or as synchronous condensers.

NS Power considers maintaining four operational units at Burnside to be a prudent, risk-mitigating investment. These units offer valuable operational flexibility and enhance system security through black start capability, rapid response, and improved system stability.

Why do this project now?

Completing the refurbishment of this engine in 2026 will reduce the likelihood of an unplanned failure. During the planned borescope inspection in March 2025, several indicators suggested the need for a shop-level teardown. Notably, damage was observed on the stage 9 blades, a compressor stage where NS Power has previously experienced unplanned failures due to blade liberation. Please refer to Attachment 1, which outlines the specific issues found during inspection.

The areas of highest risk are in the low-pressure compressor stage 1 blades and the high-pressure compressor stage 9 blades. Looseness and visible damage in these components are strong indicators of hidden wear in the blade roots and corresponding disk dovetails—issues that can only be confirmed through depot-level disassembly.

Additionally, offline but available periods expose engine components to temperature and humidity fluctuations, introducing corrosive elements into inaccessible areas of the engine.

The strategic approach to removing the engine and proceeding to the shop level disassembly and inspection is typical for all aeroderivative engines. By 2026, it will have been 10 years since the last major inspection and refurbishment. Although NS Power conducts thorough annual borescope inspections and continuous monitoring of other operation parameters, certain failure modes such as blade root wear and disk dovetail degradation can only be identified through depot-level disassembly in accordance with Original Equipment Manufacturer (OEM) procedures. Without this teardown, there remains a significant risk that hidden defects could evolve into unplanned unit failures.

Why do this project this way?

A “run to failure” strategy is not appropriate because of the risk of collateral damage to the rest of the unit and potential lead times of a replacement unit. The unit would be inoperable for an extended timeframe, with no firm capacity replacement available.

Refurbishment of the engine is a more cost-effective solution than replacing this component with a new asset, which is not considered necessary at this time. The 2025 10-Year System Outlook, filed with the Nova Scotia Energy Board in July 2025, reaffirms the value of sustaining the CT fleet to meet firm capacity requirements and maintain system reliability. This investment aligns with the resource plan outlined in the Evergreen IRP scenario CE1-E1-R2 and the Province’s Clean Power Plan.

New FT4 engine designs are no longer being produced and the only other option available would have been to purchase a previously owned and refurbished engine. Based on the asset condition of the existing P686632 engine and the available timeline for refurbishment, it was determined to be more cost effective to refurbish the existing engine rather than purchasing a previously owned engine. A new engine would be a magnitude of cost higher when compared to this engine refurbishment and still would require the same inspection and maintenance cost going forward.

Contingency:

Contingency for this project has been determined using a combination of internal subject matter expert judgement (professional engineers), similar CT engine projects (C0041506 – LM6000 191-253 Major Engine Refurbishment)

and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 15 percent. Risks intended to be covered by the contingency are for increased fallout from what has been experienced in previous NS Power P&W Engine depot-level refurbishments which includes potential for additional scrap items from the depot and vendor inspections. The scope of the refurbishment cannot be fully defined and costed until the depot level disassembly and inspection is completed.

Capital Project Detailed Estimate

Location: Gas Turbine
CI# : C0080135
Title: CT-BGT2 Engine Refurbishment
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	25	$ 466	$ 11,651		
Gas Turbine Operators	PD	100	$ 428	$ 42,780		
			Sub-Total	$ 54,431		
OT Labour						
Gas Turbine Operators	PD	25	$ 856	$ 21,390		
			Sub-Total	$ 21,390		
Travel Expense						
Quality Review & Witness Factory Acceptance Testing	lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 25,000		
Materials						
Engine Disassembly Clean & Inspection	Lot	1	[redacted]		Attachment 2, Page 1	
Major Shop Inspection	Lot	1			Attachment 2, Page 1	
Engine Fallout Replacement & Refurbishment	Lot	1	$ 500,000	$ 500,000		
USD to CAD	Lot	40%	[redacted]			
			Sub-Total	[redacted]		
Contracts						
Crane	lot	1	$ 12,500	$ 12,500		
Non-Destructive Examination	lot	1	$ 15,000	$ 15,000		
Alignment & Cooling Tube Inspection	lot	1	$ 35,000	$ 35,000		
			Sub-Total	$ 62,500		
Freight Postage Delivery						
Engine Freight	lot	1	$ 75,000	$ 75,000		
			Sub-Total	$ 75,000		
Consulting						
3rd Party Expert Review of Inspection Findings	lot	1	$ 25,000	$ 25,000		
Baseline Vibration Sampling	lot	1	$ 25,000	$ 25,000		
Shop & Test Oversite	lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 75,000		
Overtime Meals						
OT Meals	lot	1	$ 1,500	$ 1,500		
			Sub-Total	$ 1,500		
Rentals						
Rentals	lot	1	$ 2,500	$ 2,500		
			Sub-Total	$ 2,500		
Other Goods & Services						
Contingency	lot	15%	$ 2,100,007	$ 315,001		
			Sub-Total	$ 315,001		
Interest Capitalized						
AFUDC				$ 17,501		
			Sub-Total	$ 17,501		
Administrative Overhead						
Labour AO				$ 24,261		
Contractor AO				$ 5,894		
			Sub-Total	$ 30,155		
			SUB-TOTAL (no AO, AFUDC)	$ 2,415,008		
			TOTAL (AO, AFUDC included)	$ 2,462,664		
Original Cost				$ 1,897,341		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Process Industries	Required fields:	Estimate Classification				
Project Name: CT-BGT2 Engine Refurbishment	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Non-Process Facilities (Infrastructure, Ports, Pipeline, Power Transmission)	Not Applicable (NA)					
Project Scope of Work Description	Preliminary (P)	P	P			
Byproduct and Waste Disposal	Not Applicable (NA)	NR				
Site Infrastructure (Access, Construction Power, Camp, etc.)	Not Applicable (NA)	NR				
B. Capacity						
Plant Production/Facility (includes power facilities)	Not Applicable (NA)					
Electrical Power Requirements (when not the primary capacity driver)	Not Applicable (NA)	NR				
C. Project Location						
Plant and Associated Facilities	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Communication Systems	Not Applicable (NA)	NR				
Fire Protection and Life Safety	Not Applicable (NA)	NR				
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Process Technology	Not Applicable (NA)					
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Not Applicable (NA)	NR				
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Block Flow Diagrams	Not Applicable (NA)					
Equipment Data Sheets	Not Applicable (NA)	NR/S				
Equipment Lists: Electrical	Not Applicable (NA)	NR/S				
Equipment Lists: Process/Utility/Mechanical	Not Applicable (NA)	NR/S				
Heat & Material Balances	Not Applicable (NA)	NR				
Process Flow Diagrams (PFDs)	Not Applicable (NA)	NR				
Utility Flow Diagrams (UFDs)	Not Applicable (NA)	NR				
Design Specifications	Not Applicable (NA)	NR				
Electrical One-Line Drawings	Complete (C)	NR	S/P	C	C	C
General Equipment Arrangement Drawings	Complete (C)	NR	S/P	C	C	C
Instrument List	Not Applicable (NA)	NR				
Piping & Instrumentation Diagrams	Complete (C)	NR	S/P	C	C	C
Plot Plans/Facility Layouts	Not Applicable (NA)	NR				
Construction Permits	Not Applicable (NA)	NR				
Civil/Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Fire Protection & Life Safety Drawings & Details	Not Applicable (NA)	NR				
Electrical Schedules	Complete (C)	NR	NR/S	P	P/C	C
Instrument & Control Schedules	Complete (C)	NR	NR/S	P	P/C	C
Instrument Data Sheets	Complete (C)	NR	NR/S	P	P/C	C
Piping Schedules	Not Applicable (NA)	NR	NR/S			
Piping Discipline Drawings	Not Applicable (NA)	NR	NR/S			
Spare Parts Listings	Complete (C)	NR	NR	P	P/C	C
Electrical Discipline Drawings	Not Applicable (NA)	NR	NR			
Facility Emergency Communication Plan & Drawings	Not Applicable (NA)	NR	NR			
Information Systems/Telecommunication Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Mechanical Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	3	14	15	15	15
	% Defined/Complete towards Class Estimate	100%	100%	83%	83%	83%

Comments:

This project is being filed as a Class 3 estimate with a contingency of 15%. The defined deliverables for this project indicate that 83% of Class 3 deliverables are completed. A contingency value of 15% was selected based on similar CT engine projects in the past that have been filed before shop inspection(CI C0041506 – LM6000 191-253 Major Engine Refurbishment) .The contingency accounts for specific risks such as increased fallout from what has been experienced in previous NS Power P&W Engine depot level refurbishments. This includes potential for additional scrap items from both the depot inspection and vendor inspections. The contingency will also cover costs related to the scope of the refurbishment, which cannot be fully defined and costed until the depot level disassembly and inspection is completed.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions

For the purposes of this document, the term *process industries* is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs), piping and instrument diagrams (P&IDs), and electrical one-line drawings as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information. This RP applies to a variety of project delivery methods such as traditional design-bid-build (DBB), design-build (DB), construction management for fee (CM-fee), construction management at risk (CM-at risk), and private-public partnerships (PPP) contracting methods.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this recommended practice may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

Most plants also have significant electrical power equipment (e.g., transformers, switchgear, etc.) associated with them. As such, this RP also applies to electrical substation projects, either associated with the process plant, as part of power transmission or distribution infrastructure, or supporting the power needs of other facilities. This RP excludes power generating facilities and high-voltage transmission.

BGT2 BSI March 25, 2025

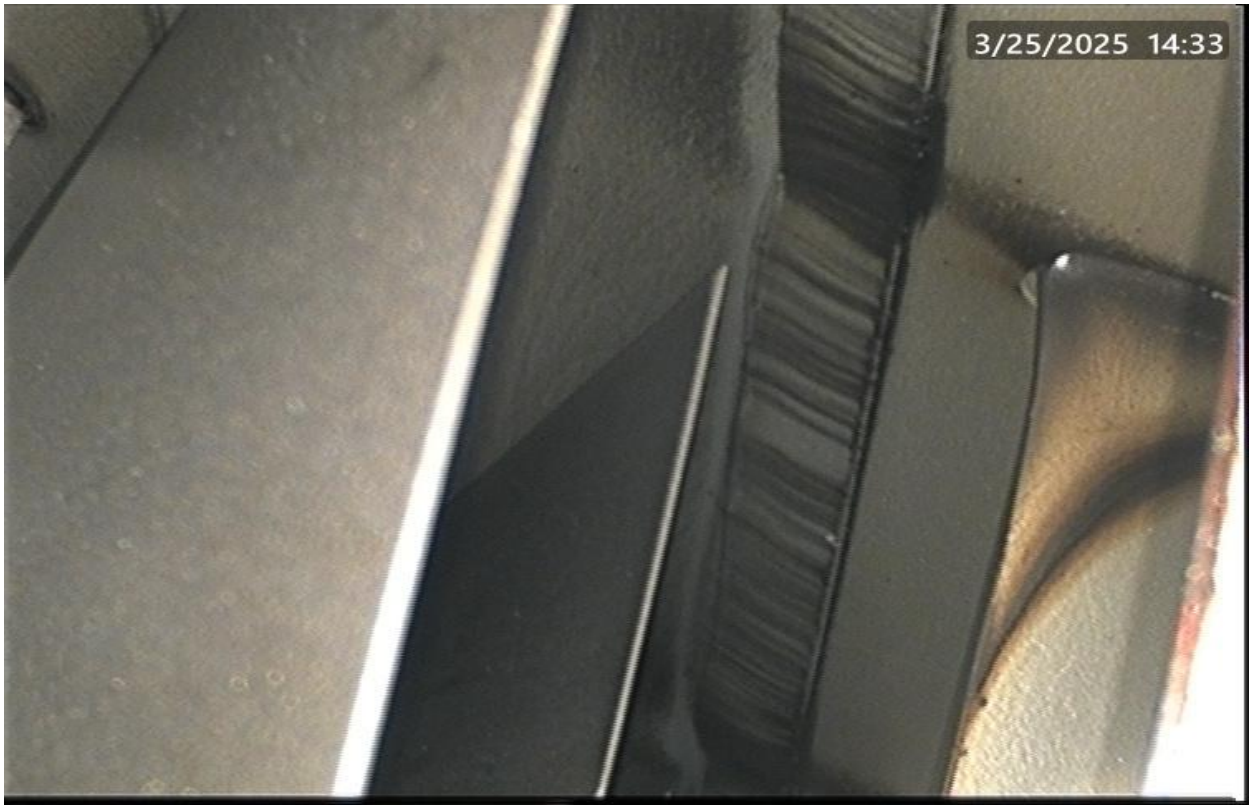
- LPC Inlet case rubbing @ 3 O'clock Position and from 4 to 7 O'clock position.
- LPC Stage 1 blades starting to show signs of looseness in the roots.
- LPC Inlet case #1 Bearing oil weeping/staining.
- Stage 9 several leading edge dents/dings.
- Replaced 2 combustion chambers.
- Outer transition duct several cracks to keep an eye on and some misalignment during installation at the 3 O'clock split line aft edge.
- HPT IGV trailing edge deterioration and cracking.
- Tt7 Probe inner retainer chafing through to the outside of the probe body.
- Free Turbine Inlet Guide Vanes Inspection conducted this year, no replacements required but some vanes will need closer scrutinizing next year. Recommend doing FT again next year as we also did HSI and combustion chamber replacements this year.

BGT2 BSI March 25, 2025

LPC Stage 1 Case Rubbing

BGT2 BSI March 25, 2025

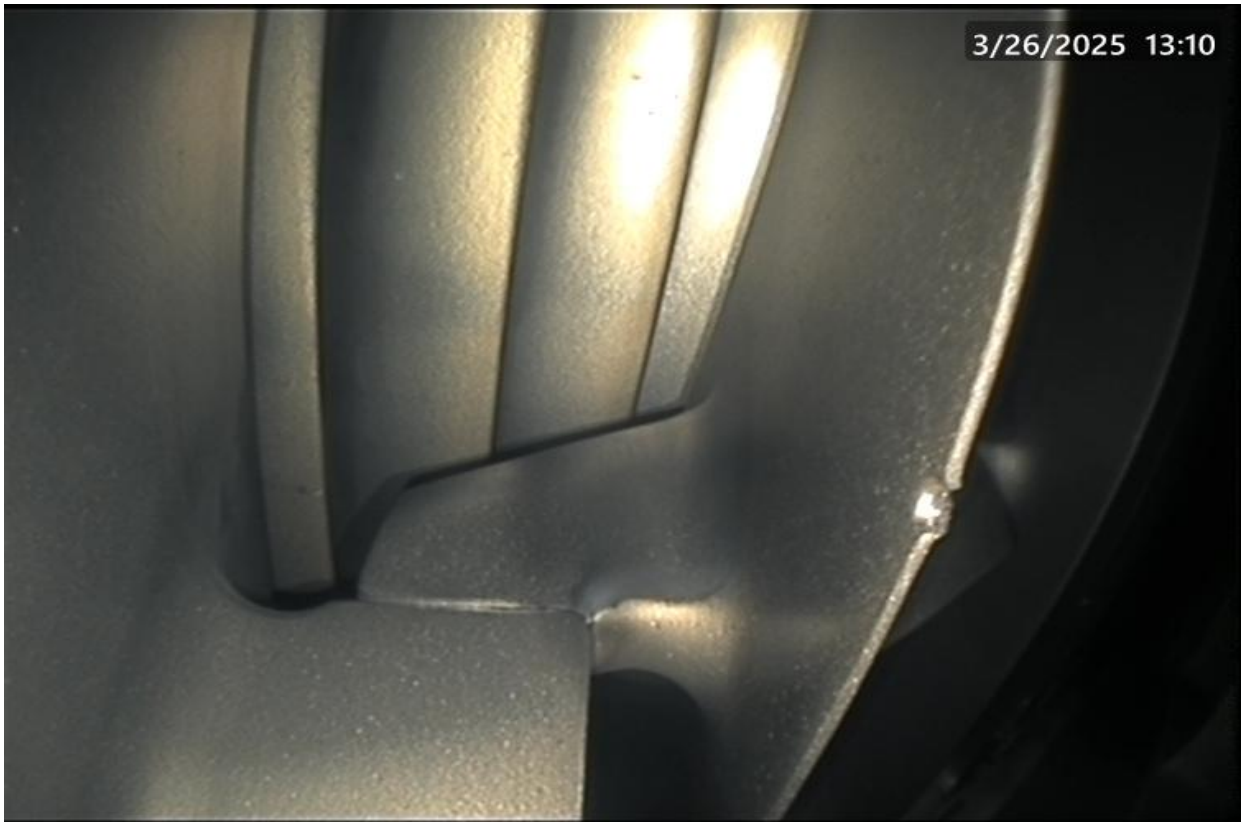
LPC Stage 1 oil staining from #1 Bearing Seal weeping.

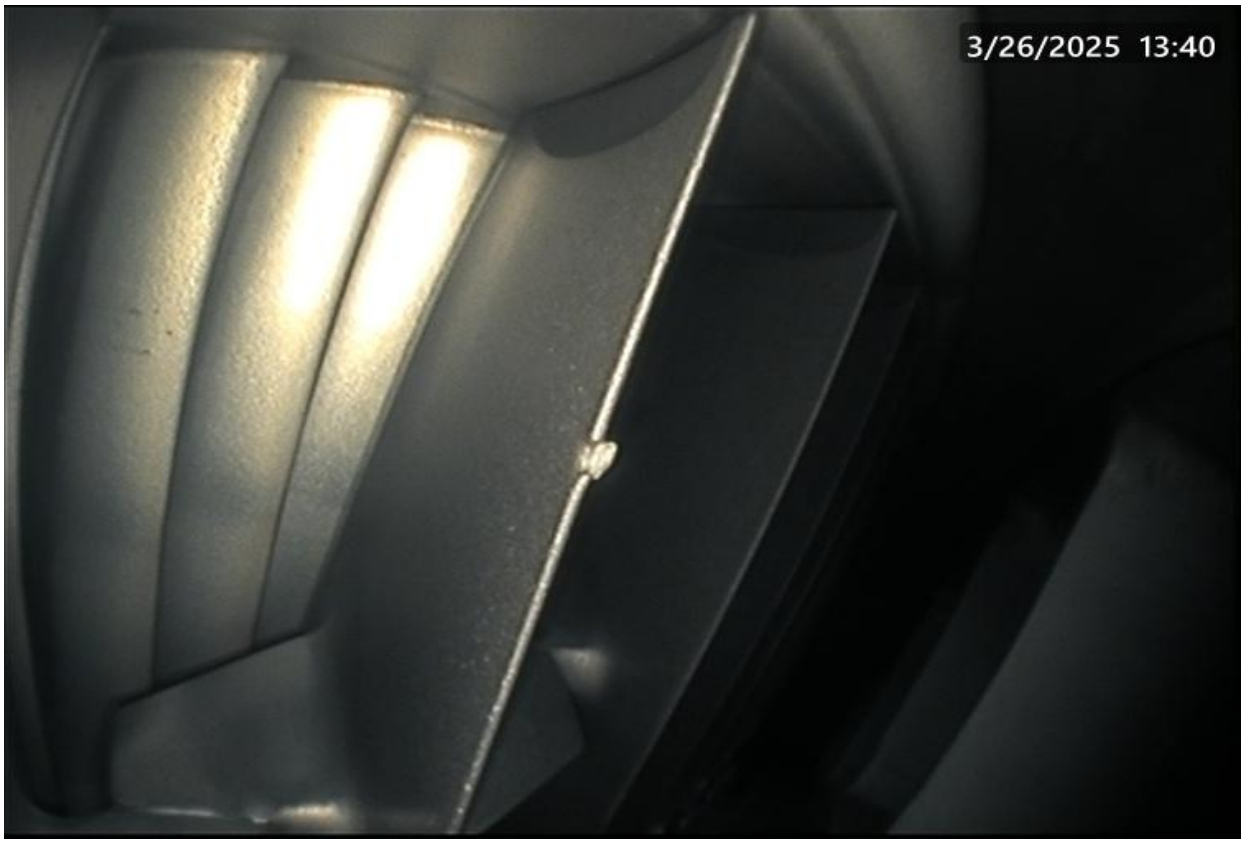


BGT2 BSI March 25, 2025

Stage 9

BGT2 BSI March 25, 2025





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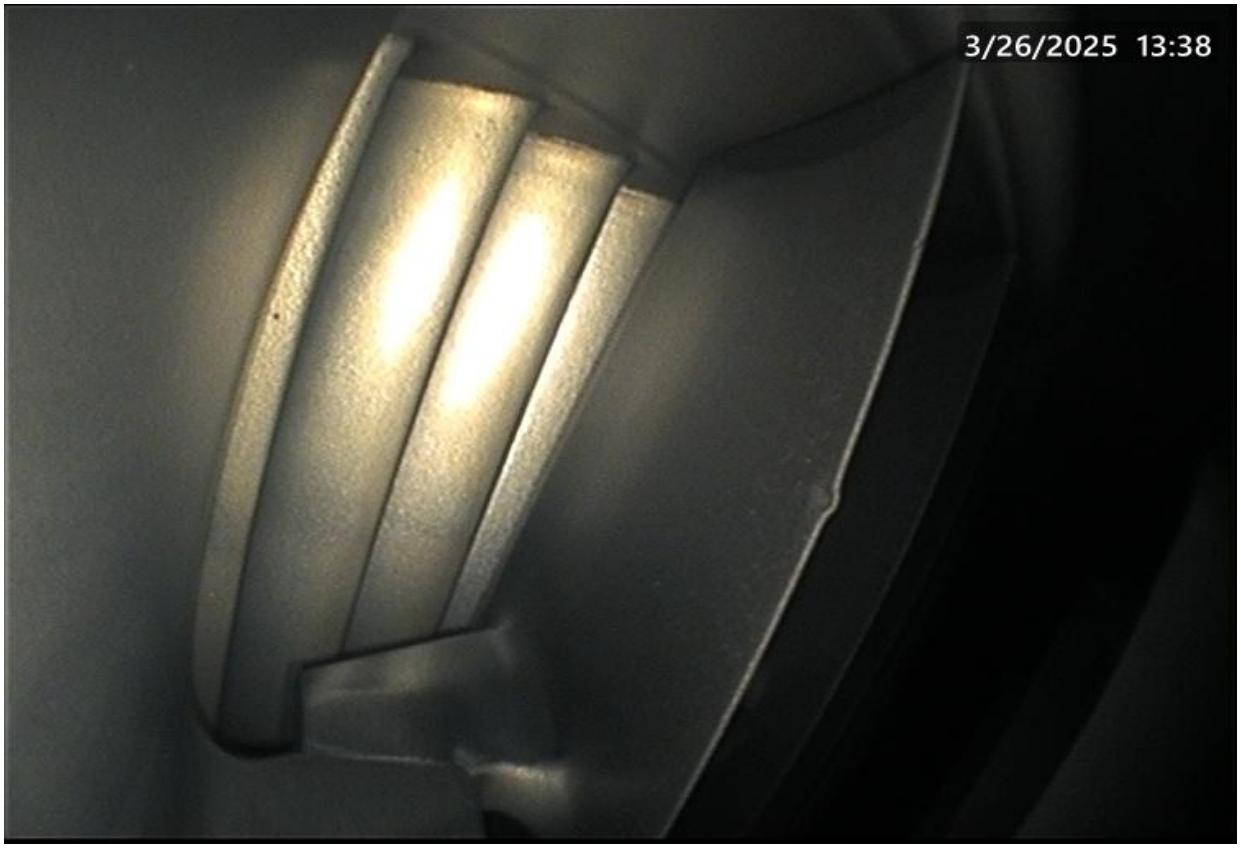
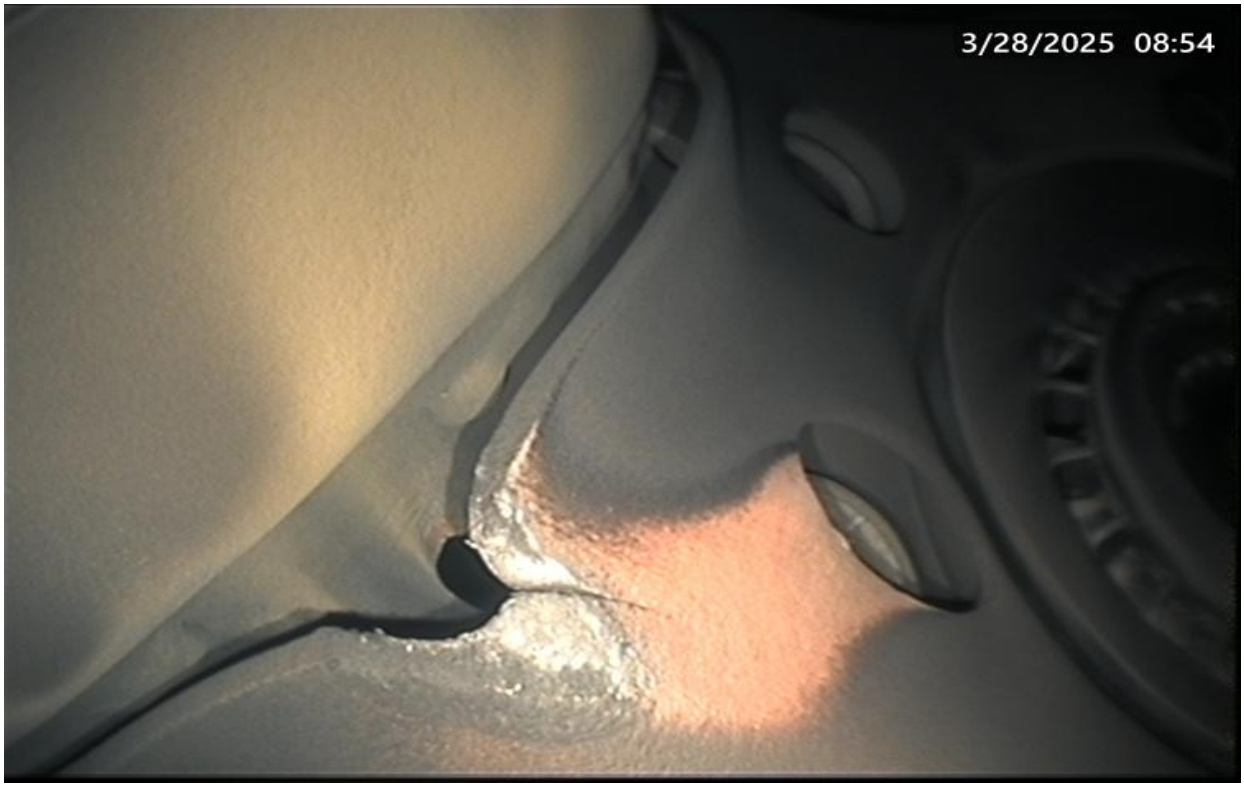


BGT2 BSI March 25, 2025

Igniter Tips

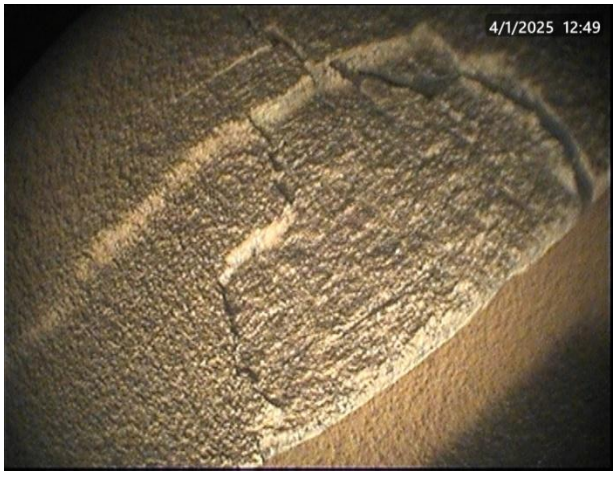
Combustion Section

BGT2 BSI March 25, 2025



BGT2 BSI March 25, 2025

Outer Transition Duct



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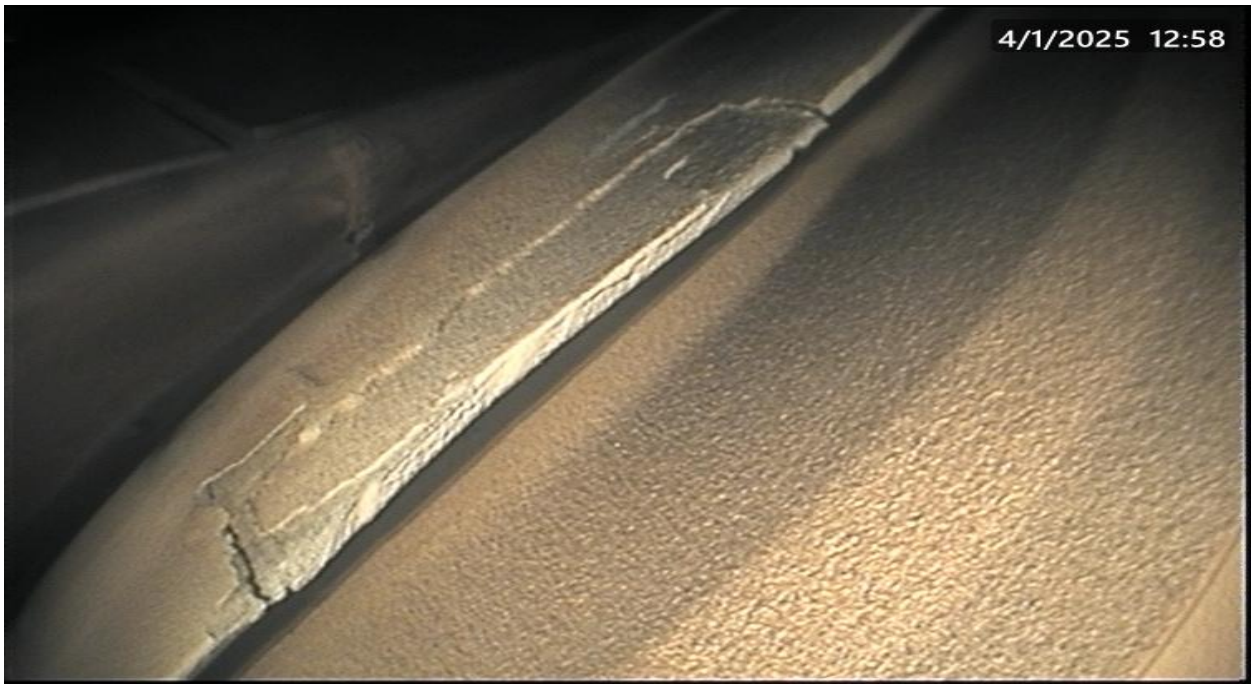

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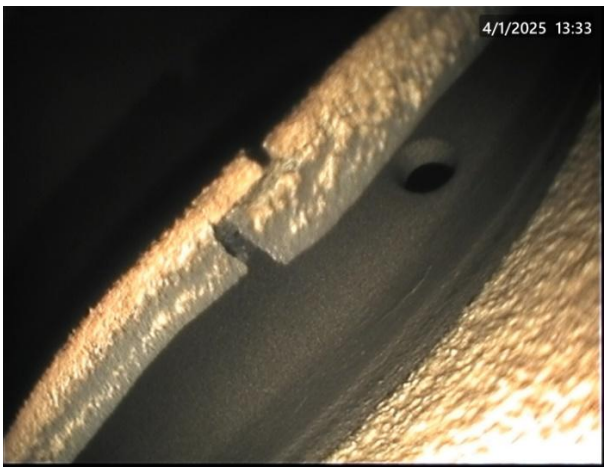

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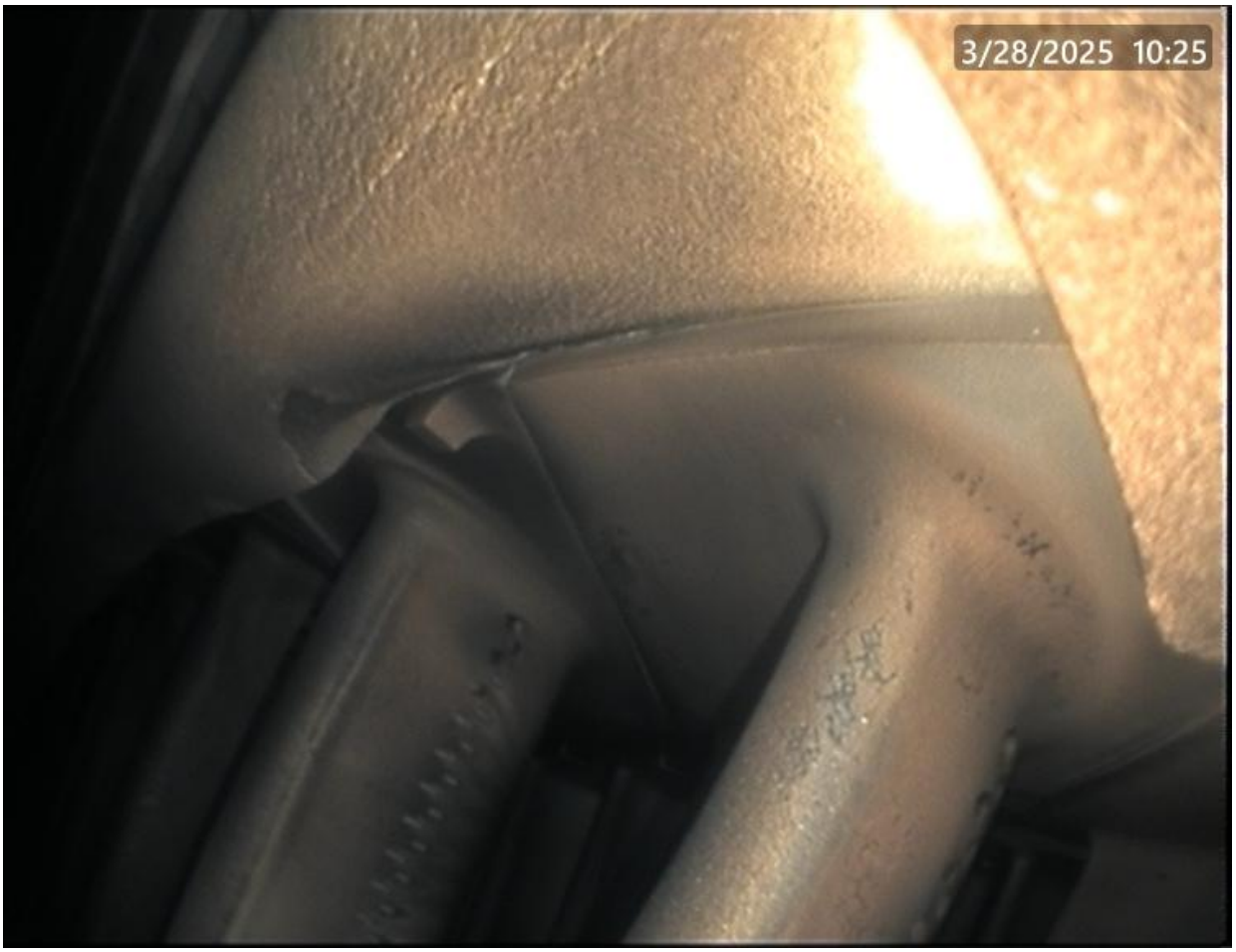
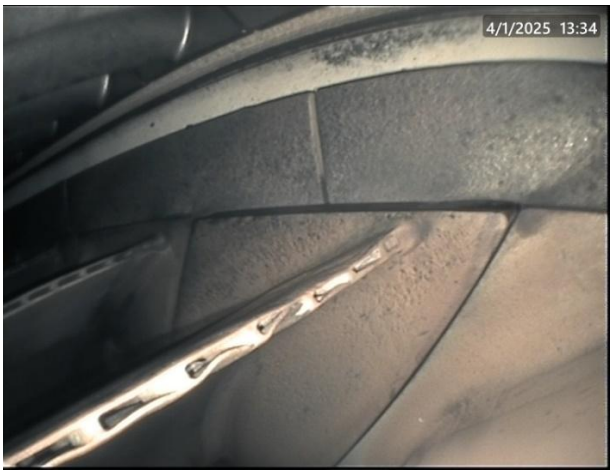


BGT2 BSI March 25, 2025

HPT IGV's

BGT2 BSI March 25, 2025

BGT2 BSI March 25, 2025



HPT (T1)

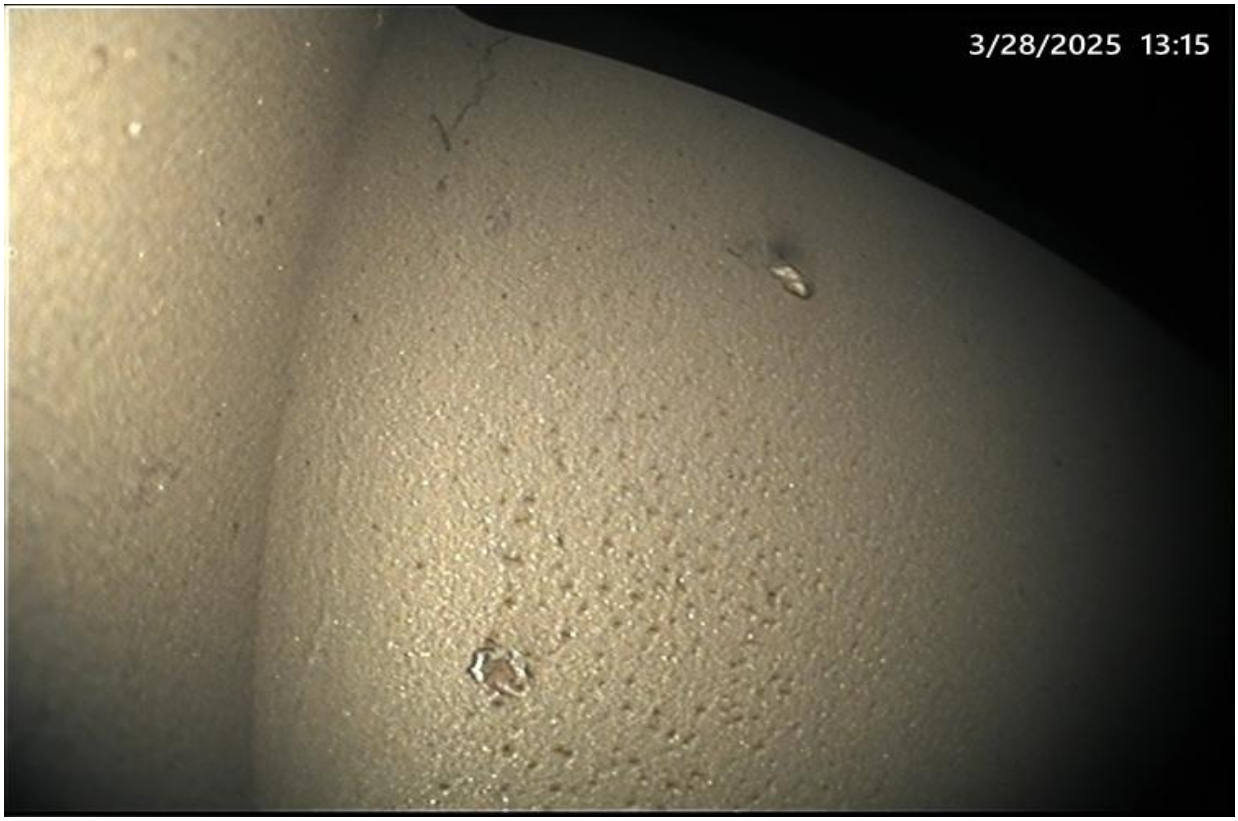
BGT2 BSI March 25, 2025

LPT (T3)

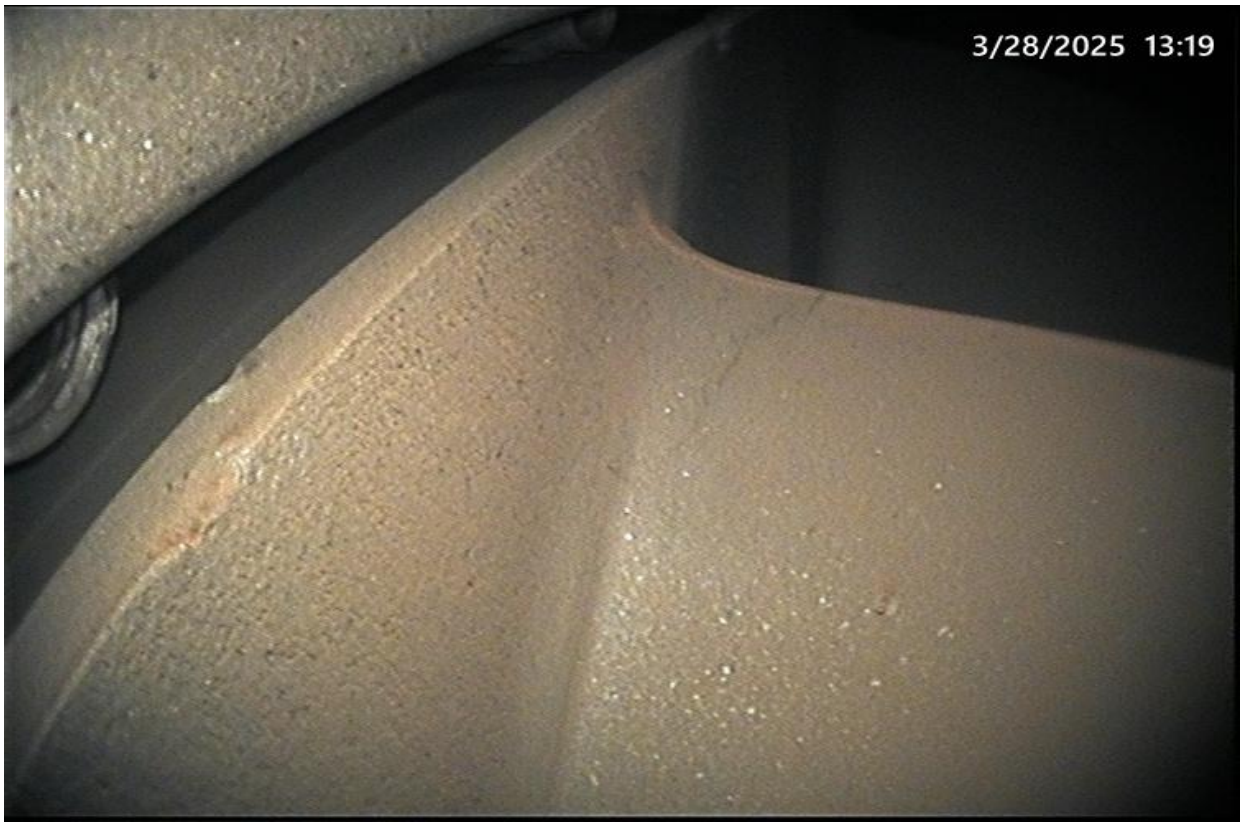
TT7 #5 Probe

BGT2 BSI March 25, 2025

Free Turbine



BGT2 BSI March 25, 2025



BGT2 BSI March 25, 2025

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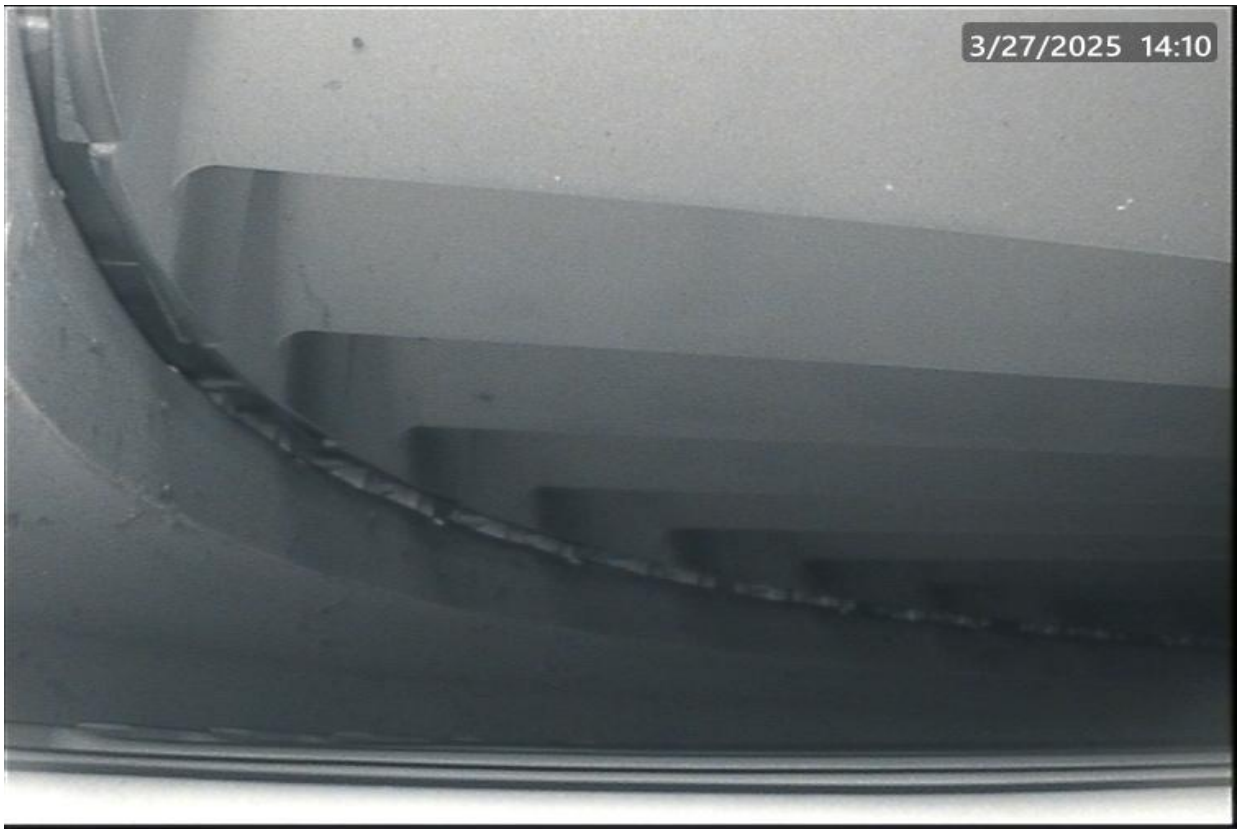

BGT2 BSI March 25, 2025

END

2026 ACE Plan C0080135 Attachment 2 has been removed due to confidentiality.

CI Number: C0080110

Title: L7012 Replacements and Upgrades Phase 1

Start Date: 2026/01
In-Service Date: 2026/01
Final Cost Date: 2028/01
Function: Transmission
Forecast Amount: $5,370,318

DESCRIPTION:

L-7012 is a 102.9 kilometer (493 structures) 230 kV transmission line, built in 1982, connecting the 3C Port Hastings and 101S Woodbine substations. This project is required to replace deteriorated assets that have been identified through NS Power's transmission line inspection program. This project includes the replacement of deteriorated assets on a total of 72 structures.

The project scope includes:
- Structure Replacements: 57
- Timber and Insulator Replacements: 12
- Insulator Replacements: 2
- Other Deteriorated Asset Replacements: 1

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)"
- 2028 CI TBD – L7012 Replacements and Upgrades Phase 2 $TBD

Depreciation Class: Transmission Plant – Poles and Fixtures
Transmission Plant – Overhead Conductors and Devices

Estimated Life of the Asset: 45 years

Retirement Information:
- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.27%

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The NS Power transmission line inspection program identified deteriorated assets on this line that require replacement to mitigate the risk of unplanned transmission interruptions. Failure to complete this project would compromise the reliable operation of this transmission line. Asset failures on this line would decrease the transmission system's redundancy.

Why do this project now?

This work has been prioritized based on the assessed condition of the transmission line assets as determined through NS Power's transmission line inspection program results, as well as the criticality of the line to the overall system operation. This project is required to support the reliable operation of the transmission line.

This project is deemed in-service when the first portion of work is forecast to be completed (January 2026); therefore, the Final Cost Date (January 2028) is listed as six months after the last portion of work is forecast to be completed (July 2027).

Why do this project this way?

Replacing the existing deteriorated assets is the only technically feasible option to accomplish the intended scope of this project.

Contingency Statement

Contingency is determined by 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 of 15 percent. Risks intended to be covered by this contingency are additional overtime work that may be required to complete the project if the outage window is shortened, 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 on projects that experience cost increases, generally experienced cost pressures in the 8-15 percent range above the NSEB approved project budget which generally used a 10 percent contingency amount. Based on these past similar projects an increased contingency of 15 percent is being applied to this project.

Capital Project Detailed Estimate

Location: Transmission
CI# : C0080110
Title: L7012 Replacements and Upgrades Phase 1
Execution Year: 2026-2027

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Site Supervision	PD	98	$ 461	$ 45,156		
Design - Engineering	PD	269	$ 452	$ 121,543		
Design - Planning	PD	60	$ 452	$ 26,989		
T&D Labour - System Maintenance	PD	34	$ 444	$ 15,000		
			Sub-Total	$ 208,688		
Overtime Labour						
T&D Labour - Site Supervision	PD	5	$ 922	$ 4,303		
T&D Labour - System Maintenance	PD	2	$ 889	$ 2,151		
			Sub-Total	$ 6,454		
Materials						
Wood Poles	Lot	1	$ 1,319,018	$ 1,319,018		
O/H Conductor	Lot	1	$ 30,443	$ 30,443		
			Sub-Total	$ 1,349,462		
Contracts						
Wood Poles	Lot	1	$ 1,716,369	$ 1,716,369		
O/H Conductor	Lot	1	$ 914,592	$ 914,592		
Survey and Mapping	Lot	1	$ 70,000	$ 70,000		
			Sub-Total	$ 2,700,961		
Other Goods & Services						
Contingency	%	15%	$ 4,265,565	$ 639,835		
			Sub-Total	$ 639,835		
Vehicle Overhead						
Vehicle Labour AO				$ 68,190		
			Sub-Total	$ 68,190		
Administrative Overhead						
Labour AO				$ 114,396		
Contractor AO				$ 282,331		
			Sub-Total	$ 396,728		
			SUB-TOTAL (no AO, AFUDC)	$ 4,905,400		
			TOTAL (AO, AFUDC included)	$ 5,370,318		
Original Cost				$ 1,145,367		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: L7012 Replacements and Upgrades Phase 1	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Preliminary (P)	NR	P			
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Preliminary (P)	NR	NR	P	P	
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Preliminary (P)	NR	P			
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Not Applicable (NA)	NR				
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainability Assessment	Preliminary (P)	NR	P			
Environment/Existing Conditions	Preliminary (P)	NR	P			
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Complete (C)	S	P	C	C	C
Foundation/Structure (Tower) Design	Not Applicable (NA)					
Route Mapping/Survey	Preliminary (P)	S/P	P/C			
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Not Applicable (NA)	NR				
Construction Permits	Preliminary (P)	NR	S/P	P/C		
Geometric Layout, Alignment, Profile, Cross Section	Preliminary (P)	NR	S/P	P/C		
Land/ROW Title Negotiation	Not Applicable (NA)	NR				
Civil/ Site/Structural/Architectural Discipline Drawings	Preliminary (P)	NR	S/P	P		
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Preliminary (P)	NR	S/P	P		
Foundation/Structure (Tower) Discipline Drawings	Not Applicable (NA)	NR				
Tower/Structure Location/Spotting	Complete (C)	NR	S/P	P	C	C
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Electrical Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	8	25	18	13	11
	% Defined/Complete towards Class Estimate	100%	100%	67%	48%	41%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 67% of Class 3 deliverables are completed. A contingency value of 15% was selected to account for specific risks such as 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.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0070909

Title: 70W-T52 Transformer Addition

Start Date:	2025/03
In-Service Date:	2026/10
Final Cost Date:	2027/04
Function:	Transmission
Forecast Amount:	$3,957,128

DESCRIPTION:

This project is for the addition of a new 69kV-12kV transformer (70W-T52) at the 70W High St. Bridgewater substation to support system reliability, load growth, and future voltage conversion in Bridgewater. The new transformer will be rated at 15/20/25 MVA and operate in parallel with 70W-T53, providing contingency capacity and relieving loading constraints.

Existing transformer 70W-T51 will remain in service until the remaining two 4kV feeders are converted to 12kV, at which point 70W-T51 will be retired. Its removal will allow for the installation of a mobile transformer connection capable of accommodating larger mobile units, addressing long-standing substation access challenges and eliminating the need for foreseeable future upgrades at the site.

Summary of Related CIs +/- 2 years
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- No other projects in 2024, 2025, 2026, 2027 or 2028

Depreciation Class: Transmission Plant – Station Equipment

Estimated Life of the Asset: 50 years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The addition of a new 69kV-12kV transformer (70W-T52) addresses multiple system needs in Bridgewater including the required 12kV capacity needed to convert the Bridgewater 4kV load currently supplied via transformer 70W-T51. Existing 69-4.2kV transformer 70W-T51 is now 68 years old and has exceeded its expected service life. Based on the condition and age of transformer 70W-T51, and loading levels on 70W-T53, this warrants a transformer addition. The new transformer will operate in parallel with 70W-T53, providing increased capacity, redundancy, and contingency support. This project also enables the planned conversion of two 4kV feeders to 12kV, aligning with long-term distribution planning and reliability goals outlined in Partially Confidential Attachment 1.

Why do this project now?

The Bridgewater area is experiencing steady load growth, and condition assessment of 70W-T53 has shown signs of loading stress in recent years. Installing 70W-T52 now allows for immediate offloading of 70W-T53 and ensures infrastructure readiness ahead of the 4kV feeder conversion project. Keeping 70W-T51 in service during the transition maintains 4kV system supply as load is converted to 12kV.

Why do this project this way?

This project takes a phased approach by adding a new transformer to off-load 70W-T53 and to provide additional contingency capacity at 70W while maintaining 70W-T51 until voltage conversions are complete. Once the 4kV feeder conversions are complete, retiring and removal of 70W-T51 creates space for a mobile transformer connection capable

of accommodating larger mobile units. This resolves long-standing access challenges and traffic impacts on High Street, improving emergency response capability. However, as 70W-T52 and 70W-T53 will provide contingency capacity for each other, a mobile transformer installation would not be required if one unit is out of service, and 70W load remains below the energized unit's seasonal capacity ratings. The substation improvements align with NS Power's asset management strategy.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgment (professional engineers and field personnel) based on previous transformer replacement project 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 of 15 percent. Risks intended to be covered by this contingency include unforeseen material and contract cost increases, schedule setbacks, and possible complications during execution.

Capital Project Detailed Estimate

Location: Transmission
CI# : C0070909
Title: 70W-T52 Transformer Addition
Execution Year: 2025-2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering and Project Management	Lot	443	$ 452	$ 200,419		
Field Labour	Lot	151	$ 444	$ 66,891		
Field Labour - Comissioning	Lot	36	$ 452	$ 16,243		
			Sub-Total	$ 283,553		
Materials						
Transformer,15/20/25 MVA, 69 kV x 15 kV	Lot	1	[redacted]			
Transformer Oil	Lot	1				
HV Bushing with Gaskets	Lot	1				
LV & Tertiary Bushing with Gaskets	Lot	1	$ 12,400	$ 12,400		
Buildings, Structures & Grounds	Lot	1	$ 49,000	$ 49,000		
Environmental Equipment	Lot	1	$ 32,850	$ 32,850		
Electrical Control Equipment	Lot	1	$ 6,930	$ 6,930		
Power Equipment - Station Service	Lot	1	$ 8,250	$ 8,250		
Wood Poles	Lot	1	$ 8,000	$ 8,000		
Insulators	Lot	1	$ 3,125	$ 3,125		
Overhead Conductors	Lot	1	$ 7,500	$ 7,500		
Substation Devices	Lot	1	$ 76,400	$ 76,400		
			Sub-Total	[redacted]		
Contracts						
Oil Filling, Assembly, and Testing	Lot	1	[redacted]			
Site Supervision	Lot	1	$ 15,000	$ 15,000		
Buildings, Structures & Grounds	Lot	1	$ 277,500	$ 277,500		
Environmental Equipment	Lot	1	$ 85,000	$ 85,000		
Wood Poles	Lot	1	$ 12,000	$ 12,000		
			Sub-Total	[redacted]		
Freight, Postage, Delivery						
Freight and Offloading (FOB Destination)	Lot	1	[redacted]			
			Sub-Total	[redacted]		
Travel Expenses						
Engineering and Project Management	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Meals						
Engineering Project Management	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Other Goods & Services						
Contingency	%	15%	$ 3,161,587	$ 474,238		
			Sub-Total	$ 474,238		
Vehicle Overhead						
Vehicle AO				$ 91,953		
			Sub-Total	$ 91,953		
Interest Capitalized						
AFUDC				$ 28,667		
			Sub-Total	$ 28,667		
Administrative Overhead						
Labour AO				$ 153,174		
Contractor AO				$ 47,509		
			Sub-Total	$ 200,683		
			SUB-TOTAL (no AO, AFUDC)	$ 3,635,825		
			TOTAL (AO, AFUDC included)	$ 3,957,128		
Original Cost				N/A		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B.
Columns C through G will auto-populate.

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: 70W-T52 Transformer Addition	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Preliminary (P)	NR	P			
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
System / Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Defined (D)	NR	P	D	D	D
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Defined (D)	NR	P	D	D	D
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainablity Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Meteorology and/or Oceanographic / Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Preliminary (P)	S	P			
Foundation / Structure (Tower) Design	Complete (C)	S	P	C	C	C
Route Mapping / Survey	Not Applicable (NA)					
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Complete (C)	NR	S/P	C	C	C
Construction Permits	Not Applicable (NA)	NR				
Geometric Layout, Alignment, Profile, Cross Section	Complete (C)	NR	S/P	P/C	C	C
Land / ROW Title Negotiation	Complete (C)	NR	S/P	P/C	C	C
Civil / Site / Structural / Architectural Discipline Drawings	Preliminary (P)	NR	S/P	P		
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Preliminary (P)	NR	S/P	P		
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Foundation / Structure (Tower) Discipline Drawings	Preliminary (P)	NR	S/P	P		
Tower / Structure Location / Spotting	Complete (C)	NR	S/P	P	C	C
Instrument Datasheets	Complete (C)	NR	NR/S	P	P/C	C
Electrical Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
Instrumentation / Control System Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
	Total # Deliverables for this Project	8	29	30	27	25
	% Defined/Complete towards Class Estimate	100%	100%	91%	82%	76%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 91% of Class 3 deliverables are completed. A contingency value of 15% was selected to account for specific risks associated with unforeseen material and contract cost increases, schedule setbacks, and complications during execution.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
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Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

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The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

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Bridgewater Area

W-AREA-2025-017

Distribution Study Addendum
Bridgewater, NS

Revision		Date	Drafted By	Reviewed by	Approved By
0	Issued for Review	10-Nov-2025	RD	BH	CM

EXECUTIVE SUMMARY

This addendum to the 2006 Bridgewater Distribution Planning Study 211-0606-W62 provides updated justification and context for the planned retirement of transformer 70W-T51 (69-4 kV, 5/6.7 MVA) and installation of transformer 70W-T52 (69-12 kV, 15/20/25 MVA) at the 70W-High Street substation in Bridgewater.

The original 2006 study assessed several options to address capacity and voltage limitations in the Bridgewater area. The long-term recommendation was to convert the remaining 4 kV feeders to 12 kV.

Since that study, the regional load profile has evolved. Transformer 70W-T51 has reached the end of its service life, while the 12 kV system supplied by 70W-T53 is approaching its contingency capacity limit. Updated forecasts show that the 12 kV contingency violation will occur in 2026 and transformer 70W-T53 is projected to exceed 133 % of its top winter rating by 2035.

The recommended alternative from this addendum includes installing 69-12 kV transformer 70W-T52 rated 15/20/25 MVA and converting the remaining 4 kV feeders to 12 kV at a total estimated cost of 4.3 million dollars. Construction is scheduled to begin in 2026 and completion planned for January 2029. This solution provides the required capacity at the lowest cost while achieving full system standardization to 12 kV and retiring aging assets at 70W-High Street Substation.

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1.0 SCOPE

This addendum provides an update to the Bridgewater Area System Planning Study (211-0606-W61), with emphasis on the recommendations related to transformer 70W-T51 and the conversion of the Bridgewater distribution system from 4 kV to 12 kV.

The objective is to summarize the progress achieved since the original study, and incorporate updated load forecasts, asset condition information, and system performance data. While the 2006 study identified transformer 70W-T51 and the associated 4 kV system as deteriorated and nearing capacity limits, recent data indicate that loading on 70W-T51 has remained stable. Conversely, transformer 70W-T53 has experienced a moderate increase in loading, contributing to the need to proceed with the installation of a new 69 kV-12 kV transformer (70W-T52) to create the 12 kV capacity required to complete 4 kV conversions.

These actions will facilitate load sharing between transformers, improve system reliability, and ensure adequate capacity to accommodate future growth. The addendum also addresses the existing Deteriorated Plant Criteria Violation associated with 70W-T51 and updates timelines, investment requirements, and EAM documentation to align with current planning criteria and Nova Scotia Power's long-term strategy to standardize the distribution network at 12 kV or 25 kV.

2.0 SUMMARY OF ORIGINAL STUDY FINDINGS (211-0606-W62)

The Bridgewater Area System Planning Study (211-0606-W61) identified 70W-High Street substation as a critical supply point, serving both 4 kV and 12 kV distribution systems from the 69 kV sub-transmission network. At the time of the study, the substation contained two power transformers: 70W-T51 (69/4 kV, 5/6.7 MVA), supplying the downtown Bridgewater 4 kV network, and 70W-T53 (69/12 kV, 15/20/25 MVA), supplying Bridgewater's existing 12 kV feeders. The study emphasized that continued investment in the 4 kV network was not consistent with Nova Scotia Power's long-term strategy to standardize on 12 kV and 25 kV distribution voltages.

The analysis of regional reinforcement options included three alternatives that affected 70W-High Street substation:

- **Alternative A-1 – Replace Transformer at 70W to Relieve 89W Substation**

  This alternative proposed replacing T51 with a 69/12 kV unit and converting 4 kV feeders to 12 kV to allow load transfer from 89W. Although it addressed regional loading and standardization, it was not pursued due to higher cost. The subsequent capacity issue at 89W was later resolved through replacement of the 89W-Bridgewater East Substation transformer, eliminating the need for system reconfiguration between the two substations.

- **Alternative B-1 – Replace 70W-T51 and Maintain 4 kV System**

  This option recommended replacing 70W-T51 with a new 69/4 kV unit of similar capacity to maintain the existing 4 kV network. Although this represented the lowest initial cost, it conflicted with corporate standardization objectives and would have required continued investment in obsolete 4 kV assets.

- **Alternative B-2 – Add 70W-T52 (69/12 kV) and Convert 4 kV to 12 kV**

  This alternative focused on converting the existing 4 kV feeders to 12 kV operation and reconfiguring 70W-High Street substation to accommodate additional 12 kV feeders supplied from the existing 70W-T53 transformer. 70W-T51 would remain in service temporarily to supply residual 4 kV load during the transition, after which it and the 4 kV bus would be retired. Though requiring more upfront distribution investment, this option was identified as the preferred long-term solution for efficiency and operational flexibility.

The study ultimately recommended proceeding with Alternative B-2, establishing a long-term plan for 70W-High Street Substation to transition entirely to 12 kV operation once all remaining 4 kV loads were converted.

3.0 SYSTEM UPGRADES COMPLETED SINCE 2006

Since the 2006 Bridgewater Area Study, the recommended 4 kV to 12 kV conversions at 70W-High Street were deferred due to other system priorities in the capital investment plan.

The replacement of transformer 89W-T1 and addition of a fourth 12 kV circuit at 89W-Bridgewater East (2012) improved reliability in the area but did not eliminate the need for additional 12 kV capacity at 70W-High Street Substation.

As a result, the Bridgewater system continues to operate with both 4 kV and 12 kV networks, and the scope defined in this addendum remains essential to complete the transition initiated in the 2006 study.

4.0 SYSTEM CONDITIONS

4.1 Feeder Voltage Levels

The Bridgewater Area distribution system operates with a mix of 4 kV and 12 kV feeders supplied from substation 70W-High Street and 89W-Bridgewater East. The 4 kV network, supplied by transformer 70W-T51, serves downtown and nearby residential areas, while newer developments and expansion zones are supplied at 12 kV from transformer 70W-T53 and 89W-T1. This mixed-voltage configuration limits operational flexibility and increases maintenance complexity. Voltage conversion from 4 kV to 12 kV is consistent with Nova Scotia Power's long-term strategy to standardize the distribution system at 12 kV and 25 kV, improving voltage regulation, feeder capacity, and system reliability. See in Figure 1 the illustration of System Voltage in Bridgewater Area.

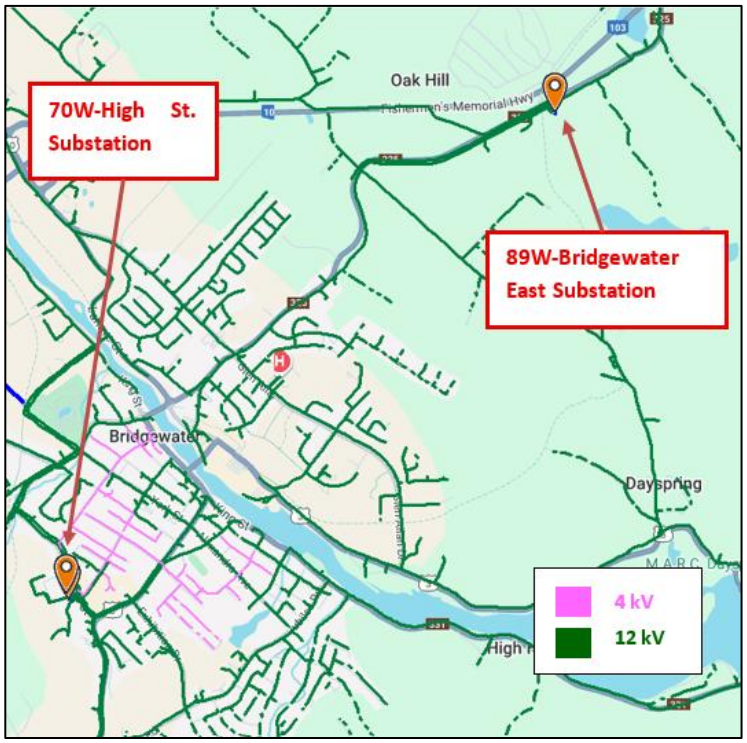


Figure 1: 70W and 89W System Voltage

4.2 Substation Loading and Contingency Capacity

Contingency capacity (N-1) is evaluated as the total available capacity under loss of one transformer, accounting for mobile transformer installation and load transfer between substations. Below is Table 1 that shows load history of substation 70W and 89W.

Table 1: 70W and 89W - Load History

Load History											
Transformer	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Top Rating (Winter Peak)**	**Loading 2025**	**Load Growth**
70W-T51	2.4	2.5	2.2	2.4	2.3	2.2	2.6	2.5	8.9	28%	0.7%
70W-T53	24.3	26.6	23.2	24.6	26.7	21.4	27.1	28.4	33.3	85%	2.0%
89W-T1	13.2	12.6	13.4	14.2	15.0	13.8	17.5	18.6	33.3	56%	4.4%

4.1.1 70W-T53 - 70W-High Street 12 kV System

The rating of the 70W-T53 transformer is 33 MVA during winter peak, based on the allowable 133% loading during winter. The contingency capacity for the 12 kV system supplied from 70W-High St is based on the failure of 70W-T53, the available capacity of 25 MVA from a mobile substation and 4 MVA of transfer capability from the adjacent substation 89W-Bridgewater East, resulting in a total contingency capacity of 29 MVA. According to the 90th-percentile load forecast, this contingency limit is expected to be exceeded in 2026, establishing the year when new capacity becomes necessary.

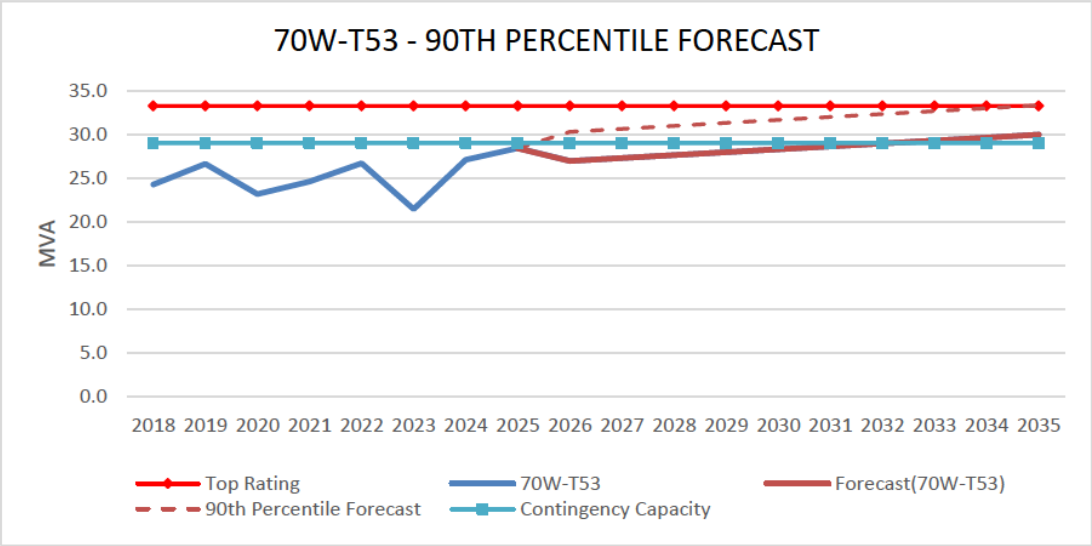


Figure 2: 70W 12 kV System Forecast

4.1.2 70W-T51 – 70W-High Street 4 kV System

The 70W-High Street Substation 4 kV system has a total contingency capacity of 7.5 MVA, which includes mobile transformation but no practical transfer capability due to the isolated configuration of the 4 kV network. The existing 4 kV load remains well below this limit, and no contingency capacity violation is expected within the study window.

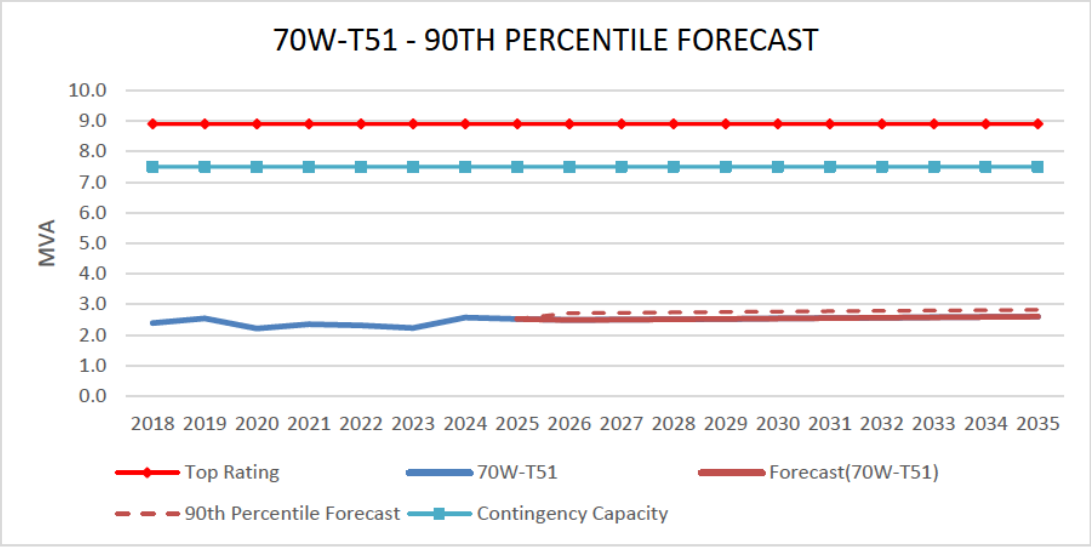


Figure 3: 70W 4 kV System Forecast

4.1.2 89W-T1 Transformer

For the 89W Bridgewater East Substation, the contingency capacity is 28 MVA, consisting of a 25 MVA mobile transformer and 3 MVA of transfer capacity to adjacent substations. Based on the 90th-percentile forecast, a contingency capacity violation is anticipated in 2034. This later constraint reinforces the need to add new transformation capacity at 70W first, to maintain flexibility and contingency support between both substations.

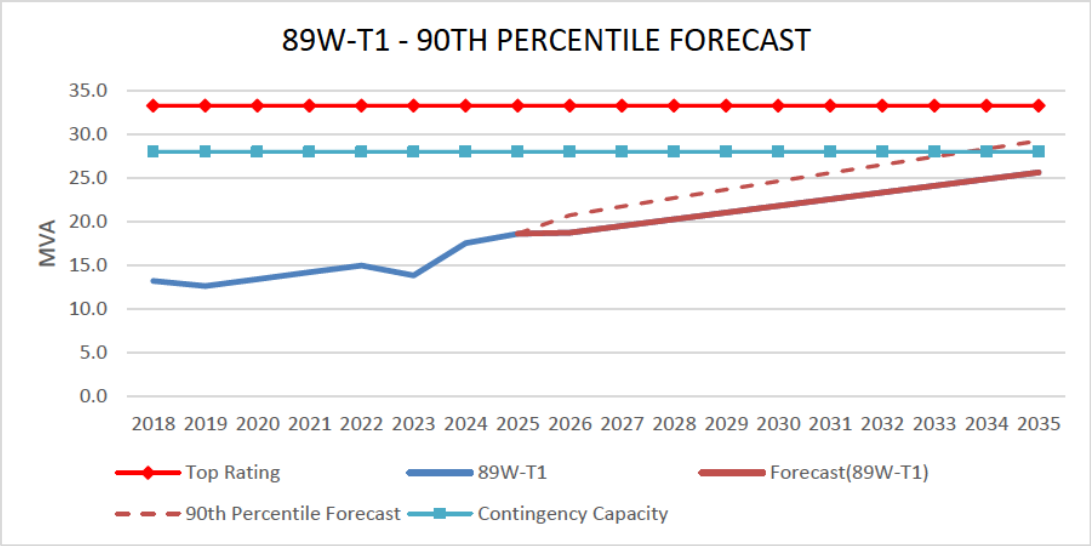


Figure 4: 80W-T1 Forecast

4.3 Deteriorated Plant

Transformer 70W-T51, commissioned in 1957, has operated well beyond its expected service life. The unit shows normal signs of aging, including insulation and oil deterioration, and the load tap changer has been out of service for more than ten years. The transformer has also presented oil leakage. Based on the Iowa R2.5 curve, only 1.3% of transformers are expected to remain in service at 68 years of age, indicating that this unit is nearing statistical end of life. According to the same curve, the transformer has approximately 1.7 years of remaining life. Given both its age and physical condition, 70W-T51 clearly meets the Deteriorated Plant criteria and should be considered for retirement within the current planning period.

5.0 SOLUTIONS

Two alternatives were evaluated to address the deteriorated condition of transformer 70W-T51 and 12 kV contingency capacity at 70W-High Street Substation in the Bridgwater area.

5.1 Alternative A – Replace T51 in 2026 (Maintain 4 kV System) and Add T52 (69-12 kV, 15/20/25 MVA) in 2027

This option would replace transformer 70W-T51 with a new 69-4 kV, 5 MVA unit in 2026 and include installation of transformer 70W-T52 rated 69-12 kV 15/20/25 MVA in 2027 to address contingency capacity limitations. The estimated total investment is approximately $5.4 million, including both transformer replacements.

Although this alternative resolves the immediate Deteriorated Plant Criteria Violation associated with the existing transformer, it retains the 4 kV system in service, requiring ongoing maintenance of aging assets.

5.2 Alternative B – Add T52 (69-12 kV, 15/20/25 MVA) in 2026 and Convert Remaining 4 kV Feeders in 2027-2028

This alternative involves advancing the installation of transformer 70W-T52 at 70W-High Street Substation to 2026 and converting all remaining 4 kV feeders to 12 kV in 2027 and 2028. All load currently supplied from 70W-T51 would be transferred to transformers 70W-T52 and 70W-T53, allowing 70W-T51 to be retired. The total estimated investment is approximately $4.3 million.

This approach provides greater long-term value by aligning with Nova Scotia Power’s voltage standardization strategy (12 kV and 25 kV), increasing contingency capacity, and improving operational flexibility between 70W and 89W substations. It also removes the need for ongoing investment in the 4 kV system.

Alternative B is therefore the recommended solution, offering the lowest cost with significantly higher system and operational benefits.

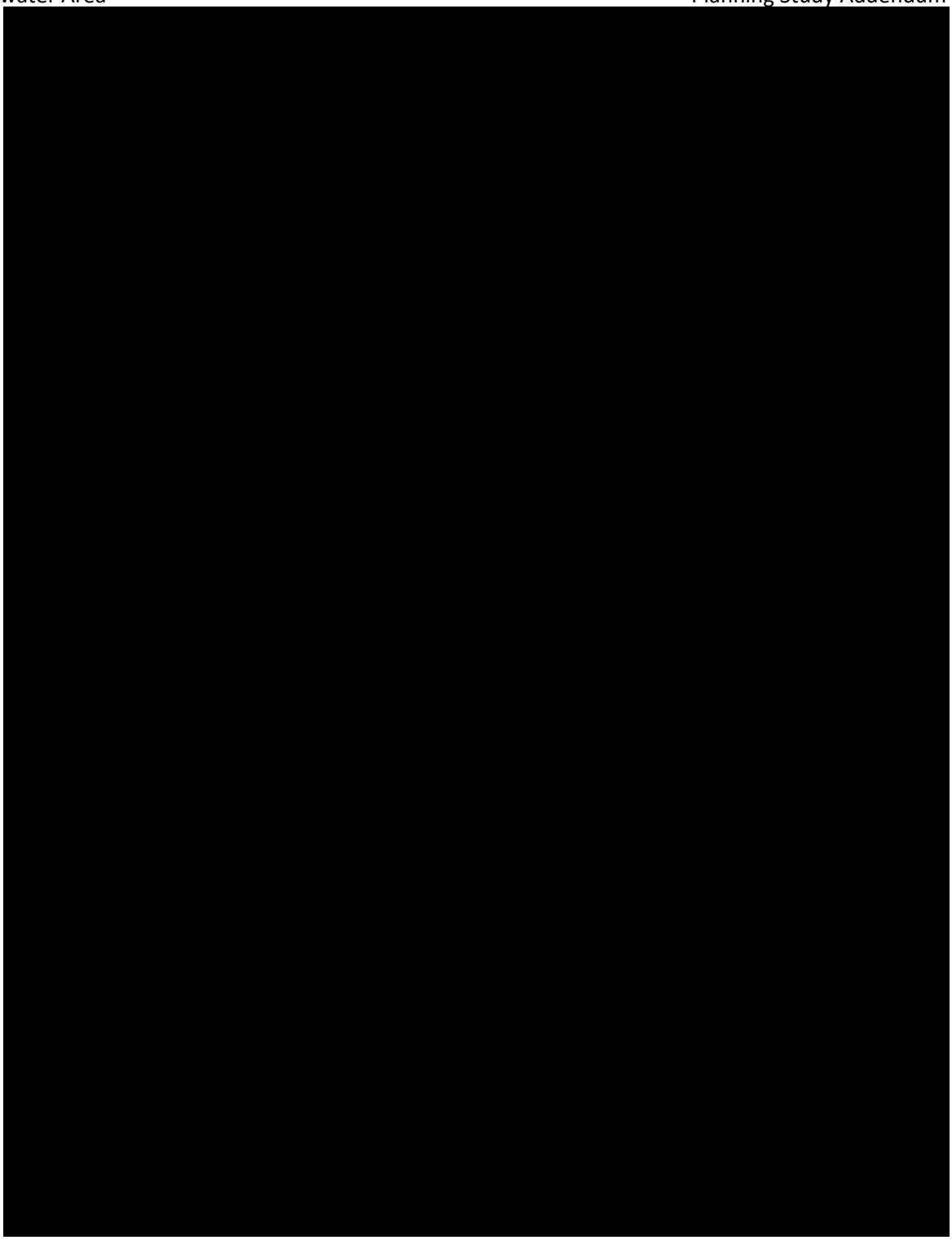
6.0 CONCLUSION

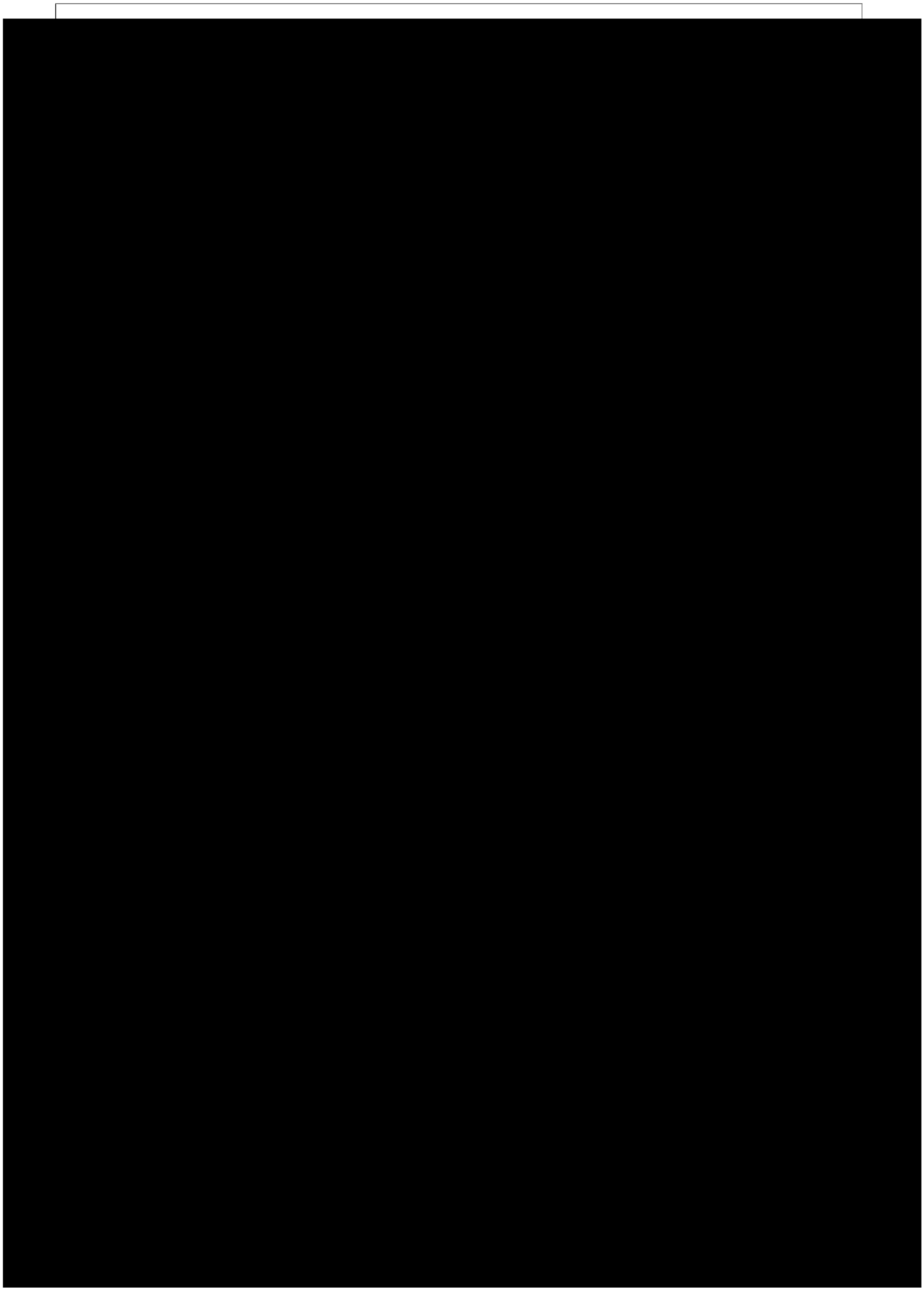
The planned replacement of transformer 70W-T51 and completion of voltage conversions at 70W-High Street Substation are consistent with the recommendations of the 2006 planning study. The existing transformer 70W-T51 has reached the end of its useful life and no longer meets Nova Scotia Power's standardization or reliability objectives. Installing a new 69-12 kV transformer, 70W-T52, will provide the capacity required to support full system conversion, improve contingency performance, and ensure compliance with current planning criteria.

This coordinated project will retire the remaining 4 kV assets, establish 12 kV transformation with firm capacity above the projected demand, and position the Bridgewater area system to accommodate future growth efficiently. The proposed solution, Alternative B, addresses both asset condition and system performance needs while aligning with the company's long-term distribution strategy. The estimated investment is 4.3 million dollars, with completion planned for January 2029.

Appendix A

System Operating Diagram





Appendix B

Economic Analysis Data

Bridgewater Study Addendum
Summary of Alternatives

Division :	Nova Scotia Power
Department :	Distribution Planning
Date :	10-Nov-25
CI Number:	C0070909
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Replace 70W-T51 + Add 70W-T52	5.77%	5,391,987	-5,858,651	2	-11.87%	0.0 years
B	Add 70W-T52 + Voltage Conversion	5.77%	4,260,821	-4,482,169	1	-8.18%	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years

Recommendation :

Alternative B, the installation of transformer 70W-T52 and conversion of remaining 4 kV feeders to 12 kV, is the recommended solution. It addresses the asset condition of 70W-T51, resolves the 12 kV contingency capacity violation, and completes the Bridgewater system standardization at the lowest overall cost.

Notes/Comments :

Replace 70W-T51 + Add 70W-T52
This option involves replacing transformer 70W-T51 in 2026 with a new 69-4 kV, 5 MVA unit, followed by the addition of a new 69-12 kV transformer rated 15/20/25 MVA in 2027 to address the contingency capacity limitation at the substation.

Add 70W-T52 + Voltage Conversion
This option involves adding transformer 70W-T52, rated 69-12 kV and 25 MVA , in 2026 at 70W-High Street substation and converting 70W-203 and 70W-204 4 kV feeders to 12 kV in two phases scheduled for 2027 and 2028.

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2025 EAM - Bridgewater Study Addendum 2025-11-10

CI Number: C0080109

Title: L7001 Replacements and Upgrades Phase 1

Start Date: 2026/01
In-Service Date: 2026/01
Final Cost Date: 2028/01
Function Class: Transmission
Forecast Amount: $3,063,280

DESCRIPTION:

L-7001 is a 73.4 kilometer (344 structures) 230 kV transmission line, built in 1979, connecting the 67N Onslow and 120H Brushy Hill substations. This project is required to replace deteriorated transmission assets that have been identified through NS Power's transmission line inspection program. This project includes the replacement of deteriorated assets on a total of 59 structures.

The project scope includes:

- Structure Replacements: 12
- Timber and Insulator Replacements: 34
- Insulator Replacements: 11
- Other Deteriorated Asset Replacements: 2

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)"

- 2028 CI TBD – L7001 Replacements and Upgrades Phase 2 $TBD

Depreciation Class: Transmission Plant – Poles and Fixtures
Transmission Plant – Overhead Conductors and Devices

Estimated Life of the Asset: 45 years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.11%

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The NS Power transmission line inspection program identified deteriorated assets on this line that require replacement to mitigate the risk of unplanned transmission interruptions. Failure to complete this project would compromise the reliable operation of this transmission line. Asset failures on this line would decrease the transmission system's redundancy.

Why do this project now?

This work has been prioritized based on the assessed condition of the transmission line assets as determined through NS Power's transmission line inspection program results, as well as the criticality of the line to the overall system operation. This project is required to support the reliable operation of the transmission line.

This project is deemed in-service when the first portion of work is forecast to be completed (January 2026); therefore, the Final Cost Date (January 2028) is listed as six months after the last portion of work is forecast to be completed (July 2027).

Why do this project this way?

Replacing the existing deteriorated assets is the only technically feasible option to accomplish the intended scope of this project.

Contingency Statement

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 of 15 percent. Risks intended to be covered by this contingency are additional overtime work that may be required to complete the project if the outage window is shortened, 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 on projects that experience cost increases, generally experienced cost pressures in the 8-15 percent range above the NSEB approved project budget which generally used a 10 percent contingency amount. Based on these past similar projects an increased contingency of 15 percent is being applied to this project.

Capital Project Detailed Estimate

Location: Transmission
CI# : C0080109
Title: L-7001 Replacements and Upgrades Phase 1
Execution Year: 2026-2027

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Site Supervision	PD	64	$ 461	$ 29,560		
Design - Engineering	PD	182	$ 452	$ 82,162		
Design - Planning	PD	19	$ 452	$ 8,590		
T&D Labour - System Maintenance	PD	34	$ 444	$ 15,000		
			Sub-Total	$ 135,312		
Overtime Labour						
T&D Labour - Site Supervision	PD	3	$ 922	$ 2,790		
T&D Labour - System Maintenance	PD	2	$ 889	$ 1,395		
			Sub-Total	$ 4,185		
Materials						
Wood Poles	lot	1	$ 413,998	$ 413,998		
O/H Conductor	lot	1	$ 15,493	$ 15,493		
			Sub-Total	$ 429,491		
Contracts						
Wood Poles	lot	1	$ 1,237,760	$ 1,237,760		
O/H Conductor	lot	1	$ 508,068	$ 508,068		
Survey and Mapping	lot	1	$ 80,000	$ 80,000		
			Sub-Total	$ 1,825,828		
Other Goods & Services						
Contingency	%	15%	$ 2,394,816	$ 359,222		
			Sub-Total	$ 359,222		
Vehicle Overhead						
Vehicle Labour AO				$ 44,214		
			Sub-Total	$ 44,214		
Administrative Overhead						
Labour AO				$ 74,174		
Contractor AO				$ 190,854		
			Sub-Total	$ 265,028		
			SUB-TOTAL (no AO, AFUDC)	$ 2,754,038		
			TOTAL (AO, AFUDC included)	$ 3,063,280		
Original Cost				$ 477,998		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER An Emera Company

Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: L-7001 Replacements and Upgrades Phase 1	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Preliminary (P)	NR	P			
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Preliminary (P)	NR	NR	P	P	
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Preliminary (P)	NR	P			
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Not Applicable (NA)	NR				
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainability Assessment	Preliminary (P)	NR	P			
Environment/Existing Conditions	Preliminary (P)	NR	P			
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Complete (C)	S	P	C	C	C
Foundation/Structure (Tower) Design	Not Applicable (NA)					
Route Mapping/Survey	Preliminary (P)	S/P	P/C			
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Not Applicable (NA)	NR				
Construction Permits	Preliminary (P)	NR	S/P	P/C		
Geometric Layout, Alignment, Profile, Cross Section	Preliminary (P)	NR	S/P	P/C		
Land/ROW Title Negotiation	Not Applicable (NA)	NR				
Civil/ Site/Structural/Architectural Discipline Drawings	Preliminary (P)	NR	S/P	P		
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Preliminary (P)	NR	S/P	P		
Foundation/Structure (Tower) Discipline Drawings	Not Applicable (NA)	NR				
Tower/Structure Location/Spotting	Complete (C)	NR	S/P	P	C	C
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Electrical Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	8	25	18	13	11
	% Defined/Complete towards Class Estimate	100%	100%	67%	48%	41%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 67% of Class 3 deliverables are completed. A contingency value of 15% was selected to account for specific risks such 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.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0053214

Title: 76W-T1 Transformer Replacement

Start Date: 2024/02
In-Service Date: 2026/09
Final Cost Date: 2027/03
Function: Transmission
Forecast Amount: $2,818,855

DESCRIPTION:

This project is for the replacement of the 76W-T1 Transformer at Mahone Bay Substation. Serving as the only electrical supply for the Town of Mahone Bay, the existing 76W-T1 69-4.16kV, 3.75/5 MVA transformer will be replaced with a 69-13.2/4.16kV, 5/6.66 MVA unit.

Existing high voltage wooden structures within the substation will be upgraded to steel. A new 69kV fuse and switch will be installed. The low voltage equipment, owned by the Town of Mahone Bay but operated by NS Power, will be upgraded outside of this project and filed by the Town of Mahone Bay.

The project also includes redesigning and installing new transformer foundation, adding a new transmission structure, improving oil containment, and updating the ground grid to meet modern standards.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- No other projects in 2024, 2025, 2026, 2027, or 2028

Depreciation Class: Transmission Plant – Station Equipment

Estimated Life of the Asset: 47 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.09%

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The 76W-T1 transformer is the sole transmission supply to the Town of Mahone Bay, serving both residential and commercial customers. Utilizing NS Power's Transformer Risk Assessment Methodology the transformer has reached the end of its expected service life, with deterioration observed in key subcomponents including auxiliary gauges and the tap changer. Dissolved gas analysis (DGA) testing has identified ethylene in the main tank, indicating early signs of internal overheating and insulation breakdown.

This transformer also experiences mild overloading during system peaks, which increases thermal stress and accelerates aging. With load growth anticipated by Mahone Bay, the advanced age of the transformer, and early signs of internal overheating indicates that replacing the unit with a new, higher-capacity transformer is the best approach. Overall, this project is crucial to maintain reliable, safe, and efficient power delivery to Mahone Bay.

Why do this project now?

Replacing 76W-T1 now mitigates the risk of unplanned failure and ensures reliable service to Mahone Bay. The presence of ethylene in the main tank suggests active internal degradation, and delaying replacement increases the likelihood of sudden failure, which would result in a major disruption for the town. Overall, timely action will maintain safe, reliable, and efficient power delivery to Mahone Bay.

Advancing this project now also allows coordination with the Town of Mahone Bay's planned upgrades to low-voltage infrastructure, minimizing disruption and optimizing construction efficiency. Completing the work within the current capital planning cycle ensures alignment with NS Power's asset management strategy improving the asset condition rating and overall risk profile.

Why do this project this way?

This project is designed to deliver a comprehensive and effective upgrade of the transformer and substation infrastructure. Given that the 76W – Mahone Bay substation is the sole provider of NS Power electrical transmission, replacing the transformer is the most viable solution. Using a low side dual voltage unit will enhance the substation's capabilities in the future when the distribution system is upgraded to a rated 12kV voltage and supports future load growth. Necessary upgrades to existing substation equipment and structures will ensure they meet modern NS Power standards and can support the operation of the new transformer. Collaborating with the Town of Mahone Bay, who are enhancing their low voltage side equipment and redesigning the structure, will improve operational performance and reliability

Constructing a new substation is an alternative, but it would be at least twice as costly due to additional land, civil and interconnection costs. Another option that was explored was to connect Mahone Bay to an existing nearby feeder. This was determined to not be feasible as it would risk overloading the feeder during winter peak periods. Building a new feeder from another nearby substation would require similar upgrades to another transformer elsewhere on the system to handle the increased load. Therefore, replacing the existing transformer at 76W is the most practical and cost-effective choice.

Upgrading the high voltage substation structure to a steel H-frame structure and installing new fuses and switches ensures alignment with modern design standards and improved protection of substation equipment. These upgrades collectively ensure the substation can handle the new transformer's capacity, maintain reliable power delivery, and meet current safety and performance standards. This holistic approach addresses both immediate and future needs, ensuring long-term reliability and efficiency for Mahone Bay.

Contingency Statement

Contingency is assessed through a blend of insights from internal subject matter experts, including professional engineers and field personnel. This assessment draws on their extensive experience with transmission line and transformer replacements and upgrades, as well as the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 15 percent on project costs, excluding the transformer costs. Risks intended to be covered by the contingency are potential overtime work that may be required for switching procedures and mobile installations, and more deterioration in service wires than expected, which may require replacement. Contingency on the transformer is removed as pricing is secured and all design changes are final for this transformer.

Capital Project Detailed Estimate

Location: Transmission
CI#: C0053214
Title: 76W-T1 Transformer Replacement
Execution Year: 2024 - 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Site Supervision	PD	19	$ 461	$ 8,741		
Design & Engineering	PD	132	$ 452	$ 59,766		
Commissioning	PD	83	$ 452	$ 37,541		
			Sub-Total	$ 106,048		
Materials						
Bldg.,Struct.Grnd.	Lot	1	$ 45,000	$ 45,000		
Substation Devices	Lot	1	$ 50,000	$ 50,000		
Transformer, 5/6.66 MVA, 69-13.2/4.16kV	Lot	1	[redacted]			
Bushings with Gaskets	Lot	1				
Transformer Oil	Lot	1				
Asset Condition & Online Gas Monitoring	Lot	1				
Overhead Conductor	Lot	1	$ 3,400	$ 3,400		
			Sub-Total	[redacted]		
Contracts						
Bldg.,Struct.Grnd.	Lot	1	$ 81,000	$ 81,000		
Oil Filing, Assembly, and Testing	Lot	1	[redacted]			
Substation Transformer - Removal	Lot	1	$ 58,000	$ 58,000		
Overhead Conductor	Lot	1	$ 7,200	$ 7,200		
PLT Labour	Lot	1	$ 37,100	$ 37,100		
Field Supervision	Lot	1	$ 16,800	$ 16,800		
			Sub-Total	[redacted]		
Consulting						
Design	Lot	1	[redacted]			
			Sub-Total			
Meals						
Meals	Lot	1	$ 182	$ 182		
			Sub-Total	$ 182		
Travel Expense						
Travel Expense	Lot	1	$ 4,650	$ 4,650		
			Sub-Total	$ 4,650		
Freight Postage Delivery						
Transformer Delivery	Lot	1	[redacted]			
			Sub-Total	[redacted]		
Other Goods & Services						
Contingency (Minus Transformer Costs)	%	15%	$ 725,139	$ 108,771		
			Sub-Total	$ 108,771		
Interest Expense						
AFUDC				$ 168,144		
			Sub-Total	$ 168,144		
Vehicle Overhead						
Vehicle AO				$ 39,788		
			Sub-Total	$ 39,788		
Administrative Overhead						
Labour AO				$ 58,236		
Contract AO				$ 30,508		
			Sub-Total	$ 88,744		
			SUB-TOTAL (no AO, AFUDC)	$ 2,522,179		
			TOTAL (AO, AFUDC included)	$ 2,818,855		
Original Cost				$ 466,719		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: 76W-T1 Transformer Replacement	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Preliminary (P)	NR	P			
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Not Applicable (NA)	NR				
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainability Assessment	Defined (D)	NR	P	D	D	D
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Defined (D)	NR	P	D	D	D
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Preliminary (P)	S	P			
Foundation/Structure (Tower) Design	Preliminary (P)	S	P			
Route Mapping/Survey	Complete (C)	S/P	P/C	C	C	C
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Complete (C)	NR	S/P	C	C	C
Construction Permits	Complete (C)	NR	S/P	P/C	C	C
Geometric Layout, Alignment, Profile, Cross Section	Complete (C)	NR	S/P	P/C	C	C
Land/ROW Title Negotiation	Complete (C)	NR	S/P	P/C	C	C
Civil/ Site/Structural/Architectural Discipline Drawings	Preliminary (P)	NR	S/P	P		
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Preliminary (P)	NR	S/P	P		
Erosion Control Plan & Drawings	Preliminary (P)	NR	S/P	P		
Foundation/Structure (Tower) Discipline Drawings	Preliminary (P)	NR	S/P	P		
Tower/Structure Location/Spotting	Complete (C)	NR	S/P	P	C	C
Instrument Datasheets	Complete (C)	NR	NR/S	P	P/C	C
Electrical Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
Instrumentation/Control System Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
	Total # Deliverables for this Project	9	31	31	26	24
	% Defined/Complete towards Class Estimate	100%	100%	89%	74%	69%

Comments:

The estimate for this project is classified as a Class 3 estimate. A 15% contingency has been used for the estimate for this project. This aligns with AACE recommendations for this level of project definition. A Class 3 classification has been applied to this project based on the level of definition of the work taking place within the substation.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0070586

Title: L6536 Switch Replacements

Start Date: 2024/11
In-Service Date: 2026/09
Final Cost Date: 2027/03
Function Class: Transmission
Forecast Amount: $2,074,494

DESCRIPTION:

L-6536 is a 138kV transmission line that was built in 1991. This project is for the replacement of two 138kV in-line transmission switches located in Amherst (22N-603 and 22N-604) which are currently not capable of live-line operation. Live line switches can be operated while the circuit is energized. These switches isolate line L-6536 and have reached end-of-life, with one being inoperable.

Due to the existing switches not being capable of live-line operation, an outage to this line is required to enable personnel to safely complete work in this area, posing operational and reliability challenges.

The scope of work includes the installation of a new ground grid, fencing, and all necessary modifications to transmission structures to support the switch upgrade to meet the criteria for live line operation.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- No other projects in 2024, 2025, 2026, 2027, or 2028

Depreciation Class: Transmission Plant – Poles and Fixtures
Transmission Plant – Overhead Conductors and Devices

Estimated Life of the Asset: 35 years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 – Retirement and disposal of Capital Assets
- Percentage of Asset Pool: 0.23%

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The installation of the new switches will enable live-line operation, eliminating the need for outages during routine switching activities. Currently, 22N-603 and 22N-604 switches have been assessed to be at end-of-life and need to be replaced. To isolate L-6536, an outage is required, after which the switch is then operated under dead-line conditions. Depending on transmission constraints, it is not always possible to take an outage to L-6536. Taking an outage to this line negatively impacts customer reliability in the area. In addition, safety and reliability concerns were highlighted by NS Power's regional field resources tasked with operating these switches. The feedback suggests that these two switches are physically difficult to operate.

Why do this project now?

To reduce disruptive customer outages and improve reliability of NS Power's transmission assets, the installation of a proper ground grid along with new switches will allow live-line operation. This live-line operation will allow NS Power's transmission network to increase operational flexibility, supporting more efficient operational and maintenance activities. Proactively replacing these two switches now will mitigate the risk of failure while in operation. If the switch devices fail, installation of a temporary bypass around the switches in an emergency mode would be required, potentially resulting in an extended unplanned outage.

Why do this project this way?

The only method to make switches 22N-603 and 22N-604 live-line operable is to design a new ground grid and install new live-line operable switches that will make it safe for personnel to operate these devices when required.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert (Professional Engineers) judgement and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 20 percent. Risks intended to be covered by this contingency include contractor availability, coverage for delays in the delivery of long lead material items, as well as increases in material costs due to tariff impacts, and any unknowns that may be discovered during the detailed engineering design process.

Capital Project Detailed Estimate

Location: Transmission
CI#: C0070586
Title: L6536 Switch Replacement
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Engineering	PD	89	$ 452	$ 40,346		
T&D Labour - Project Management	PD	68	$ 452	$ 30,621		
T&D Labour - Design	PD	50	$ 452	$ 22,500		
T&D Labour - PLT Switching	PD	18	$ 444	$ 8,060		
T&D Labour - Site Supervision	PD	22	$ 461	$ 10,000		
T&D Labour - Closing	PD	15	$ 444	$ 6,750		
			Sub-Total	$ 118,277		
Materials						
Transmission structure replacement material	Lot	1	$ 121,918	$ 121,918		
Substation material	Lot	1	$ 98,827	$ 98,827		
Standard Quick break Whip Assembly	Lot	1	[redacted]		Attachment 1, Item 2	
Inline 138kV Disconnect Switch	Lot	1	[redacted]		Attachment 1, Item 1	
138kV Live Line Operable Switch	EA	2	[redacted]		Attachment 2, Item 1	
USD to CAD Conversion	Lot	40%	$ 129,037	$ 51,615		
			Sub-Total	$ 401,397		
Contracts						
Transmission structure replacement	Lot	1	$ 299,304	$ 299,304		
Substation Construction	Lot	1	$ 457,204	$ 457,204		
Vegetation Clearing	Lot	1	$ 25,000	$ 25,000		
Road Access Upgrade	Lot	1	$ 50,000	$ 50,000		
Surveying/AsBuilts of Comissioned Structures	Lot	1	$ 15,000	$ 15,000		
Geotechnical Study	Lot	1	$ 13,520	$ 13,520		
Engineering Design Standard (138kV Switch)	Lot	1	$ 38,198	$ 38,198		
Foundation Engineering Design	Lot	1	$ 30,000	$ 30,000		
Traffic Control (Flagging)	Lot	1	$ 15,000	$ 15,000		
QA/QC checks (concrete foundations)	Lot	1	$ 24,000	$ 24,000		
Staking	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 977,226		
Application Software						
Application Software	Lot	1	$ 8,777	$ 8,777		
			Sub-Total	$ 8,777		
Royalty, Easement and Appraisal						
Environmental Permits	Lot	1	$ 6,000	$ 6,000		
			Sub-Total	$ 6,000		
Other Goods & Services						
Contingency	%	20%	$ 1,511,677	$ 302,335		
			Sub-Total	$ 302,335		
Interest Capitalized						
AFUDC			45,990	$ 45,990		
			Sub-Total	$ 45,990		
Vehicle Overhead						
Vehicle AO			$ 47,369	$ 45,873		
			Sub-Total	$ 45,873		
Administrative Overhead						
Labour AO			$ 66,718	$ 65,019		
Contract AO			$ 104,228	$ 103,601		
			Sub-Total	$ 168,620		
			SUB-TOTAL (no AO, AFUDC)	$ 1,814,012		
			TOTAL (AO, AFUDC included)	$ 2,074,494		
Original Cost				$ 1,004,426		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: L6536 Switch Replacements	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Preliminary (P)	NR	P			
Escalation	Not Applicable (NA)	NR				
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Preliminary (P)	P	P			
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Preliminary (P)	NR	P			
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Defined (D)	P	P	P/D	D	D
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Preliminary (P)	NR	P			
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Preliminary (P)	S	P			
Foundation/Structure (Tower) Design	Preliminary (P)	S	P			
Route Mapping/Survey	Complete (C)	S/P	P/C	C	C	C
Design Specifications	Started (S)	NR	S/P			
Instrument List	Started (S)	NR	S/P			
Construction Permits	Not Applicable (NA)	NR				
Geometric Layout, Alignment, Profile, Cross Section	Complete (C)	NR	S/P	P/C	C	C
Land/ROW Title Negotiation	Complete (C)	NR	S/P	P/C	C	C
Civil/ Site/Structural/Architectural Discipline Drawings	Started (S)	NR	S/P			
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Started (S)	NR	S/P			
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Foundation/Structure (Tower) Discipline Drawings	Preliminary (P)	NR	S/P	P		
Tower/Structure Location/Spotting	Preliminary (P)	NR	S/P	P		
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Electrical Discipline Drawings	Started (S)	NR	NR	S/P		
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	10	30	19	14	14
	% Defined/Complete towards Class Estimate	100%	100%	59%	44%	44%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 59% of Class 3 deliverables are completed. A contingency value of 20% was selected to account for specific risks such as contractor availability, coverage for delays in the delivery of long lead material items, as well as increases in material costs due to tariff threats. The contingency will also provide a buffer for any unknown items that may be discovered during the detailed engineering design process.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
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For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

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Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CLEAVELAND / PRICE INC.
14000 Route 993 | Trafford, PA 15085-9550
(724) 864-4177 | Fax (724) 864-9040
visit www.cleavelandprice.com

Quote: 25G1118

NOVA SCOTIA POWER-US$
25 Lakeside Park Drive
Lakeside Industrial Park
Halifax, Nova Scotia B3J 2W5
Attention: Nitesh Bishwakarma
Email: nitesh.bishwakarma@nspower.ca
Freight Terms: Freight prepay and add
FOB Point: Shipping point
Payment Terms: Net 30 Days

Quoted: July 11, 2025
Valid to August 11, 2025
Delivery: [redacted]
Prices Firm: Through delivery
Direct Inquiries To Chris Pushic
ChrisP@cleavelandprice.com
Rep(s): C/P HOUSE ACCOUNT

Item	Quantity	Description	Style Number	Unit Price (USD)	Extended Sell (USD)
1	3	In-line disconnect switch, type ILO-C, single pole, in-line, hookstick operated, rated 138 kV, 1200 Amp., 61 kA momentary, 650 kV BIL. All copper switch featuring: • 180 degree blade latching • In-line mounted pole units • In-line polymer insulator(fully assembled) • Silver-plated hinge and jaw contacts • Tin-plated terminal pads	C02A520G03	[redacted]	
2	3	**standard quick break whips for item #1** Standard quick break whip assembly for 138kV/1200A ILO-C (1-phase)	C102C925G001		
				Total:	[redacted]

Technical Notes

Freight terms quoted are prepay and add to invoice.

*Any modification to the switches based upon future clarification or additional specifications could result in a price adjustment.

This quotation has been prepared without a specification available.

Commercial Notes

*Delivery is dependent on factory capacity at time of order placement.

Pricing and payment is in US Dollars.

Sales tax, tariffs, duties & GSA taxes and freight forwarder are by others.

Cleaveland/Price, Inc. is not CSA certified. We manufacture to ANSI/IEEE standards.

Cleaveland/Price Inc. warrants that the products sold will, upon shipment, be free of defects in workmanship or material. Should any failure to conform to this warranty become apparent, Cleaveland/Price Inc. shall, upon prompt written notice from the Purchaser, correct such nonconformity by repair or replacement. The warranty period is a five-year period after date of shipment for mechanical components, a one-year period for electronic components, and six months on batteries. Labor for removing and reinstalling the equipment, and any other costs related to part replacement are the responsibility of the purchaser. IN/OUT charges do not apply.

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Quote: 25B0507

NOVA SCOTIA POWER-US$
25 Lakeside Park Drive
Lakeside Industrial Park
Halifax, Nova Scotia B3J 2W5
Attention: Michael Barron
Email: michael.barron@nspower.com
Freight Terms: Freight collect
FOB Point: Shipping point
Payment Terms: Net 30 Days

Quoted: February 05, 2025
Valid to March 05, 2025
Delivery: [redacted]
Prices Firm: Through Delivery
Reference: 138kV ROW Switches
Direct Inquiries To Chris Pushic
ChrisP@cleavelandprice.com
Rep(s): C/P HOUSE ACCOUNT

Item	Quantity	Description	Style Number	Unit Price (USD)	Extended Sell (USD)
1	1	**22N-603** Outdoor loadbreak switch, type V2-CA, vertical break, three pole, group operated, rated 138 kV, 2000 Amp. , 100 kA momentary, 650 kV BIL. Aluminum switch featuring: • Horizontal upright mounted pole units • TR-288 gray station post insulators(fully assembled) • Rotating insulator stop • 40:1 geared hand crank operator • C/P ReliaVac® Vacuum Interrupter (Full Load Break) • Silver-plated hinge and jaw contacts • Vertical pipe insulator (porcelain) / Vertical Pipe Insulator Assembly Similar to C110A742 (TR-278) • Provision for mounting key interlock • 3 phase 120 kA ground switch with Perpendicular ground blades located at the jaw end of the main disconnect switch featuring: - Swing handle operator - Manually operated ground switch interlock - Provision for mounting key interlock • Vernier adjustable interphase and drive pipe • Galvanized steel mounting hardware • Adjustable radius outboard bearing drive lever	C06B033G10	[redacted]	
				Total:	[redacted]

Technical Notes

*Only Cleaveland/Price's Terms and Conditions will Apply on Orders Placed.

*Any Modification to the Switches Based on Future Clarification or Additional Specs may Result in a Price Adjustment.

Commercial Notes

*Delivery is dependent on factory capacity at time of order placement.
*Delivery is Dependent on Factory Capacity at Time of Order Placement.

*All Pricing is in US Dollars (USD).

*Cleaveland/Price Inc. warrants that the products sold will, upon shipment, be free of defects in workmanship or material. Should any failure to conform to this warranty become apparent, Cleaveland/Price Inc. shall, upon prompt written notice from the Purchaser, correct such nonconformity by repair or replacement. The warranty period is a five-year period after date of shipment for mechanical components, a one-year period for electronic components, and six months on batteries. Labor for removing and reinstalling the equipment, and any other costs related to part replacement are the responsibility of the purchaser.

*No special tools are required for switch installation.

*Taxes, duties, fees by other not included in quote.

*Switch prices do not include structures, terminal connectors, or operator platforms all by others.

*Price is for all switches quoted, any change in quantity may result in price adjustment.

*C/P does not agree to any liquidated damages, late fees, charge-backs, or hold-backs of any type (including set-off monies).

CI Number: C0053234

Title: 96H-T1 Transformer Replacement

Start Date:	2024/09
In-Service Date:	2026/10
Final Cost Date:	2027/04
Function:	Transmission
Forecast Amount:	$2,056,752

DESCRIPTION:

This project is for the replacement of the 96H-T1 transformer, a 7.5/10/12.5 MVA, 6.9–69 kV step-up transformer located at the Ruth Falls Hydro Generating Station. The transformer plays a critical role by stepping up energy to 69kV which then supplies both local distribution through 96H-T53 and transmission on line L-5512.

The existing transformer is exhibiting significant internal and external corrosion, resulting in persistent oil leaks. These conditions have led to increased maintenance requirements and environmental risks. This project includes procurement of a new transformer, removal and disposal of the existing unit, installation, testing, and associated design work.

Summary of Related CIs +/- 2 years
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- No other projects in 2024, 2025, 2026, 2027 or 2028

Depreciation Class: Transmission Plant – Station Equipment
Transmission Plant – Overhead Conductor and Devices

Estimated Life of the Asset: 47 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.11%

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

Utilizing NS Power's Transformer Risk Assessment Methodology the 96H-T1 transformer has reached the end of its expected service life. The transformer has experienced recurring oil leaks due to severe internal and external corrosion. Previous repair efforts have been unsuccessful due to the severity of tank corrosion, and further refurbishment would require a major internal overhaul, posing a high risk of additional damage and reduced reliability due to the necessity of exposing the already aged internal components to further atmospheric contamination and moisture. On less deteriorated transformers, moisture could be addressed via vacuum oil processing. Due to the heavy corrosion on this unit, multiple leaks would make achieving the necessary vacuum for moisture removal impossible, and even if it could be achieved, it risks creating or worsening existing breaches around pressure seals. The transformer is critical for connecting the Ruth Falls Hydro Generating Station to the transmission grid, enabling the delivery of renewable hydroelectric energy. Its continued degradation poses operational, financial, and environmental risks.

Why do this project now?

The 96H-T1 transformer is consistently experiencing oil leaks and is located near a river, which poses significant environmental risk. Its condition is expected to deteriorate further. Continued operation increases the likelihood of unplanned outages caused by leaks, costly maintenance callouts, and environmental remediation. Replacing the transformer now is a proactive measure that aligns with NS Power's asset management strategy, improves the asset condition and overall risk and avoiding impacts associated with emergency response.

Why do this project this way?

Refurbishment is not a viable option due to the recurring nature of the oil leaks and the overall condition of the transformer. All other components are equally aged, and OEM support is limited as vendor is no longer in business. Replacement is the most reliable and cost-effective solution to ensure long-term performance and environmental protection.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert judgment (professional engineers and field personnel) based on previous transformer replacement project 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 of 15 percent. Risks intended to be covered by the contingency include unforeseen material and contract cost increases, schedule setbacks, and complications during execution.

Capital Project Detailed Estimate

Location: Transmission
CI# : C0053234
Title: 96H-T1 Transformer Replacement
Execution Year: 2024 - 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering and Project Management	PD	266	$ 452	$ 120,238		
Field Labour	PD	53	$ 444	$ 23,463		
Field Labour - Comissioning	PD	36	$ 452	$ 16,243		
			Sub-Total	$ 159,944		
Travel Expense						
Engineering and Project Management	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Materials						
Transformer, 7.5/10/12.5 MVA, 69 kV x 6.9 kV	Lot	1	[redacted]			
Transformer Oil	Lot	1				
High Voltage Bushing with Gaskets	Lot	1				
Low Voltage Bushing with Gaskets	Lot	1				
Electrical Control Equipment	Lot	1	$ 6,930	$ 6,930		
Insulators	Lot	1	$ 3,125	$ 3,125		
Overhead Conductors	Lot	1	$ 1,500	$ 1,500		
			Sub-Total	[redacted]		
Contracts						
Oil Filling, Assembly, and Testing	Lot	1	[redacted]			
Site Supervision	Lot	1	$ 15,000	$ 15,000		
Substation Transformer - Removal	Lot	1	$ 44,900	$ 44,900		
			Sub-Total	[redacted]		
Freight, Postage, Delivery						
Freight and Offloading (FOB Destination)	Lot	1	[redacted]			
			Sub-Total	[redacted]		
Other Goods & Services						
Contingency	%	15%	$ 1,643,994	$ 246,599		
			Sub-Total	$ 246,599		
Vehicle Overhead						
Vehicle Labour AO				$ 52,777		
			Sub-Total	$ 52,777		
Interest Capitalized						
AFUDC				$ 13,789		
			Sub-Total	$ 13,789		
Administrative Overhead						
Labour AO				$ 86,537		
Contractor AO				$ 13,056		
			Sub-Total	$ 99,593		
			SUB-TOTAL (no AO, AFUDC)	$ 1,890,593		
			TOTAL (AO, AFUDC included)	$ 2,056,752		
Original Cost				$ 290,199		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B.
Columns C through G will auto-populate.

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: 96H-T1 Transformer Replacement	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
System / Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Defined (D)	NR	P	D	D	D
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Preliminary (P)	NR	P			
Stakeholder Consultation/Engagement/Management Plan	Preliminary (P)	NR	P			
Work Breakdown Structure (WBS)	Defined (D)	NR	P	D	D	D
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainablity Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Meteorology and/or Oceanographic / Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Preliminary (P)	S	P			
Foundation / Structure (Tower) Design	Not Applicable (NA)					
Route Mapping / Survey	Complete (C)	S/P	P/C	C	C	C
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Construction Permits	Not Applicable (NA)	NR				
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Instrumentation / Control System Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
	Total # Deliverables for this Project	8	26	26	24	22
	% Defined/Complete towards Class Estimate	100%	100%	87%	80%	73%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 87% of Class 3 deliverables are completed. A contingency value of 15% was selected to account for specific risks associated with additional overtime work that may be required to complete the project within the available outage window, and any unforeseen material or contract cost increases.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
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Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0068969

Title: 2026 Pennsylvania Breaker Replacements

Start Date: 2024/12
In-Service Date: 2026/08
Final Cost Date: 2029/06
Function Class: Transmission
Forecast Amount: $1,620,028

DESCRIPTION:

This project is for the replacement of one 69 kV and three 138 kV Pennsylvania circuit breakers. NS Power currently has fourteen remaining Pennsylvania circuit breakers, purchased in the early 2010s, that are considered high risk. Reliability concerns involving the trip and close functions of the breakers pose a risk of wider outages if these circuit breakers fail to operate as expected during grid events, requiring circuit breakers in an upstream zone of protection to open to clear a fault. This has the potential to affect a much larger portion of the transmission system and in some cases affects a higher number of customers. This project will complete replacement of four Pennsylvania circuit breakers on NS Power's system.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2024 C0057882 2024 Pennsylvania Breaker Replacements - $2,163,832
- 2027 CI TBD 2027 Pennsylvania Breaker Replacements - $TBD

Depreciation Class: Transmission Plant – Station Equipment

Estimated Life of the Asset: 40 Years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 – Retirement and disposal of Capital Assets
- Percentage of Asset Pool: 0.37%

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The performance of the Pennsylvania circuit breakers installed on NS Power's transmission system is poor and the reliability concerns surrounding their trip and close functions have the potential to impede system operations involving these circuit breakers. Furthermore, their unreliability increases the risk of equipment damage or injury to personnel if these circuit breakers fail to operate when required.

The proactive replacement of the remaining Pennsylvania circuit breakers will contribute to improved system reliability and safety.

The original equipment manufacturer is no longer in business, and replacement parts and manufacturer support are not available, making refurbishment an unfeasible option. The Company's limited ability to maintain and repair these breakers, combined with their poor operation history, results in an unacceptably high risk associated with continued operation.

Why do this project now?

These circuit breakers are required to be in a safe and reliable state as they are critical components to the transmission system. Completing this project now will help mitigate the risk of breaker failure or mis-operation causing

transmission supply interruptions and will support the continued reliable operation of the transmission system for the benefit of NS Power customers.

NS Power has already observed several cases of breakers from this manufacturer experiencing premature failures. This project is part of a multi-year initiative to remove Pennsylvania circuit breakers from the transmission system.

This project is deemed in-service when the first circuit breaker is replaced (estimated August 2026); therefore, the Final Cost Date (June 2029) is six months after the last circuit breaker is expected to be replaced on this project (December 2028).

Why do this project this way?

Proactively replacing Pennsylvania circuit breakers allows NS Power to maintain a fleet of safe and reliable circuit breakers on the transmission system by eliminating failure modes inherent to circuit breakers produced by this manufacturer. The original equipment manufacturer is no longer in business, and replacement parts and manufacturer support are not available, making refurbishment an unfeasible option. This staged approach allows NS Power to reduce the risk associated with the continued operation of these circuit breakers each year until it is eliminated while ensuring that the scope of each annual program remains achievable without the requirement for excessive substation or transmission line outages. Additionally, the immediate risk of an unplanned failure can be mitigated through the Critical Spare Program.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert (professional engineers and capital planner) judgment, previous experience in previous switch and breaker replacement projects and the non-binding contingency guidelines. Consistent with maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 10 percent. Risks intended to be covered by the contingency include overtime work that may be required to complete the project within the available outage window, and any unforeseen material or contract cost increases related to tariffs and USD to CAD exchange rate.

Capital Project Detailed Estimate

Location: Transmission
CI# : C0068969
Title: 2026 Pennsylvania Breaker Replacements
Execution Year: 2024-2028

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering and Project Management	PD	371	$ 452	$ 167,757		
Field Labour	PD	81	$ 444	$ 36,096		
Field Labour - Comissioning	PD	144	$ 452	$ 64,973		
			Sub-Total	$ 268,826		
Materials						
MEPPI 138kV Circuit Breaker	Lot	1	[redacted]			
MEPPI 69kV Circuit Breaker	Lot	1				
Substation Devices	Lot	1	$ 9,374	$ 9,374		
			Sub-Total	[redacted]		
Contracts						
Buildings, Structures & Grounds	Lot	1	[redacted]			
Remove Existing Breaker	Lot	1	$ 57,100	$ 57,100		
			Sub-Total	[redacted]		
Meals						
Engineering Project Management	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Other Goods & Services						
Contingency	%	10%	$ 1,232,292	$ 123,229		
			Sub-Total	$ 123,229		
Vehicle Overhead						
Vehicle AO				$ 87,034		
			Sub-Total	$ 87,034		
Interest Capitalized						
AFUDC				$ 4,591		
			Sub-Total	$ 4,591		
Administrative Overhead						
Labour AO				$ 145,200		
Contractor AO				$ 27,682		
			Sub-Total	$ 172,882		
			SUB-TOTAL (no AO, AFUDC)	$ 1,355,521		
			TOTAL (AO, AFUDC included)	$ 1,620,028		
Original Cost				$ 908,185		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B.
Columns C through G will auto-populate.

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: 2026 Pennsylvania Breaker Replacements	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
System / Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Defined (D)	NR	P	D	D	D
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Preliminary (P)	NR	P			
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Defined (D)	NR	P	D	D	D
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Routing Options	Defined (D)	P	P	D	D	D
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainablity Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Meteorology and/or Oceanographic / Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Complete (C)	S	P	C	C	C
Foundation / Structure (Tower) Design	Not Applicable (NA)					
Route Mapping / Survey	Not Applicable (NA)					
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Complete (C)	NR	S/P	C	C	C
Construction Permits	Not Applicable (NA)	NR				
Geometric Layout, Alignment, Profile, Cross Section	Complete (C)	NR	S/P	P/C	C	C
Land / ROW Title Negotiation	Not Applicable (NA)	NR				
Civil / Site / Structural / Architectural Discipline Drawings	Preliminary (P)	NR	S/P	P		
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Preliminary (P)	NR	S/P	P		
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Foundation / Structure (Tower) Discipline Drawings	Not Applicable (NA)	NR				
Tower / Structure Location / Spotting	Not Applicable (NA)	NR				
Instrument Datasheets	Complete (C)	NR	NR/S	P	P/C	C
Electrical Discipline Drawings	Complete (C)	NR	NR	S/P	P/C	C
Instrumentation / Control System Discipline Drawings	Preliminary (P)	NR	NR	S/P	P/C	
	Total # Deliverables for this Project	7	25	28	26	25
	% Defined/Complete towards Class Estimate	100%	100%	97%	90%	86%

Comments:

This project is being submitted as a Class 3 estimate. The defined deliverables of this project indicate that 97% of the Class 3 deliverables have been completed. A contingency value of 10% was selected to account for specific risks associated with additional overtime work that may be required to complete the project within the available outage window, and any unforeseen material or contract cost increases.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0080266

Title: New Distribution Right of Way Phase 11

Start Date: 2026/01
In-Service Date: 2026/01
Final Cost Date: 2027/08
Function: Distribution
Forecast Amount: $20,889,694

DESCRIPTION:

This project is to establish new rights-of-way (6 meters of clearance, wherever feasible) for distribution feeders, where rights of way had not previously existed. NS Power targets circuits where current vegetation management maintenance practices have limited impact on preventing off right-of-way tree contacts and their negative influence on reliable operation of NS Power's distribution system. The new rights-of-way will primarily be established adjacent to the road right-of-way edge, where most distribution feeders are currently located and bordered by vegetation.

Phase 11 continues the step change in investment that occurred in Phases 9 and 10, compared to previous Phases of this program. Beginning in 2023, NS Power began an acceleration of this program to further improve the resiliency of the system towards ever increasing significant weather events. The nature of the work being completed remains the same as prior phases, establishment of new rights-of-ways, but this phase is advancing work that otherwise would have been completed in future years.

Phase 11 will be influenced by vegetation condition data derived from Satellite Imagery and artificial intelligence. This data will allow NS Power to be better informed on the updated vegetative condition information, leading to an improved prioritization process on what feeders require work ahead of others. This information will largely be used to determine where the New Distribution ROW program and the D010 ROW Widening routine program focus their efforts.

NS Power continues to work closely and proactively with landowners in efforts to achieve the desired clearances wherever possible. These relationships remain largely positive across the province with the desired clearances being achieved 90-95% of the time.

The targeted circuits expected to be included in this project are subject to change based on landowner permissions and feeder risk factors such as performance and criticality are:

Feeder	Geographic Location	Kilometers
137H-411	Hammonds Plains	20
137H-412	Hammonds Plains	14
137H-414	Hammonds Plains	2
48H-301	Dartmouth	5
96H-412	Sheet Harbour	12
100C-422	Mulgrave	3
22C-403	Dundee	17
22C-404	Hureauville	8
24C-442	Phillips Harbour	2
3S-308	North Sydney	2
57S-401	Albert Bridge	20
57S-402	Albert Bridge	23
81S-305	Glace Bay	1
85S-401	Ingonish	15
15N-401	Harmony	15
30N-412	River Hebert	5

Feeder	Geographic Location	Kilometers
4N-313	Tatamagouche	15
57C-417	Ogden	2
57C-426	Jordanville	17
62N-413	Thorburn	18
74N-412	Millevale	9
102W-311	Wedgeport	10
23W-301	Clyde River	5
25W-302	Shelburne	16
57W-401	Molega Lake	25
57W-402	Caladonia	16
63V-313	Aylesford	27
76V-301	Maitland Bridge	2
77V-401	Tiverton	23
78W-301	Sunnybrook	15
78W-302	Spectacle Lakes	6
80W-301	Tanners Settlement	16
91W-411	Greenfield	22
92W-302	Moodys Corner	18

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Distribution include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2024 CI C0057142 New Distribution Rights-of-Way Phase 9 $19,141,914
- 2025 CI C0061521 New Distribution Rights-of-Way Phase 10 $20,890,176
- 2027 CI TBD New Distribution Rights-of-Way Phase 12 $TBD
- 2028 CI TBD New Distribution Rights-of-Way Phase 13 $TBD

Depreciation Class: Distribution Plant - Land Rights- Easements, Surveys and Clearing

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Outage Performance

Why do this project?

This project directly supports the Storm Hardening – Vegetation Management program outlined in NS Power's Five-Year Reliability Plan. By proactively establishing new rights-of-way, Phase 11 mitigates the leading cause of outages—tree contacts—particularly those from outside existing corridors and contributes to the Plan's goal of reducing SAIDI through targeted vegetation strategies that improve system resilience during both normal and extreme weather conditions.

Tree contacts are a leading cause of outage impacts to customers, both during non-storm and storm events. Over the last five years (2020-2024), tree contacts have caused over 19,200 outage events, 2.2 million customer interruptions and 19.2 million customer hours of interruption, which represents 24 percent, 22 percent, and 31 percent of these totals, respectively. Approximately 80 percent of these tree contacts are caused by fallen trees from outside of the right-of-way. The traditional vegetation management practices performed under NS Power's asset management program targets vegetation within the rights-of-way, in order to maintain the existing rights-of-way. These activities prevent tree growth from causing outages from within the right-of-way, but do not address edge or off right-of-way trees. Establishing new rights-of-way under this project will reduce the occurrence of edge of right-of-way tree contacts by increasing the separation between trees and distribution feeders.

Completing this project has a direct, and immediate impact on the vegetative condition of the feeder being worked on. As the vegetative condition is improved, the likelihood of tree caused outages decreases compared to if this work were to not be completed. This condition, including the results of vegetation assessment as well as lagging tree contact reliability indicators (SAIFI and SAIDI), is rated on a 1 to 5 scale (1 being the best and 5 being the worst) which feeds into the overall Distribution Feeder condition score. Attachment 1 is a list of all distribution feeders that had more than 5km of ROW creation completed in 2024, and the improvement in vegetative condition for each. In some cases, the overall average condition (combined vegetation assessment and reliability indicators) for the feeder was satisfactory prior to completing the work, but there were localized sections on small parts of the feeder that required mitigation. This resulted in the overall condition rating of the feeder remaining the same, but the rating of the individual section would see improvement.

Why do this project now?

During the Post-Tropical Storm Arthur Review (M06321), the Board's consultant, The Liberty Consulting Group (Liberty) recommended NS Power to accelerate the Distribution Right-of-Way sustainability efforts to achieve additional reliability benefits during major storm events. As set out in NS Power's February 13, 2015 Stakeholder Consultation Report, there was general stakeholder support for accelerating the sustainability program.

A focus on removing trees within and along the edge of the NS Public Works rights-of-way will result in more immediate improvements in reliability. Proactive establishment of new distribution rights-of-way will further improve customer reliability during major and extreme weather events with respect to tree contacts.

This project is forecast to be in-service when the first right of way is forecast to be created/widened (January 2026), therefore the Final Cost date (August 2027) is six months after the last new right of way is forecast to be established (February 2027).

Why do this project this way?

Liberty's report on its review of NS Power's response to Post-Tropical Storm Arthur included the recommendation that, for distribution rights-of-way, NS Power should "develop a comprehensive plan for reclaiming and/or widening the overgrown ROW corridors".[1]

The distribution vegetation management program will be carried out under three broad initiatives:

1) Operating activities for distribution vegetation management
2) Capital Routine D010 - Distribution Right-of-Way Widening
3) New Distribution Right-of-Ways individual capital projects (i.e. CI 49611, CI 50796, CI C0001950, CI C0010040, CI C0020623, CI C0031083, CI C0041892, CI C0052056, CI C0057142, CI C0061521 and C0080266)

Taken together, these initiatives will address the findings of the Post-Tropical Storm Arthur proceeding. The scope of work to be completed under this CI and subsequent phases is to establish new rights-of-way where none have previously existed. The new rights-of-way will primarily be established adjacent to the road right-of-way edge, where most distribution feeders are currently located and bordered by vegetation.

[1] Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, M06321, The Liberty Consulting Group, Comments on Review of NS Power's Storm Response, Exhibit A-4, September 9, 2014, page 7

Location: Provincial Distribution System
CI# : C0080266
Title: New Distribution Right of Way Phase 11
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Forestry Coordinator	PD	690	$442	$304,980		
			Sub-Total	$304,980		
Contracts						
137H-411	Km	20	$43,200	$864,000		
137H-412	Km	14	$43,200	$604,800		
137H-414	Km	2	$43,200	$86,400		
48H-301	Km	5	$43,200	$216,000		
96H-412	Km	12	$43,200	$518,400		
100C-422	Km	3	$43,200	$129,600		
22C-403	Km	17	$43,200	$734,400		
22C-404	Km	8	$43,200	$345,600		
24C-442	Km	2	$43,200	$86,400		
3S-308	Km	2	$43,200	$86,400		
57S-401	Km	20	$43,200	$864,000		
57S-402	Km	23	$43,200	$987,495		
81S-305	Km	1	$43,200	$43,200		
85S-401	Km	15	$43,200	$648,000		
15N-401	Km	15	$43,200	$648,000		
30N-412	Km	5	$43,200	$216,000		
4N-313	Km	15	$43,200	$648,000		
57C-417	Km	2	$43,200	$86,400		
57C-426	Km	17	$43,200	$734,400		
62N-413	Km	18	$43,200	$777,600		
74N-412	Km	9	$43,200	$388,800		
102W-311	Km	10	$43,200	$432,000		
23W-301	Km	5	$43,200	$216,000		
25W-302	Km	16	$43,200	$691,200		
57W-401	Km	25	$43,200	$1,080,000		
57W-402	Km	16	$43,200	$691,200		
63V-313	Km	27	$43,200	$1,166,400		
76V-301	Km	2	$43,200	$86,400		
77V-401	Km	23	$43,200	$993,600		
78W-301	Km	15	$43,200	$648,000		
78W-302	Km	6	$43,200	$259,200		
80W-301	Km	16	$43,200	$691,200		
91W-411	Km	22	$43,200	$950,400		
92W-302	Km	18	$43,200	$777,600		
			Sub-Total	$ 18,397,095		
Travel Expense						
Travel Expense	Lot	1	$1,800	$1,800		
			Sub-Total	$1,800		
Vehicle Overhead						
Vehicle Overhead				$98,136		
			Sub-Total	$98,136		
Administrative Overhead						
Labour AO				$164,634		
Contractor AO				$1,923,048		
			Sub-Total	$2,087,683		
			SUB-TOTAL (no AO, AFUDC)	$18,703,875		
			TOTAL (AO, AFUDC included)	$20,889,694		
Original Cost				N/A		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.

Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: New Distribution Right of Way Phase 11	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Not Applicable (NA)	NR				
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Not Applicable (NA)	NR				
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Not Applicable (NA)	NR				
Risk Register	Not Applicable (NA)	NR				
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Not Applicable (NA)	NR				
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Routing Options	Not Applicable (NA)					
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Not Applicable (NA)					
Foundation/Structure (Tower) Design	Not Applicable (NA)					
Route Mapping/Survey	Not Applicable (NA)					
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Not Applicable (NA)	NR				
Construction Permits	Not Applicable (NA)	NR				
Geometric Layout, Alignment, Profile, Cross Section	Not Applicable (NA)	NR				
Land/ROW Title Negotiation	Preliminary (P)	NR	S/P	P/C		
Civil/ Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Foundation/Structure (Tower) Discipline Drawings	Not Applicable (NA)	NR				
Tower/Structure Location/Spotting	Not Applicable (NA)	NR				
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Electrical Discipline Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
Total # Deliverables for this Project		5	14	15	14	14
% Defined/Complete towards Class Estimate		100%	100%	100%	93%	93%

Comments:

This project is being filed as a Class 3 estimate. The deliverables of this project indicate that 100% of the Class 3 deliverables have been completed. The maturity checklist complted above demonstartes that the majority of the project deliverables have been defined and the costs are known. As a result, no contingency amount has been included in the estimate.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
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Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

Feeder	# of Kms Completed	2023 Condition	2024 Condition	Change*
103W-312	15	5	3	2
10C-211	7	3	2	1
126H-313	7	4	3	1
127H-411	12	5	3	2
12V-302G	6	5	3	2
16N-301	8	5	3	2
16V-315	10	3	3	0
16V-315G	8	5	3	2
16W-302J	9	3	3	0
18V-412	22	3	3	0
1N-402	5	5	3	2
1N-402G	8	3	3	0
1N-402GA	10	3	2	1
1N-402GB	11	4	3	1
1V-443	13	5	3	2
20V-311	6	3	3	0
22C-404	15	3	3	0
22N-403	7	3	3	0
22N-403G	15	2	2	0
23W-301	11	3	2	1
24C-442	9	3	1	2
24C-442G	6	5	3	2
24C-442GA	7	5	2	3
24C-443	41	3	2	1
25W-301	7	3	3	0
36W-304	7	5	3	2
3N-412	9	3	2	1
4C-424	8	3	3	0
4C-430	9	5	3	2
4C-432	12	3	3	0
4C-432G	9	3	3	0
4N-313G	32	3	2	1
4N-313GB	8	2	1	1
4N-313H	7	2	2	0
503N-311	5	2	1	1
503N-321	17	3	1	2
509N-301	19	3	1	2
516C-311G	12	5	2	3
516N-311	9	3	2	1
517C-301	6	3	3	0
518N-311	17	5	1	4
528C-301	8	3	2	1

Feeder	# of Kms Completed	2023 Condition	2024 Condition	Change*
55V-313JB	6	3	3	0
568C-311	11	5	3	2
56N-414	11	3	2	1
56N-414G	9	3	3	0
57C-426G	11	3	2	1
57S-401	11	2	2	0
580C-311	7	5	1	4
583C-211	10	3	1	2
585C-311	12	5	3	2
585C-311G	14	5	3	2
587C-311G	7	3	1	2
59C-402G	19	2	1	1
605C-311	10	3	1	2
62N-413	7	3	3	0
62N-413J	6	2	3	-1
62N-416G	6	1	3	-2
642V-311	7	5	3	2
644N-311	10	5	1	4
65N-201	6	3	1	2
6N-301	6	3	3	0
70V-312H	18	3	3	0
70W-313G	5	5	5	0
73W-411	8	5	3	2
73W-411GB	7	5	3	2
73W-411GCA	8	4	3	1
74N-412	16	3	2	1
74N-412G	18	5	1	4
88H-402G	9	3	2	1
91W-411	9	3	2	1

** In some cases, the overall condition average condition (combined vegetation assessment and reliability indicators) for the of the feeder was satisfactory prior to completing the work, but there were localized sections on small parts of the feeder that required mitigation. This resulted in the overall condition rating of the feeder to remain the same but the rating of the individual section would see an improvement.*

CI Number: C0080104

Title: 36V-303 Baxter's Harbour Rd Reconductor Phase 1

Start Date:	2026/01
In-Service Date:	2026/08
Final Cost Date:	2027/07
Function:	Distribution
Forecast Amount	$1,062,416

DESCRIPTION:

This project is for the replacement of 5.28 km of deteriorated single-phase line on 36V-303 located along Baxter's Harbour Rd and west of Old Baxter Mill Rd in Baxter's Harbour, Kings County. The scope includes replacing approximately 5,280 meters of 1-Phase #4 copper primary and neutral conductors, 5 distribution transformers, and 9 poles with 5,280 meters of single-phase 2/0 AASC primary and neutral conductors, 5 distribution transformers, and 11 poles. Associated hardware and framing will also be replaced.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Distribution projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2024 – CI C0031107 55V-314G-Aylesford East Reconductor $363,650
- 2024 – CI C0043230 65V-301-Nictaux West Reconductor $286,340
- 2025 – CI C0075168 16W-301G-Short Beach Reconductor $672,641
- 2027 – CI TBD Baxter's Harbour Rd Reconductor Phase 2 $TBD

Depreciation Class: Distribution Plant – Poles, Towers and Fixtures
Distribution Plant – Overhead Conductors and Devices
Distribution Plant – Line Transformers

Estimated Life of the Asset: 40 years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.01%

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

This project is designed to mitigate the circuit risk highlighted through condition assessment and past performance of this feeder. NS Power's feeder inspection program has identified that the existing conductor is severely deteriorated and has experienced multiple failures leading to unplanned customer outages. Due to advanced deterioration of the conductor, the line can no longer be safely worked on live by powerline technicians, increasing the operational risk and NS Power's ability to respond to identified deficiencies. In addition to the conductor, condition assessments have identified deterioration in other overhead components such as insulators, connectors, and legacy framing hardware, which are also being addressed through the reframing and equipment replacement included in this project. Failure to execute this project is expected to result in continued deterioration of overhead conductor leading to unplanned customer outages. Replacing the conductor and other overhead equipment as planned in the project is expected to improve the overall condition of the feeder by addressing identified deficiencies and improving the reliability of this section.

Why do this project now?

This section of line is deteriorated and has reached the end of its service life. Inspection of the targeted assets and past outage performance has confirmed that conductor replacement is necessary. Delaying this project increases the likelihood of additional unplanned interruptions for customers served by this line.

This project is deemed in service when the first distribution transformer is replaced (August 2026); therefore, the Final Cost date (July 2027) is six months after the last transformer is expected to be replaced on this project (January 2027).

Why do this project this way?

There is no alternative source of single-phase supply for customers in the targeted area. The selected approach focuses on replacing the most deteriorated sections of the line starting near Civic #1208 and extending north along Baxter's Harbour Rd and the west of Old Baxter Mill Rd. This targeted replacement will address known asset deficiencies and improve reliability for customers served by 36V-303GA.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert (professional engineers and capital planner) judgment, previous experience in similar reconductoring projects, and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 10 percent. Risks intended to be covered by the contingency include the replacement of any additional equipment, further project requirements including the balancing of load for transformers, and any additional tree trimming required.

Capital Project Detailed Estimate

Location: Distribution
CI# : C0080104
Title: 36V-303 Baxter's Harbour Rd Reconductor Phase 1
Execution Year: 2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Project Manager	PD	83	$ 452	$ 37,707		
Scoping	PD	15	$ 398	$ 5,927		
Engineering	PD	91	$ 452	$ 40,944		
			Sub-Total	$ 84,578		
Travel Expense						
Travel Expense	Lot	1	$ 8,553	$ 8,553		
			Sub-Total	$ 8,553		
Materials						
Environment (Bird Guards)	Lot	1	$ 110	$ 110		
Wood Poles	Lot	1	$ 15,056	$ 15,056		
Overhead Conductor	Lot	1	$ 28,122	$ 28,122		
Overhead Transformers	Lot	1	$ 17,410	$ 17,410		
			Sub-Total	$ 60,698		
Contracts						
Environment (Bird Guards)	Lot	1	$ 372	$ 372		
Wood Poles	Lot	1	$ 57,769	$ 57,769		
Overhead Conductor	Lot	1	$ 263,199	$ 263,199		
Overhead Transformers	Lot	1	$ 16,313	$ 16,313		
Streetlight	Lot	1	$ 286	$ 286		
Transfer Service	Lot	1	$ 18,603	$ 18,603		
Tree Trimming	Lot	1	$ 21,600	$ 21,600		
Flagging	Lot	1	$ 259,418	$ 259,418		
Backhoe	Lot	1	$ 22,962	$ 22,962		
Rock Breaking	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 670,522		
Meals						
Meals	Lot	1	$ 1,500	$ 1,500		
			Sub-Total	$ 1,500		
Other Goods & Services						
Contingency	%	10%	$ 825,851	$ 82,585		
			Sub-Total	$ 82,585		
Vehicle Overhead						
Vehicle Labour AO				$ 27,216		
			Sub-Total	$ 27,216		
Interest Capitalized						
AFUDC				$ 11,017		
			Sub-Total	$ 11,017		
Administrative Overhead						
Labour AO				$ 45,657		
Contractor AO				$ 70,090		
			Sub-Total	$ 115,747		
			SUB-TOTAL (no AO, AFUDC)	$ 908,436		
			TOTAL (AO, AFUDC included)	1,062,416		
Original Cost				$ 111,854		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: 36V-303 Baxter's Harbour Rd Reconductor Phase 1	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Not Applicable (NA)	NR	NR			
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Not Applicable (NA)					
Logistics Plan	Preliminary (P)	P	P	P		
Integrated Project Plan	Defined (D)	NR	P	D	D	D
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Preliminary (P)	NR	P			
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
H. Studies						
Routing Options	Not Applicable (NA)					
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainability Assessment	Not Applicable (NA)	NR				
Environment/Existing Conditions	Not Applicable (NA)	NR				
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Complete (C)	S	P	C	C	C
Foundation/Structure (Tower) Design	Not Applicable (NA)					
Route Mapping/Survey	Preliminary (P)	S/P	P/C			
Design Specifications	Complete (C)	NR	S/P	C	C	C
Instrument List	Not Applicable (NA)	NR				
Construction Permits	Not Applicable (NA)	NR				
Geometric Layout, Alignment, Profile, Cross Section	Not Applicable (NA)	NR				
Land/ROW Title Negotiation	Not Applicable (NA)	NR				
Civil/ Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Foundation/Structure (Tower) Discipline Drawings	Not Applicable (NA)	NR				
Tower/Structure Location/Spotting	Not Applicable (NA)	NR				
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Electrical Discipline Drawings	Complete (C)	NR	NR	S/P	P/C	C
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	6	19	17	15	15
	% Defined/Complete towards Class Estimate	100%	100%	85%	75%	75%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 85% of Class 3 deliverables have been completed. A contingency value of 10% was selected to account for specific risks such as replacement of any additional equipment. The contingency will also provide coverage for further project requirements including the balancing of load for transformers, and any additional tree trimming required along the service lines.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
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For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0080612

Title: 57C-426H Melrose Reconductor and Line Extension Phase 1

Start Date: 2025/11
In-Service Date: 2027/06
Final Cost Date: 2028/05
Function: Distribution
Forecast Amount: $1,288,474

DESCRIPTION:

This project is for the extension of approximately 3.0 kilometers of a 3-phase distribution line along Melrose County Harbour Road, Guysborough County, as well as for the 1-phase to 3-phase extension and reconductor of approximately 0.5 kilometers of 1-phase on 57C-426H along Highway 7 in Melrose, Guysborough County, to improve the reliability of feeder 57C-426H. The existing primary and neutral conductors within the scope of this project along Highway 7 are deteriorated and will be replaced with new 336 ACSR primary conductor, and 4/0 AASC neutral conductor. Similarly, the net new conductors along Melrose Country Harbour Road will be 336 ACSR primary conductor and 4/0 AASC neutral conductor. A total of 73 new poles will be installed, with 11 of these poles replacing existing assets along Highway 7. Field inspections concluded that the condition of these in-service poles require replacement. These will be replaced with poles that adhere to the latest CSA and NS Power standards.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Distribution include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2025 CI C0070646 57C-426H Stillwater Phase Extension - $857,133
- 2027 CI TBD Melrose Country Harbour Line Extension Phase 2 - $TBD
- 2028 CI TBD Melrose Country Harbour Rd to Cross Roads Country Harbour Phase Extension - $TBD

Depreciation Class: Distribution Plant – Poles and Fixtures
Distribution Plant – Overhead Conductors and Devices
Distribution Plant – Line Transformers

Estimated Life of the Asset: 45 years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.05%

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Outage Performance

Why do this project?

The majority of existing spans on feeder 57C-426H are located cross-country, contributing to delays in power restoration efforts when unplanned outages occur on this section. By replacing deteriorated poles and conductor, both outage duration and outage frequency will be positively impacted on this feeder section. Furthermore, this line extension enables the connection of future 1-phase and 3-phase customers along Melrose Country Harbour Road. Reconductoring the existing 650-meter section along Highway 7 in Melrose will replace deteriorated conductors, while the addition of two phases will improve load balancing across the feeder.

Why do this project now?

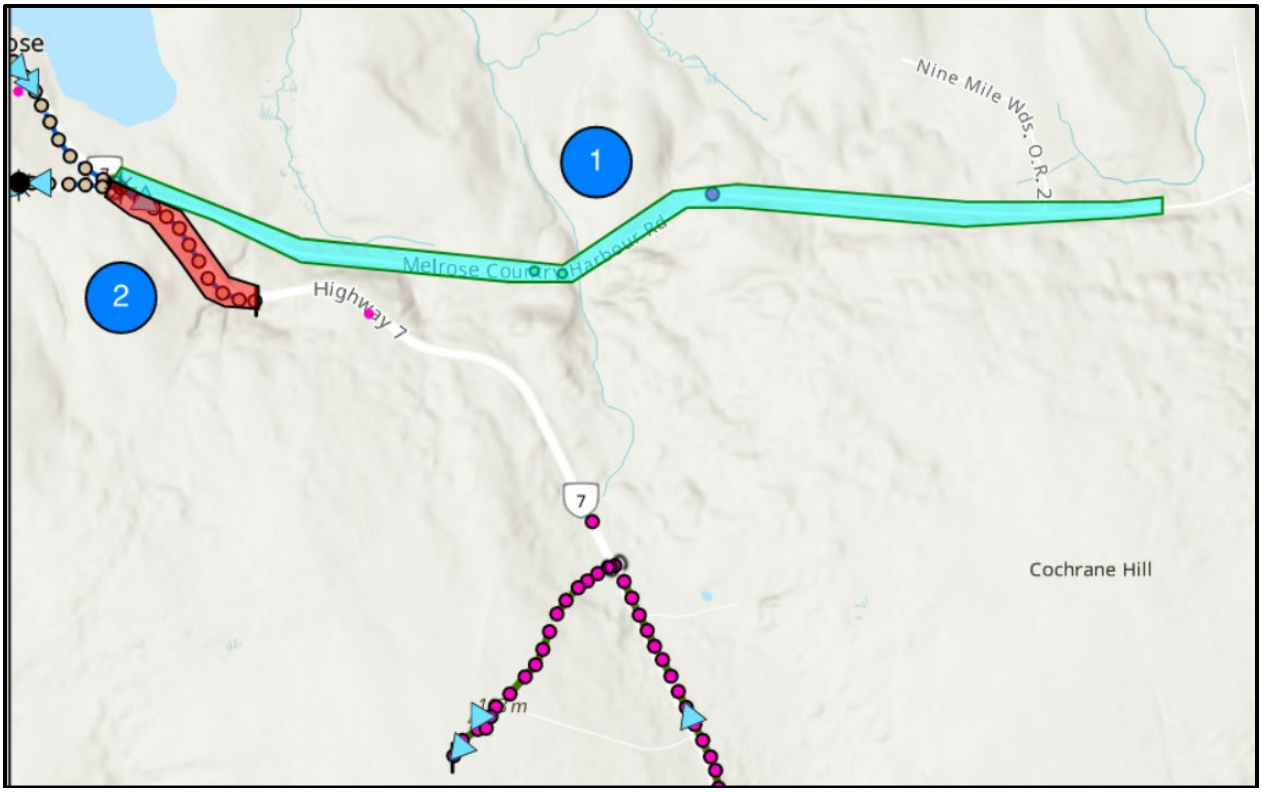
This project is part of a continued effort to improve the reliability of feeder 57C-426H, which, due to a significant off-road section, has historically ranked in the higher percentile for distribution feeder performance. Upgrading the

distribution assets on this feeder section in this manner is imperative, as delaying further upgrades or continuing to operate overhead equipment in its current condition is expected to negatively impact reliability and overall feeder performance. The reconfiguration of 57C-426H directly impacts nearly 1,000 customers. NS Power anticipates a change in overall feeder risk through improving key circuit condition factors of reliability, asset condition, and to a lesser extent, feeder balancing.

This project is deemed in service when the line is energized (June 2027); therefore, the Final Cost date (May 2028) is six months after switching is expected to be completed on this project (November 2027).

Why do this project this way?

Feeder section 57C-426H between Country Harbour and Indian Harbour Lake is a radial feeder. There is no viable alternative to complete the distribution line extension, 1-phase to 3-phase extension, and reconductoring as envisioned within the scope of this project.



1. Construct new 3PH distribution line along Melrose Country Harbour Road
2. Reconductor and phase extension of existing 1-phase line along Highway 7, Melrose.

Contingency Statement

Contingency for this project has been determined using a combination of internal subject matter expert (professional engineers and capital planner, vegetation management team) judgment, previous experience in similar distribution projects and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 estimate with a contingency of 10 percent. Risks intended to be covered by the contingency include the replacement of any additional equipment, rock breaking, and any additional tree trimming required.

Capital Project Detailed Estimate

Location: Capital Distribution
CI# : C0080612
Title: 57C-426H Melrose Reconductoring and Line Extension Phase 1
Execution Year: 2026-2027

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
On Site Supervisor	PD	125	$ 461	$ 57,519		
Engineering Design	PD	10	$ 452	$ 4,727		
Scoping Planner	PD	21	$ 398	$ 8,350		
PLT	PD	201	$ 444	$ 89,435		
Project Management	PD	8	$ 452	$ 3,694		
			Sub-Total	$ 163,724		
Travel Expense						
Travel	Lot	1	$ 6,586	$ 6,586		
			Sub-Total	$ 6,586		
Materials						
Wood Poles	Lot	1	$ 73,117	$ 73,117		
Overhead Conductor	Lot	1	$ 59,632	$ 59,632		
Overhead Transformers	Lot	1	$ 3,257	$ 3,257		
			Sub-Total	$ 136,006		
Contracts						
Vegetation Management	Lot	1	$ 450,000	$ 450,000		
Flagging	Lot	1	$ 71,611	$ 71,611		
Backhoe	Lot	1	$ 112,500	$ 112,500		
			Sub-Total	$ 634,111		
Royalty, Easements and Appraisal						
Easements	Lot	1	$ 11,200	$ 11,200		
			Sub-Total	$ 11,200		
Meals & Entertainment						
Meals	Lot	1	$ 1,600	$ 1,600		
			Sub-Total	$ 1,600		
Other Goods & Services						
Contingency	%	10%	$ 953,227	$ 95,323		
			Sub-Total	$ 95,323		
Vehicle Overhead						
Vehicle Labour AO				$ 52,787		
			Sub-Total	$ 52,787		
Interest Capitalized						
AFUDC				$ 32,456		
				$ -		
			Sub-Total	$ 32,456		
Administrative Overhead						
Labour AO				$ 88,397		
Contractor AO				$ 66,284		
			Sub-Total	$ 154,681		
			SUB-TOTAL (no AO, AFUDC)	$ 1,048,550		
			TOTAL (AO, AFUDC included)	$ 1,288,474		
Original Cost				$ 227,486		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Transmission Line Infrastructure	Required fields:	Estimate Classification				
Project Name: 57C-426H Melrose Reconductoring and Line Extension Phase 1	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
c	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp, etc.)	Defined (D)	NR	P	D	D	D
B. Capacity						
Voltage (kV) and Circuits	Defined (D)	P	P	D	D	D
C. Project Location						
Not Applicable						
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Environmental Monitoring	Defined (D)	NR	NR	P	P	D
E. Technology Selection						
Not Applicable						
F. Strategy						
Right-of-Way (ROW)	Defined (D)	P	P	D	D	D
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
System/Grid Planning (including substation and interconnect locations)	Defined (D)	P	P	D	D	D
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Defined (D)	NR	P	D	D	D
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Defined (D)	NR	P	D	D	D
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
H. Studies						
Routing Options	Not Applicable (NA)					
Topography & Bathymetry	Not Applicable (NA)					
Environmental Impact/Sustainability Assessment	Defined (D)	NR	P	D	D	D
Environment/Existing Conditions	Defined (D)	NR	P	D	D	D
Meteorology and/or Oceanographic/Subsea	Not Applicable (NA)	NR				
Soils & Hydrology	Not Applicable (NA)	NR				
Technical Deliverables (Specifications and/or Drawings)						
Conductor, Insulator, Grounding, Joint Design (including protection for buried or subsea)	Not Applicable (NA)					
Foundation/Structure (Tower) Design	Not Applicable (NA)					
Route Mapping/Survey	Not Applicable (NA)					
Design Specifications	Started (S)	NR	S/P			
Instrument List	Started (S)	NR	S/P			
Construction Permits	Started (S)	NR	S/P			
Geometric Layout, Alignment, Profile, Cross Section	Not Applicable (NA)	NR				
Land/ROW Title Negotiation	Not Applicable (NA)	NR				
Civil/ Site/Structural/Architectural Discipline Drawings	Not Applicable (NA)	NR				
Crossings and Borings Designs and Drawings	Not Applicable (NA)	NR				
Demolition Plans and Drawings	Not Applicable (NA)	NR				
Erosion Control Plan & Drawings	Not Applicable (NA)	NR				
Foundation/Structure (Tower) Discipline Drawings	Not Applicable (NA)	NR				
Tower/Structure Location/Spotting	Not Applicable (NA)	NR				
Instrument Datasheets	Not Applicable (NA)	NR	NR/S			
Electrical Discipline Drawings	Not Applicable (NA)	NR	NR			
Instrumentation/Control System Discipline Drawings	Not Applicable (NA)	NR	NR			
	Total # Deliverables for this Project	5	22	20	20	20
	% Defined/Complete towards Class Estimate	100%	100%	87%	87%	87%

Comments:

This project is being filed as a Class 3 estimate. The defined deliverables for this project indicate that 87% of Class 3 deliverables have been completed. A contingency value of 10% was selected to account for specific risks such as replacement of any additional equipment. The contingency will also provide coverage for further project requirements including rock breaking, and any additional tree trimming required.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required (NR):** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary (P):** Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined (D):** Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- **Not Required (NR):** Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

Inclusions:

For the purposes of this document, the term *power transmission line infrastructure industries* is assumed to include greenfield or brownfield sites for overhead, buried and submarine transmission of electrical power in the infrastructure industries. High voltage is typically >100kV but may be less (e.g., 33 or 66kv) if long distance with light electrical loads. This excludes power supply and distribution scope within a process plant, mining facility, building complex or other facility site. It also excludes power generation facilities and substations. The defining deliverables of those excluded project scopes are covered in other RPs (e.g., 18R-97 for process plants [2]).

Power transmission is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [3]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, power transmission lines are a vector or linear scope element that connects substation or other facility nodes at its terminations. The substation nodes may be part of or associated with a generation, consuming or interconnection facility. As such, transmission projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements. Buried and submarine installations increase the focus on the protection philosophy and strategies affecting cable selection, armoring and joint considerations. While many distinguish power transmission (higher voltage, long distances) from power distribution (short distance, lower voltage connections to retail customers), the principles of estimating these elements are similar; i.e., the RP applies to both.

The main physical power transmission line scope elements are conductors and their support structures if installed overhead. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection and conductor stringing if overhead, or trenching, laying and horizontal boring if subsurface or subsea. Special scope elements are involved with crossings of water, road, rail and so on and at terminations. Because conductor (e.g., aluminum) and structure (e.g., steel) material costs are usually a significant cost element, these project estimates are particularly sensitive to escalation uncertainty. In general, the more developed the route, the more complex the installation will be. In urban areas, visual appeal and concern for safety and health can be major issues. Installation in remote location and/or difficult or environmentally sensitive terrain creates its own challenges. Subsea installation adds the need for bathymetry[1] and metocean[2] studies and specialized installation equipment and vessels. Before any installation work can begin in an area, stakeholder consultation must be advanced (sometimes requiring agreements with local populations with rights), and appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with defining the power requirements (i.e., kV), the conductors and structure, and the routing. Conductors can vary widely in content (copper, aluminum, etc.) and insulation. Overhead structures may be wood, concrete, composite or steel in various configurations with various foundation designs including pilings, concrete and so on. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. Operability and maintainability considerations may also affect ROW and access design. Brownfield and revamp projects add their own concerns for interface with existing elements, crowded working conditions, etc. For each scope definition decision, stakeholder requirements need to be considered.

Power substation projects are usually associated with transmission projects. However, substations being equipment-centric and located on a facility site have physical and defining characteristics similar to process plant projects (e.g., reliance on one-line diagrams, plot plans, etc.).

CI Number: C0080111

Title: 2026 RTU Deployment

Start Date:	2026/04
In-Service Date:	2027/10
Final Cost Date:	2030/06
Function:	General Plant
Forecast Amount:	$8,322,655

DESCRIPTION:

This project will install 21 new Remote Terminal Units (RTUs) in substations throughout Nova Scotia over the next 3 – 4 years. The resulting installations will establish remote visibility of additional substations at the Energy Control Centre for improved system operation. The 21 substations targeted by this project have been prioritized based on the substation criticality, including the number of customers served in conjunction with areas of the grid benefiting from additional visibility for Control Centre operations.

Beyond improving day-to-day operation of the grid, with RTUs installed at a substation, a System Operator can remotely disconnect power within seconds in an emergency (such as a house fire or car accident) compared with response times of approximately 45 minutes or more for a field crew to be deployed and arrive on site. Increased visibility, remote operability, and overall improved situational awareness can reduce time to identify, resolve, and restore unplanned outages.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for General Plant projects include "Work completed on the same asset (application, building, etc.)."

- No other projects in 2024, 2025, 2026, 2027, or 2028

Depreciation Class: General Plant - Communication Equipment - SCADA Equipment

Estimated Life of the Asset: 20 years

JUSTIFICATION:

Justification Criteria: Work Support Facilities

Sub Criteria: Telecontrol & Telecommunication

Why do this project?

This project directly supports the Advanced Grid Modernization program outlined in NS Power's Five-Year Reliability Plan. By deploying RTUs, NS Power enhances real-time visibility and remote operability, which are foundational to reducing SAIDI and improving grid resilience. The project contributes to faster fault detection, improved outage response, and more strategic control actions during major events, aligning with the Plan's goals to strengthen system performance and customer reliability.

In areas with RTUs installed, NS Power System Operations teams have real time visibility and/or remote-control access to carry out day-to-day operations such as monitoring of substation alarms and real time power flows. Further, RTUs support targeted remote-control restorations during outage events and provide switching assistance during maintenance or other project work. This project will deliver enhanced system reliability as a result of the RTUs enabling improved real time visibility and control through NS Power's SCADA system at more substations, while also improving functionality and reducing time to restore through access to remote operations. Overall, this contributes to sustaining improvements achieved in customer reliability on NS Power's distribution system.

During severe weather events and other emergencies, NS Power benefits from this project as the improved visibility allows NS Power System Operations teams to see issues quickly and deploy restoration teams while minimizing further outages. In cases where adverse system conditions require load to be shed, visibility through RTUs (telemetry

and control) to substation and feeder loading enables NS Power System Operators to take strategic actions and allows this activity to be executed much faster via remote control.

Why do this project now?

Increasing visibility of system conditions and enabling remote control of switching operations in the field contributes to more efficient and effective operation of NS Power's network and sustains reliability improvements achieved through other targeted investments. Additionally, as Nova Scotia continues to see an increasing trend in the frequency and severity of weather events, NS Power continues to seek opportunities to improve its ability to respond to these events safely and effectively while mitigating negative impacts on customers. This project is an opportunity allowing NS Power to improve situational awareness and ultimately expedite critical operating functionalities during severe weather events and other emergencies.

This project is deemed in-service when the first portion of work is forecast to be completed (October 2027); therefore, the Final Cost Date (June 2030) is listed as six months after the last portion of work is forecast to be completed (December 2029).

Why do this project this way?

Installing RTUs at these substations is the only way to provide System Operators with access to real time system information to enable improved situational awareness and a more strategic approach to switching and maintenance activities both during normal operations as well as during major events.

Contingency Statement

Contingency is determined using a combination of internal subject matter expert judgement (professional engineers and project managers), experience with similar past projects, and the non-binding contingency guidelines. Consistent with the maturity matrix, this project is being filed as a Class 3 Estimate with a contingency of 10 percent. Risks intended to be covered by the contingency are overtime work that may be required, unexpected significant increase in the currency exchange rate, or material costs.

Capital Project Detailed Estimate

Location: General Plant
CI# : C0080111
Title: 2026 RTU Deployment
Execution Year: 2026-2029

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Telecom Field Technician	PD	54	$ 434	$ 23,245		
Engineering	PD	1437	$ 452	$ 649,912		
Drafting	PD	189	$ 375	$ 70,886		
Power Line Technician	PD	84	$ 444	$ 37,336		
Electrical Technologist	PD	315	$ 375	$ 118,144		
System Maintenance Technician	PD	578	$ 434	$ 250,860		
Project Manager	PD	543	$ 452	$ 245,518		
			Sub-Total	$ 1,395,902		
Term Labour						
RTU Technician	PD	630	$ 434	$ 273,729		
			Sub-Total	$ 273,729		
Overtime Labour						
System Maintenance Electrician	PD	24	$ 869	$ 21,210		
Telecom Field Technician	PD	13	$ 869	$ 11,514		
			Sub-Total	$ 32,724		
Materials						
RTUs	Ea	21	$ 59,865	$ 1,257,165	Attachment 1	
USD to CAD	Ea	40%	$ 1,257,165	$ 508,284		
Test Equipment & Tools	Ea	1	$ 10,000	$ 10,000		
Other RTU Materials (Misc. Cables & Accessories, Power Meter)	Ea	21	$ 17,567	$ 368,907		
Telecom (Substation to radio) - E (Conduit; Antennas; Poles; Radios)	Ea	6	$ 11,560	$ 69,360		
Telecom (Substation to radio) - VHF (Conduit; Antennas; Poles; Radios)	Ea	7	$ 24,880	$ 174,160		
Telecom (Substation to radio) - M (Conduit; Antennas; Poles; Radios)	Ea	8	$ 25,600	$ 204,800		
			Sub-Total	$ 2,592,676		
Consulting						
Tower Analysis/Upgrades	Lot	1	$ 200,000	$ 200,000		
			Sub-Total	$ 200,000		
Contracts						
Civil Construction	Lot	1	$ 428,750	$ 428,750		
Electrical Design	Lot	1	$ 411,056	$ 411,056		
Telecom Construction	Lot	1	$ 521,000	$ 521,000		
			Sub-Total	$ 1,360,806		
Travel Expense						
Travel - RTU Field & Engineering	Lot	1	$ 140,814	$ 140,814		
Travel - Telecom Field	Lot	1	$ 52,500	$ 52,500		
			Sub-Total	$ 193,314		
Meals						
Meals - RTU Field & Engineering	Lot	1	$ 27,600	$ 27,600		
			Sub-Total	$ 27,600		
Training & Development						
Training & Development	Lot	1	$ 9,000	$ 9,000		
			Sub-Total	$ 9,000		
Other Goods and Services						
Contingency	%	10%	$ 6,085,751	$ 608,575		
			Sub-Total	$ 608,575		
Vehicle Overhead						
Vehicle AO	%			$ 454,438		
			Sub-Total	$ 454,438		
Interest Capitalized						
AFUDC				$ 121,513		
			Sub-Total	$ 121,513		
Administrative Overhead						
Labour AO	%			910,133		
Contractor AO	%			$ 142,245		
			Sub-Total	$ 1,052,378		
			SUB-TOTAL (no AO, AFUDC)	$ 6,694,326		
			TOTAL (AO, AFUDC included)	$ 8,322,655		
Original Cost				N/A		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

Equipment Replacement	Required fields:	Estimate Classification				
Project Name: 2026 RTU Deployment	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
B. Capacity						
Not Applicable						
C. Project Location						
Hardware (server, network infrastructure)	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Legislative Requirements	Not Applicable (NA)	NR				
E. Technology Selection						
Design/Technology	Defined (D)	NR	P	D	D	D
F. Strategy						
Contracting/Sourcing	Defined (D)	NR	P	D	D	D
Escalation	Defined (D)	NR	P	D	D	D
G. Planning						
Logistics Plan	Defined (D)	P	P	P	D	D
Integrated Project Plan	Preliminary (P)	NR	P			
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Preliminary (P)	NR	P			
Regulatory Approval & Permitting	Defined (D)	NR	P	D	D	D
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Preliminary (P)	NR	P			
Start-up & Commissioning Plan	Preliminary (P)	NR	P	P/D		
Technical Deliverables (Specifications and/or Drawings)						
Network Infrastructure	Complete (C)	P	P	C	C	C
Data Architecture	Complete (C)	P	P	C	C	C
Security Assessment	Complete (C)	NR	P	C	C	C
Privacy Impact Assessment	Not Applicable (NA)	NR				
Information Systems / Telecommunication Drawings	Preliminary (P)	NR	P			
Total Responses	**Total # Deliverables for this Project**	5	19	15	14	14
Percentage	**% Defined/Complete towards Class Estimate**	100%	100%	79%	74%	74%

Comments:

This project is being submitted as a Class 3 estimate. The defined deliverables for this project indicate that 79% of Class 3 deliverables are completed. A contingency value of 10% was selected for this project. Risks intended to be covered by the contigency are foreign currency fluctuations, additional tariffs or duties due to ongoing uncertainties in international supply chains, resource rate increases and potential overtime work that may be required.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required (NR):** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary (P):** Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined (D):** Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- **Not Required (NR):** Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

Note: This checklist is intended to be used for IT/OT projects. In lieu of specific AACE guidelines for these types of projects, this checklist was developed by NSPI following the principles of the guidelines to demonstrate confidence in the cost estimate maturity.

NovaTech AUTOMATION

0925-147

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Date: September 23, 2025
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Commercial

Qty	Product & Description	Lead Time	Unit Price (USD)	Extended (USD)
1	Outdoor Enclosure, Style A3B as described above	14-16 Weeks ARO	59,865.00	59,865.00
			Total:	**$59,865.00**

CI Number: C0080252

Title: Intelligent Asset Data Capture & Integration Platform

Start Date: 2025/06
In-Service Date: 2026/01
Final Cost Date: 2027/06
Function: General Plant
Forecast Amount: $267,941

DESCRIPTION:

This project will provide NS Power with additional tools using an advanced machine learning form of AI to enhance physical, locational, and visual intelligence of its assets across the approximately 27,000 km of overhead Distribution network. These capabilities will provide detailed asset information to be used in supporting the prioritization of various work streams across Energy Delivery.

This project scope includes two key elements:

The first component is the establishment of a platform that hosts data being collected through photographic documentation and coupled with advanced machine learning technologies to identify and annotate assets associated with the photographs. This technology enables enhanced and expeditious asset recognition and annotation, which, over time, will evolve to AI annotation processes. The data is subsequently integrated into the NS Power GIS and joined to the NS Power Facility ID (FID) to maximize the ability for multiple business units and downstream NS Power processes and individual team members to also leverage this data very soon after it has been updated.

The second component of the Data Capture Technology platform involves deploying this tool onto NS Power field devices which enables employee access to the most current asset information as well as the ability to capture photos themselves, which, through machine learned automation and AI, will compile the geolocation and image data and match this information to the existing FID within NS Power's GIS Database and update the stored image(s) while also updating any difference in the asset annotation from the previously stored version without the requirement of resource effort at a desk. Again, once captured and annotated, this information becomes available to be utilized to enhance a wide variety of current business tasks that may otherwise have required mobilization of different team resources to the field to plan customer or maintenance work.

To fully populate and establish this platform and to achieve the machine learning to AI evolution, a full exercise of data collection, annotation, integration, and photographic documentation of Distribution Poles, Substations, and associated assets throughout NS Power's system is also being carried out. Once gathered and as noted, this data will be integrated directly into the NS Power GIS for continued operational use by multiple business units throughout the company.

Photographs of each pole and asset will be hyperlinked within the NS Power GIS System, against each asset's FID to provide visibility to its corresponding photo, enabling immediate and detailed visual access and review.

This project is utilizing funding through Natural Resources Canada.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for General Plant projects include "work completed on the same asset (application, building.)."

- No other projects in 2024, 2025, 2026, 2027, or 2028

Depreciation Class: General Plant - Office Furniture & Equip - Computer Software

Estimated Life of the Asset: 10 years

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

This project advances NS Power's overall asset intelligence in a way that is sustainable through the use of the enhanced technology that will be deployed to NS Power's field resources which will facilitate asset data updates, and an easy data access approach, through integration directly into the NS Power GIS System that is backed by photographic documentation. The execution of this project will provide full data updates on the Distribution pole system within a 16-month period, not only related to condition and priorities assessment but also structure design and pole attachments on poles, including streetlights and telecommunications. Once deployed to Field Services Resources, the continuous updates and linkage of this information to other NS Power datasets will help to support process improvements through accurate desktop access to current asset information without requiring additional time to plan field resource mobilization on a case by case basis. This can help to streamline the processing of customer requests.

This project's costs are offset by significant federal funding, covering all expenditures with the exception of Administrative Overheads and contingency.

Why do this project now?

Federal funding is only provided within a specific timeframe and therefore NS Power is required to execute this work on this timeline to secure the funds for this project.

This project is deemed in service when the first portion of the work is completed (January 2026); therefore, the Final Cost Date (June 2027) is listed as six months after the last portion of the work is forecast to be completed).

Why do this project this way?

This project establishes an effective way to improve current data intelligence on distribution assets. Manual data collection efforts used historically have been labour intensive and asset information can become outdated without a quicker, more cost-effective and sustainable approach.

This alternative, that leverages technology advancement and machine learned automation, can be more efficiently performed by NS Power resources on an ongoing basis and is therefore a more effective and sustainable option.

Contingency Statement

This project has received full Federal funding, except for Administrative Overheads, and as such, it is being filed as a Class 1 estimate. As procurement is fully complete, this project has started, and vendor solution design and development have been completed, a 2% contingency is being applied to account for unforeseen issues that may arise during final execution of the project given the level of uniqueness of this overall solution.

Capital Project Detailed Estimate

Location: General Plant
CI# : C0080252
Title: Intelligent Asset Data Capture & Integration Platform
Execution Year: 2025-2026

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
GIS Technologist	PD	14	$ 375	$ 5,250		
GIS Specialist	PD	70	$ 375	$ 26,250		
IT Integration Specialist	PD	3	$ 446	$ 1,125		
IT Security	PD	3	$ 446	$ 1,500		
Joint Use Coordinator	PD	17	$ 375	$ 6,375		
Joint Use Contract Manager	PD	14	$ 452	$ 6,375		
Program Manager	PD	153	$ 452	$ 69,010		
			Sub-Total	$ 115,885		
Software						
Data Capture Platform	Lot	1	[redacted]			
USD to CAD	Lot	40%				
			Sub-Total	[redacted]		
Consulting						
GIS Consultant Programmer	Lot	1	$ 85,470	$ 85,470		
Interim Project Manager	Lot	1	$ 30,240	$ 30,240		
GIS Technical Resource	Lot	1	$ 77,700	$ 77,700		
Field Data Collection	Lot	1	[redacted]			
USD to CAD	Lot	40%				
			Sub-Total	[redacted]		
Other Goods & Services						
Contingency	%	2%	$ 10,222,827	$ 204,457		
			Sub-Total	$ 204,457		
Interest Capitalized						
AFUDC				$ 178		
			Sub-Total	$ 178		
Administrative Overhead						
Labour AO				$ 63,306		
			Sub-Total	$ 63,306		
			SUB-TOTAL (no AO, AFUDC)	$ 10,363,978		
			Federal Funding Offset	$ (10,159,521)		
			TOTAL (AO, AFUDC included)	$ 267,941		
Original Cost				N/A		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER An Emera Company

Instructions: Select option in Column B. Columns C through G will auto-populate.

Document No: XXX-XX-XXXX-XXXX

Project Cost Estimate Input Checklist and Maturity Matrix

ECC Renewable Dispatch Data	Required fields:	Estimate Classification				
Project Name: Intelligent Asset Data Capture & Integration Platform	Started or Preliminary	Class 5	Class 4	Class 3	Class 2	Class 1
Maturity Level of Project Definition Deliverables	Defined or Complete					
General Project Data						
A. Scope						
Project Scope of Work Description	Defined (D)	P	P	D	D	D
B. Capacity						
Not Applicable						
C. Project Location						
Energy Control Centre (ECC); Distribution Control Centre (DCC); Back Up Control Centre	Defined (D)	P	P	D	D	D
D. Requirements						
Codes and/or Standards	Defined (D)	NR	P	D	D	D
Legislative Requirements	Defined (D)	NR	P	D	D	D
E. Technology Selection						
Design/Technology	Defined (D)	NR	P	D	D	D
F. Strategy						
Internal/External Resourcing	Defined (D)	NR	P	D	D	D
Solution Contracting / RFP	Defined (D)	NR	P	D	D	D
G. Planning						
Cross Team Planning (i.e., ECC/Energy Delivery ROPS/Corporate Security/IT Sec	Defined (D)	P	P	P	D	D
Integrated Project Plan	Defined (D)	NR	P	D	D	D
Project Code of Accounts	Defined (D)	NR	P	D	D	D
Project Schedule	Defined (D)	NR	P	D	D	D
ECC Leadership (Sponsor) approval to proceed	Defined (D)	NR	P	D	D	D
Risk Register	Defined (D)	NR	P	D	D	D
Stakeholder Consultation/Engagement/Management Plan	Defined (D)	NR	P	D	D	D
Work Breakdown Structure (WBS)	Defined (D)	NR	P	D	D	D
Start-up & Commissioning Plan	Defined (D)	NR	P	P/D	D	D
Technical Deliverables (Specifications and/or Drawings)						
Network Infrastructure	Complete (C)	P	P	C	C	C
Data Architecture	Complete (C)	P	P	C	C	C
Security Assessment	Complete (C)	NR	P	C	C	C
Solution Integration	Complete (C)	NR	P	C	C	C
Information Systems/Telecommunication Drawings	Complete (C)	NR	P	C	C	C
Total Responses	**Total # Deliverables for this Project**	5	21	21	21	21
Percentage	**% Defined/Complete towards Class Estimate**	100%	100%	100%	100%	100%

Comments:

This project is being filed as a Class 1 estimate. The defined deliverables for this project indicate that 100% of Class 1 requirements have been met. As procurement is fully complete, this project has started and vendor solution design and development have completed a 2% contingency is being applied to account for unforseen issues that may arise during final execution of the interface connectivity and given the level of uniqueness and innovation brought to bear on this overall solution.

Legend:

The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- Not Required (NR): May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Preliminary (P): Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- Defined (D): Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- Not Required (NR): Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- Started (S): Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): The deliverable has been reviewed and approved as appropriate.

Note: This checklist is intended to be used for Energy Control Centre projects. In lieu of specific AACE guidelines for these types of projects, this checklist was developed by NSPI following the principles of the guidelines to demonstrate confidence in the cost estimate maturity.

CONFIDENTIALITY MATRIX

LEGEND	
Confidential in Entirety (shaded)	TS = Technical Support
Partially Confidential (Italicized)	CS = Cost Support
(1) = Commercial/Cost Information	
(2) = Third Party Proprietary Information	*Includes Description, PowerPlant (PP), Detailed Cost Estimate (DCE), and Economic Analysis Model (EAM) (or Total Cost of Ownership (TCO) for IT projects).
(3) = System Security	

Function/Tab	Capital Work Order	Work Order Main Body*	Attachment 1	Attachment 2	Attachment 3
Generation					
	Steam Projects				
	Boiler				
G01	C0080206 - POA Boiler Refurbishment 2026				
G02	C0080205 - POA Boiler Refractory Refurbishments 2026				
	Steam Turbine				
G03	C0021608 - TUC Shoreline Sheetpile Refurbishment	*DCE (1)*	Condition Assessment	Vendor Quote (1)	
G04	C0068898 - TUC1 IP LP Last Stage Blade Replacement	*DCE (1)*	*Vendor Quote (1)*	*Vendor Quote (1)*	
G05	C0080134 - TUC2 Stack Coating and Structural Refurbishment	*DCE (1)*	Inspection Report	*Vendor Quote (1,2)*	
G06	C0080133 - TUC3 IP Turbine Refurbishment	*DCE (1)*	*Vendor Quote (1)*	*Vendor Quote (1)*	
G07	C0068888 - TUC3 Continuous Ash Hauling System	*DCE (1)*	*Vendor Quote (1,2)*	*Vendor Quote (1,2)*	*Vendor Quote (1,2)*
	Gas Turbine Projects				
G08	C0080135 - CT-BGT2 Engine Refurbishment	*DCE (1)*	Inspection Report	Vendor Quote (1)	
Transmission					
T01	C0080110 - L7012 Replacements and Upgrades Phase 1				
T02	C0070909 - 70W-T52 Transformer Addition	*DCE (1)*	*Planning Study (3)*		
T03	C0080109 - L-7001 Replacements and Upgrades Phase 1				
T04	C0053214 - 76W-T1 Transformer Replacement	*DCE (1)*			
T05	C0070586 - L6536 Switch Replacements	*DCE (1)*	*Vendor Quote (1)*	*Vendor Quote (1)*	
T06	C0053234 - 96H-T1 Transformer Replacement	*DCE (1)*			
T07	C0068969 - 2026 Pennsylvania Breaker Replacements	*DCE (1)*			
Distribution					
D01	C0080266 - New Distribution Right of Way Widening Phase 11		Condition Change		
D02	C0080104 - 36V-303 Baxter's Harbour Rd Reconductor Phase 1				
D03	C0080612 - 57C-426 Melrose Reconductor and Line Extension Phase 1				
General Plant					
GP01	C0080111 - 2026 RTU Deployment Project		Vendor Quote		
GP02	C0080252 - Intelligent Asset Data Capture & Integration Platform	*DCE (1)*			

1 - Commercial Information

To protect value for customers and mitigate the risk of prospective proponents having access to the information itemized in the confidentiality matrix, and maintain good business relations with vendors, this information is confidential.

The more a supplier is aware of NS Power's specific requirements and a competing vendor's costs, the better the supplier's ability to obtain the highest price, reduce competition and ultimately increase the cost for NS Power and its customers. The cost of such transparency is not always immediately evident. Information from regulatory proceedings can provide competitive advantages over other suppliers, and that could be advantageous in bidding or negotiation. Higher prices, or avoidable contractual constraints, will result in unnecessary higher costs to customers.

NS Power seeks to keep the terms and conditions of suppliers pricing and arrangements confidential from their other customers or potential competitors. This prevents competitors from using the information to gain a competitive advantage. This is equally true for NS Power, which desires to protect its ability to acquire services and equipment on the most competitive terms. Those "best" terms may not be available if there is a risk that they will be disclosed to the customers or competitors of the supplier.

Since NS Power customer rates are cost-based, the maintenance of confidentiality for this item is to the direct benefit of customers.

2 - Third Party Proprietary Information

This is information belonging to third parties for which those third parties have asserted confidentiality over proprietary cost and technical information.

3 - System Security

One-Line diagrams frequently included in system planning studies are confidential due to system security concerns. Protection of the power system preserves reliability and reduces the risks associated with external threats.

2026 ACE Plan Appendix B has been filed electronically.

NS Power 2025 Capital Spend Detail - As per 2025 ACE Plan

3rd Quarter Overview - as of September 30, 2025

	Generation	Distribution	Transmission	General Property	Total NS Power
2025 ACE Plan Total					
2025 Submitted ACE Total	188,123,238	182,568,887	256,543,819	65,139,528	692,375,472
Total YTD Spend*	**155,296,277**	**147,490,649**	**112,532,563**	**46,718,693**	462,038,183
Variance YTD/ACE Spend	**(32,826,962)**	**(35,078,237)**	**(144,011,256)**	**(18,420,835)**	**(230,337,289)**
Percentage of ACE Spent as of September 30, 2025	**83%**	**81%**	**44%**	**72%**	**67%**
Add:					
ATOs	1,048,240	-	3,256,427	-	4,304,667
U&Us/P&As	6,703,770	1,256,042	-	1,493,832	9,453,644
Changes to ACE Items for Subsequent Approval**	17,405,672	(382,505)	(21,069,355)	9,510,868	5,464,680
Total Increase	25,157,683	873,537	(17,812,928)	11,004,700	19,222,992
Less:					
Projects cancelled	(5,210,408)	-	-	(725,124)	(5,935,532)
Projects deferred	(6,386,570)	(322,774)	(36,518,253)	(11,123,069)	(54,350,665)
Total Decrease	(11,596,977)	(322,774)	(36,518,253)	(11,848,193)	(60,286,197)
2025 Potential Capital Spend***	**$ 201,683,943**	**$ 183,119,650**	**$ 202,212,638**	**$ 64,296,036**	**$ 651,312,267**

*Total YTD Transmission spend includes ($11M) of proceeds received from WTI for the transfer of pre-2025 development costs transferred to Wasoqonatl Transmission Inc. (WTI) for CI C0044391 NS-NB Reliability Tie.

**The Changes to ACE Items for Subsequent Approval amount listed under Transmission includes the removal of C0044391 that was filed on April 10, 2025 by Wasoqonatl Transmission Inc.

*** Amounts do not reflect the reforecast of capital projects since the 2025 ACE Plan submission, or reforecasting of subsequent items filed.

NS Power Capital Item Status Update
3rd Quarter Overview - as of September 30, 2025
This report includes all projects submitted to the NSEB and remain active, as well as ACE Plan subsequent submittal projects. Projects are removed from this report once the project has been final costed (internal or external), cancelled, or falls below $1M.

Status	Category	CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	FIN Submission Date	FIN Amount	Variance
Less than $1M	General Plant	C0061285	IT - Enterprise Governance, Risk and Compliance	2025 ACE Plan (for Subsequent Approval)		$ 1,179,857		$ 256,112			
Deferred	Generation	39472	HYD - Mersey Redevelopment Phase 1	2022 ACE Plan (for Subsequent Approval)		$ 189,447,076		$ 20,987,833			
Awaiting Approval	General Plant	47751	ECC Dynamic Line Rating Implementation	2022 ACE Plan (for Subsequent Approval)	OTQ - December 1, 2025	$ 5,144,525	$ 2,148,364	$ 5,486,323			
Approved	Generation	49634	HYD - Trout River Diversion Structure Replacement	2022 ACE Plan (for Subsequent Approval)	Q1 - May 13, 2024	$ 1,822,300	$ 3,402,776	$ 3,309,528			
Approved	Distribution	C0008638	Cogswell HRM Redevelopment Program	2022 ACE Plan (for Subsequent Approval)	OTQ - June 6, 2022	$ 6,982,854	$ 6,617,148	$ 6,076,172			
Approved	Transmission	43267	13V Gulch Hydro Replace 13V-GT1 and 13V-VR1	2015 ACE Plan	2015 ACE Plan	$ 1,061,902	$ 1,061,902	$ 1,011,993			
Awaiting Approval	Transmission	52314	1C-GT1/UT1 Replacement	2018 ACE Plan	2018 ACE Plan	$ 2,032,393	$ 2,032,393	$ 1,678,006	OTQ - December 1, 2025	$ 1,678,006	$ (354,387)
Approved	Transmission	49815	2017 / 2018 Steel Tower Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 2,003,317	$ 2,003,317	$ 1,937,433			
Approved	Distribution	49919	2017 PCB Pole Top Transformer Replacement	2017 ACE Plan	2017 ACE Plan	$ 2,446,051	$ 2,446,051	$ 2,550,603			
Approved	Distribution	51493	2018 PCB Pole Top Transformer Replacement	2018 ACE Plan	2018 ACE Plan	$ 1,360,354	$ 1,360,354	$ 1,384,292			
Approved	Transmission	51403	2018 PCB Removal Program	2018 ACE Plan	2018 ACE Plan	$ 4,402,342	$ 4,402,342	$ 3,533,869			
Approved	Transmission	52258	2018/2019 Isolated Structure Replacement	2018 ACE Plan	2018 ACE Plan	$ 4,818,521	$ 4,818,521	$ 294,849			
Approved	Transmission	51398	2018/2019 Steel Tower Refurbishment	2018 ACE Plan	2018 ACE Plan	$ 1,992,692	$ 1,992,692	$ 2,055,804			
Approved	Distribution	47787	2H Armdale New Feeders	2017 ACE Plan (for Subsequent Approval)	OTQ - April 6, 2020	$ 1,285,679	$ 1,734,221	$ 1,723,920			
Approved	Transmission	52328	56N-T1 Transformer Upgrades	2018 ACE Plan	2018 ACE Plan	$ 1,279,271	$ 1,279,271	$ 1,307,910			
Approved	Transmission	51975	5P Mobile Substation Replacement	2018 ACE Plan	2018 ACE Plan	$ 4,829,458	$ 4,829,458	$ 2,970,055			
Awaiting Approval	Transmission	51956	6P Mobile Substation Rewind U&U	U&U	Q3 2017 - October 30, 2017	$ -	$ 1,516,121	$ 635,776	OTQ - December 1, 2025	$ 635,776	$ (880,345)
Approved	Distribution	47124	Advanced Metering Infrastructure	2017 ACE Plan (for Subsequent Approval)	OTQ - February 17, 2023	$ 8,274,738	$ 143,495,844	$ 142,777,897			
Approved	Generation	48914	HYD - Malay Falls Facility Repair	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 446,237	$ 1,034,045	$ 1,101,869			
Approved	Generation	47551	HYD - SHH Controls Upgrade	2016 ACE Plan (for Subsequent Approval)	Q4 2015 - January 29, 2016	$ 1,092,851	$ 1,749,212	$ 1,955,374			
Deferred	Generation	49942	HYD - Tidewater Facility Refurbishment	2018 ACE Plan	2018 ACE Plan	$ 1,234,178	$ 1,234,178	$ 914,558			
Withdrawn	Generation	29807	HYD - Tusket Falls Main Dam	2017 ACE Plan (for Subsequent Approval)	OTQ - July 23, 2021	$ 9,940,664	$ 36,826,119	$ 25,568,901			
Approved	Generation	51234	HYD - WRC HVAC Upgrade	2018 ACE Plan	2018 ACE Plan	$ 1,876,537	$ 1,876,537	$ 1,880,426			
Approved	Generation	48791	HYD - WRC Safety Standards Upgrades	2018 ACE Plan (for Subsequent Approval)	OTQ - June 4, 2018	$ 1,019,928	$ 1,760,570	$ 1,919,441			
Approved	Generation	51236	HYD - WRC Tailrace Rock Bolting	2018 ACE Plan	2018 ACE Plan	$ 8,861,996	$ 8,861,996	$ 7,664,784			
Approved	Generation	48052	HYD Annapolis HVAC Upgrade	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 1,498,367	$ 1,573,596	$ 1,987,326			
Approved	Generation	44978	HYD-Wreck Cove Automation	2015 ACE Plan (for Subsequent Approval)	Q2 2015 - July 31, 2015	$ 2,379,999	$ 3,802,446	$ 4,026,586			
Deferred	General Plant	49600	IT - Network Architecture Redesign	2017 ACE Plan (for Subsequent Approval)		$ 1,183,826		$ -			
Approved	General Plant	49855	IT Desktop SW Modernization	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 2,013,034	$ 4,620,516	$ 4,501,621			
Approved	Transmission	47950	L5017 Replacements & Upgrades	2016 ACE Plan	Q1 2018 - May 7, 2018	$ 2,182,142	$ 3,062,664	$ 3,012,632			
Approved	Transmission	47949	L5028 Replacements and Upgrades	2016 ACE Plan	2016 ACE Plan	$ 1,144,355	$ 1,144,355	$ 943,265			
Approved	Transmission	49790	L5505 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 1,223,571	$ 1,223,571	$ 816,588	OTQ - June 9, 2025	$ 816,588	$ (406,983)
Approved	Transmission	49778	L5535 Replacements and Upgrades	2017 ACE Plan	OTQ - April 16, 2018	$ 1,261,920	$ 2,590,269	$ 2,837,177			
Approved	Transmission	49779	L6537 Replacements and Upgrades	2018 ACE Plan	OTQ - March 4, 2019	$ 1,255,220	$ 2,331,474	$ 2,284,616			
Approved	Transmission	52320	L6549 2018 Replacements & Upgrades	2018 ACE Plan	2018 ACE Plan	$ 1,406,535	$ 1,406,535	$ 1,452,523			
Approved	Transmission	44987	L7003 Lidar Upgrades	2015 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2015	$ 6,885,817	$ 11,032,275	$ 10,907,019			
Approved	Transmission	49793	L7011 Replacements and Upgrades	2017 ACE Plan	OTQ - April 1, 2019	$ 3,343,484	$ 4,810,276	$ 4,591,706			
Approved	Transmission	47954	L7012 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 4,428,520	$ 4,428,520	$ 4,392,086			
Approved	Generation	49940	LM6000 TUC5 Control System Upgrade	2017 ACE Plan (for Subsequent Approval)	OTQ - July 3, 2018	$ 1,018,769	$ 1,275,559	$ 1,070,506			
Approved	Transmission	C0001900	Mount Hope 69-25kV Substation	2018 ACE Plan	2018 ACE Plan	$ 2,982,338	$ 2,982,338	$ 2,998,218			
Approved	Transmission	52323	Port Hastings 2C BPS Upgrade	P&A	Q2 - August 7, 2018	$ -	$ 4,201,449	$ 3,997,958			
Approved	General Plant	50153	Self Serve Development Phase 2	2017 ACE Plan (for Subsequent Approval)	OTQ - September 15, 2017	$ 1,827,720	$ 1,160,528	$ 1,316,269			
Not Approved at this	Transmission	43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(	2017 ACE Plan (for Subsequent Approval)	OTQ - January 27, 2022*	$ 16,183,691	$ 20,387,278	$ 20,387,278			
Not Approved at this	Transmission	45066	Upgrade L6511 and L7019 Thermal Rating	2015 ACE Plan (for Subsequent Approval)	OTQ - January 27, 2022*	$ 3,693,033	$ 2,691,017	$ 2,691,017			
Not Approved at this	Transmission	43324	Replace L6513 / Upgrade Line Terminals	2015 ACE Plan (for Subsequent Approval)	OTQ - January 27, 2022*	$ 23,429,902	$ 18,626,428	$ 18,625,082			
Not Approved at this	Transmission	45067	67N Onslow 345 KV Node Swap	2014 ACE Plan (for Subsequent Approval)	OTQ - January 27, 2022*	$ 3,006,487	$ 2,982,714	$ 2,982,585			
Approved	Transmission	48022	Spider Lake Substation Addition	2016 ACE Plan (for Subsequent Approval)	OTQ - March 4, 2019	$ 6,348,981	$ 9,158,260	$ 9,066,398			
Approved	Generation	50518	HYD - Ruth Falls Main Dam Refurbishment	2019 ACE Plan	OTQ - October 11, 2024	$ 7,244,422	$ 14,839,116	$ 7,384,253			
Approved	Transmission	C0010042	2019 Transmission Right-of-Way Widening 69kV	2019 ACE Plan	2019 ACE Plan	$ 5,650,794	$ 5,650,794	$ 5,634,125			
Approved	Transmission	C0010948	2019/2020 Sacrificial Anode Installation Program	2019 ACE Plan	2019 ACE Plan	$ 3,099,862	$ 3,099,862	$ 3,244,208			
Approved	Transmission	C0010952	2019/2020 Substation Polychlorinated Biphenyl (PCB) Equipmer	2019 ACE Plan	2019 ACE Plan	$ 2,786,245	$ 2,786,245	$ 2,792,347			
Approved	Transmission	C0010949	2019/2020 Steel Tower Life Extension	2019 ACE Plan	2019 ACE Plan	$ 2,414,140	$ 2,414,140	$ 2,178,231			
Approved	Transmission	C0011339	L6549 - Replacements and Upgrades Phase 2	2019 ACE Plan	Q1 - May 13, 2024	$ 2,209,907	$ 3,993,974	$ 3,904,481			
Approved	Transmission	C0011241	L5026 - Replacements and Upgrades	2019 ACE Plan	2019 ACE Plan	$ 1,498,789	$ 1,498,789	$ 1,379,563			
Approved	Transmission	C0010978	2019/2020 Transmission Switch & Breaker Replacement	2019 ACE Plan	2019 ACE Plan	$ 1,044,148	$ 1,044,148	$ 1,029,498			
Approved	Transmission	C0011243	L5551 - Replacements and Upgrades	2019 ACE Plan	2019 ACE Plan	$ 1,014,077	$ 1,014,077	$ 1,115,386			
Approved	Distribution	C0011208	2019 Padmount Replacement Program	2019 ACE Plan	2019 ACE Plan	$ 1,413,544	$ 1,413,544	$ 1,464,940			
Approved	Distribution	C0006319	2019 PCB Pole Top Transformer Replacements	2019 ACE Plan	2019 ACE Plan	$ 1,177,592	$ 1,177,592	$ 1,456,959			
Approved	General Plant	C0013438	IT - T&D WAM Phase 1 - GIS and Field Design System	2019 ACE Plan (2018 Pending Submission)	OTQ - December 7, 2018	$ 7,978,434	$ 7,978,434	$ 8,098,333			
Partial Approval	Generation	C0013838	HYD WRC LEM Unit Rehabilitation	2020 ACE Plan (2019 Pending Submission)	OTQ - February 21, 2020	$ 109,691,967	$ 101,787,264	$ 103,396,872			

NS Power Capital Item Status Update
3rd Quarter Overview - as of September 30, 2025
This report includes all projects submitted to the NSEB and remain active, as well as ACE Plan subsequent submittal projects. Projects are removed from this report once the project has been final costed (internal or external), cancelled, or falls below $1M.

Status	Category	CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	FIN Submission Date	FIN Amount	Variance
Approved	Distribution	47794	Heckman's Island Submarine Cable Replacement	2021 ACE Plan (for Subsequent Approval)	Q1 2021 - May 3, 2021	$ 1,296,112	$ 1,338,364	$ 1,554,833			
Approved	General Plant	C0011378	Route Network Upgrades	2020 ACE Plan (2019 Pending Submission)	OTQ - December 2, 2019	$ 5,724,240	$ 5,717,752	$ 6,008,798			
Approved	General Plant	49480	IT - Data Centre Disaster Recovery	2020 ACE Plan (2019 Pending Submission)	OTQ - December 2, 2019	$ 6,103,798	$ 6,335,162	$ 6,249,505			
Approved	General Plant	C0010838	MCC - HVAC Replacement	2019 ACE Plan (for Subsequent Approval)	OTQ - October 4, 2021	$ 1,071,364	$ 1,606,254	$ 1,531,910			
Approved	General Plant	C0002137	ECC - Map Board and Technology Modernization	2019 ACE Plan (for Subsequent Approval)	Q3 - November 4, 2019	$ 2,568,789	$ 2,506,268	$ 2,274,318			
Approved	Transmission	C0021105	L7002 Replacements and Upgrades Phase 2	P&A	Q3 - November 4, 2019	$ -	$ 3,121,442	$ 3,320,027			
Approved	Distribution	C0020623	New Distribution Rights-of-Way Phase 5	2020 ACE Plan	2020 ACE Plan	$ 10,015,266	$ 10,015,266	$ 9,930,358			
Approved	Transmission	C0020627	2020 Transmission Right-of-Way Widening 69kV	2020 ACE Plan	2020 ACE Plan	$ 5,489,820	$ 5,489,820	$ 5,617,282			
Approved	Transmission	C0011261	101W Port Mersey Substation Expansion	2020 ACE Plan	2020 ACE Plan	$ 4,651,384	$ 4,651,384	$ 4,707,040			
Approved	Transmission	C0021123	2020/2021 Substation Polychlorinated Biphenyl (PCB) Equipmer	2020 ACE Plan	2020 ACE Plan	$ 5,197,372	$ 5,197,372	$ 5,482,882			
Approved	Generation	49949	LM6000 TUC4 Control System Replacement	2020 ACE Plan	2020 ACE Plan	$ 1,149,996	$ 1,149,996	$ 901,766			
Approved	Transmission	C0011321	L5031 Replacements and Upgrades Phase 1	2020 ACE Plan	2020 ACE Plan	$ 2,147,212	$ 2,147,212	$ 368,505			
Approved	Transmission	C0021107	L8001 Replacements and Upgrades Phase 1	2020 ACE Plan	2020 ACE Plan	$ 2,292,093	$ 2,292,093	$ 2,517,260			
Approved	Distribution	C0020835	2020 Padmount Replacement Program	2020 ACE Plan	2020 ACE Plan	$ 1,612,389	$ 1,612,389	$ 1,518,893			
Approved	Transmission	C0021122	2020/2021 Transmission Switch & Breaker Replacement	2020 ACE Plan	2020 ACE Plan	$ 1,312,643	$ 1,312,643	$ 1,518,310			
Approved	Distribution	C0020834	2020/2021 Inaccessible PCB Transformer Replacements	2020 ACE Plan	2020 ACE Plan	$ 2,950,294	$ 2,950,294	$ 3,103,289			
Approved	General Plant	C0021109	New RTU Deployment Project	2020 ACE Plan	2020 ACE Plan	$ 8,028,097	$ 8,028,097	$ 7,447,876			
Approved	Transmission	52303	L7019 Replacements and Upgrades	2020 ACE Plan	2020 ACE Plan	$ 1,374,092	$ 1,374,092	$ 1,383,196			
Approved	Transmission	C0021026	Willow Lane 15N-T3 Replacement	2020 ACE Plan	2020 ACE Plan	$ 1,326,647	$ 1,326,647	$ 1,179,586			
Approved	Generation	49756	HYD - Marshall Falls Main Dam Refurbishment	2020 ACE Plan	2020 ACE Plan	$ 5,452,794	$ 5,452,794	$ 627,329			
Approved	Transmission	C0021142	19W-T51 Transformer Replacement	2020 ACE Plan	2020 ACE Plan	$ 1,512,336	$ 1,512,336	$ 1,473,279			
Approved	Distribution	C0021182	93V-313-Meteghan Rebuild	2020 ACE Plan	2020 ACE Plan	$ 1,075,625	$ 1,075,625	$ 927,225			
Approved	Distribution	C0010778	Smart Grid Nova Scotia Project	2020 ACE Plan (for Subsequent Approval)	OTQ - December 5, 2019	$ 6,740,589	$ 7,053,622	$ 6,409,670			
Approved	Distribution	C0019379	50N-410 - 4C-430 Highway 104 Twinning	2020 ACE Plan (for Subsequent Approval)	OTQ - June 1, 2020	$ 1,361,237	$ 1,137,223	$ 1,228,682			
Approved	General Plant	C0023622	AMO Substation and Transmission APM Program	2020 ACE Plan (for Subsequent Approval)	OTQ - April 6, 2020	$ 2,087,848	$ 2,217,589	$ 2,369,151			
Partial Approval	Generation	C0014218	HYD WRC LEM Balance of Plant	2021 ACE Plan (2020 Pending Submission)	OTQ - April 30, 2021	$ 21,186,378	$ 27,637,896	$ 20,352,613			
Approved	General Plant	C0023623	AMO Distribution APM Program	2020 ACE Plan (for Subsequent Approval)	OTQ - April 6, 2020	$ 1,708,240	$ 1,721,484	$ 1,817,942			
Approved	Generation	16374	HYD Gaspereau Dam Safety	2008 ACE Plan	OTQ - February 23, 2020	$ 4,354,889	$ 22,703,451	$ 12,443,594			
Approved	General Plant	C0017098	Ragged Lake Generator Replacement	P&A	Q2 2020 - August 4, 2020	$ -	$ 2,229,267	$ 1,681,714	OTQ - July 7, 2025	$ 1,681,714	$ (547,553)
Approved	Distribution	C0031083	New Distribution Rights-of-Way Phase 6	2021 ACE Plan	2021 ACE Plan	$ 9,762,735	$ 9,762,735	$ 9,705,373			
Approved	Transmission	C0031263	2021/2022 Substation Polychlorinated Biphenyl (PCB) Equipmer	2021 ACE Plan	2021 ACE Plan	$ 7,512,226	$ 7,512,226	$ 7,055,536			
Approved	Transmission	C0031089	2021/2022 Transmission Right-of-Way Widening 69kV	2021 ACE Plan	2021 ACE Plan	$ 5,288,520	$ 5,288,520	$ 5,512,846			
Approved	Transmission	C0031122	L6539 Replacements and Upgrades	2021 ACE Plan	OTQ - April 7, 2025	$ 2,821,842	$ 5,584,042	$ 1,377,455			
Approved	Transmission	C0031085	L6516 Line Replacement and Upgrades	2021 ACE Plan	2021 ACE Plan	$ 2,730,592	$ 2,730,592	$ 2,544,187			
Approved	Transmission	C0031050	New Spare Large Autotransformer	2021 ACE Plan	2021 ACE Plan	$ 2,398,564	$ 2,398,564	$ 2,374,092			
Approved	Transmission	C0033644	2021/2022 Steel Tower Life Extension	2021 ACE Plan	2021 ACE Plan	$ 2,332,746	$ 2,332,746	$ 1,830,762			
Approved	Transmission	C0033645	2021/2022 Steel Tower Refurbishment	2021 ACE Plan	2021 ACE Plan	$ 1,944,005	$ 1,944,005	$ 2,205,105			
Approved	Distribution	C0031145	2021 Padmount Replacement Program	2021 ACE Plan	2021 ACE Plan	$ 1,636,153	$ 1,636,153	$ 1,176,604			
Approved	Transmission	C0031262	2020/2021 Transmission Switch and Breaker Replacement	2021 ACE Plan	2021 ACE Plan	$ 1,483,048	$ 1,483,048	$ 1,456,360			
Approved	Transmission	C0031064	L5054 Replacements and Upgrades	2021 ACE Plan	2021 ACE Plan	$ 1,134,737	$ 1,134,737	$ 996,872			
Approved	Generation	46483	CT - TUS Control System Upgrade	2021 ACE Plan	2021 ACE Plan	$ 1,046,322	$ 1,046,322	$ 1,093,242			
Approved	Generation	C0026285	TRE Heavy Fuel Oil Tank Refurbishment	2021 ACE Plan (for Subsequent Approval)	OTQ - June 10, 2021	$ 1,732,921	$ 2,979,546	$ 2,474,844			
Approved	General Plant	C0030987	IT - NERC CIP Environment Refresh	2022 ACE Plan (2021 Pending Submission)	OTQ - March 7, 2022	$ 1,446,131	$ 1,259,927	$ 1,309,293			
Approved	Distribution	C0041892	New Distribution Rights-of-Way Phase 7	2022 ACE Plan	2022 ACE Plan	$ 9,854,291	$ 9,854,291	$ 10,221,584			
Approved	Transmission	C0041893	2022/2023 Transmission Right-of-Way Widening 69kV	2022 ACE Plan	2022 ACE Plan	$ 5,312,315	$ 5,312,315	$ 5,187,078			
Approved	Transmission	C0041837	2022/2023 Substation Polychlorinated Biphenyl (PCB) Equipmer	2022 ACE Plan	2022 ACE Plan	$ 3,805,434	$ 3,805,434	$ 4,100,264			
Approved	Transmission	C0041793	L7002 Replacements and Upgrades Phase 2	2022 ACE Plan	2022 ACE Plan	$ 3,640,960	$ 3,640,960	$ 3,856,785			
Approved	Transmission	C0041805	L7005 Replacements and Upgrades Phase 2	2022 ACE Plan	2022 ACE Plan	$ 3,182,518	$ 3,182,518	$ 2,910,451	OTQ - October 10, 2025	$ 2,910,451	$ (272,067)
Approved	Transmission	C0041989	2022/2023 Sacrificial Anode Installation Program	2022 ACE Plan	2022 ACE Plan	$ 3,015,107	$ 3,015,107	$ 2,773,423			
Deferred	Transmission	C0041794	L5031 Replacements and Upgrades Phase 2	2022 ACE Plan	2022 ACE Plan	$ 2,905,019	$ 2,905,019	$ -			
Approved	Transmission	C0041791	L6551 Replacements and Upgrades	2022 ACE Plan	2022 ACE Plan	$ 1,988,246	$ 1,988,246	$ 1,090,712			
Approved	Distribution	C0043130	2022 Padmount Replacement Program	2022 ACE Plan	2022 ACE Plan	$ 1,807,359	$ 1,807,359	$ 1,877,876			
Approved	Transmission	C0043571	2022/2023 Transmission Switch & Breaker Replacement	2022 ACE Plan	2022 ACE Plan	$ 1,612,638	$ 1,612,638	$ 1,776,298			
Approved	Generation	C0036368	HYD - Lower Great Brook Switchgear Replacement	2022 ACE Plan	2022 ACE Plan	$ 1,362,281	$ 1,362,281	$ 1,414,118			
Awaiting Approval	Transmission	C0043010	2022/2023 Wood Pole Retreatment Program	2022 ACE Plan	2022 ACE Plan	$ 1,300,037	$ 1,300,037	$ 791,054	OTQ - October 10, 2025	$ 791,054	$ (508,983)
Approved	Transmission	C0041804	2022 Line Retirement Program	2022 ACE Plan	2022 ACE Plan	$ 1,242,178	$ 1,242,178	$ 159,807			
Approved	Generation	C0024484	HYD - Fourth Lake Switchgear Replacement	2022 ACE Plan	2022 ACE Plan	$ 1,145,245	$ 1,145,245	$ 1,560,285			
Approved	Generation	C0029691	CT - VJ1 Control System Upgrade	2022 ACE Plan	2022 ACE Plan	$ 1,016,225	$ 1,016,225	$ 1,002,085			
Approved	Transmission	C0045132	ECEI - Battery Energy Storage System Project	2022 ACE Plan (for Subsequent Approval)	OTQ - January 25, 2024	$ 171,207,920	$ 237,772,259	$ 98,440,934			
Deferred	Generation	C0044392	Eastern Clean Energy Initiative (ECEI) - Coal Conversion	2022 ACE Plan (for Subsequent Approval)		$ 32,341,325		$ 1,810,843			
Deferred	Generation	C0034486	HYD - WRC LEM Penstock intake	2022 ACE Plan (for Subsequent Approval)		$ 11,239,851		$ 1,206,698			
Approved	Generation	C0000979	HYD - Governor Dam Refurbishment	2022 ACE Plan (for Subsequent Approval)	OTQ - November 6, 2023	$ 2,696,630	$ 4,844,345	$ 4,843,593			
Approved	Distribution	C0022662	22C-404GA Lennox Passage Rebuild	2022 ACE Plan (for Subsequent Approval)	OTQ - July 4, 2022	$ 2,352,191	$ 2,609,595	$ 2,684,386			
Deferred	Transmission	C0036826	L8004 Parallel Canso Strait Crossing	2022 ACE Plan (for Subsequent Approval)		$ 2,139,081		$ -			
Approved	General Plant	C0041994	NERC CIP 2022	2022 ACE Plan (for Subsequent Approval)	OTQ - April 4, 2022	$ 1,379,474	$ 1,247,663	$ 1,186,070			
Approved	Generation	C0041651	TUC HFO Tank 4 Refurbishment	2022 ACE Plan (for Subsequent Approval)	Q4 - February 6, 2023	$ 1,110,293	$ 2,734,313	$ 2,756,903			
Approved	Transmission	C0010956	78W-Martin's Brook Substation Relocation	P&A	OTQ - March 3, 2025	$ -	$ 5,122,761	$ 4,690,775			
Approved	Transmission	C0045510	20V-T52 Transformer Replacement	U&U	Q3 - November 7, 2022	$ -	$ 1,506,566	$ 1,516,378			

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Status	Category	CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	FIN Submission Date	FIN Amount	Variance
Approved	Transmission	C0041807	L5534 Replacements and Upgrades	P&A	OTQ - December 5, 2022	$ -	$ 1,426,418	$ 1,558,205			
Approved	Transmission	C0049212	L8001 Replacements and Upgrades Phase 3	P&A	OTQ - December 5, 2022	$ -	$ 1,263,906	$ 1,208,027			
Approved	Transmission	C0050835	2023/2024 Steel Tower Refurbishment	P&A	OTQ - December 5, 2022	$ -	$ 2,056,635	$ 1,553,777			
Approved	Transmission	C0052055	2023/2024 Transmission Right-of-Way Widening 69kV	P&A	OTQ - December 5, 2022	$ -	$ 5,332,315	$ 4,826,689			
Approved	Distribution	C0052056	New Distribution Rights-of-Way Phase 8	P&A	OTQ - December 5, 2022	$ -	$ 9,796,663	$ 9,088,167			
Approved	Transmission	C0052634	L5016 Replacements and Upgrades	P&A	OTQ - December 5, 2022	$ -	$ 2,697,637	$ 2,907,266			
Approved	Generation	C0001222	CT BGT1 Engine Exchange	P&A	OTQ - January 9, 2023	$ -	$ 2,338,747	$ 2,350,941			
Approved	Generation	C0055376	TUC1 - LP Blade Refurbishment U&U	U&U	Q4 - February 6, 2023	$ -	$ 2,025,440	$ 1,988,075			
Approved	Generation	C0041506	LM6000 Engine 191-253 Refurbishment	2023 ACE Plan	OTQ - March 7, 2024	$ 8,740,979	$ 13,473,407	$ 13,067,325			
Approved	Generation	C0012838	HYD - Lequille Canal Dyke, Gates and Tailrace Refurbishment	2023 ACE Plan	2023 ACE Plan	$ 7,058,816	$ 7,058,816	$ 5,666,283			
Approved	Generation	C0029682	CT VJ2 - Replace Generator Assembly	2023 ACE Plan	2023 ACE Plan	$ 5,397,738	$ 5,397,738	$ 3,266,712			
Approved	Generation	C0051134	TUC2 - L-0 Blade Replacement	2023 ACE Plan	2023 ACE Plan	$ 4,157,503	$ 4,157,503	$ 4,172,144			
Approved	Transmission	C0041788	L6516 Replacements and Upgrades Phase 2	2023 ACE Plan	OTQ July 2, 2024	$ 3,123,474	$ 5,442,794	$ 4,417,850			
Approved	Transmission	C0055539	10H-T1 Transformer Replacement	2023 ACE Plan	2023 ACE Plan	$ 2,420,892	$ 2,420,892	$ 41,916			
Approved	Transmission	C0052299	2023/2024 Steel Tower Life Extension	2023 ACE Plan	2023 ACE Plan	$ 2,195,463	$ 2,195,463	$ 771,268			
Approved	Transmission	C0055796	2023 EHV Breaker Replacements	2023 ACE Plan	OTQ - October 2, 2023	$ 2,048,411	$ 3,463,489	$ 489,115			
Approved	Transmission	C0055696	L5031 Replacement and Upgrades Robinson Corner Tap	2023 ACE Plan	2023 ACE Plan	$ 1,357,477	$ 1,357,477	$ 1,481,749			
Approved	Distribution	C0050836	2023 Padmount Replacement Program	2023 ACE Plan	2023 ACE Plan	$ 1,309,551	$ 1,309,551	$ 1,527,046			
Approved	Generation	C0051135	TUC2 - Turbine Valves Refurbishment 2023	2023 ACE Plan	2023 ACE Plan	$ 1,048,924	$ 1,048,924	$ 967,772			
Approved	Transmission	C0052654	L5541 Water Crossing Upgrades	2023 ACE Plan	2023 ACE Plan	$ 1,047,074	$ 1,047,074	$ -			
Approved	Transmission	C0053316	Michelin Voltage Sag Reduction DVR	2023 ACE Plan (for Subsequent Approval)	OTQ - April 12, 2024	$ 21,007,507	$ 31,170,675	$ 32,729,208			
Approved	General Plant	C0042166	IT - Data Loss Prevention (DLP) Platform	2023 ACE Plan (for Subsequent Approval)	OTQ - June 7, 2023	$ 3,233,905	$ 4,261,239	$ 3,944,010			
Approved	Generation	C0051894	TUC - HFO Tank 3 Refurbishment	2023 ACE Plan (for Subsequent Approval)	OTQ - March 7, 2024	$ 2,053,937	$ 2,218,012	$ 2,251,680			
Approved	General Plant	C0030984	IT - Cisco UCS Lifecycle	2023 ACE Plan (for Subsequent Approval)	OTQ - September 5, 2023	$ 2,047,691	$ 2,456,609	$ 2,088,998	Q2 - August 5, 2025	$ 2,088,998	$ (367,611)
Approved	Generation	C0044030	WIN - DIG Haight's Brook Crossing Replacement	2023 ACE Plan (for Subsequent Approval)	OTQ - November 6, 2023	$ 2,046,985	$ 2,024,052	$ 297,229			
Approved	Transmission	C0055557	76V-T1 Transformer Replacement	2023 ACE Plan (for Subsequent Approval)	OTQ - April 7, 2025	$ 1,751,258	$ 3,151,575	$ 2,198,206			
Approved	General Plant	C0011167	IT - Backup Infrastructure Upgrade	2023 ACE Plan (for Subsequent Approval)	OTQ - June 7, 2023	$ 1,557,471	$ 2,315,457	$ 2,310,350			
Approved	Generation	C0048591	CT VJ1 Engine P686621 Refurbishment	P&A	OTQ - March 6, 2023	$ -	$ 2,312,509	$ 2,283,878			
Approved	Generation	C0054356	TUC – Roof Replacement U&U	U&U	OTQ - March 6, 2023	$ -	$ 1,459,455	$ 1,412,165			
Approved	Generation	C0053916	CT BGT4 Engine P686630 Refurbishment	U&U	OTQ - April 3, 2023	$ -	$ 1,850,501	$ 1,718,317			
Approved	Transmission	C0031052	Replenish Spare Transformer Used at 58C	2021 ACE Plan (Less than $1M)	OTQ - June 7, 2023	$ 982,910	$ 1,303,827	$ 1,183,122			
Approved	Generation	51761	LIN2 2022/2023 Winter Capacity Requirement	U&U	OTQ - September 5, 2023	$ -	$ 2,512,341	$ 2,526,651			
Approved	Generation	C0006418	HYD WRC Tailrace Tunnel Rock Bolting Phase 2	2024 ACE Plan	2024 ACE Plan	$ 15,722,669	$ 15,722,669	$ 9,787,743			
Approved	General Plant	C0047277	IT - GIS Utility Network Upgrade	2024 ACE Plan	2024 ACE Plan	$ 6,175,230	$ 6,175,230	$ 3,336,285			
Approved	Generation	C0049013	HYD - Lower Great Brook Log Hoist Replacement	2024 ACE Plan	2024 ACE Plan	$ 2,158,658	$ 2,158,658	$ 1,816,362			
Approved	Generation	C0049032	HYD - Cowie Falls Log Hoist Replacement	2024 ACE Plan	2024 ACE Plan	$ 2,237,991	$ 2,237,991	$ 1,886,112			
Approved	General Plant	C0049619	IT - ERP Upgrade (EBS, PS, PP, OBIA)	2024 ACE Plan	2024 ACE Plan	$ 6,198,799	$ 6,198,799	$ 5,392,637			
Approved	Transmission	C0050842	2024 Bulk Oil Breaker Replacement Program	2024 ACE Plan	2024 ACE Plan	$ 3,274,756	$ 3,274,756	$ 859,084			
Approved	Generation	C0051136	TUC2 - HP/IP Turbine Refurbishment	2024 ACE Plan	2024 ACE Plan	$ 4,264,777	$ 5,965,028	$ 5,921,807			
Approved	Transmission	C0056240	2024/2025 Transmission Switch and Breaker Replacements	2024 ACE Plan	2024 ACE Plan	$ 3,271,622	$ 3,271,622	$ 3,081,411			
Approved	Distribution	C0057142	New Distribution Rights-of-Way Phase 9	2024 ACE Plan	2024 ACE Plan	$ 19,141,914	$ 19,141,914	$ 19,189,121			
Approved	Transmission	C0057882	2024 Pennsylvania Breaker Replacements	2024 ACE Plan	2024 ACE Plan	$ 2,163,832	$ 2,163,832	$ 520,212			
Approved	Generation	C0058942	WRC D11-2 Foundation Stabilization	2024 ACE Plan	2024 ACE Plan	$ 1,540,602	$ 1,540,602	$ 1,451,471			
Approved	Transmission	C0059046	101S and 79N Reactor Replacements	2024 ACE Plan	2024 ACE Plan	$ 1,460,062	$ 1,460,062	$ 822,765			
Approved	Generation	C0060608	TUC6 Turbine Refurbishment	2024 ACE Plan	2024 ACE Plan	$ 2,472,311	$ 2,472,311	$ 562,396			
Approved	Generation	C0060707	CT BGT1 Generator Refurbishment	2024 ACE Plan	2024 ACE Plan	$ 3,482,602	$ 3,482,602	$ 7,684			
Approved	Distribution	C0060749	2024 Padmount Replacement Program	2024 ACE Plan	2024 ACE Plan	$ 1,288,198	$ 1,288,198	$ 1,868,271			
Approved	Transmission	C0061023	2024 EHV Breaker Replacements	2024 ACE Plan	2024 ACE Plan	$ 3,638,480	$ 3,638,480	$ 435			
Approved	Transmission	C0061046	2024 Merlin Gerin Breaker Replacements	2024 ACE Plan	2024 ACE Plan	$ 1,169,591	$ 1,169,591	$ 326,312			
Approved	Transmission	C0061387	2024 2025 Wood Pole Retreatment Program	2024 ACE Plan	2024 ACE Plan	$ 1,209,391	$ 1,209,391	$ 258,382			
Approved	Transmission	C0061403	2024 2025 Sacrificial Anode Installation Program	2024 ACE Plan	2024 ACE Plan	$ 2,382,113	$ 2,382,113	$ 2,586,372			
Approved	Transmission	C0061545	L6006 Replacements and Upgrades	2024 ACE Plan	2024 ACE Plan	$ 5,032,640	$ 5,032,640	$ 6,015,794			
Approved	Transmission	C0061546	L6514 Replacements and Upgrades	2024 ACE Plan	2024 ACE Plan	$ 2,102,666	$ 2,102,666	$ 1,588,417			
Approved	Transmission	C0061547	L7022 Replacements and Upgrades	2024 ACE Plan	2024 ACE Plan	$ 2,283,569	$ 2,283,569	$ 21,085			
Approved	Transmission	C0061550	L5031 Replacements and Upgrades - Hubbards to East Chester	2024 ACE Plan	2024 ACE Plan	$ 5,297,584	$ 5,297,584	$ 4,001,201			
Approved	Transmission	C0061551	L7009 Replacements and Upgrades	2024 ACE Plan	2024 ACE Plan	$ 3,280,328	$ 3,280,328	$ 1,317,705			
Approved	Transmission	C0061743	L6038 Realignment	2024 ACE Plan	2024 ACE Plan	$ 1,032,911	$ 1,032,911	$ 1,485,549			
Approved	Transmission	C0061883	129H - Kearney Lake Substation Rebuild	2024 ACE Plan	2024 ACE Plan	$ 1,017,322	$ 1,017,322	$ 53,949			
Approved	General Plant	C0054755	IT - Connect My Data (Green Button)	2024 ACE Plan (for Subsequent Approval)	Q4 - February 5, 2024	$ 2,309,350	$ 2,964,237	$ 2,884,398			
Deferred	Transmission	C0031286	Spare Padmounted Substation	2024 ACE Plan (for Subsequent Approval)		$ 1,319,838		$ -			
Awaiting Approval	General Plant	C0032664	ECC Optimization Tools Project	2024 ACE Plan (for Subsequent Approval)	OTQ - December 1, 2025	$ 4,329,150	$ 7,486,068	$ 1,776,697			
Approved	Generation	C0050414	HYD Roseway Asset Decommissioning	2024 ACE Plan (for Subsequent Approval)	OTQ - December 20, 2024	$ 4,650,648	$ 4,915,649	$ 3,657,667			
Approved	Generation	C0060816	POT - HFO Tank Refurbishment	2024 ACE Plan (for Subsequent Approval)	OTQ - December 17, 2024	$ 2,012,803	$ 3,684,622	$ 3,628,104			
Deferred	General Plant	C0061287	IT - Third Party Risk Management	2024 ACE Plan (for Subsequent Approval)		$ 1,405,970		$ -			
Approved	General Plant	C0061289	IT - Network Next Generation Security Design	2024 ACE Plan (for Subsequent Approval)	OTQ - April 7, 2025	$ 2,632,635	$ 1,814,216	$ 1,884,878			
Approved	Distribution	C0061521	New Distribution Rights-of-Way Phase 10	2024 ACE Plan (for Subsequent Approval)	OTQ - October 7, 2024	$ 18,904,608	$ 20,890,176	$ 16,467,375			
Approved	Generation	C0038126	HYD Cowie Falls Unit 12 Overhaul	2024 ACE Plan (Less than $1M)	Q1 - May 13, 2024	$ 964,521	$ 1,274,890	$ 1,288,270			
Approved	Generation	C0053655	HYD Cowie Falls Unit 11 Overhaul	2023 ACE Plan (Less than $1M)	Q1 - May 13, 2024	$ 913,947	$ 1,225,491	$ 1,291,556			

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Status	Category	CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	FIN Submission Date	FIN Amount	Variance
Approved	Generation	C0059283	LIN2 PE 2023/2024 Winter Capacity Requirements	U&U	Q1 - May 13, 2024	$ -	$ 1,661,834	$ 1,663,858			
Approved	Transmission	C0062123	143H-Mount Uniacke Substation	P&A	Q2 - August 6, 2024	$ -	$ 9,040,869	$ 3,853,853			
Approved	General Plant	C0056461	IT - Contact Centre Cloud Migration	2024 ACE Plan (for Subsequent Approval)	OTQ - September 16, 2024	$ 929,372	$ 3,237,539	$ 2,264,821			
Approved	Transmission	C0031048	91H-T11 Transformer Replacement	2025 ACE Plan	2025 ACE Plan	$ 6,914,622	$ 6,914,622	$ 85,570			
Approved	Generation	C0039266	HYD - Gulch Overhaul	2025 ACE Plan	2025 ACE Plan	$ 1,371,379	$ 1,371,379	$ 287,049			
Approved	Generation	C0048990	HYD AVO 2 Switchgear Replacement	2025 ACE Plan	2025 ACE Plan	$ 1,814,631	$ 1,814,631	$ 777,176			
Approved	Transmission	C0050834	Spare EHV Breaker Replacements	2025 ACE Plan	2025 ACE Plan	$ 1,178,832	$ 1,178,832	$ 162			
Approved	Transmission	C0050852	10V-T1 Transformer Replacement	2025 ACE Plan	2025 ACE Plan	$ 2,113,337	$ 2,113,337	$ 1,453,501			
Pending Submission	General Plant	C0051815	RTU Replacements Program Phase 6	2025 ACE Plan	2025 ACE Plan	$ 5,959,915	$ 5,959,915	$ 1,192,508			
Approved	Transmission	C0053295	L5004 Kearney Lake Structure Replacement	2025 ACE Plan	2025 ACE Plan	$ 2,478,537	$ 2,478,537	$ 304,281			
Approved	Transmission	C0057682	Spare Transformer Replacement	2025 ACE Plan	2025 ACE Plan	$ 2,286,389	$ 2,286,389	$ 3,610,651			
Approved	Generation	C0068659	TRE5 - IP-LP Turbine Refurbishment	2025 ACE Plan	2025 ACE Plan	$ 1,282,670	$ 1,282,670	$ 3,091,267			
Approved	Distribution	C0068786	2025 Padmount Replacement Program	2025 ACE Plan	2025 ACE Plan	$ 1,354,219	$ 1,354,219	$ -			
Approved	Generation	C0068882	TUC1 Generator Refurbishment	2025 ACE Plan	2025 ACE Plan	$ 2,124,211	$ 2,124,211	$ -			
Approved	Generation	C0068887	TUC3 Turbine Valves Refurbishment	2025 ACE Plan	2025 ACE Plan	$ 1,869,104	$ 1,869,104	$ 1,615,312			
Approved	Distribution	C0068952	2025 PCB Poletop Sampling and Replacement	2025 ACE Plan	2025 ACE Plan	$ 7,158,974	$ 7,158,974	$ 1,557,845			
Approved	Distribution	C0068953	2025 PCB Light Replacement	2025 ACE Plan	2025 ACE Plan	$ 4,225,224	$ 4,225,224	$ -			
Approved	Distribution	C0068954	2025 PCB Downline Device Sampling and Replacement	2025 ACE Plan	2025 ACE Plan	$ 1,716,718	$ 1,716,718	$ -			
Approved	Transmission	C0068961	2025 PCB Substation Sampling and Replacement	2025 ACE Plan	2025 ACE Plan	$ 6,650,933	$ 6,650,933	$ 39,831			
Approved	Transmission	C0069227	L6516 Replacements and Upgrades Phase 3	2025 ACE Plan	2025 ACE Plan	$ 3,104,925	$ 3,104,925	$ 1,535,110			
Approved	Transmission	C0069231	L8002 Replacements and Upgrades Phase 1	2025 ACE Plan	2025 ACE Plan	$ 3,093,176	$ 3,093,176	$ 1,223,077			
Approved	Transmission	C0069232	L6021 Replacements and Upgrades Phase 1	2025 ACE Plan	2025 ACE Plan	$ 3,253,068	$ 3,253,068	$ 1,614,847			
Approved	Transmission	C0069238	2025/2026 Steel Tower Refurbishment	2025 ACE Plan	2025 ACE Plan	$ 2,337,250	$ 2,337,250	$ -			
Approved	General Plant	C0069270	2025 SCADA/EMS Upgrade	2025 ACE Plan	2025 ACE Plan	$ 1,306,288	$ 1,306,288	$ 22,718			
Approved	Transmission	C0070048	L5027B Replacements and Upgrades Phase 1	2025 ACE Plan	2025 ACE Plan	$ 2,916,728	$ 2,916,728	$ -			
Approved	Distribution	C0070787	91W-411 Labelle Road Phase Extension	2025 ACE Plan	2025 ACE Plan	$ 1,150,616	$ 1,150,616	$ -			
Approved	General Plant	C0070907	MDR-8000 Microwave Radio Replacement	2025 ACE Plan	2025 ACE Plan	$ 1,572,478	$ 1,572,478	$ -			
Deferred	Generation	48913	HYD - Tusket Facility Refurbishment	2025 ACE Plan (for Subsequent Approval)		$ 12,972,226		$ 1,078,895			
Deferred	Transmission	C0011358	New Bridgewater Substation	2025 ACE Plan (for Subsequent Approval)		$ 18,173,047		$ 2,177,530			
Approved	Transmission	C0021140	New 138KV-25KV Substation Stellarton	2025 ACE Plan (for Subsequent Approval)	Q1 - May 16, 2025	$ 10,511,998	$12,960,396	$ 3,494,364			
Approved	Transmission	C0041830	Spare Power Production Unit Transformer	2025 ACE Plan (for Subsequent Approval)	OTQ - April 7, 2025	$ 1,264,622	$ 1,266,552	$ 1,212,412			
Filed by WTI	Transmission	C0044391	Eastern Clean Energy Initiative (ECEI) - Transmission	2025 ACE Plan (for Subsequent Approval)	OTQ - April 10, 2025	$ 800,229,290	$ 684,685,646	$ 12,684,032			
Awaiting Approval	General Plant	C0053699	Renewable to Retail Implementation	2025 ACE Plan (for Subsequent Approval)	OTQ - December 1, 2025	$ 5,062,652	$ 5,644,468	$ 4,635,351			
Approved	Generation	C0059783	HYD Upper Lake Falls 2 Overhaul	2025 ACE Plan (for Subsequent Approval)	OTQ - September 9, 2025	$ 1,678,153	$ 1,582,014	$ 27,269			
Approved	General Plant	C0061284	IT - OT Cyber Security Control Implementation	2025 ACE Plan (for Subsequent Approval)	OTQ - March 3, 2025	$ 5,459,313	$ 6,826,426	$ 1,993,686			
Less than $1M	Generation	C0061484	PTMT - E-Crane Refurbishment	2025 ACE Plan (for Subsequent Approval)		$ 2,433,081		$ 299,711			
Approved	Generation	C0063803	HYD AVO 2 Access Road Stabilization	2025 ACE Plan (for Subsequent Approval)	OTQ - April 7, 2025	$ 2,406,283	$ 1,862,826	$ 328,456			
Approved	Generation	C0067023	LIN2 2024/25 Capacity Requirement	2025 ACE Plan (for Subsequent Approval)	OTQ - June 9, 2025	$ 1,083,800	$ 1,257,127	$ 1,290,724			
Approved	Generation	C0068566	LIN DCS Upgrade 2025	2025 ACE Plan (for Subsequent Approval)	Q1 - May 16, 2025	$ 1,440,911	$1,544,190	$ 340,357			
Awaiting Approval	Generation	C0068655	LM6000 191-332 Life Extension	2025 ACE Plan (for Subsequent Approval)	Q2 - August 5, 2025	$ 6,013,454	$ 18,948,560	$ 18,457,860			
Pending Submission	Generation	C0069166	POT-Turbine Valve Refurbishment	2025 ACE Plan (for Subsequent Approval)		$ 2,872,598		$ -			
Awaiting Approval	Generation	C0070486	HYD LGB Stoplog Replacement	2025 ACE Plan (for Subsequent Approval)	OTQ - December 1, 2025	$ 1,288,404	$ 3,593,884	$ 1,418,999			
Awaiting Approval	Distribution	C0071528	FLISR Implementation	2025 ACE Plan (for Subsequent Approval)	Q2 - August 5, 2025	$ 5,299,248	$ 4,638,245	$ 34,654			
Approved	Generation	C0061003	POA LP HP IP Turbine Refurbishment	2025 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2025	$ 4,155,131	$ 4,861,261	$ 1,356,415			
Approved	Generation	C0061005	POA Cell Capping 2025	2025 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2025	$ 3,255,440	$ 2,530,405	$ 1,843,307			
Approved	Generation	C0067906	POA Boiler Refurbishment 2025	2025 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2025	$ 1,213,152	$ 1,218,254	$ 1,525,527			
Approved	Generation	C0067908	POA Boiler Refractory Refurbishment 2025	2025 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2025	$ 1,089,478	$ 1,378,466	$ 744,891			
Approved	General Plant	C0011159	Plant Information System Upgrade	2024 ACE Plan (Less than $1M)	OTQ - March 3, 2025	$ 362,679	$ 1,142,652	$ 1,081,538			
Approved	Distribution	C0042687	15N-202 Arthur St Conversion	2022 ACE Plan (Less than $1M)	OTQ - April 7, 2025	$ 718,195	$ 1,399,459	$ 1,200,267			
Approved	Generation	C0049192	HYD - GUL Generator Refurbishment	2025 ACE Plan (Less than $1M)	Q1 - May 16, 2025	$ 732,043	$ 1,316,589	$ 447,455			
Approved	Generation	C0068662	TRE5 Baghouse Filter Replacement	2025 ACE Plan (Less than $1M)	Q1 - May 16, 2025	$ 534,006	$ 1,241,640	$ 1,065,703			
Approved	Generation	C0073348	HYD - WRC Surge Lake Volume Optimization	U&U	Q1 - May 16, 2025	$ -	$ 1,736,278	$ 691,019			
Approved	Generation	C0073965	TRE5 U&U Burner Nest Waterwall Tube Replacement	U&U	Q1 - May 16, 2025	$ -	$ 2,156,407	$ 668,079			
Approved	General Plant	C0073777	IT - Complex Customer Projects	P&A	OTQ - June 9, 2025	$ -	$ 3,025,518	$ 396,568			
Approved	General Plant	49036	HYD - Avon 2 Controls Upgrade	2025 ACE Plan (Less than $1M)	Q2 - August 5, 2025	$ -	$ 1,073,463	$ 398,861			
Awaiting Approval	Generation	C0073491	LM6000 191-443 Engine Replacement	P&A	Q2 - August 5, 2025	$ -	$ 24,217,289	$ 22,864			
Approved	Generation	C0067183	TUC Wharf Access Bridge Replacement	U&U	Q2 - August 5, 2025	$ -	$ 2,426,669	$ 445,032			
Approved	Transmission	C0074130	Robie Street Underground	P&A	OTQ - September 9, 2025	$ -	$ 4,465,119	$ 1,221,314			
Awaiting Approval	Generation	C0080112	HYD Big Falls Unit 6 Rotor Re-Insulation	U&U	OTQ - October 10, 2025	$ -	$ 1,025,626	$ 48,185			
Awaiting Approval	General Plant	C0053696	ECC Wind Integration	2025 ACE Plan (Less than $1M)	OTQ - December 1, 2025	$ 757,358	$ 4,428,335	$ 16,080			
Awaiting Approval	Generation	C0080228	HYD HOB Stator Rewind and Generator Refurbishment	U&U	OTQ - December 1,2025	$ -	$ 2,587,170	$ -			
Awaiting Approval	Generation	C0021608	TUC Shoreline Sheetpile Refurbishment	2026 ACE Plan	2026 ACE Plan	$ 5,691,466	$ 5,691,466	$ 272,027			
Awaiting Approval	Transmission	C0053214	76W-T1 Transformer Replacement	2026 ACE Plan	2026 ACE Plan	$ 2,818,855	$ 2,818,855	$ 66,043			
Awaiting Approval	Transmission	C0053234	96H-T1 Transformer Replacement	2026 ACE Plan	2026 ACE Plan	$ 2,056,752	$ 2,056,752	$ 21,093			
Awaiting Approval	Generation	C0068888	TUC3 Continuous Ash Hauling System	2026 ACE Plan	2026 ACE Plan	$ 1,359,984	$ 1,359,984	$ -			
Awaiting Approval	Generation	C0068898	TUC1 IP LP Last Stage Blade Replacement	2026 ACE Plan	2026 ACE Plan	$ 5,215,861	$ 5,215,861	$ -			
Awaiting Approval	Transmission	C0068969	2026 Pennsylvania Breaker Replacements	2026 ACE Plan	2026 ACE Plan	$ 1,620,028	$ 1,620,028	$ 33,474			
Awaiting Approval	Transmission	C0070586	L6536 Switch Replacements	2026 ACE Plan	2026 ACE Plan	$ 2,074,494	$ 2,074,494	$ 72,103			

NS Power Capital Item Status Update
3rd Quarter Overview - as of September 30, 2025
This report includes all projects submitted to the NSEB and remain active, as well as ACE Plan subsequent submittal projects. Projects are removed from this report once the project has been final costed (internal or external), cancelled, or falls below $1M.

Status	Category	CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	FIN Submission Date	FIN Amount	Variance
Awaiting Approval	Transmission	C0070909	70W-T52 Transformer Addition	2026 ACE Plan	2026 ACE Plan	$ 3,957,128	$ 3,957,128	$ 11,475			
Awaiting Approval	Distribution	C0080104	36V-303 Baxter's Harbour Rd Reconductor Phase 1	2026 ACE Plan	2026 ACE Plan	$ 1,062,416	$ 1,062,416	$ -			
Awaiting Approval	Transmission	C0080109	L7001 Replacements and Upgrades Phase 1	2026 ACE Plan	2026 ACE Plan	$ 3,063,280	$ 3,063,280	$ -			
Awaiting Approval	Transmission	C0080110	L7012 Replacements and Upgrades Phase 1	2026 ACE Plan	2026 ACE Plan	$ 5,370,318	$ 5,370,318	$ -			
Awaiting Approval	General Plant	C0080111	2026 RTU Deployment	2026 ACE Plan	2026 ACE Plan	$ 8,322,655	$ 8,322,655	$ -			
Awaiting Approval	Generation	C0080133	TUC3 IP Turbine Refurbishment	2026 ACE Plan	2026 ACE Plan	$ 2,588,734	$ 2,588,734	$ -			
Awaiting Approval	Generation	C0080134	TUC2 Stack Coating and Structural Refurbishment	2026 ACE Plan	2026 ACE Plan	$ 4,256,511	$ 4,256,511	$ -			
Awaiting Approval	Generation	C0080135	CT - BGT2 Engine Refurbishment	2026 ACE Plan	2026 ACE Plan	$ 2,462,664	$ 2,462,664	$ -			
Awaiting Approval	Generation	C0080205	POA Boiler Refractory Replacement 2026	2026 ACE Plan	2026 ACE Plan	$ 1,024,385	$ 1,024,385	$ -			
Awaiting Approval	Generation	C0080206	POA Boiler Refurbishment 2026	2026 ACE Plan	2026 ACE Plan	$ 1,304,600	$ 1,304,600	$ -			
Awaiting Approval	General Plant	C0080252	Intelligent Asset Data Capture & Integration Platform	2026 ACE Plan	2026 ACE Plan	$ 267,941	$ 267,941	$ -			
Awaiting Approval	Distribution	C0080266	New Distribution Right of Way Phase 11	2026 ACE Plan	2026 ACE Plan	$ 20,889,694	$ 20,889,694	$ -			
Awaiting Approval	Distribution	C0080612	57C-426H Melrose Reconductor and Line Extension Phase 1	2026 ACE Plan	2026 ACE Plan	$ 1,288,474	$ 1,288,474	$ -			
Pending Submission	Generation	47649	HYD Salmontail Gate Pedestal and Main Dam Refurbishment	2026 ACE Plan (for Subsequent Approval)		$ 5,870,708		$ 705,758			
Pending Submission	Generation	47650	HYD - Annapolis Decision Analysis	2026 ACE Plan (for Subsequent Approval)		$ 30,732,442		$ 2,873,660			
Pending Submission	Generation	49595	HYD - TUS 1 Overhaul	2026 ACE Plan (for Subsequent Approval)		$ 5,649,954		$ 310,075			
Pending Submission	Transmission	51098	L-6014 Shannon Park Transmission Towers	2026 ACE Plan (for Subsequent Approval)		$ 39,471,723		$ 1,476,385			
Pending Submission	General Plant	C0000017	Storm Management Software Implementation	2026 ACE Plan (for Subsequent Approval)		$ 2,235,914		$ -			
Pending Submission	General Plant	C0021835	IT - CIS Replacement	2026 ACE Plan (for Subsequent Approval)		$ 84,502,844		$ 3,517,009			
Pending Submission	Transmission	C0022247	1N Onslow Transformer Addition (1N-T66)	2026 ACE Plan (for Subsequent Approval)		$ 3,645,131		$ 1,743,772			
Pending Submission	Transmission	C0023802	L-6515 Canso Causeway Rebuild	2026 ACE Plan (for Subsequent Approval)		$ 3,925,352		$ 397,400			
Pending Submission	General Plant	C0032202	Sydney Depot Improvements	2026 ACE Plan (for Subsequent Approval)		$ 2,700,000		$ -			
Pending Submission	Transmission	C0032382	142H - Susie Lake Substation	2026 ACE Plan (for Subsequent Approval)		$ 8,256,386		$ 671,904			
Pending Submission	General Plant	C0047278	IT - Oracle MDM Upgrade	2026 ACE Plan (for Subsequent Approval)		$ 7,949,409		$ 29,355			
Pending Submission	General Plant	C0047301	IT - Cloud Integration Platform	2026 ACE Plan (for Subsequent Approval)		$ 2,004,962		$ 137,727			
Pending Submission	Generation	C0047973	HYD ANN Sluice Gates and Check Refurbishment	2026 ACE Plan (for Subsequent Approval)		$ 5,673,491		$ 215,551			
Pending Submission	Generation	C0052514	HYD MacDonald Dam Access Improvements	2026 ACE Plan (for Subsequent Approval)		$ 1,547,398		$ 123,275			
Pending Submission	Generation	C0057361	HYD ANN Facility Isolation	2026 ACE Plan (for Subsequent Approval)		$ 4,083,925		$ 2,778,287			
Pending Submission	Transmission	C0059483	83V L-5017 and L-5046 Rebuild Tap	2026 ACE Plan (for Subsequent Approval)		$ 1,207,318		$ 212,714			
Pending Submission	Transmission	C0061552	L-6043 Replacements and Upgrades	2026 ACE Plan (for Subsequent Approval)		$ 2,457,629		$ -			
Pending Submission	General Plant	C0062043	IT - SharePoint Technical Migration	2026 ACE Plan (for Subsequent Approval)		$ 3,134,674		$ 1,006,383			
Pending Submission	Generation	C0064967	Tusket Powerhouse Tidal Pool Fish Passage	2026 ACE Plan (for Subsequent Approval)		$ 1,315,495		$ -			
Pending Submission	Generation	C0067686	HYD Lumsden Rubber Dam Replacement	2026 ACE Plan (for Subsequent Approval)		$ 1,304,068		$ 54,524			
Pending Submission	General Plant	C0067863	IT - Managed Detect & Respond	2026 ACE Plan (for Subsequent Approval)		$ 2,585,071		$ 140,002			
Pending Submission	General Plant	C0068714	IT - Identity & Access Management	2026 ACE Plan (for Subsequent Approval)		$ 4,324,589		$ 914,563			
Pending Submission	General Plant	C0068718	IT - DERMS Solution Project	2026 ACE Plan (for Subsequent Approval)		$ 2,954,002		$ 121,257			
Pending Submission	General Plant	C0068719	IT - Distributed Intelligence Apps	2026 ACE Plan (for Subsequent Approval)		$ 2,637,356		$ 15,822			
Pending Submission	General Plant	C0068721	IT - ADMS Upgrade 2026	2026 ACE Plan (for Subsequent Approval)		$ 7,200,000		$ -			
Pending Submission	Transmission	C0069534	IR 669 Network Upgrade Higgins Mountain Wind	2026 ACE Plan (for Subsequent Approval)		$ 9,496,174		$ 115,697			
Pending Submission	Transmission	C0070086	10H-T2 Transformer Replacement	2026 ACE Plan (for Subsequent Approval)		$ 2,878,891		$ 20,582			
Pending Submission	Transmission	C0070327	IR 673 Network Upgrade Benjamins Mill Wind	2026 ACE Plan (for Subsequent Approval)		$ 265,000		$ 7,946			
Pending Submission	Transmission	C0070367	IR 618 Network Upgrade Goose Harbour Lake Wind	2026 ACE Plan (for Subsequent Approval)		$ 11,015,684		$ 9,085			
Pending Submission	Transmission	C0071888	New Tidewater Substation	2026 ACE Plan (for Subsequent Approval)		$ 4,141,223		$ 73,909			
Pending Submission	Transmission	C0071889	77V-T1 Transformer Replacement	2026 ACE Plan (for Subsequent Approval)		$ 3,486,796		$ 8,209			
Pending Submission	Transmission	C0072808	ECEI Synchronous Condensers	2026 ACE Plan (for Subsequent Approval)		$ 364,566,804		$ 553,600			
Pending Submission	Generation	C0073368	HYD Malay Falls Rubber Dam	2026 ACE Plan (for Subsequent Approval)		$ 2,237,339		$ 42,684			
Pending Submission	Generation	C0076273	Bear Head Ash Management Site - Life Extension	2026 ACE Plan (for Subsequent Approval)		$ 10,148,108		$ 18,725			
Pending Submission	Generation	C0076672	ICP - RC SCR Bridge 10.10 Refurbishment	2026 ACE Plan (for Subsequent Approval)		$ 1,353,592		$ -			
Pending Submission	Distribution	C0080101	539N-210 Big Island Sub-Sea Cable Replacement	2026 ACE Plan (for Subsequent Approval)		$ 3,539,067		$ -			
Pending Submission	Distribution	C0080102	92H-331 Double Circuit Peggys Cove Rd	2026 ACE Plan (for Subsequent Approval)		$ 1,882,573		$ -			
Pending Submission	Transmission	C0080107	L-5532 Reliability Upgrade - 91W Middle Field Substation	2026 ACE Plan (for Subsequent Approval)		$ 3,053,526		$ -			
Pending Submission	Transmission	C0080108	L-5532 Replacements and Upgrades Phase 1	2026 ACE Plan (for Subsequent Approval)		$ 2,490,532		$ -			
Pending Submission	Generation	C0080219	HYD Deep Brook Spillway & Intake Refurbishment	2026 ACE Plan (for Subsequent Approval)		$ 3,142,201		$ 4,250			
Pending Submission	Generation	C0080671	LIN1 HIP Turbine Refurbishment 2026	2026 ACE Plan (for Subsequent Approval)		$ 3,244,992		$ -			
Pending Submission	Generation	C0080691	LIN3 DCS Migration 2026	2026 ACE Plan (for Subsequent Approval)		$ 1,359,218		$ -			
Pending Submission	Generation	C0080732	POA Ash Cell Capping/ Cell Development 2026	2026 ACE Plan (for Subsequent Approval)		$ 2,420,358		$ -			
Pending Submission	Generation	C0080768	POT - CW Pump & Motor Replacement	2026 ACE Plan (for Subsequent Approval)		$ 2,872,183		$ -			
Pending Submission	Transmission	C0081985	Michelin DVR Phase 2	2026 ACE Plan (for Subsequent Approval)		$ 13,000,000		$ 2,875,292			
Pending Submission	General Plant	C0082133	IT - Renew Microsoft Enterprise Agreement	2026 ACE Plan (for Subsequent Approval)		$ 1,800,000		$ -			
Pending Submission	Generation	C0082195	LIN2 2025/26 Capacity Requirement	2026 ACE Plan (for Subsequent Approval)		$ 3,162,203		$ -			

* Maritime Link Transmission capital work orders were filed as part of the Company's General Rate Application. They were not approved at the time of the GRA Decision.

NS Power 2025 ACE Plan Items – Deferred or Cancelled
3rd Quarter Overview - as of September 30, 2025
This report includes any deferred or cancelled projects that were included in the 2025 ACE Plan.

CI	Project Title	2025 ACE Amount	2025 ACE Project Total	Cancelled / Deferred	Deferred To	Prior Approval	2025 ACE Plan Reference	Commentary
Generation								
48913	HYD - Tusket Facility Refurbishment	1,093,904	12,972,226	Deferred	2027		Subsequent Submittal	As condition assessments related to the Powerhouse continue, it has been determined that additional engineering is required to prepare the capital filing. Curent assessment indicates that this can safety be deferred to 2027.
C0020329	TRE5 Stack Expansion Joint Replacement	362,991	395,291	Deferred	2026		Less than $1M	Through further scoping it was determined the risk could be mitigated in 2025 with additional monitoring and detection.
C0020331	TRE5 Air Heater Expansion Joint Replacement	354,575	385,222	Deferred	2026		Less than $1M	Through further scoping it was determined the risk could be mitigated in 2025 with additional monitoring and detection.
C0061366	TRE6 - Caustic Heater Heat Exchanger	84,017	91,767	Cancelled			Less than $1M	This project has been cancelled. Leak test on existing heat exchange bundle and gasket replacements mitigated risk and need for project.
C0068660	TRE5 - Boiler Refurbishment 2025	825,182	896,932	Cancelled			Less than $1M	This project has been cancelled as the scope of work will not be completed under C0073965 TRE5 U&U Burner Nest Waterwall Tube Replacement
C0030122	LIN4 HIP Insulation Replacement	106,894	126,234	Deferred	2026		Less than $1M	Additional scoping found the condition of the insulation allows for this project to be deferred to 2026.
C0067945	POA Pond Transfer Pumps	367,194	417,194	Cancelled			Pt. Aconi	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.
C0060572	TUC1 Secondary Air & Recirculation Damper Replacement	77,424	77,424	Cancelled			Less than $1M	This project has been cancelled, as the risk can be managed through 2026 and will also be completed as part of a major boiler upgrade on TUC1 which will begin in 2027.
C0068894	TUC1 Gas Block Valve Upgrades	607,737	607,737	Cancelled			Less than $1M	This project has been cancelled, as the risk can be managed through 2026 and will also be completed as part of a major boiler upgrade on TUC1 which will begin in 2027.
C0069047	TUC2 FD Fan Duct Refurbishment	99,940	99,940	Deferred	2027		Less than $1M	Further scoping showed that engineering was required to determine the final project requirements and that the risks could be managed through to 2027.
C0069567	TUC1 - Boiler Cyclone Tube Replacements	859,647	859,647	Cancelled			Less than $1M	This project has been cancelled, as the risk can be managed through 2026 and will also be completed as part of a major boiler upgrade on TUC1 which will begin in 2027.
C0068303	LIN Wastewater Lagoon Algae Control 2025	102,074	111,164	Cancelled			Less than $1M	Monitoring has shown that recent algae levels are being managed through current risk mitigation practices.
C0068236	LIN4 North Water Wall Replacement 2025	446,612	526,275	Deferred	2026		Less than $1M	This project is being deferred to the 2026 outage. The existing approach to management of this asset is expected to address near-term risks.
C0068228	LIN3 Air Preheater Seal Refurbishment	102,249	110,788	Deferred	2026		Less than $1M	As part of an updated condition assessment during this year's planned outage, the condiiton of the air preheater seals allows for this project to be deferred to 2026.
40023	TRE - Sewage Lift Station Upgrades	158,493	158,493	Cancelled			Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.
C0020367	TRE5 Main Oil Pump & Gearbox Refurbishment	195,312	212,312	Deferred	2026		Less than $1M	This project is being deferred to 2026 outage. The existing approach to management of this asset is expected to address near-term risks.
C0061363	TRE5 - Screenwash Pump Replacement	129,989	151,107	Deferred	2026		Less than $1M	Updated condition assessment determined the condition of the asset allows the project to be deferred to 2026.
C0068624	TRE - Overhead / Person Door Refurbishments	92,756	100,556	Cancelled			Less than $1M	This project is cancelled as the necessary scope to mitigate these risks will be completed through CI C0061356 TRE Overhead/Person Door Refurbishments
C0068627	TRE - Rotating Equipment Guards 2025	131,614	143,314	Cancelled			Less than $1M	This project has been cancelled, as further scoping revealed the risk can be managed without need for proactive replacement.
C0068658	TRE6 - Battery Charger Replacement	80,589	87,789	Deferred	2026		Less than $1M	Further scoping determined the condition of the asset allows the project to be deferred to 2026.
C0068675	TRE6 Parallel Slide HP heater isolations	494,861	540,411	Deferred	2026		Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.
C0068691	TRE6 - Boiler Main Stop Valve	148,839	162,539	Deferred	2026		Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.
C0068692	TRE6 - 6A BFP Discharge Valve Refurbishment	149,279	159,779	Deferred	2026		Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.
C0068693	TRE6 Instrument Air Dry Replacement	81,210	88,310	Deferred	2026		Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.
C0070850	TRE Shaker House Hoist Replacement	83,854	91,354	Deferred	2026		Less than $1M	Deferred to better define project scope. The exisiting approach to management of this asset is expected to address near-term risks.
C0060610	TUC Cable Spreading Room Fire Protection	250,108	250,108	Cancelled			Less than $1M	This project has been cancelled. Project scope will be completed as part of CI C0069829 TUC - Relay Room Fire Suppression System.
C0068906	TUC6 Boiler Feed Pump Refurbishment 2025	302,097	302,097	Deferred	2026		Less than $1M	This project is deferred until the 2026 TUC6 outage. The existing approach to management of this asset is expected to address near-term risks.
C0057361	HYD - ANN Facility Isolation	210,689	2,899,094	Deferred	2026		Subsequent Submittal	Deferred to better define project scope. The exisiting approach to management of this asset is expected to address near-term risks.
C0051932	HYD - Avon 2 Penstock Recoating	152,346	688,897	Deferred	2027		Less than $1M	Deferred due to reprioritization. The existing approach to management of this asset is expected to address near-term risks.
C0067383	HYD HMS Electrical Replacement	135,290	156,003	Cancelled			Less than $1M	This project has been cancelled as further scoping needed before proceeding, and near-term risks being managed by current asset management approach.
C0068703	HYD COW Battery Bank Replacement	78,187	90,747	Deferred	2027		Less than $1M	Deferred due to reprioritization. The existing approach to asset management of this asset is expected to address near-term risks.
C0039046	LIN Ash Silo Refurbishment 2024	197,599	214,456	Cancelled			Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.
C0061340	LIN12 Diesel Generator Room Refurbishment	336,843	365,589	Cancelled			Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.

NS Power 2025 ACE Plan Items – Deferred or Cancelled
3rd Quarter Overview - as of September 30, 2025
This report includes any deferred or cancelled projects that were included in the 2025 ACE Plan.

CI	Project Title	2025 ACE Amount	2025 ACE Project Total	Cancelled / Deferred	Deferred To	Prior Approval	2025 ACE Plan Reference	Commentary
C0068144	LIN Coal Amenities Trailer Replacement	302,813	331,363	Cancelled			Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.
C0068150	LIN Coal Stacker Refurbishment 2025	135,428	147,338	Cancelled			Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.
C0068184	LIN HFO/LFO Line Refurbishment 2025	195,187	212,427	Cancelled			Less than $1M	This project has been cancelled. Project scope will be completed as part of CI C0060819 LIN HFO/LFO Line Refurbishment 2024.
C0068186	LIN Kubota Replacement 2025	36,674	43,972	Cancelled			Less than $1M	Cancelled due to U&U capital work utilizing available resources. Kubota will not be replaced.
C0068226	LIN1 SoER Installation 2025	227,364	246,717	Cancelled			Less than $1M	Cancelled due to U&U capital work utilizing available resources. The exisiting approach is sufficient to address near-term risks.
C0052536	POA Demin Tank Heater	86,963	98,963	Cancelled			Pt. Aconi	Cancelled due to U&U capital work utilizing available resources. The exisiting approach is sufficient to address near-term risks.
C0068039	POA Sootblower Refurb 2025	102,854	117,854	Deferred	2027		Pt. Aconi	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.
C0068687	TRE6 "A" and "B" CW Screens Refurb	177,892	192,892	Deferred	2026		Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.
C0059533	WIN - DIG Gearbox Replacement WTG19	716,489	761,741	Deferred	2026		Less than $1M	Deferred due to reprioritization. The existing approach to asset management of this asset is expected to address near-term risks.
C0059602	WIN - DIG Gearbox Replacement WTG10	714,917	782,510	Deferred	2026		Less than $1M	Deferred due to reprioritization. The existing approach to asset management of this asset is expected to address near-term risks.
Transmission								
C0041822	WRC Spare Cable Replacement & Storage System	50,000	189,342	Deferred	2027		Less than $1M	Additional engineering is required before project can progress to construction.
C0011358	New Bridgewater Substation	1,385,538	18,173,047	Deferred	2027		Subsequent Submittal	Additional engineering is required before project can progress to construction.
C0032382	Susie Lake Substation Addition	5,149,415	13,954,518	Deferred	2026		Subsequent Submittal	Additional engineering is required before project can progress to construction.
C0053214	76W-T1 Transformer Replacement	1,938,848	2,279,295	Deferred	2026		Subsequent Submittal	Project now forecasted for 2026 ACE request approval. Project had been deferred as additional engineering was required before project could progress to construction.
C0072808	Synchronous Condensers (ECEI)	27,197,774	243,807,241	Deferred	2026		Subsequent Submittal	Project now forecasted for filing in 2026, as preliminary engineering and planning work continues throughout 2025 and is required prior to submission.
C0061552	L6043 Replacements and Upgrades	796,677	1,346,809	Deferred	2027		Subsequent Submittal	Deferred to better define project scope.
Distribution								
C0071410	25W-301 Welshtown Phase Addition	322,774	594,945	Deferred	2026		Less than $1M	Deferred due to reprioritization of projects in the West. The existing approach to asset management of this asset is expected to address near-term risks.
General Plant								
C0071652	IT - ZTN Security and Restrictive Network Controls	725,124	869,124	Cancelled			Less than $1M	Scope of this project included in C0061289 - IT - Network Next Generation Security Design.
C0032202	Sydney T&D Depot Consolidation	1,578,174	1,879,855	Deferred	2026		Subsequent Submittal	Deferred to better define project scope.
C0021835	IT - CIS Replacement	2,243,592	77,890,771	Deferred	2026		Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.
C0047278	IT - Oracle MDM Upgrade	912,789	3,010,689	Deferred	2026		Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.
C0061285	IT - Enterprise Governance, Risk, and Compliance	664,056	1,179,857	Deferred	2026		Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.
C0061347	IT - Wireless Video Solution	56,424	72,924	Deferred	2026		Less than $1M	This project is delayed due to the cyber event. Resources were required for priority restoration.
C0068719	IT - Distributed Intelligence Apps	2,086,440	4,353,461	Deferred	2026		Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.
C0068718	IT - DERMS Solution Project	1,950,047	2,993,200	Deferred	2026		Subsequent Submittal	Deferred to better define project scope through the Distributed Energy Resource Integration Roadmap.
C0068714	IT - Identity and Access Management	963,267	1,275,524	Deferred	2026		Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.
C0067863	IT - Managed Detect & Respond	668,280	1,126,413	Deferred	2026		Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.

NS Power Final Cost Report

3rd Quarter Overview - as of September 30, 2025

This report includes a list of all FIN capital work orders that have fallen outside the timelines under the CEJC. (Within six months of in-service.)

These projects have either been completed and are outside the FIN tolerances or forecast to be outside of the FIN tolerances. (The greater of +/- 5% or +/- $250,000.)

Projects that have been in-service for 6 months, but have a project forecast within the allowed FIN tolerance, are not included on this list.

Project #	Project	In-service Date	NSEB Approval	Spend to September 30, 2025	Comment
C0031145	2021 Padmount Replacement Program	3/31/2021	1,636,153	1,176,604	This project is now complete and a Final Cost Application is planned for submission in 2026.
51956	6P Mobile Substation Rewind	1/31/2019	1,516,121	635,776	FIN CWO submitted to NSEB on December 1, 2025
52314	1C-GT1/UT1 Replacement	11/30/2020	2,032,393	1,678,006	FIN CWO submitted to NSEB on December 1, 2025
C0042166	IT - Data Loss Prevention (DLP) Platform	11/30/2023	4,261,239	3,944,010	This project is now complete; however, the final cost application is being held until the functionality of the asset has been confirmed, pending findings relating to the Cyber Incident investigation.
C0043010	2022/2023 Wood Pole Retreatment Program	9/30/2022	1,300,037	791,054	FIN CWO submitted to NSEB on October 6, 2025
C0010778	Smart Grid Nova Scotia Project	5/31/2020	7,053,622	6,409,670	This project is now complete, however, final costs are dependent on final asset disposition treatment under the SGNS Asset Disposition proceeding (M12178).

CEJC Stakeholder Engagement Presentation

CEJC Amendments – Stakeholder Engagement

October 29, 2025

Agenda

- Board Directives
  - 2025 ACE Plan Directive
  - 2016 ACE Plan Directive
- Interim Updates
  - Amendments submitted in 2025 ACE Plan assumed approved/accepted
  - References to “UARB” updated to “NSEB” per Board request
- New Updates
  - Scope Change
  - FIN
  - Other
- Pre-filed Questions

Board Directives

2025 ACE Plan Directive:

The Board's 2025 ACE Plan (M12012) Order and Decision provided the following directive to enhance the current Scope Change definition:

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

2016 ACE Plan Directive:

The Board's 2016 ACE Plan (M07176) Order and Decision provided the following directive requiring stakeholder engagement:

4. The Board directs NSPI to discuss any changes to the Capital Expenditure Justification Criteria with stakeholders before submitting them to the Board.

Interim Updates

- Amendments submitted in 2025 ACE Plan assumed approved/accepted
  - NS Power included amendments to the Detailed and Summary CEJC in Appendix F of the 2025 ACE Plan, and requested the Board's acceptance and approval, respectively as part of that process. The Board noted that no intervenors took issue with the amendments but that the IG requested more clarity on ATO and Scope Change processes under the CEJC specifically.
- References to UARB updated to NSEB per Board request
  - The Board requested NS Power to update references from UARB to NSEB or Board; NS Power completed this change on October 21, 2025. The Detailed and Summary CEJC documents included for current review reflect this requested change, but do not show these changes in redline.

New Updates - Scope Change

- As discussed in the 2025 ACE Plan process, there is opportunity to clarify the definition of a Scope Change application in the CEJC.
- As stated in the Board's Decision:
  - ...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.
- NS Power has recommended changes in the Detailed/Summary CEJC documentation:
  - Addition of Definition (page 6 in both versions):
    - A project is considered to have had a scope change when the overarching intent of the project description has been changed.
  - Updates to Section 12.2 to provide clearer definition (additions underlined):
    - Scope Change applications may experience cost variances from the original application, but are submitted regardless of whether the thresholds for ATO and FIN applications have been exceeded <u>when the overarching intent of the project description has been changed</u>.

New Updates - Scope Change

- Examples that would trigger a Scope Change application:
  - The refurbishment (component replacement) of an asset is changed to a full asset replacement. (i.e. a Steam Turbine Refurbishment project intended to replace / refurbish individual turbine blades is changed to a full turbine replacement).
  - A technology project that intended to replace / upgrade a system with a specified application changes to a different application from what was listed in the project description.
  - A distribution project such as a feeder rebuild through component replacement changes to a new line in an alternative locations (i.e. changing to a “Build to Roadside” approach).
- A scope change is not considered to have occurred when:
  - The quantity of units within a project changes, and the intent of the project is still being completed. For example:
    - Replacing 6 turbine blades instead of 5
    - Completing more / fewer kilometres of New Distribution Rights-of-Way through vegetation management

New Updates – FIN

- FINs often take more time to process than other capital applications, due to required final costing activities.
- In particular, underspent FINs can take more time to process as capital leads focus priority attention on active projects or projects that are at risk of overspend. For underspent FINs, the reason for variance frequently includes unused contingency. Approximately 50% of the underspent FINs over the last 12-18 months were below the threshold because of unused contingency.
- As a result, several FINs in recent years have been later than the six month requirement outlined in the CEJC.
- Recommendation:
  - Overspend threshold – remains the same (+5%/+$250,000)
  - Underspend threshold – amended to -10%/-$500,000 (from -5%/-$250,000)
    - This change is intended to recognize that the prior underspend threshold would typically capture unused contingency. Goal is to improve regulatory efficiency.
  - Timeline to file – amended to 12 months (from 6 months)
    - This change is intended to recognize the internal processes required to finalize and close out a project, including: receiving final copies of engineering drawings, final testing, receiving and processing all final invoices (allowing time for potential invoice disputes), closing out work orders, and preparing/reviewing/filing required documentation for Board approval.

New Updates - Other

- Removed “Revenue Requirement in ACE Plan” section, in alignment with 2022 ACE Plan Decision (M10366)
- Addition of Retirement Information and Contingency Information under Capital Application Requirements, in alignment with Board direction under Revised Accounting Policies (M09229) and 2022 ACE Plan (M10366), respectively.
- Addition of sentence to clarify that if a sub-routine is less than $1 million threshold, then no Routine ATO application for specific sub-routine.
- Minor clarification edits in Thermal (Section 17.7) and Routines (Appendix A in Detailed CEJC only).

Questions?
9

CEJC Amendments for Approval / Acceptance

CEJC Revisions

Section (Summary/Detailed)	Summary CEJC Page #	Detailed CEJC Page #	Substantive/ Non-Substantive	Revision Description
Definitions (1.0)	5-6 of 54	6 of 113	Substantive	Modification of FIN definition and addition of Scope and Scope Change definitions
Revenue Requirement in Annual Capital Expenditure Plan (6.3.2/6.7.2)	21 of 54	23 of 113	Substantive	Removed section - this information has not been included in an ACE Plan since the Board's direction in its 2022 ACE Plan Decision: *The Board will not require this information to be included in the 2023 ACE Plan but reserves the right to seek information on the revenue requirement in a future proceeding.* This section is therefore outdated, and has been removed.
Capital Application Requirements (11.2)	27-28 of 54	45-46 of 113	Substantive	Addition of Retirement Information and Contingency Information as required information for capital applications, in alignment with directives from Revised Accounting Policies (M09229) and 2022 ACE Plan (M10366).
Capital Application Requirements (11.2)	27 of 54	45 of 113	Non-Substantive	Removed duplication of language and improved formatting of Summary of Related Capital Items
Individual Capital Item Scope Change (12.2)	31-32 of 54	49-50 of 113	Substantive	Updated section to provide clearer definition of Scope Change.
Routine Capital ATO (12.3)	32 of 54	50 of 113	Substantive	Addition of sentence to clarify that if a sub-routine budget and actual spend is less than $1 million threshold, then no Routine ATO application for the specific sub-routine.
Final Cost Application (FIN) Requirements (13.0)	33 of 54	51 of 113	Substantive	Amended underspend threshold from -5%/-$250,000 to -10%/-500,000 and timeline to file from 6 months to 12 months, and added reference to rate base rules for projects that are completed in ATO position.
Thermal (17.7)	48 of 54	67 of 113	Non-Substantive	Added "/or" to clarify sentence in first paragraph under "Equipment Replacement / Refurbishment".
Appendix A: Capital Projects within the NS Power Routine Program	N/A	89-91 of 113	Non-Substantive	Minor edits to clarify.

NOVA SCOTIA POWER INC. CAPITAL PLANNING & CAPITAL EXPENDITURE JUSTIFICATION CRITERIA
Summary Document

Effective Date: Month DD, YYYY

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Summary Document

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Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Summary Document

1.0 Definitions

Annual Capital Expenditure (ACE) Plan: A document containing details regarding all of NS Power's capital projects planned for a given calendar year. The ACE Plan is submitted to the NSEB every year.

Authorization to Overspend (ATO): A capital work order package for submission to the NSEB should the project forecast final costs with a variance of more than the greater of 5% or $250,000.

Bulk Power System: The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area.

Carry Over Project: A capital project that is approved and initiated in one calendar year, but the investment of capital carries over into the subsequent year(s).

Capital Cost: The cost required to complete a capital project.

Capital Cost Allowance: A yearly deduction of depreciation that can be claimed for income tax purposes on the cost of certain assets.

Capital Expenditure Justification Criteria (CEJC): The criteria contained in this manual defining matters related to capital expenditures. The CEJC contains the criteria defining what, why and when a project qualifies as a capital project.

Capital Identification (CI) Number: The unique identification number associated with a capital project.

Capital Lead: Employee responsible for technical and financial justification of capital work from a particular area (e.g. generation), program (e.g. reliability), or function (e.g. system reinvestment).

Discounted Payback Period: This is a measure of economic value. It represents the number of years required to pay back the initial capital cost of a project. It measures the levered payback period.

Discretionary Project: Investments that are incremental to an essential capital investment and which are made solely on the basis of economics, and there is an acceptable "do-nothing" alternative. Discretionary projects may yield defined benefits that minimize the revenue requirements of NS Power.

Do Nothing Alternative: A "do nothing" alternative refers to the alternative to not proceed with a discretionary capital project with corresponding acceptable outcomes. Whereas discretionary projects are based solely on economics, they are not addressing safety, legal, reliability or technical scenarios, and therefore "doing nothing" results in little or no risk to NS Power's system.

Economic Analysis Model (EAM): The standard software model used by NS Power to calculate the present value of revenue requirement and economic value of any project. The software takes capital costs, avoided costs, revenue, expenses, and taxes into consideration to give a Net Present Value (NPV), internal rate of return (IRR), and discounted payback period.

Economically Justified Project: A capital project that is justified, in part, on economic benefits. The Economic Analysis Model (EAM) is used to derive the economic benefits of all economically justified projects. Economically justified projects may also be justified on other technical justifications.

Environmental Project: A capital project that is justified on the basis of environmental criteria. These criteria include operating permit approval, Environmental Act or regulation compliance, regulatory standards and industry standard compliance.

Essential Project: A capital addition or replacement which must be made to satisfy technical, legal, safety, regulatory or environmental directives.

Executive: A member of the NS Power Executive Team including General Managers, Vice Presidents, Executive Vice Presidents and the President and CEO.

Final Cost (FIN): A capital work order package for submission to the NSEB if final costs result in a variance of more than the greater of +5%/+$250,000 or -10%/-$500,000. FIN capital work orders consist of final cost details and a variance analysis.

Deleted: should the project experience a scope change or

Deleted: /-

Deleted: or +

Deleted: -

Individual Capital Item: Individual capital items, typically of a non-repetitive nature, and justified and budgeted separately from capital routines.

Integrated Resource Plan: A long-term planning process and framework within which the costs and benefits of both demand and supply side resources are evaluated to develop the least total cost mix of utility resource options.

Information Request (IR): A request from the NSEB, or other intervenors, for additional information pertaining to a capital project.

Internal Rate of Return (IRR): The discount rate used in capital budgeting that makes the net present value of all cash flows from a particular project equal to zero. Generally speaking, the higher a project's internal rate of return, the more desirable it is to undertake the project. As such, IRR can be used to rank prospective projects. Assuming all other factors are equal among the various projects, the project with the highest IRR would likely be considered the best and undertaken first.

Investment Review Team (IRT): The IRT is composed of a diverse group of Directors and Managers who offer expertise and experience from different functional areas within NS Power. The IRT

manages NS Power's capital program in an integrated manner ensuring that projects are prioritized across NS Power. Investment initiatives are continuously monitored and the status of the capital program is communicated to NS Power's Leadership Team.

Leadership Team: Senior Managers, Directors and Executive of NS Power.

Nova Scotia Energy Board (NSEB): On April 1, 2025, on proclamation of the *Energy and Regulatory Boards Act*, S.N.S. 2024, c. 2, Sch. A, the Utility and Review Board (UARB) was succeeded by the Nova Scotia Energy Board for all applications related to electric utilities. Pursuant to the Energy and Regulatory Boards Act, the Nova Scotia Energy Board ("NSEB" or "Board") exercises general supervision over all electric utilities operating as public utilities within the Province.

Planned and Advanced (P&A): A capital item that is planned (foreseen and budgeted) in future years but advanced for commencement and/or completion in the current year. They are not U&Us despite not being referenced in prior ACE Plans.

PowerPlan (software): The software that is used to manage all aspects of capital projects including project scope, justification, budget, approvals and actual project information. The software can be used to research information on past projects and forecast project activity into the future.
Production Costing Model: A system modelling tool which provides detailed forecasts of fleet dispatch and production costing, reflecting the increasing complexity of the system. Used in the calculation of replacement energy costs.

Routine Capital Item: A capital item containing a number of projects that are high volume, repetitive, like-for-like capital replacements, enhancements, or additions that are expected to continue into the foreseeable future.

Safety Project: A project that is justified based on the basis of health and safety criteria. Some of these criteria include regulatory requirements, Nova Scotia Department of Labour orders, NS Power safe work methods/practices, revisions to industry standards, Joint Occupational Health and Safety Committee (JOHSC) actions and mitigating risk of potential health and safety incidents.

Scope: A project's stated goals (overall objectives the project aims to achieve), deliverables (end result that will be produced for the asset), and boundaries (what the project will and will not achieve).

Scope Change: A project is considered to have had a scope change when the stated intent from the original capital application of the project description has been changed.

Special Protection System (SPS): A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic underfrequency load shedding, as defined in the

NPCC Emergency Operation Criteria A-3, is not considered a Special Protection System. Conventionally switched, locally controlled shunt devices are not Special Protection Systems.

Total Cost of Ownership (TCO): The upfront capital cost of a new or upgraded capital asset plus all capital costs and operating expenses over its expected useful life.

Unforeseen and Unbudgeted (U&U): A capital item that develops throughout the year, typically in response to discoveries made through routine inspections, maintenance, and/or unplanned failures, and was not included in prior ACE Plans or the current ACE plan. Projects foreseen and budgeted for future years, but advanced for commencement and/or completion in the current year, are not U&Us despite not being referenced in prior ACE Plans (these are designated as P&A projects). A U&U is submitted because the capital item cannot wait until the next ACE Plan for approval.

Weighted Average Cost of Capital (WACC): The cost of capital (discount rate or interest rate) determined by the weighted average, at forecasted book value, of the cost of all financing sources (debt, corporate bonds, equity) in the capital structure of NS Power. The weighted average cost of capital (WACC) is determined by the Finance Team and incorporated into the Economic Analysis Model (EAM) in order to determine the Net Present Value (NPV) and discounted payback of a capital project

Acronyms

ACE	Annual Capital Expenditure
ACHI	Avoided Customer Hours of Interruption
AFUDC	Allowance for Funds Used During Construction
AO	Administrative Overhead
ASTM	American Society for Testing and Materials
ATO	Authorization to Overspend
CAIDI	Customer Average Interruption Duration Index
CCA	Capital Cost Allowance
CEJC	Capital Expenditure Justification Criteria
CI	Capital Item
CO	Carry Over
CSA	Canadian Standards Association
EAM	Economic Analysis Model
FIN	Final Cost
DEP	Distribution Engineering Practices
IR	Information Request
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
IRT	Investment Review Team
MC	Measurement Canada

NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NSEB	Nova Scotia Energy Board, “NSEB” or “Board”
NS Power	Nova Scotia Power Incorporated, “the Company”
P&A	Planned and Advanced
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SPS	Special Protection System
U&U	Unforeseen and Unbudgeted
WACC	Weighted Average Cost of Capital

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Summary Document

2.0 Introduction

In its 1995 ACE Plan Decision, the Board provided the following:

> By an Order dated January 5, 1995 the Board directed that Nova Scotia Power Inc. (NS Power, the Utility, the Company) file evidence relating to its 1995 Annual Capital Expenditure (ACE) Plan by January 12, 1995, and set March 6, 1995 as the commencement date for a hearing.
>
> In an exchange of correspondence between the Company and the Board in early 1994, an understanding was reached that NS Power would make a yearly presentation of its Annual Capital Expenditure Plan and that NS Power would ensure work orders for projects less than $1 million meet Board approved technical and financial capital expenditure justification criteria. The Board indicated that it would undertake periodic audits on samples of work orders to ensure that such criteria had been satisfied.[1]

Those technical and financial justification criteria are contained in this document, the Capital Expenditure Justification Criteria (CEJC).

NS Power is a public utility, subject to the provisions of the *Public Utilities Act* (the Act). NS Power is subject to general supervisory oversight of the NSEB (previously the UARB). Prior to October 30, 2019, each capital item in excess of $250,000 required approval by the Board. Section 35 of the Act was amended on that date to raise this limit to $1,000,000 for "large scale public utilities", which is defined under the Act as a public utility with an annual revenue of one hundred million dollars or more. Accordingly, NS Power can carry-out capital work on projects of $1,000,000 or less in value without Board approval. The Board can perform periodic audits to ensure that the criteria are being properly applied. Projects found to be inappropriately justified or imprudent can be excluded from NS Power's rate base.

[1] 1995 ACE Plan Board Decision (March 31, 1995) NS Power-P-866-DEC.

3.0 Administration

This document will be maintained by NS Power. Pursuant to the Board's 2016 ACE Plan Decision directives, revisions to the CEJC will be reviewed by stakeholders prior to filing with the Board. The CEJC will be filed with the Board, with revisions noted for the Board's approval, as required. Revisions to this document will be accompanied by a brief review of the updates or changes. A corresponding Detailed CEJC will be provided for the Board's information.

4.0 NS Power Commitment

NS Power will manage its capital expenditures in accordance with the principles and guidelines contained within this document. The CEJC is applicable during all phases of the capital approval process. This begins during the development and submittal of the ACE Plan and continues until the project is complete and receives final cost approval.

NS Power is committed to:

- Delivering effective and efficient service to NS Power customers;
- Providing the assurance that NS Power is using sound and consistent economic, financial and technical criteria to justify capital expenditures;
- Effectively responding to changing environmental, operational, technical, safety and financial conditions in compliance with legislative and regulatory requirements; and
- Providing complete and timely capital filings for Board consideration and approval.

5.0 Objectives

The objectives of the CEJC are as follows:

- To provide assurance that NS Power is using consistent economic, financial and technical criteria to justify all capital expenditures;
- To provide assurance that the capital expenditures result in the maximum benefit for customers and minimum impact to rates;
- To communicate the NS Power's justification requirements to all personnel involved in the execution and approval of capital projects in a clear and structured manner;
- To provide the assurance NS Power has appropriate levels of accountability regarding the oversight of the capital processes;
- To ensure that the justification criteria reflect a multi-disciplined approach to justifying capital expenditures using current financial and technical standards; and
- To support the use of consistent practices within NS Power.

6.0 Overview of Capital Planning

6.1 Summary of Capital Planning, Budgeting & Execution Process

NS Power's capital program is overseen by the Company's Investment Review Team (IRT). The IRT is chaired by a senior NS Power employee in the capital planning business function, and the team is composed of a diverse group of Directors and Managers who offer expertise and experience from different functional areas within NS Power. The IRT manages NS Power's capital program in an integrated manner ensuring that projects are prioritized across the Company, investment initiatives are continuously monitored and the status of the capital program is communicated to NS Power's Leadership Team.

The initial phase in the preparation of the ACE Plan is compiling a project list to collect all pertinent information about the capital projects that may be included in the ACE Plan. This requires coordination between the generation, transmission, distribution and corporate groups, Asset Management, Finance and Regulatory Affairs.

In Generation, Transmission, Distribution, and Information Technology (IT), the process begins at the start of each year with the functional groups compiling information about projects that require consideration for the following year.

As this information is gathered, each functional lead will input information into NS Power's capital management system, PowerPlan. The addition of a project to PowerPlan requires the inclusion of a project title, project description, project justification, capital cost spending profile and identification of primary and secondary justification criteria (ranking category).

Projects identified within PowerPlan are reviewed by capital planning and division management for each function. There is a standard ranking methodology for Generation, Transmission, Distribution, and Information Technology, which is described in further detail below.

Generation, Transmission and Distribution projects are broadly ranked using the following criteria:

- Health and Safety: Regulatory requirements, Operating Permits, Protection of Equipment and Personnel Safety, and JOHSC actions.
- Environmental/Regulatory Compliance: Renewable Energy Standards, Greenhouse Gas (GHG) Regulations, or Air Emission Regulations.
- Business Sustainability: SAIDI, SAIFI, CAIDI; unit reliability; system upgrade requirements; code requirements; NERC/NPCC Requirements, or economics (based on payback period, and revenue requirement); requirement to serve.

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Technically justified IT projects are broadly ranked using the following criteria:

- Customer: service impacts to customers as a result of technical failure
- Finance: financial impacts to the Company as a result of technical failure
- Compliance: safety, environmental, security, legal or regulatory requirements (e.g. NERC/CIP and NI-52 compliance)
- Operating Sustainability: ability for NS Power staff or contractor to perform critical functions of the business.

Each year, the capital program includes those projects which are essential for health and safety objectives, regulatory compliance, those which are required to provide service to a given area, and mitigate risks. Projects which serve to improve customer reliability are evaluated based on the probability factors related to performance targets (SAIDI, SAIFI, CAIDI). Economic initiatives are evaluated based on their economic and performance ranking. The capital program can be constrained by a number of factors including the ability to effectively execute the annual program with the available time and resources, the maintenance cycle of the generating facilities and company cash flow.

The NS Power Executive approval process involves a detailed review of the consolidated ACE Plan. Division management work with the executive team to address any comments or concerns which may arise from this review.

Following this review and approval, final changes to the capital plan are made and the ACE Plan is compiled for submission to the NSEB. Included as part of this process is the identification of projects that are not ready for formal submission to the NSEB for review and approval. These projects are noted on the Subsequent Submittal list in the ACE Plan. While these projects continue to form part of the total ACE Plan budget, submission to the NSEB for review and approval is deferred until they are filed separately later in the year.

NS Power's capital program is intended to be dynamic and flexible in accordance with a complex business. Revisions may include scope changes, timing changes, costing updates, new project additions, etc.

6.2 Ranking Process

Generation, Transmission, Distribution, and Information Technology

Each Generation, Transmission, Distribution, and Information Technology capital project is ranked using the criteria provided in the matrices below. The ranking process is completed first in the early stages of project development and continues to be refined as the scope and estimated costs

for the capital project are further defined. All rankings are reviewed by a centralized Investment Review Team to ensure the projects are justified and appropriate for inclusion in the ACE Plan.

The scale of the rankings is detailed in the matrices below.

Criticality and Condition values are typically influenced by one predominant factor and ranked accordingly. However, other factors may also influence the ranking of a project. In the event that multiple factors are present for a project, individual rankings will be taken into consideration in determining the overall Criticality rankings. For example, Health and Safety considerations for a project may warrant a Criticality ranking of serious (3), while Environmental considerations for the same project may also independently warrant a Criticality ranking of serious (3); this project may therefore warrant a higher Criticality ranking due to multiple influencing factors.

The four colours of the ranking matrix are a visual representation of the likelihood of a capital project being completed. A project falling within the red rankings is considered a high priority and should be completed. Projects falling within the orange and yellow rankings represent projects that carry a higher risk than the projects in the green rankings. While the colours provide a visual illustration of risk, the ranking numbers are the focus of the ranking process.

A lower ranking suggests a lower level of risk and urgency, but not always a lower level of priority. Lower ranked projects that fall in the green, yellow or orange rankings may be completed in certain cases. For example, a project that does not carry a high enough ranking may be completed during a planned outage if the condition of the asset is expected to deteriorate such that action would be required prior to the next available outage.

Considerations of multiple influencing factors, all rankings applied to projects under the ranking methodology noted above, and the order of completion of projects ahead of others, are all subject to the evaluation and professional judgment of NS Power staff and third party industry experts.

ASSET MANAGEMENT CRITICALITY & CONDITION RISK ALIGNMENT MATRIX

Criticality (Based on Consequence)				CRITICALTY VALUE	RISK MATRIX				
Health & Safety	Environment	Business Sustainability	Consequence						
• Regulatory requirement breached. •Critical safety incident requiring support from external resources •Fatality or Permanent Disability.	• Regulatory requirement breached. • Loss of generating station or facility operating permit. • Critical liquid, chemical or particulate release with off-site or off-facility impact.	Business Sustainability Criticality Ranking is informed through factors such as replacement energy costs, Regulatory Requirements, SAIFI, SAIDI, DAFOR, System Upgrade Requirements, Code Requirements and Project Economics (payback period, NPV, Revenue Requirement).	Critical	5	5	10	15	20	25
• Major safety incident leading to JOHSC actions and controllable by internal resources. • Lost time Injury	• Corporate environmental target exceedence. • Major reportable environmental incident with off-site or off-facility impact.		Major	4	4	8	12	16	20
• Serious safety incident leading to JOHSC actions and controllable by internal resources. • Recordable injury, >1 medical Aid	• Serious reportable environmental release causing license exceedance and off-site or off-facility impact.		Serious	3	3	6	9	12	15
• Moderate safety incident controllable by internal resources and no JOHSC actions required. • Recordable injury, < 1 Medical Aid	• Moderate reportable environmental release without license exceedance and internal impact only.		Moderate	2	2	4	6	8	10
• Minor safety incident controllable by internal resources and no JOHSC actions required • First Aid Injury	• Minor non-reportable environmental release with internal impact only and no license exceedance.		Minor	1	1	2	3	4	5
					1	2	3	4	5
					Rare	Unlikely	Possible	Likely	Almost Certain

LEGEND

	Acceptability of Risk
High Risk	Requires Mitigation
Medium-High Risk	Considered for Mitigation
Moderate Risk	Acceptable
Low Risk	Acceptable

CONDITION

Condition Description	
Rare 1	Failure or occurrence is rare (0-10%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate of less than 1 in 100 operating years.
Unlikely 2	Failure or occurrence is unlikely (11-25%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate of less than 1 in 75 operating years.
Possible 3	Failure or occurrence is possible (26-75%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate between 1 in 10 and 1 in 75 operating years.
Likely 4	Failure or occurrence is likely (76-90%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate between once per year and 1 in 10 operating years.
Almost Certain 5	Failure or occurrence is almost certain (91-100%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate of greater than once per year.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria

Summary Document

Nova Scotia POWER An Emera Company

INFORMATION TECHNOLOGY ASSETS CRITICALITY & CONDITION RISK ALIGNMENT MATRIX

Business Criticality (Based on Consequence)					Criticality Value
Customer	Finance	Compliance	Operational Sustainability	Criticality	
Loss of a service for all customers	Financial Impact > $30m	Breach of compliance with any of safety, environmental, security, legal or regulatory requirement	Employees could not perform their role or an employee / contractor could not perform their role safely	Critical	5
Customer Experience is significantly degraded for majority of customers but not complete loss of service	Financial Impact - $5M -$30m	Non-compliant with internal Corporate safety, security policies	Significant impact to employees; work arounds require excessive time and additional resources	Major	4
Customer Experience degradation is minor for all customers	Financial Impact - $1M-$5M	Non-compliant with other internal Corporate policies (non-safety , non-security related)	Moderate impact to employees; work arounds require some increase in time with same resources	Serious	3
Customer Experience degradation is minor for small group of customers	Financial Impact - $0.1M-$1M	Non-compliant with internal departmental policy	Minimum impact to employees; work around in place with minimum impact to time	Moderate	2
No impact to the Customer Experience	Financial Impact <$0.1M	No impact on compliance	Nuisance / inconvenience for employees but with no impact on time	Minor	1

RISK MATRIX					
5	10	15	20	25	
4	8	12	16	20	
3	6	9	12	15	
2	4	6	8	10	
1	2	3	4	5	
1	2	3	4	5	
Rare	Unlikely	Possible	Likely	Almost Certain	

CONDITION

LEGEND

	Acceptability of Risk
High Risk	Requires Mitigation
Medium-High Risk	Considered for Mitigation
Moderate Risk	Acceptable
Low Risk	Acceptable

	Support	Reliability	Vendor contract	Fit for Purpose
Rare	Expertise is readily available from authorized support sources to meet the service level targets for the business	Service has a high reliability rate with minimal downtime ; Operating as designed	Licensing is compliant; versions are up to date to comply with vendor support requirements	Features, functionality, performance meets business expectations and requirements and is suitable to meet 5 yr technology road map requirements
Unlikely	Local resources readily available to source as needed; skills training available	Small number of failures reported.Minimal downtime	Licensing is compliant; Current service will be considered "end of life" in 3 years	Features, functionality, performance will not meet the business requirements planned in the next 4 years
Possible	Resourcing options available within North America at a premium cost.	Increase in number of failures reported over previous year, downtime hours impacting business operations.	Licensing is compliant; Current service will be considered "end of life" in 2 years;	Features, functionality, performance will not meet the business requirements planned within the next 3 years
Likely	No resource options within North America; limited availability outside of North America at premium cost	Material number of failures reported. Replacement parts difficult to source	Licensing is compliant; Current service will be considered "end of life" in 1 year	Features, functionality, performance will not meet the business requirements planned within the next 2 years
Almost Certain	Minimal to no options for resources that can provide support; training not available	Diagnostics predicting eminent hardware failure ; Priority software defects that vendor is not able to correct and no acceptable work around is available; hardware replacement parts cannot be sourced	Non- compliance with licensing requirements; Service is considered "end of life" by the vendor	Features, functionality, performance will not meet the business requirements planned within the next year

General Plant

Projects under General Plant primarily involve information technology, communications and facilities initiatives. With the exception of IT which is ranked according to the matrix above, these other areas are too diverse to develop a comparable and useful ranking system across the groups, and therefore the determination of whether a project will proceed is based upon technical justifications, or economic benefit.

6.3 Economic Analysis

6.3.1 Economic Analysis Model

The Economic Analysis Model (EAM) is an electronic spreadsheet which calculates and compares the revenue requirement by comparing alternatives to complete the project and avoided costs.

With respect to alternatives to completing the project, all else being equal, the alternative with the lowest discounted revenue requirement will be the preferred alternative. A cash flow analysis determining net present value (NPV) of the alternative cash flows is also incorporated into the EAM to further evaluate the economics of the project.

The following are typical inputs into the model:

- Capital investment profile
- Operating cash flows, including avoided costs

The model calculates the following:

- Revenue requirement
- Income tax associated with the capital expenditures
- Discounted net cash flow at the after-tax weighted average cost of capital (WACC)
- Net present value (NPV), Internal Rate of Return (IRR) and discounted payback period for each alternative

Each year an updated version of the model is provided to users with current tax rates, depreciation rates and WACC.

With respect to avoided costs, avoided costs are calculated using probabilities of failure, unit capacity factors, avoided maintenance costs, and avoided replacement energy costs. Capacity factors and avoided replacement energy costs are forecasted for five years, beginning in the year of project construction. If the avoided costs outweigh the capital costs of the project, the project is considered economic. The timeframe in which the benefit of the project equals the avoided costs is considered the “pay-back period”. NS Power will use an estimate of inflation as an escalator for year six (6) onward to determine future year avoided replacement energy costs.

On an annual basis, NS Power will compare its estimated inflation escalator to fuel forecasts for years 6 onward. If results materially vary, the continued use of inflation as an escalator will be more closely examined and discussed with stakeholders.

The benefits of the model are that it is relatively simple to use, promotes consistency of capital analysis across the organization and provides immediate information regarding the economics of alternatives. The model does not allow monthly cash flow entry. In this regard, where the results of alternatives are close, further review may be required.

Sensitivity analyses are incorporated into the model as adjustable variances for capital spend, avoided expenses, and timing of the project. These are adjustable to further test whether reasonable variances in those categories affect the rankings and therefore preference of alternatives.

With respect to various alternatives considered within an EAM, project developers will endeavour to provide realistic alternatives, and clarity on what is included in the costs comprising each alternative. Additional clarifying notes, if necessary, can be written onto the “Notes/Comments” section on the first page/tab of the EAM.

Administrative Overhead (AO) - Project capital cost and the revenue requirement analysis include Administrative Overhead (AO). While it is understood that costs included in NS Power’s eligible expenses used to determine the AO rate are largely fixed, NS Power will examine further those projects where elimination of the AO credit from the revenue requirement analysis could affect the recommended alternative for economically justified projects. Where this occurs, NS Power will examine the effect of the AO amount more closely to determine the level of reduction to the AO credit which would change the recommended project, and based on this, provide appropriate comment on this in the Capital Item justification.

6.3.3 Total Cost of Ownership

In the Board's 2022 ACE Plan decision, the Board provided the following directive:

> [T]he Board directs NS Power to use a TCO for IT projects over $1 million when an EAM is not provided, whether or not an alternative is available.

Total cost of ownership (TCO) is the cost of a new or upgraded capital asset plus all capital costs and operating expenses over its expected useful life. It accounts for all the capital and operating costs, including the upfront capital costs. In addition to providing a comprehensive understanding of the total cost of a capital investment over the course of its useful life, a TCO is also a useful tool for comparing capital investment options to determine the best value for money.

The TCO timeframe should match that of the expected useful life of the IT software or hardware. This allows for the flexibility to select an appropriate timeframe for a TCO analysis that is in keeping with the useful life of an investment rather than a prescribed timeline.

Deleted: 6.3.2 Revenue Requirement Directive in Annual Capital Expenditure Plan¶
¶
In the Board's 2011 ACE Plan decision, the Board provided the following directive:¶
¶
In future ACE Plan applications, NSPI is directed to make an approximate calculation of how the Plan will affect revenue requirements.¶
Beginning in the 2012 ACE Plan NS Power has provided the overall approximate impact of the ACE Plan on revenue requirement. Beginning in the 2017 ACE Plan and pursuant to the 2016 ACE Plan Terms of Consensus, NS Power also provides a version of the overall revenue requirement table based on stakeholder assumptions and calculation methodology.¶
The underlying principle in calculating NS Power's revenue requirement table and impact is that capital expenditures that equal NS Power's depreciation expense do not change the customer revenue requirement. The premise is that rate base is not growing or declining if capital expenditures equal the rate of depreciation. To the extent depreciation expense equals capital expenditures in a given year, there is minimal effect on rate base or associated revenue requirement and therefore it is excluded from the calculation.¶
impact considers the following inputs:¶
¶
• Capital expenditures compared to forecasted depreciation expense annually.¶
¶
• Administrative overhead credit based on proportion of capital expenditures in excess of depreciation expense in each year.¶
• Depreciation expense of assets added during the examined timeframe based on the proportion of capital expenditures in excess of depreciation expense of all assets in each year.¶
• Incremental interest based on the cost of debt multiplied by the portion of debt to total capital of the incremental rate base¶
• AFUDC based on the proportion of capital expenditures in excess of depreciation expense of all assets in each year.¶
• Income taxes based on the resultant effects and prorated Capital Cost Allowance for tax purposes.¶
¶
• Net earnings based on the rate of return multiplied by the portion of equity to total capital of the incremental rate base.¶
• Additional fixed cost recovery received from customer growth achieved through capital investment to serve these customers.¶
Depreciation expense and additional fixed cost recoveries are delineated in the overall revenue requirement calculation presented in the ACE Plan.¶
¶
An important consideration is that this method does ... [1]

7.0 Capital Planning Financial Criteria & Policies

- NS Power will be responsible for creating financial criteria for the Company;
- Accountability to develop and maintain the general and function-specific justification criteria resides in identified areas of NS Power;
- Capital planning, as a function, is distributed throughout NS Power, but is centrally managed. The respective functional areas of NS Power are accountable for developing, analysing and documenting projects and submitting all items to the Capital Planning group for review and approval;
- Accounting policies and procedures will be presented to the NSEB for their approval prior to implementation. These policies and criteria are presented to the Board for approval through a separate proceeding, or can be incorporated within a proceeding, such as the Annual Capital Expenditure Plan.

8.0 Financial Parameters

The capital program is financed through a combination of debt and equity. The weighted average cost of capital (WACC) is the average of the costs of these sources of financing, each of which is weighted by its respective use to fund the activities of NS Power. The weighted average calculation identifies the cost NS Power has to pay for every dollar it finances. WACC is used to calculate Allowance for Funds Used During Construction (AFUDC) applied to eligible capital projects. The WACC used by NS Power to calculate AFUDC will be the WACC most recently approved by the NSEB. NS Power applies for approval of an AFUDC rate annually through a separate proceeding.

In making investments in capital projects, NS Power must be aware of a number of financial factors which are important in economic analysis:

- Cost of capital
- Depreciation
- Inflation
- Taxes
- Competition for investment capital in capital markets
- Investment risk

9.0 Economic Analysis of Alternatives

The guiding principle of economic analysis is to seek the most economic alternative based on establishing which alternative, among a number of alternatives that satisfy basic requirements, yields the best value for customers and NS Power. Alternatives, where applicable, must be reviewed prior to initiating a capital item.

The essentials of conducting an economic analysis of alternatives may include, when appropriate:

- Analysis methodology
- Financial parameters
- Cost components for analysis
- Analysis period
- Calculating the present worth
- Sensitivity analysis

10.0 NS Power Capital: Types of Capital Applications Submitted for NSEB Approval

- Capital projects submitted to the Board in the Annual Capital Expenditure Plan (ACE).
- Capital projects identified in the ACE Plan requiring subsequent submission to the Board.
- Capital projects included in the ACE Plan, but for which the Board has withheld approval in the ACE Decision; (typically requires a filing by NS Power of additional supporting information, in a separate, or revised capital application).
- Unforeseen and Unbudgeted (U&U) capital projects. These projects are not included in the ACE Plan and are filed separately for Board approval.
- Planned and Advanced (P&A) capital projects. These projects are not included in the ACE Plan and are filed separately for Board approval.
- Authority to Overspend (ATO) applications. These applications represent request for NSEB approval of over-expenditure on a capital project or routine.
- Scope Change applications. These applications represent request for NSEB approval of scope changes within a previously NSEB approved capital project. This is independent of any variances in costs.
- Final Cost (FIN) applications: These applications are required for NSEB approval if final costs of the project are over or under the specified spend thresholds. They consist of final cost details and variance analysis.

11.0 Requirements for NSEB Approval

11.1 General Requirements

NS Power is a public utility, subject to the provisions of the *Public Utilities Act* (the Act). NS Power is subject to general supervisory oversight of the NSEB. Section 35 and Section 35AA (effective October 30, 2019) of the Act provide the following:

> 35 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.
>
> 35AA (1) In this Section, "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.

The Board may approve, or disallow capital projects requested by NS Power. The Board's approval may be in the amount applied for by NS Power or another amount the Board considers appropriate. The form of Board review is determined by the Board and may involve direct review by the Board, its staff and consultants and/or a public hearing, either oral or written.

NS Power retains the discretion to defer or cancel capital projects submitted and/ or approved by the Board based on condition reassessment and reprioritization in accordance with engineering, business judgment and resource availability. Any projects cancelled or deferred are reported in the Quarterly Capital Reports.

11.2 Capital Application Requirements

Supporting documentation is provided with each capital work order application. The following information will be filed with each capital application in the project description, as relevant:

- Project Start Date
- Project In Service Date
- Project Final Cost Date
- Utility Function
- Forecast Amount
- Project's Estimated Useful Life

- Depreciation Class
- Retirement Information
- Contingency Information

Project Description, that clearly defines the intended scope of the project.

Justification Criteria Including:

- Sub Criteria (when applicable)
- Description of why the project is being undertaken (i.e. Why do this project?)
- Description of why the project is necessary at the time proposed (i.e. Why do this project now?)
- Description of why the project will be carried out in the manner proposed (i.e. Why do this project this way?)
- Whether the work will be undertaken by an affiliate and reason for affiliate involvement

Summary of Related Capital Items

- Related Projects approved or having taken place in the past 2 years, current year or anticipated for the next 2 years including the projects' estimated costs. When multiple projects relate to the same asset, or initiative they should be grouped as a package.

- A project can be considered related if it meets the following parameters:

  Steam/Gas Turbine – Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example).

  Hydro – Work completed on the same generating unit and dam structures, but not necessarily the same asset.

  Wind – Work completed on the same Wind Farm site.

  Transmission & Distribution – Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line).

  General Plant – Work completed on the same asset (application, building, etc.).

Retirement Information

- The categorization of retirement (as either under Accounting Policy 6420 - Retirement and Disposal of Capital Assets OR 6350 - Assets Not Used or Useful), and the percentage of the asset pool it represents.

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Moved down [1]: Related Projects approved or having taken place in the past 2 years, current year or anticipated for the next 2 years including the projects' estimated costs. When multiple projects relate to the same asset, or initiative they should be grouped as a package.¶

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Deleted: A list of related capital projects that have been or are scheduled to be completed within +/- 2 years of the submitted project will be included in capital applications.¶

Contingency Information

- Project maturity classification checklist
- Statement of the basis for the contingency guidelines including, as applicable:
  - a. Predetermined guidelines - reference to or statement of documented basis for use of a standard "single contingency" or other referenced practice;
  - b. Subject matter expert judgement - documented reasons for the determination, including a supporting risk register; and
  - c. Other, more technical reasoning - Supporting analysis as described in the Contingency Guidelines.

Cost Support - This may include but is not limited to:

- Supplier quotes, or estimates
- Significant contract terms & conditions
- Management's best estimate based on previous experience or related projects

Additional Information required to justify the project - This may include but is not limited to:

- Engineering/condition assessment reports
- Independent consultant reports
- Planning studies
- Business cases

Cost Benefit Analysis - This may include but is not limited to:

- The Economic Analysis Model; including inputs, assumptions, and results for all alternatives
- The Levelized Cost Model; including inputs, assumptions, and results for all alternatives
- Production Costing Modelling Results
- NS Power procurement documentation and recommendations; (i.e. Requests for Expressions of Interest and Requests for Proposals)

Project Due Diligence Summaries

Industry Information

Real Estate Information - This may include but is not limited to:

- Lease agreements
- Property evaluations and assessments

NS Power Performance Data - This may include but is not limited to:

- Load statistics
- Outage performance data
- Annual maintenance schedules
- Historical results for multi-year projects
- Internal NS Power reviews
- Operating performance indicators

Technical Details - This may include but is not limited to:

- Substation drawings
- Line drawings
- System Impact Studies
- Generation Interconnection Agreement

Stakeholder Information - This may include but is not limited to:

- Government legislation
- Letters of project support
- Stakeholder engagement communication

11.3 Capital Costs Incurred Prior to Application

NS Power strives to submit all capital applications to the NSEB for review and approval on a timely basis. Capital costs incurred prior to application submission will be subject to the criteria noted below with respect to their inclusion into rate base.

Preliminary Engineering Projects

Each quarter, any spend above $1,000,000 associated with a preliminary engineering project that has been inactive (i.e. no internal or external engineering or scoping work, exceeding $10,000, being carried out within the last 12 month period) will be removed from rate base until such time as the preliminary engineering becomes active again or these costs are submitted for approval to the NSEB.

Under $1,000,000 Projects Subsequently Exceeding $1,000,000

Projects originally budgeted at less than $1,000,000, but subsequently exceeding that threshold during project execution, must be filed with the NSEB for approval no later than within six months of the project exceeding $1,000,000. Any projects that do not get filed within this timeframe will have all costs in excess of $1,000,000 removed from rate base in the quarter after the six month timeframe until these costs are submitted for approval to the NSEB.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Summary Document

Capital Projects in ATO Position

If a previously approved capital project exceeds the allowable variance of the greater of 5% or $250,000 and is not filed within six months of exceeding the approved amount, then the costs in excess of Board approval will be removed from rate base each quarter until these costs are approved by the NSEB.

Unapproved Plant in Service Spending

Any capital item with unapproved plant in service above $1,000,000 that does not fall under any of the above categories, and where a capital work order has not been filed with the Board within 6 months of the project's completion, the spend to date on that project in excess of $1,000,000 will be excluded from rate base each quarter until such time as the work order is filed.

12.0 Authorization to Overspend (ATO) Requirements

12.1 Individual Capital Item ATO

Approval to Overspend (ATO) applications are intended to request Board approval prior to incurring additional expenditures above the approved amount. Individual capital items (non-routine) that are tracking final costs with a variance of more than the greater of 5% or $250,000 must be submitted as ATO applications, within 6 months, if NS Power intends to include costs in excess of Board approval in its regulated rate base.

The reporting included with the Quarterly submission of capital project applications will provide the budget, forecast and actual financial details in a one line format for all projects. Those projects that are tracking final costs with a variance of more than the greater of 5% or $250,000 will be specifically identified.

The following documentation shall be filed with the Board in an individual capital item ATO application:

- Updated NSEB approval sheet reflecting the revised project amount;
- Revised Capital Item Description Page reflecting the revised project amount;
- Cost support for the ATO request; and
- Updated economic analysis and / or production costing modelling results (if applicable).

12.2 Individual Capital Item Scope Change

Scope Change applications are intended to request Board approval prior to proceeding with a change in scope, when feasible, as compared to the previously Board approved scope. Scope Change applications may experience cost variances from the original application, but are submitted regardless of whether the thresholds for ATO and FIN applications have been exceeded when the stated intent from the original capital application of the project description has been changed. In the event a project has exceeding the ATO and FIN cost thresholds and has also experienced a scope change, the project will be submitted as a combined ATO or FIN and Scope Change application.

Examples of what a scope change may include are as follows:

- The refurbishment (component replacement) of an asset is changed to a full asset replacement. (i.e. a Steam Turbine Refurbishment project intended to replace / refurbish individual turbine blades is changed to a full turbine replacement).

- A technology project that intended to replace / upgrade a system with a specified application changes to a different application from what was listed in the project description.
- A distribution project such as a feeder rebuild through component replacement changes to a new line in an alternative locations (i.e. changing to a "Build to Roadside" approach).

A scope change is not considered to have occurred when the quantity of units within a project changes (i.e., replacing 6 turbine blades instead of 5, or completing more / fewer kilometres of New Distribution Rights-of-Way through vegetation management). In both instances the stated intent of the project is still being completed.

The following documentation shall be filed with the Board in an individual capital item Scope Change application:

- Updated NSEB approval sheet reflecting the revised project amount if applicable;
- Revised Capital Item Description Page reflecting the revised Scope Change;
- Cost support for the Scope Change request (if applicable); and
- Updated economic analysis and / or production costing modelling results (if applicable).

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12.3 Routine Capital ATO

Routine capital ATOs are based on the annual budget of individual sub-routines noted in the preceding ACE Plan.

Those sub-routines with variances compared to the annual budget of more than the greater of 5% or $250,000 will require submission to the NSEB for review and approval in the first half of the following year. If, however, the sub-routine budget and its total actual incurred cost is less than the $1 million threshold, then no sub-routine ATO filing is required as it falls outside of the 35AA approval threshold for the NSEB.

The following documentation shall be filed with the Board in a sub-routine capital ATO application:

- NSEB approval sheet including the sub-routines subject to overspend, the revised sub-routine amount, variance amounts, and detailed variance explanations for each in the comments section.

13.0 Final Cost Application (FIN) Requirements

Individual capital item projects that have final costs with a variance of more than the greater of +5%/+$250,000 or -10%/-$500,000 will require that a final cost application be submitted to the Board for approval.

Deleted: realized a scope change or have

Deleted: +/-5% or +/-$250,000

Projects not falling within this threshold may require final cost applications as requested by the NSEB. If the final cost of a project falls below the $1 million approval threshold, no FIN application would be required as it falls outside of the 35AA approval threshold for the NSEB.

The information provided in these submissions includes:

- Updated NSEB approval sheet reflecting the Final Cost amount;
- Revised Capital Item Description Page reflecting the Final Cost of the project;
- Line by line project account variances explanations will be provided for those accounts with material variances; and
- Project scope variances.

All projects should be final costed within twelve months of their in-service date. Exceptions to this requirement will be required on occasion. A final cost submission may be delayed due to certain circumstances or unique projects. Circumstances may include not receiving final vendor invoicing in a timely fashion. Unique projects may include projects for which in-service dates are well in advance of project completion. In all cases where final costing capital work orders are submitted past twelve months after their in-service, justifications for the delay will be provided. Projects that are completed in an ATO position remain subject to the rate base rules outlined in **Section 11.3**, which requires costs to be removed from rate base if not filed in accordance with the stated rules.

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14.0 Retirement of Capital Assets

NS Power retires capital assets for various reasons, including:

Normal Wear and Tear

This is referred to as normal deterioration of physical plant caused by use over time and usually occurs because of the physical deterioration of the asset. This type of retirement usually causes an asset to be scrapped.

Inadequacy

This usually occurs because of such items as customer safety, employee safety, public safety, increased customer demand.

The asset can no longer be used safely or cannot supply the customers adequately. The asset is retired but could be reused in another location.

Technical and Economic Obsolescence

The asset is technically obsolete or becomes redundant and no longer economically supplies customers' needs. The asset is retired but could be reused in another location.

Public Authority Requirements

The asset is required to be removed and or replaced for some of the following reasons:

- Environmental regulations (e.g. PCBs)
- Regulatory requirements (e.g. meter replacement)
- Highway relocations

The asset is retired but could be reused in another location.

Customer Requirements

The asset currently serving the customer does not meet customer requirements in a manner other than adequacy and efficiency of supply (e.g. customer requests underground service).

The customer usually pays for any of these requests but the assets must be retired. However they could be reused elsewhere.

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Procedures

When capital assets reach the end of their useful life and are no longer able to contribute to the service of customers, they must be retired from the Plant in Service records at their original cost. In doing so, they are removed from rate base.

For retirements of property, plant and equipment other than land and entire production plants, the original cost plus any costs of removal less salvage proceeds is charged to accumulated depreciation, with no immediate gain or loss recognized.

Gains or losses on capital assets, with the exception of land, are deferred and depreciated over the remaining life of the assets, in accordance with depreciation rate filings with the Nova Scotia Utility and Review Board.

The only exception to this policy concerns the sale of land, in which the resulting gain or loss is recognized immediately.

In those cases where the disposal of land requires expenditures to address environmental issues, then this transaction will be viewed on its own merit, as per approved financial policies.

15.0 Routine Expenditures

15.1 Foreword

NS Power's Routine Program (the Program) is organized and managed through a subset of capital items (Routines) which are provided below. The Program provides for recurring annual allocations of funds for high volume, repetitive, like-for-like capital replacements, enhancements, or additions that are expected to continue into the foreseeable future.

The Program is held to the same standards as individual ACE Plan projects with regards to compliance with Capital Expenditure Justification Criteria and NS Power's Financial Policies and Procedures.

On an annual basis NS Power requests NSEB approval for the Program and its component Routines through NS Power's ACE Plan. Within the approval request further context and justification is provided to support the annual funding levels of the Routines. This information includes specific project budget details, historical trending and year over year variances.

15.2 Definition

Routines include recurring annual capital expenditures for:

- Replacement of worn out or technologically deficient stand-alone equipment.
- Additions/improvements to existing capital assets to raise or improve productivity levels and asset value.
- Additions to existing equipment base resulting from system growth.
- Addition of customers to the system.

15.3 Unit Cost Materiality Limits

The threshold for capitalizing smaller asset purchases is to be consistent with the materiality limits contained in the financial policies. Expenditures for amounts less than the stated capitalization limits should be charged to operations as they are incurred, regardless of the volume purchased.

Exceptions:

Where smaller components are implicit within the scope of a capital project they will be capitalized as part of the overall project.

IT Infrastructure:

NS Power's computer platforms are made up of the following components:

- Keyboards
- Monitors
- Docking stations
- Peripheral communication devices
- Desktop and laptop computers
- Software
- Licenses
- Servers
- Networks
- Data Storage

Each of these assets is integral to the operation of the computer systems which allow employees to perform their daily work functions. NS Power's annual IT capital investment allows for the periodic refresh of certain components to ensure that each platform is functioning at its intended potential. As these purchases are included in and required to ensure the adequate performance of each employee's computer system, the investments will be capitalized.

15.4 Routine Classification

Routines are classified into four functional categories:

- Generation
- Transmission
- Distribution
- General Plant

The Routines included in the Program are as follows:

Generation Routines

Generation Equipment Replacements Generation Other Hydro
Generation Other Thermal

Transmission Routines

Transmission Substation Replacements, Additions, Modifications
Primary Equipment Spares
Protection Modification & Replacement
Transmission Line Replacements, Additions, Modifications

Distributions Routines

Meters
Distribution Upgrades and Replacement
New Customers
Joint Use
Right-of-Way Widening

General Plant Routines

Work Vehicles
Tools and Test Equipment
Telecommunications
Computing Asset Management
Property Improvements and Furniture
Other

15.5 Approval

Routines are provided for Board approval on an Annual basis through the ACE Plan. As part of the ACE Plan proceeding, stakeholders are provided the opportunity to evaluate each Routine. If a new Routine is required, NS Power will file for Board approval of the Routine prior to or by including it in the ACE Plan. If there are new projects added to an existing Routine, NS Power will identify the projects within the ACE Plan documentation.

Over-expenditure

Please refer to section 12.2.

Limits

All individual expenditures are tracked separately within the routine.

Routine Expenditure Reporting

The Board is kept apprised of the actuals incurred during a given year through the ACE Plan process and in the Q4 capital reports provided to the Board.

16.0 Confidentiality

Where the above documentation packages provide confidential information (e.g. commercially sensitive information such as vendor quotes, cost estimates, and internal procurement recommendations; proprietary third party information such as consultant reports and standards documentation; and security sensitive information such as transmission one-line diagrams), NS Power will justify and request the Board, in accordance with Rule 12 of the Board's Rules, maintain portions of the capital filings as confidential. NS Power will minimize such requests for increased transparency and to support the Board's objective in issuing transparent, non- confidential, public decisions.

17.0 Capital Expenditure Justification Criteria

17.1 Introduction - General Considerations

The following considerations are used to evaluate the economic justification for procurement and replacement of equipment, materials and services on the NS Power system.

- Examination of basic needs and alternatives (e.g. why is this required, why now, what other options are available, what are the consequences of doing nothing?).
- Examination of suitable technologies to provide an appropriate solution(s).
- Evaluation of alternative means of acquiring technologies including: design and build NS Power owned facilities and provide services using NS Power staff; rent or lease facilities and provide services using NS Power staff; rent or lease facilities and contract to others for services; and variants of the above as appropriate.
- The alternatives will be ranked using the most appropriate measure (e.g. Revenue Requirement or Net Present Value (NPV)), and the best alternative will be chosen (i.e. lowest Revenue Requirement or highest NPV or lowest Net Present Cost, etc.)
- Capability to meet industry norms for performance, such that NS Power's ability to provide its customers with the required levels of service are not compromised.
- Obsolescence and/or lack of support from facility, spare parts and service suppliers, such that NS Power incurs unacceptable risk of financial loss and/or liability.
- Ability to provide the lowest overall operating costs to NS Power.
- Required to ensure compliance with NPCC and, or NERC Reliability Standards.

The least cost option meeting the requirements and constraints specified above shall be selected.

17.1.1 Integrated Resource Plan

An Integrated Resource Plan (IRP) assesses various supply and demand scenarios to determine the best ways for NS Power to meet future requirements (including emission standards) in a cost-effective and reliable manner, while maintaining a minimum 20% capacity reserve margin above firm loads. The IRP is an important resource document used in the development of the capital plan.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Summary Document

NS Power's IRP is:

- A strategic document;
- A planning document that helps NS Power and governing bodies create long-term sustainable plans based on in-depth analysis;
- A result of broad consultation with stakeholders;
- A roadmap that outlines the primary demand and supply options to be used by NS Power to meet future electricity and emission requirements;
- An analysis framework that integrates demand and supply options to meet future electricity requirements reliably and cost effectively in compliance with current and emerging operational and environmental constraints;
- A reference against which to assess demand and supply-side applications;
- A living document that will be updated as conditions change materially; and
- Developed using models that incorporate the best information available at the time of planning, as well as predictions about potential decisions that are subject to change as societal and technology priorities evolve.

NS Power's IRP:

- Is based on current information about basic assumptions;
- Sources include:
    - Recognized experts and consultants
    - NSEB staff and NSEB consultants
    - Proprietary information sources
    - Publicly available trends
    - Stakeholders / suppliers
    - NS Power's professional experience and judgment;
- Has a 25-year planning horizon;
- Provides ranges of realistic values based on current information.

NS Power's IRP is not:

- An application for NSEB approval of specific NS Power initiatives;
- A commitment by NS Power to undertake specific initiatives;
- A prohibition against specific third-party initiatives; or
- A review of regulatory or accounting treatment for NS Power assets or costs.

17.2 Innovation

Justification Criteria

Innovation capital projects are justified on the basis that there is a reasonable expectation that they will provide customer value in some or all of the areas of reducing upward pressure on revenue requirement, reliability and grid stability, government policy compliance, and customer experience, through the deployment of proven technologies in innovative ways. In addition, innovation capital investments may be justified on the basis that they are reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable.

Sub-Justification Criteria

Innovation capital projects may be justified under one or more of the following sub-criteria:

- reduce upward pressure on revenue requirement
- reliability and grid stability
- environmental and other compliance
- customer experience improvements

Reduce Upward Pressure on Revenue Requirement

Innovation capital projects justified under reducing upward pressure on revenue requirement must (1) be reasonably expected to reduce upward pressure on revenue requirement, based on known issues increasing pressure on revenue requirement, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learning, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in reducing upward pressure on revenue requirement.

Reliability and Grid Stability

Innovation capital projects justified under reliability and grid stability must (1) be reasonably expected to improve reliability and grid stability, based known issues affecting the same, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in improving the reliability of the system.

Environmental and Other Compliance

Innovation capital projects justified under environmental and other compliance must (1) be reasonably expected to support environmental or other compliance, based on environmental compliance or other legislation and regulation, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in complying with environmental or other policy.

Customer Experience

Innovation capital projects justified under customer experience must (1) be reasonably expected to improve the customer experience, based on either stated or predicted needs of customers, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in improving the customer experience.

17.3 Health & Safety

This criteria applies to capital projects undertaken to comply with applicable laws and accepted industrial practices, including but not restricted to:

- Nova Scotia Occupational Health and Safety Act and Regulations
- NS Power standards and work practices
- Orders issued by the N.S. Department of Labour, or Environment
- Accepted industrial practice or codes
- Exercise of due diligence

As well as applying to active NS Power sites, the Health and Safety criterion is applicable to temporarily or permanently decommissioned NS Power sites. Examples of such expenditures include the following:

- Demolition of physical plant to eliminate all liability

- Alterations to a site or physical plant to render it secure against public intrusion in order to limit liability (e.g. signage, fencing, boarding of windows and doors, electrical isolation, etc.)

- Security devices to alarm intruders

- Alterations to a site or physical plant in preparation for sale or disposal

Projects where compliance with such requirements is the primary driver for the investment will utilize the Health and Safety justification criteria. There are often projects where other (discretionary) asset management criteria may be major drivers in addition to Safety improvements that will be accomplished through a capital upgrade. The intent is to code the project to its primary driver but judgment is often required to ensure consistency.

17.4 Environment

As an industrial enterprise, NS Power is obligated to act in a manner which is respectful and protective of the environment in accordance with Company policy, environmental legislation and regulations and agreements with governments. Subsequent to appropriate analysis of its existing and proposed operations, NS Power may need to make capital expenditures to achieve the required environmental performance. NS Power is committed to an environmental ethic which supports environmental and economic sustainability.

The environmental justification criteria include the following:

Environmental Permit, License, Regulation Criteria

These criteria refer to the specific law(s) and the enabling legislation which is enacted to provide for processes, project approvals, environmental monitoring, and standards of performance.

Resulting from regulations, laws and legislation are instruments which require a certain level of environmental performance. They can significantly impact capital expenditures.

These instruments are:

- permits
- licenses
- regulations

NS Power's capital expenditure criteria will include justification based on the type of instrument placing the requirements.

Environmental Agreement, Guidelines, International Standards and Voluntary Action Criteria

These criteria respond to agreements between governments, government guidelines, international standards developed for various industrial sectors and voluntary action that bind the owner/operator to carry out its business in a certain way so as to meet agreed environmental performance.

These instruments may be more flexible than those described in section 1.0 above. However, there is usually little choice given the expectations of performance under international trade agreements. These agreements have provisions which can be used to punish and/or reward industries, economic sectors and countries based on environmental performance.
NS Power’s capital expenditure criteria will include justification to make such an expenditure by reference to the specific instrument in question.

17.5 Land and Right-Of-Way

NS Power needs to occupy and access land to enable the Company's operations. Land can be held as a fee simple title or through some other interest or type of right over land. Fee simple ownership is normally taken for facilities where permanent exclusive occupation is required, for example a thermal generating plant. Where these requirements are lessened in some way, NS Power can acquire interests which are less than the fee simple interest in land, including rights-of-way or easements for power lines, or utility corridors and leases or licences for the occupation of land.

Land and Rights owned by NS Power are managed according to their use, with the main distinction being between those in current use for company operations and those where there is no operational use. Sites without an operational use can be held to mitigate or protect adjoining operational uses, allow management of the remnants of past use, or to allow for future activities or to generate revenue.

The criteria governing NS Power land transactions are as follows:

Land Acquisition

Land is normally acquired as part of a capital project associated with the five year capital budget. Occasionally land that will satisfy the requirements of a future capital project that is beyond the five year capital budget will become available on the open market. In such instances the property may be acquired if no economically practical alternative property is available to satisfy the requirements of the future project in question.

Land Disposal

NS Power can dispose of, lease or grant rights over surplus land. Land associated with hydro projects is generally retained to protect the safety and usability of the whole system. Land to be disposed of will be investigated to ensure compliance with NS Power environmental criteria and provincial regulations.

Land and Building Disposal

A building, land or rights surplus to NS Power requirements and which can be sold will be sold with its associated lands assuming all environmental criteria have been met. If the land and building cannot be sold as one entity, then the building or facility will be removed or retired under NS Power retirement of capital asset criteria and, depending upon requirements, the land will be retained or sold.

Abandoned Rights-of-Way

NS Power normally retains rights-of-way which are not in current use to allow for future use. If a right-of-way is determined to be surplus to NS Power requirements, then the right-of-way may be released, usually to the owner of the property over which the right-of-way exists.

17.6 Hydro, Wind and Biomass

The principles set out hereunder shall be used by NS Power in determining the methods used and timing of purchase and replacement of its hydro, wind and biomass production assets.

These production assets may be purchased, replaced, or modified for any of the following conditions:

- To eliminate conditions which, in the opinion of NS Power, constitute hazards to operating personnel or the general public.
- To meet NS Power's obligations to third parties or to conform with applicable laws and regulations - including Nova Scotia's Renewable Electricity Standards and Canadian Dam Safety Guidelines.
- To produce an economic benefit by reducing or minimizing operating costs, or improving generating equipment efficiency.
- To maintain reliability and quality of supply to the bulk power system.
- When the probability of failure is high enough that:
    - Making the proposed capital investment reduces the costs compared to continuing to repair the existing asset;
    - The estimated cost reduction is of significant magnitude to meet NS Power's financial criteria; and
    - The timing of investment is optimized to maximize customer net benefits.

For projects justified on the basis of economics, it must be demonstrated that the value of energy to the system is greater than the cost of the capital project in question or the next most cost effective renewable energy option to replace the renewable generation. The latter is required to ensure NS Power remains compliant with Nova Scotia's Renewable Energy Standards.

17.7 Thermal

The principles set out hereunder shall be used by NS Power in determining the methods used and timing of purchase and replacement of its thermal production assets.

Equipment Replacement / Refurbishment

Capital expenditures to purchase, replace, or refurbish equipment must be justified by an engineering and/or economic evaluation which incorporates information from planned inspection/performance programs and industry standards. An economic analysis is carried out such that the least cost option meeting all the requirements and constraints specified shall be selected.

Thermal production assets shall be purchased, replaced, or modified when the probability of failure is high enough that:

- Making the proposed capital investment reduces the costs compared to continuing to repair the existing asset;
- The estimated cost reduction is of significant magnitude to meet NS Power's financial criteria; and
- The timing of investment is optimized to maximize customer net benefits.

Heat Rate

For capital expenditures resulting in Unit heat rate improvements, an annual cost saving is calculated using the system dispatch production models (i.e. production costing model) (for major improvements) or calculated on a BTU/kWh basis using current production forecasts and current cost of fuel forecast (for minor improvements < 1% improvement in heat rate).

Capacity

For capital expenditures that result in an increase in net Unit capacity, the value of a kW is calculated using system planning models.

Labour

Impacts on present or future labour requirements are calculated on an annual savings/cost basis taking overtime and fringe benefits into account.

Forced Outage Rate

Unplanned outages result in replacement generation, often at a higher cost than the existing generation. These costs are estimated using the probabilistic production model and incorporated into the Economic Analysis Model.

17.8 System Design

The Nova Scotia Power Inc. transmission system is divided into several classifications, each of which is governed by different design criteria.

NS Power is a member of the Northeast Power Coordinating Council (NPCC). Those portions of the NS Power Bulk Power System, wherein single contingencies can potentially adversely affect the interconnected NPCC system, are designed and operated in accordance with NPCC Directory #1, Design and Operation of the Bulk Power System.

NS Power is required to follow the standards of the North American Electric Reliability Corporation (NERC). NERC is a non-government organization which regulates Bulk Power System users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices. NERC standards are filed with the NSEB through a regulatory approval process where they become mandatory and enforceable in the province of Nova Scotia. NS Power designs its Bulk Electric System to meet the requirements of the in-force NERC standards. NS Power utilizes a set of criteria for its transmission system that combines protection performance specifications with system dynamics and steady state performance requirements. The NS Power Bulk Electric System is planned, designed, and operated in accordance with single contingency criteria.

NS Power System Design Criteria are applied for all other portions of the interconnected system.

NERC standards and NPCC criteria are continually evolving. NS Power system design practices are constantly updated to meet the requirements of new and evolving standards.

17.9 Transmission Plant Conditions for Purchase

Transmission plant may be upgraded, rerouted, or otherwise modified for any of the following conditions:

- To eliminate conditions which, in NS Power's opinion, constitute hazards to operating personnel or to the general public.
- To meet NS Power's obligation to third parties or to conform with the provisions of applicable laws and regulations.
- To reduce or minimize operating costs of the transmission system.
- To maintain reliability and quality of supply to the distribution bus.

Conditions for Replacement

Transmission plant shall be replaced, if still required to meet minimum industry standard system design requirements. Additional details pertaining to the conditions for replacement are provided in the NS Power Capital Planning & Capital Expenditure Justification Criteria Detailed Document.

17.10 Distribution System

NS Power's Distribution System connects the majority of NS Power's customers to the Transmission System. (Some of the larger customers are supplied directly from the transmission network.) As such the Distribution System criteria bridge the gap between the Transmission System and the customer's service entrance. The need for distribution projects is driven by the considerations provided below.

- Requirement to Serve
- Pole Strength Compliance with Standard CAN/CSA-C22.3 No. 1-10 - Overhead Systems
- Service Voltage Outside CSA Standard CAN3-C235-83 (C2010)
- Overloaded Equipment
- Deteriorated Conductor
- Outage Performance
- Distribution System Protection
- Prevention of Catastrophic Failure of Distribution Transformers/Capacitors
- Grounding Criteria
- Joint Use Agreement
- Highway Relocation
- Radio Interference Voltage
- Voltage Unbalance
- Voltage Flicker Due to Motor Starting

- CATV Agreement

17.11 Pole Retreatment

The principles set out hereunder shall be used by NS Power in determining the methods used and the timing of retreatment of its transmission and distribution wood poles.

Conditions for Retreatment

Wood poles originally treated with pentachlorophenol and creosote preservatives may be retreated with approved wood preservatives to reinforce the preservative retention levels in the ground line area thereby maintaining acceptable toximetric thresholds necessary for protection against fungal and insect attack.

Criteria for Wood Pole Retreatment

NS Power undertakes on a line basis, retreatment of many species of wood poles that have been in service for 15 years or more to meet minimum industry standard requirements. Additional details pertaining to the conditions for retreatment are provided in the NS Power Capital Planning & Capital Expenditure Justification Criteria Detailed Document.

17.12 Metering Equipment

Conditions for Purchase

For revenue metering, NS Power purchases only those meters having Measurement Canada (MC) type approval. Meters are sealed by NS Power, or accredited verifier, to the Standard proclaimed in document S-E-02, "Specifications for Verification and Re-verification of Electricity Meters", before being placed in service. Meters are also brought in from active service on a periodic basis for re-verification according to this standard.

Meters being purchased at the present time for kWh measurement will be of the standard type, or have been determined to be the most economic choice when all factors related to metering cost have been considered. MC allows selective sampling of standard induction type meters both in verification and re-verification.

Conditions for Replacement

Metering equipment may be replaced, upgraded or otherwise modified when meters fail the criteria specified in the Standard, or when a rate class for a given customer changes, requiring a meter with greater or lesser capability. Additional details pertaining to the conditions for replacement are provided in the NS Power Capital Planning & Capital Expenditure Justification Criteria Detailed Document.

17.13 Work Support Facilities Building Facilities/Furniture

NS Power owns and operates buildings and associated systems, equipment and furniture to support the delivery of service to customers (i.e. other than that associated with generation facilities, the costs of which are included in the related function costs). These facilities are operated in a manner which provides the most suitable environment for employees to carry out their work in a safe and efficient manner and protects the asset and extends its original useful life.

Facilities may be constructed, replaced, upgraded, renovated, leased, retired or otherwise modified for any of the following purposes;

- To eliminate conditions which, in NS Power's opinion, constitute hazards to NS Power's personnel or to the general public;
- To meet NS Power's obligations to third parties or to conform with the provision of applicable laws and regulations there under;
- To protect facility assets by maintaining them in a reasonable operating condition;
- To comply with regulations and legislation.

The least cost option meeting all the requirements and constraints specified above shall generally be selected.

Telecontrol & Telecommunications

Telecontrol Facilities includes equipment which is used to provide supervisory control and data acquisition (SCADA), remote control, special protection systems and teleprotection.

Telecommunication Facilities includes broadband transport mediums such as: fibre optics, microwave radio, UHF and VHF radio, metallic-pair cable, power line carrier, and systems which employ these mediums to transfer voice and data communications from one location to another such as: telephone, mobile radio, telecontrol equipment, computer networks, video, etc.

Telecontrol and telecommunications are essential for the protection and control of the Bulk Power System. They allow for remote monitoring and control of the power system through SCADA and provide for high speed protection of generation and transmission facilities through teleprotection and special protection systems (SPS). Telecontrol and telecommunications are also required to ensure compliance with Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC) Reliability Standards. Telecontrol and telecommunication facilities are not used directly for the supply of electricity to NS Power customers. They are enabling technologies which help to satisfy NS Power's business requirements to serve its customers in the most economical, effective and safe manner possible. The need for the application of this technology is driven by the above requirements.

17.14 Information Technology Application and Hardware System

Information Technology (IT) is subject to rapid evolution, obsolescence, and evolving customer expectations. Accordingly, categories and justifications for IT capital investments vary, from mitigating risks associated with obsolescence to meeting customer needs and expectations. IT projects can be broadly justified under the following sub-criteria:

- Technical
- Economic
- Customer Experience

IT capital projects may be justified primarily under one of these sub-criteria or under a combination of them all. These categories and their justifications are expanded upon below.

Technical

Technical projects are driven by criticality and condition based risk assessments of in-service assets. They are most frequently associated with mitigating risks associated with obsolescence, security, and system performance to meet requirements of the utility to serve customers. Technical projects are ranked according to the ranking matrix and methodology outlined in Section 6.2.

Economic

Economic projects are driven by opportunities to operate in a more cost effective manner. Economics may also be associated with Technical, and Customer Experience projects.

Customer Experience

Customer experience projects are driven by either stated or predicted needs of customers, and are reasonably expected to provide improvements to their experience and interactions with NS Power.

17.15 Vehicles

Nova Scotia Power requires vehicles for the effective delivery of its services. There are two broad classifications used for vehicle identification; transportation and work vehicles.

Vehicle Replacement Process

The first step in the review of any vehicle for potential replacement is that it meet the life cycle costing methodology initial screening criteria.

Vehicles proposed for replacement based on the screening criteria of vehicle age, kilometres and maintenance history are then subject to a mechanical inspection and analysis by the Fleet Services group.

The premise of vehicle replacement is to achieve the most economical decision based on life cycle costing, which includes predictive maintenance, age and kilometres.

NS Power follows the life cycle costing methodology to establish units that are a potential for replacement. Vehicle replacements are ranked and scheduled based on the overall benefits to all operating units.

NOVA SCOTIA POWER INC. CAPITAL PLANNING & CAPITAL EXPENDITURE JUSTIFICATION CRITERIA
Detailed Document

Effective Date: Month DD, YYYY

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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1.0 Definitions

Annual Capital Expenditure (ACE) Plan: A document containing details regarding all of NS Power's capital projects planned for a given calendar year. The ACE Plan is submitted to the NSEB every year.

Authorization to Overspend (ATO): A capital work order package for submission to the NSEB should the project forecast final costs with a variance of more than the greater of 5% or $250,000.

Bulk Power System: The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area.

Carry Over Project: A capital project that is approved and initiated in one calendar year, but the investment of capital carries over into the subsequent year(s).

Capital Cost: The cost required to complete a capital project.

Capital Cost Allowance: A yearly deduction of depreciation that can be claimed for income tax purposes on the cost of certain assets.

Capital Expenditure Justification Criteria (CEJC): The criteria contained in this manual, defining matters related to capital expenditures. The CEJC contains the criteria defining what, why and when a project qualifies as a capital project.

Capital Identification (CI) Number: The unique identification number associated with a capital project.

Capital Lead: Employee responsible for technical and financial justification of capital work from a particular area (e.g. generation), program (e.g. reliability), or function (e.g. system reinvestment).

Discounted Payback Period: This is a measure of economic value. It represents the number of years required to pay back the initial capital cost of a project. It measures the levered payback period.

Discretionary Project: Investments that are incremental to an essential capital investment and which are made solely on the basis of economics, and there is an acceptable "do-nothing" alternative. Discretionary projects may yield defined benefits that minimize the revenue requirements of NS Power.

Do Nothing Alternative: A "do nothing" alternative refers to the alternative to not proceed with a discretionary capital project with corresponding acceptable outcomes. Whereas discretionary projects are based solely on economics, they are not addressing safety, legal, reliability or technical scenarios, and therefore "doing nothing" results in little or no risk to NS Power's system.

Economic Analysis Model (EAM): The standard software model used by NS Power to calculate the present value of revenue requirement and economic value of any project. The software takes capital costs, avoided costs, revenue, expenses and taxes into consideration to give a Net Present Value (NPV), internal rate of return (IRR), and discounted payback period.

Economically Justified Project: A capital project that is justified, in part, on economic benefits. The Economic Analysis Model (EAM) is used to derive the economic benefits of all economically justified projects. Economically justified projects may also be justified on other technical justifications.

Environmental Project: A capital project that is justified on the basis of environmental criteria. These criteria include operating permit approval, Environmental Act or regulation compliance, regulatory standards and industry standard compliance.

Essential Project: A capital addition or replacement which must be made to satisfy technical, legal, safety, regulatory or environmental directives.

Executive: A member of the NS Power Executive Team including General Managers, Vice Presidents, Executive Vice Presidents and the President and CEO.

Final Cost (FIN): A capital work order package for submission to the NSEB if final costs result in a variance of more than the greater of +5%/+$250,000 or -10%/-$500,000. FIN capital work orders consist of final cost details and a variance analysis.

Deleted: should the project experience a scope change or

Deleted: /-

Deleted: or +/-

Individual Capital Item: Individual capital items, typically of a non-repetitive nature, and justified and budgeted separately from capital routines.

Integrated Resource Plan: A long-term planning process and framework within which the costs and benefits of both demand and supply side resources are evaluated to develop the least total cost mix of utility resource options.

Information Request (IR): A request from the NSEB, or other intervenors, for additional information pertaining to a capital project.

Internal Rate of Return (IRR): The discount rate used in capital budgeting that makes the net present value of all cash flows from a particular project equal to zero. Generally speaking, the higher a project's internal rate of return, the more desirable it is to undertake the project. As such, IRR can be used to rank prospective projects. Assuming all other factors are equal among the various projects, the project with the highest IRR would likely be considered the best and undertaken first.

Investment Review Team (IRT): The IRT is composed of a diverse group of Directors and Managers who offer expertise and experience from different functional areas within NS Power. The IRT

manages NS Power's capital program in an integrated manner ensuring that projects are prioritized across NS Power. Investment initiatives are continuously monitored and the status of the capital program is communicated to NS Power's Leadership Team.

Leadership Team: Senior Managers, Directors and Executive of NS Power.

Nova Scotia Energy Board (NSEB): On April 1, 2025, on proclamation of the *Energy and Regulatory Boards Act*, S.N.S. 2024, c. 2, Sch. A, the Utility and Review Board (UARB) was succeeded by the Nova Scotia Energy Board for all applications related to electric utilities. Pursuant to the Energy and Regulatory Boards Act, the Nova Scotia Energy Board ("NSEB" or "Board") exercises general supervision over all electric utilities operating as public utilities within the Province.

Planned and Advanced (P&A): A capital item that is planned (foreseen and budgeted) in future years but advanced for commencement and/or completion in the current year. They are not U&Us despite not being referenced in prior ACE Plans.

PowerPlan (software): The software that is used to manage all aspects of capital projects including project scope, justification, budget, approvals and actual project information. The software can be used to research information on past projects and forecast project activity into the future.

Production Costing Model: A system modelling tool which provides detailed forecasts of fleet dispatch and production costing, reflecting the increasing complexity of the system. Used in the calculation of replacement energy costs.

Routine Capital Item: A capital item containing a number of projects that are high volume, repetitive, like-for-like capital replacements, enhancements, or additions that are expected to continue into the foreseeable future.

Safety Project: A project that is justified on the basis of health and safety criteria. Some of these criteria include regulatory requirements, Nova Scotia Department of Labour orders, NS Power safe work methods/practices, revisions to industry standards, Joint Occupational Health and Safety Committee (JOHSC) actions and mitigating risk of potential health and safety incidents.

Scope: A project's stated intent (overall objectives the project aims to achieve), deliverables (end result that will be produced for the asset), and boundaries (what the project will and will not achieve).

Scope Change: A project is considered to have had a scope change when the stated intent from the original capital application of the project description has been changed.

Special Protection System (SPS): A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic under-frequency load shedding as defined in the

NPCC Emergency Operation Criteria A-3, is not considered a Special Protection System. Conventionally switched, locally controlled shunt devices are not Special Protection Systems.

Total Cost of Ownership (TCO): The upfront capital cost of a new or upgraded capital asset plus all capital costs and operating expenses over its expected useful life.

Unforeseen and Unbudgeted (U&U): A capital item that develops throughout the year, typically in response to discoveries made through routine inspections, maintenance, and/or unplanned failures, and was not included in prior ACE Plans or the current ACE Plan. Projects foreseen and budgeted for future years, but advanced for commencement and/or completion in the current year, are not U&Us despite not being referenced in prior ACE Plans (these are designated as P&A projects). A U&U is submitted because the capital item cannot wait until the next ACE Plan for approval.

Weighted Average Cost of Capital (WACC): The cost of capital (discount rate or interest rate) determined by the weighted average, at forecasted book value, of the cost of all financing sources (debt, corporate bonds, equity) in the capital structure of NS Power. The weighted average cost of capital (WACC) is determined by the Finance Team and incorporated into the Economic Analysis Model (EAM) in order to determine the Net Present Value (NPV) and discounted payback of a capital project.

Acronyms

ACE	Annual Capital Expenditure
ACHI	Avoided Customer Hours of Interruption
AFUDC	Allowance for Funds Used During Construction
AO	Administrative Overhead
ASTM	American Society for Testing and Materials
ATO	Authorization to Overspend
CAIDI	Customer Average Interruption Duration Index
CCA	Capital Cost Allowance
CEJC	Capital Expenditure Justification Criteria
CI	Capital Item
CO	Carry Over
CSA	Canadian Standards Association
EAM	Economic Analysis Model
FIN	Final Cost
DEP	Distribution Engineering Practices
IR	Information Request
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
IRT	Investment Review Team
MC	Measurement Canada

NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NSEB	Nova Scotia Energy Board, “NSEB” or “Board”
NS Power	Nova Scotia Power Incorporated, “the Company”
P&A	Planned and Advanced
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SPS	Special Protection System
U&U	Unforeseen and Unbudgeted
WACC	Weighted Average Cost of Capital

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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2.0 Introduction

In its 1995 ACE Plan Decision, the Board provided the following:

> By an Order dated January 5, 1995 the Board directed that Nova Scotia Power Inc. (NS Power, the Utility, the Company) file evidence relating to its 1995 Annual Capital Expenditure (ACE) Plan by January 12, 1995, and set March 6, 1995 as the commencement date for a hearing.
>
> In an exchange of correspondence between the Company and the Board in early 1994, an understanding was reached that NS Power would make a yearly presentation of its Annual Capital Expenditure Plan and that NS Power would ensure work orders for projects less than $1 million meet Board approved technical and financial capital expenditure justification criteria. The Board indicated that it would undertake periodic audits on samples of work orders to ensure that such criteria had been satisfied.[1]

Those technical and financial justification criteria are contained in this document, the Capital Expenditure Justification Criteria (CEJC).

NS Power is a public utility, subject to the provisions of the *Public Utilities Act* (the Act). NS Power is subject to general supervisory oversight of the NSEB (previously the UARB). Prior to October 30, 2019, each capital item in excess of $250,000 required approval by the Board. Section 35 of the Act was amended on that date to raise this limit to $1,000,000 for "large scale public utilities", which is defined under the Act as a public utility with an annual revenue of one hundred million dollars or more. Accordingly, NS Power can carry-out capital work on projects of $1,000,000 or less in value without Board approval. The Board can perform periodic audits to ensure that the criteria are being properly applied. Projects found to be inappropriately justified or imprudent can be excluded from NS Power's rate base.

[1] 1995 ACE Plan Board Decision (March 31, 1995) NS Power-P-866-DEC.

3.0 Administration

This document will be maintained by NS Power. Pursuant to the Board's 2016 ACE Plan Decision directives, revisions to the CEJC will be reviewed by stakeholders prior to filing with the Board. The CEJC will be filed with the Board, with revisions noted for the Board's information, as required. Revisions to this document will be accompanied by a brief review of the updates or changes. A corresponding Summary CEJC will be provided for the Board's approval.

4.0 NS Power Commitment

NS Power will manage its capital expenditures in accordance with the principles and guidelines contained within this document. The CEJC is applicable during all phases of the capital approval process. This begins during the development and submittal of the ACE Plan and continues until the project is complete and receives final cost approval.

NS Power is committed to:

- Delivering effective and efficient service to NS Power customers;
- Providing the assurance that NS Power is using sound and consistent economic, financial and technical criteria to justify capital expenditures;
- Effectively responding to changing environmental, operational, technical, safety and financial conditions in compliance with legislative and regulatory requirements; and
- Providing complete and timely capital filings for Board consideration and approval.

5.0 Objectives

The objectives of the CEJC are as follows:

- To provide assurance that NS Power is using consistent economic, financial and technical criteria to justify all capital expenditures.
- To provide assurance that the capital expenditures result in the maximum benefit for customers and minimum impact to rates.
- To communicate NS Power's justification requirements to all personnel involved in the execution and approval of capital projects in a clear and structured manner.
- To provide the assurance NS Power has appropriate levels of accountability regarding the oversight of the capital processes.
- To ensure that the justification criteria reflect a multi-disciplined approach to justifying capital expenditures using current financial and technical standards.
- To support the use of consistent practices within NS Power.

6.0 Overview of Capital Planning

6.1 Summary of Capital Planning, Budgeting & Execution Process

NS Power's capital program is overseen by the Company's Investment Review Team (IRT). The IRT is chaired by a senior NS Power employee in the capital planning business function, and the team is composed of a diverse group of Directors and Managers who offer expertise and experience from different functional areas within NS Power. The IRT manages NS Power's capital program in an integrated manner ensuring that projects are prioritized across the Company, investment initiatives are continuously monitored and the status of the capital program is communicated to NS Power's Leadership Team.

The initial phase in the preparation of the ACE Plan is compiling a project list to collect all pertinent information about the capital projects that may be included in the ACE Plan. This requires coordination between the generation, transmission, distribution and corporate groups, Asset Management, Finance and Regulatory Affairs.

In Generation, Transmission, Distribution, and Information Technology (IT), the process begins at the start of each year with the functional groups compiling information about projects that require consideration for the following year.

As this information is gathered, each functional group will input information into NS Power's capital management system, PowerPlan. The addition of a project to PowerPlan requires the inclusion of a project title, project description, project justification, capital cost spending profile and identification of primary and secondary justification criteria (ranking category).

Projects identified within PowerPlan are reviewed by capital planning and division management for each function. There is a standard ranking methodology for Generation, Transmission, Distribution, and Information Technology, which is described in further detail below.

Generation, Transmission and Distribution projects are broadly ranked using the following criteria:

- Health and Safety: Regulatory requirements, Operating Permits, Protection of Equipment and Personnel Safety, and JOHSC actions.
- Environment/Regulatory Compliance: Renewable Energy Standards, Greenhouse Gas (GHG) Regulations, or Air Emission Regulations.
- Business Sustainability: SAIDI, SAIFI, CAIDI; unit reliability; system upgrade requirements; code requirements; NERC/NPCC Requirements, or economics (based on payback period, and revenue requirement); requirement to serve.

Technically justified IT projects are broadly ranked using the following criteria:

- Customer: service impacts to customers as a result of technical failure
- Finance: financial impacts to the Company as a result of technical failure
- Compliance: safety, environmental, security, legal or regulatory requirements (e.g. NERC/CIP and NI-52 compliance)
- Operating Sustainability: ability for NS Power staff or contractor to perform critical functions of the business.

Each year, the capital program includes those projects which are essential for health and safety objectives, regulatory compliance, those which are required to provide service to a given area, and mitigate risks. Projects which serve to improve customer reliability are evaluated based on the probability factors related to performance targets (SAIDI, SAIFI, CAIDI). Economic initiatives are evaluated based on their economic and performance ranking. The capital program can be constrained by a number of factors including the ability to effectively execute the annual program with the available time and resources, the maintenance cycle of the generating facilities and company cash flow.

The NS Power Executive approval process involves a detailed review of the consolidated ACE Plan. Division management work with the executive team to address any comments or concerns which may arise from this review.

Following this review and approval, final changes to the capital plan are made and the ACE Plan is compiled for submission to the NSEB. Included as part of this process is the identification of projects that are not ready for formal submission to the NSEB for review and approval. These projects are noted on the Subsequent Submittal list in the ACE Plan. While these projects continue to form part of the total ACE Plan budget, submission to the NSEB for review and approval is deferred until they are filed separately later in the year.

NS Power's capital program is intended to be dynamic and flexible in accordance with a complex business. Revisions may include scope changes, timing changes, costing updates, new project additions, etc.

6.2 Ranking Process

Generation, Transmission, Distribution, and Information Technology

Each Generation, Transmission, Distribution, and Information Technology capital project is ranked using the criteria provided in the matrices below. The ranking process is completed first in the early stages of project development and continues to be refined as the scope and estimated costs

for the capital project are further defined. All rankings are reviewed by a centralized Investment Review Team to ensure the projects are justified and appropriate for inclusion in the ACE Plan.

The scale of the rankings is detailed in the matrices below.

Criticality and Condition values are typically influenced by one predominant factor and ranked accordingly. However, other factors may also influence the ranking of a project. In the event that multiple factors are present for a project, individual rankings will be taken into consideration in determining the overall Criticality rankings. For example, Health and Safety considerations for a project may warrant a Criticality ranking of serious (3), while Environmental considerations for the same project may also independently warrant a Criticality ranking of serious (3); this project may therefore warrant a higher Criticality ranking due to multiple influencing factors.

The four colours of the ranking matrix are a visual representation of the likelihood of a capital project being completed. A project falling within the red rankings is considered a high priority and should be completed. Projects falling within the orange and yellow rankings represent projects that carry a higher risk than the projects in the green rankings. While the colours provide a visual illustration of risk, the ranking numbers are the focus of the ranking process.

A lower ranking suggests a lower level of risk and urgency, but not always a lower level of priority. Lower ranked projects that fall in the green, yellow or orange rankings may be completed in certain cases. For example, a project that does not carry a high enough ranking may be completed during a planned outage if the condition of the asset is expected to deteriorate such that action would be required prior to the next available outage.

Considerations of multiple influencing factors, all rankings applied to projects under the ranking methodology noted above, and the order of completion of projects ahead of others, are all subject to the evaluation and professional judgment of NS Power staff and third party industry experts.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria

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ASSET MANAGEMENT CRITICALITY & CONDITION RISK ALIGNMENT MATRIX

Criticality (Based on Consequence)				CRITICALTY VALUE	RISK MATRIX				
Health & Safety	Environment	Business Sustainability	Consequence						
• Regulatory requirement breached. •Critical safety incident requiring support from external resources •Fatality or Permanent Disability.	• Regulatory requirement breached. • Loss of generating station or facility operating permit. • Critical liquid, chemical or particulate release with off-site or off-facility impact.	Business Sustainability Criticality Ranking is informed through factors such as replacement energy costs, Regulatory Requirements, SAIFI, SAIDI, DAFOR, System Upgrade Requirements, Code Requirements and Project Economics (payback period, NPV, Revenue Requirement).	Critical	5	5	10	15	20	25
• Major safety incident leading to JOHSC actions and controllable by internal resources. • Lost time Injury	• Corporate environmental target exceedence. • Major reportable environmental incident with off-site or off-facility impact.		Major	4	4	8	12	16	20
• Serious safety incident leading to JOHSC actions and controllable by internal resources. • Recordable injury, >1 medical Aid	• Serious reportable environmental release causing license exceedance and off-site or off-facility impact.		Serious	3	3	6	9	12	15
• Moderate safety incident controllable by internal resources and no JOHSC actions required. • Recordable injury, < 1 Medical Aid	• Moderate reportable environmental release without license exceedance and internal impact only.		Moderate	2	2	4	6	8	10
• Minor safety incident controllable by internal resources and no JOHSC actions required • First Aid Injury	• Minor non-reportable environmental release with internal impact only and no license exceedance.		Minor	1	1	2	3	4	5
					1	2	3	4	5
					Rare	Unlikely	Possible	Likely	Almost Certain

LEGEND

	Acceptability of Risk
High Risk	Requires Mitigation
Medium-High Risk	Considered for Mitigation
Moderate Risk	Acceptable
Low Risk	Acceptable

CONDITION

Condition Description	
Rare 1	Failure or occurrence is rare (0-10%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate of less than 1 in 100 operating years.
Unlikely 2	Failure or occurrence is unlikely (11-25%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate of less than 1 in 75 operating years.
Possible 3	Failure or occurrence is possible (26-75%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate between 1 in 10 and 1 in 75 operating years.
Likely 4	Failure or occurrence is likely (76-90%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate between once per year and 1 in 10 operating years.
Almost Certain 5	Failure or occurrence is almost certain (91-100%). Available data, past experience and or subject matter expert input indicates an expected occurrence rate of greater than once per year.

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Nova Scotia POWER
An Emera Company

INFORMATION TECHNOLOGY ASSETS CRITICALITY & CONDITION RISK ALIGNMENT MATRIX

Business Criticality (Based on Consequence)					Criticality Value	RISK MATRIX				
Customer	Finance	Compliance	Operational Sustainability	Criticality						
Loss of a service for all customers	Financial Impact > $30m	Breach of compliance with any of: safety, environmental, security, legal or regulatory requirement	Employees could not perform their role or an employee / contractor could not perform their role safely	Critical	5	5	10	15	20	25
Customer Experience is significantly degraded for majority of customers but not complete loss of service	Financial Impact - $5M -$30m	Non-compliant with internal Corporate safety, security policies	Significant impact to employees; work arounds require excessive time and additional resources	Major	4	4	8	12	16	20
Customer Experience degradation is minor for all customers	Financial Impact - $1M-$5M	Non-compliant with other internal Corporate policies (non-safety, non-security related)	Moderate impact to employees; work arounds require some increase in time with same resources	Serious	3	3	6	9	12	15
Customer Experience degradation is minor for small group of customers	Financial Impact - $0.1M-$1M	Non-compliant with internal departmental policy	Minimum impact to employees; work around in place with minimum impact to time	Moderate	2	2	4	6	8	10
No impact to the Customer Experience	Financial Impact <$0.1M	No impact on compliance	Nuisance / inconvenience for employees but with no impact on time	Minor	1	1	2	3	4	5
						1	2	3	4	5
						Rare	Unlikely	Possible	Likely	Almost Certain
						CONDITION				

LEGEND

	Acceptability of Risk
High Risk	Requires Mitigation
Medium-High Risk	Considered for Mitigation
Moderate Risk	Acceptable
Low Risk	Acceptable

	Support	Reliability	Vendor contract	Fit for Purpose
Rare	Excertise is readily available from authorized support sources to meet the service level targets for the business	Service has a high reliability rate with minimal downtime. Operating as designed	Licensing is compliant, vendors are up to date to comply with vendor support requirements	Features, functionality, performance meets business expectations and requirements and is suitable to meet 5 yr technology road map requirements
Unlikely	Local resources readily available to source as needed, at its training available	Small number of failures reported,Minimal downtime	Licensing is compliant; Current service will be considered "end of life" in 3 years	Features, functionality, performance will not meet the business requirements planned in the next 4 years
Possible	Resourcing options available within North America at a premium cost.	Increase in number of failures reported over previous year; downtime hours impacting business operations.	Licensing is compliant; Current service will be considered "end of life" in 2 years.	Features, functionality, performance will not meet the business requirements planned within the next 3 years
Likely	No resource options within North America, limited availability outside of North America at premium cost	Material number of failures reported Replacement parts difficult to source	Licensing is compliant; Current service will be considered "end of life" in 1 year	Features, functionality, performance will not meet the business requirements planned within the next 2 years
Almost Certain	Minimal to no options for resources that can provide support, training not available	Diagnostics predicting eminent hardware failure. Priority software defects that vendor is not able to correct and no acceptable work around is available; hardware replacement parts cannot be sourced	Non- compliance with licensing requirements / Service is considered "end of life" by the vendor	Features, functionality, performance will not meet the business requirements planned within the next year

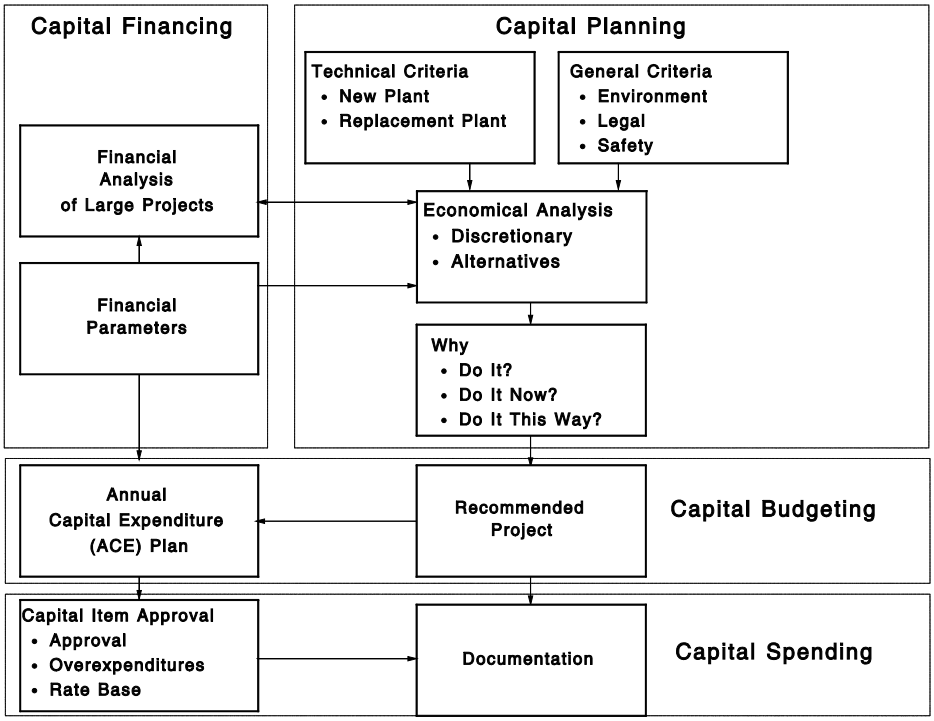
General Plant

Projects under General Plant primarily involve information technology, communications and facilities initiatives. With the exception of IT which is ranked according to the matrix above, these other areas are too diverse to develop a comparable and useful ranking system across the groups, and therefore the determination of whether a project will proceed is based upon technical justifications or economic benefit.

6.3 Capital Planning Process

Originators and approver(s) of all capital projects follow disciplined capital planning, budgeting and execution processes.

Figure 1.0: Summary of NS Power Capital Planning, Financing & Budgeting



6.4 Accounting Policies and Procedures

NS Power's Accounting Policies and Procedures and Chart of Accounts require Board approval. Revisions to the Accounting Policies and Procedures and Chart of Accounts are submitted to the NSEB for approval on an as needed basis. The NS Power Accounting Policies and Procedures Manual contains the guidelines for determining whether an expenditure is a capital or operating expense. NS Power began using United States Generally Accepted Accounting Principles (USGAAP) for external financial reporting on January 1, 2011.

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The following Accounting Policies and Procedures guide and direct NS Power's capital expenditure program:

- Rate Base (1520)
- Materiality (1560)
- Capitalization Limits (1560A)
- Generic Accounts (3350)
- Generic Accounts - Cross Reference to Capital Activities (3350A)
- Depreciation and Amortization Expense (5300)
- Amortization - Capital Contributions in Aid of Construction (5310)
- Capitalization of Cost (6000)
- Cost (6100)
- Cost Elements (6140)
- Construction Work in Progress (6200)
- Capital Expenditures - Land (6210)
- Capital Expenditures - Computer Hardware, Software and Telecommunications Equipment (6215)
- Capital Contributions in Aid of Construction (6220)
- Intangible Assets (6225)
- Application of Administrative Overhead (Self-Constructed Assets) (6230)
- Application of Administrative Overhead (Constructed Assets) (6235)
- Allowance for Funds Used During Construction (6240)
- Purchase Price Discrepancy (6250)
- Transfer Values (6260)
- Asset Retirement Obligations (ARO) (6320)
- Redundant Assets (6340)
- Assets - Not Used and Useful (6350)
- Long Lived Assets to be Disposed of by Sale (6360)
- Accumulated Depreciation (6400)
- Retirement and Disposal of Capital Assets (6420)
- Gain or Loss on Disposition of Capital Assets (6440)

Current and future interpretations of accounting policies and procedures will be made by the Corporate Accounting Department within the Controllers Division.

6.5 Capital Planning

Capital planning is a centralized function and ensures the capital projects included in the ACE Plan are those which provide maximum benefit to customers while allowing NS Power to meet its objectives. The capital planning cycle for any given year typically begins early in the preceding year and concludes at the filing of the ACE Plan.

Although the oversight and management of the capital planning process is a centralized function, many capital projects are identified at the functional level (Generation, Transmission,

Distribution, and General Plant) and brought forward for centralized review and approval. Centralized review and approval of all capital projects ensures the projects included in the ACE Plan are fully justified and consistent with NS Power's strategy.

There is a standard ranking methodology for Generation, Transmission and Distribution which is described in detail above. On an annual basis, projects identified are broadly ranked using the following criteria:

- Health and Safety: Operating Permits, Protection of Equipment and Personnel Safety
- Regulatory Compliance: Renewable Electricity Standards, GHG Regulations, Air Emission Regulations, NERC/ NPCC Requirements
- Customer Reliability: SAIDI, SAIFI, CAIDI
- Requirement to Serve
- Economics: Based on Revenue Requirement, Net Present Value of the Project, Levelized Cost Analysis, $/ Avoided Customer Hours of Interruption (ACHI)

Each year, the capital program includes those projects which are essential for health and safety objectives, regulatory compliance, and those which are required to provide service to a given area. Projects which serve to improve customer reliability are evaluated based on the probability factors related to performance targets (SAIDI, SAIFI, CAIDI, etc.). Economically justified projects are evaluated based on their economic and performance ranking. The capital program can be constrained by a number of factors including the ability to effectively execute the annual program with the available time and resources, the maintenance cycle of the generating facilities and company cash flow.

6.6 Capital Expenditure Justification Categories

All projects have a justification category. Some categories are specific to functional areas of NS Power that develop capital items, while others are more general in nature and affect capital decisions across the Company.

Examples of area-specific criteria:

- Work Support Systems
- Vehicles
- System Design

Examples of general criteria:

- Environment

- Health and Safety

6.7 Economic Analysis

6.7.1 Economic Analysis Model

The Economic Analysis Model (EAM) is an electronic spreadsheet which calculates and compares the revenue requirement by comparing alternatives to complete the project and avoided costs.

With respect to alternatives to completing the project, all else being equal, the alternative with the lowest discounted revenue requirement will be the preferred alternative. A cash flow analysis determining net present value (NPV) of the alternative cash flows is also incorporated into the EAM to further evaluate the economics of the project.

The following are typical inputs into the model:

- Capital investment profile
- Operating cash flows, including avoided costs

The model calculates the following:

- Revenue requirement
- Income tax associated with the capital expenditures
- Discounted net cash flow at the after-tax weighted average cost of capital (WACC)
- Net present value (NPV), Internal Rate of Return (IRR) and discounted payback period for each alternative

Each year an updated version of the model is provided to users with current tax rates, depreciation rates and WACC.

With respect to avoided costs, avoided costs are calculated using probabilities of failure, unit capacity factors, avoided maintenance costs, and avoided replacement energy costs. Capacity factors and avoided replacement energy costs are forecasted for five years, beginning in the year of project construction. If the avoided costs outweigh the capital costs of the project, the project is considered economic. The timeframe in which the benefit of the project equals the avoided costs is considered the “pay-back period”. NS Power will use an estimate of inflation as an escalator for year six (6) onward to determine future year avoided replacement energy costs.

On an annual basis, NS Power will compare its estimated inflation escalator to fuel forecasts for years 6 onward. If results materially vary, the continued use of inflation as an escalator will be more closely examined and discussed with stakeholders.

The benefits of the model are that it is relatively simple to use, promotes consistency of capital analysis across the organization and provides immediate information regarding the economics of alternatives. The model does not allow monthly cash flow entry. In this regard, where the results of alternatives are close, further review may be required.

Sensitivity analyses are incorporated into the model as adjustable variances for capital spend, avoided expenses, and timing of the project. These are adjustable to further test whether reasonable variances in those categories affect the rankings and therefore preference of alternatives.

With respect to various alternatives considered within an EAM, project developers will endeavour to provide realistic alternatives, and clarity on what is included in the costs comprising each alternative. Additional clarifying notes, if necessary, can be written onto the "Notes/Comments" section on the first page/tab of the EAM.

Administrative Overhead (AO) - Project capital cost and the revenue requirement analysis include Administrative Overhead (AO). While it is understood that costs included in NS Power's eligible expenses used to determine the AO rate are largely fixed, NS Power will examine further those projects where elimination of the AO credit from the revenue requirement analysis could affect the recommended alternative for economically justified projects. Where this occurs, NS Power will examine the effect of the AO amount more closely to determine the level of reduction to the AO credit which would change the recommended project, and based on this, provide appropriate comment on this in the Capital Item justification.

6.7.2 Production Costing Model

A system modelling tool used by NS Power to provide detailed forecasts of fleet dispatch and production costing which reflect the increasing complexity of the system.

6.7.3 Levelized Cost

NS Power also periodically utilizes levelized cost methodology to justify capital investments. This approach employs an economic modelling methodology used to provide a present value of the total cost of a project (and alternatives) over its economic life converted to a levelized unit cost (typically in $/MWh). The levelized cost model as used by NS Power calculates the present value based upon the annual revenue requirement for the project throughout the term. The levelized cost analysis is useful when comparing generation projects of different technologies and/or comparison to Power Purchase Agreements.

Deleted: 6.7.2 Revenue Requirement Directive in Annual Capital Expenditure Plan¶
¶
In the Board's 2011 ACE Plan decision, the Board provided the following directive:¶
¶
In future ACE Plan applications, NSPI is directed to make an approximate calculation of how the Plan will affect revenue requirements.¶
Beginning in the 2012 ACE Plan NS Power has provided the overall approximate impact of the ACE Plan on revenue requirement. Beginning in the 2017 ACE Plan and pursuant to the 2016 ACE Plan Terms of Consensus, NS Power also provides a version of the overall revenue requirement table based on stakeholder assumptions and calculation methodology.¶
The underlying principle in calculating NS Power's revenue requirement table and impact is that capital expenditures that equal NS Power's depreciation expense do not change the customer revenue requirement. The premise is that rate base is not growing or declining if capital expenditures equal the rate of depreciation. To the extent depreciation expense equals capital expenditures in a given year, there is minimal effect on rate base or associated revenue requirement and therefore it is excluded from the calculation.¶
The revenue requirement impact considers the following inputs:¶
Capital expenditures compared to forecasted depreciation expense annually.¶
¶
Administrative overhead credit based on the proportion of capital expenditures in excess of depreciation expense in each year.¶
Depreciation expense of assets added during the examined timeframe based on the proportion of capital expenditures in excess of depreciation expense of all assets in each year.¶
Incremental interest based on the cost of debt multiplied by the portion of debt to total capital of the incremental rate base.¶
AFUDC based on the proportion of capital expenditures in excess of depreciation expense of all assets in each year.¶
¶
Income taxes based on the resultant effects and prorated Capital Cost Allowance for tax purposes.¶
¶
Net earnings based on the rate of return multiplied by the portion of equity to total capital of the incremental rate base.¶
Additional fixed cost recovery received from customer growth achieved through capital investment to serve these customers.¶
Depreciation expense and additional fixed cost recoveries are delineated in the overall revenue requirement ... [1]

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6.7.4 Total Cost of Ownership

Deleted: 5

In the Board's 2022 ACE Plan decision, the Board provided the following directive:

> [T]he Board directs NS Power to use a TCO for IT projects over $1 million when an EAM is not provided, whether or not an alternative is available.

Total cost of ownership (TCO) is the cost of a new or upgraded capital asset plus all capital costs and operating expenses over its expected useful life. It accounts for all the capital and operating costs, including the upfront capital costs. In addition to providing a comprehensive understanding of the total cost of a capital investment over the course of its useful life, a TCO is also a useful tool for comparing capital investment options to determine the best value for money.

The TCO timeframe should match that of the expected useful life of the IT software or hardware. This allows for the flexibility to select an appropriate timeframe for a TCO analysis that is in keeping with the useful life of an investment rather than a prescribed timeline.

6.8 Capital Financing

Capital financing is a centralized function of NS Power, which deals with the affordability of capital expenditures on both an individual project and aggregate capital program basis. Control is achieved through determining the financial parameters for economic analysis and providing and coordinating financial analysis for large capital projects.

Financial Parameters: that influence economic analysis include the cost of capital (calculated as the weighted average cost of capital), depreciation rates for service life, depreciation rates for tax purposes (capital cost allowance - CCA), inflation rates and income taxes. To assist in selecting projects that are economic, other financial guidelines are employed. For projects that are otherwise equal in their net present value, benefits for customers are judged on payback characteristics and rate effects.

Financial Analysis: examines the impacts of the projects that are most likely to have an effect on NS Power's financial position, including debt/equity ratio, rate effects on customers, financing plan, financial plan, share prices, bond rating, etc.

The investing decision is separated from the financing decision in the sense that the cost of capital rather than the cost of the expected source for financing is used in the analysis of the investment.

6.9 Capital Budgeting

Capital budgeting is a vital part of the corporate planning process because it is at this stage that NS Power assesses future scenarios and commits the financial and physical resources needed to achieve its objectives. The process consists of the following:

1. Consolidating the estimated cost for all the individual projects approved for inclusion in the ACE Plan from the functional areas of NS Power. Consolidation is a centralized function;

2. Developing an Annual Capital Expenditure Plan (ACE Plan); and

3. Continual re-evaluation of projects after their acceptance.

The ACE Plan is comprised of those capital projects and programs that NS Power is able to and prepared to fund. The process for finalizing the ACE Plan gives consideration to financial matters that govern NS Power’s ability to fund the aggregate capital program, and the Capital Expenditure Justification Criteria included herein.

The ACE Plan is approved by NS Power’s Executive Team and submitted to the NSEB for approval.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

6.10 ACE Plan Projects

ACE Plan projects are those that are individually justified in accordance with the CEJC and allow NS Power to meet its objectives. All ACE Plan projects must answer the following questions in order to be considered justified:

1. Why do this project?
2. Why do this project now?
3. Why do this project this way?

A capital expenditure is not justified until the need is established and it is demonstrated that the proposed project is the best alternative being implemented at the optimal timeframe.

6.11 Additional Perspectives on Capital

Capital Functions

To enable appropriate cost allocation among customer classes and consistent depreciation practices across asset groups, NS Power capital expenditures are categorized according to the following utility functions:

Generation: Includes expenditures for NS Power Thermal, Hydro, Natural Gas and Renewables.

Transmission: Includes expenditures for the replacement, reinforcement or expansion of the transmission system, which transmits electrical energy from the generation plants and the NB Power/NS Power interconnection throughout the Province. Transmission includes facilities operating at voltages of 69 kV or higher.

Distribution: Includes expenditures for the replacement of and additions to equipment for delivering electrical energy from points on the transmission system to customers served at voltages below 69 kV.

General Plant: Includes expenditures for computer software, computer infrastructure, communication equipment, furniture, office equipment, tools, vehicles, land and buildings (other than generating and substation facilities).

6.11.1 Essential and Discretionary Capital

Within these categories, capital expenditures may be viewed as either:

Essential: A capital addition or replacement which must be made to satisfy technical, legal, safety, or environmental directives. Capital projects that are deemed to be essential generally meet one of the following criteria:

1. Required by law or regulation

These are capital projects that must be undertaken to conform with laws or regulations that govern NS Power's operations.

Examples:
New customer connections
Environmental projects
Civic responsibility
Safety projects

2. *Emergency*

   Projects that usually arise as a result of an unforeseen event. These projects must be undertaken in order to maintain NS Power operations.

3. *Technical Criteria*

   Technical criteria are established on the basis of the need to continue reliable supply of service. Failure to meet these criteria will result in a loss or degradation of service below acceptable levels.

Discretionary: Capital expenditures that are deemed to be discretionary are:

- Investments made solely on the basis of economics.
- There is a "do nothing" alternative.

The decision to pursue discretionary projects may yield defined benefits that minimize the revenue requirements of NS Power.
Alternatively, not proceeding with the project, the "do nothing" alternative, is an acceptable option whereas discretionary projects are based solely on economics, and the project is not addressing a pressing safety, legal, reliability or technical scenario.

For example, an acceptable "do nothing" alternative may be not proceeding with a generation capital project designed to increase the heat rate efficiency of the unit. Not proceeding with such a project, and therefore foregoing increased heat rate efficiency, does not impact the safe and reliable operation of NS Power's system.

Generally with discretionary investments, NS Power seeks projects that provide returns which minimize or reduce revenue requirement. Financial and strategic priorities may not permit NS Power to undertake all, or even any, discretionary capital expenditures in any given year.

This perspective links capital expenditures to the priorities of NS Power. Certain capital expenditures are essential and sufficient capital funds must be available to undertake them. NS Power has the discretion to request approval for funding for additional capital projects based on the economics of the projects.

NS Power has the flexibility of setting objectives for discretionary projects so as to achieve financial or strategic objectives, for example minimizing investment risk or achieving rate

reductions. The financial parameters established for the economic evaluation of alternatives and for determining the maximum capital budget comprise the internal controls for limiting spending on discretionary capital projects.

6.11.2 Documentation

Internal NS Power documentation is prepared and retained for every capital project. Refer to Appendix B.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

7.0 Capital Planning Financial Criteria & Policies

- NS Power will be responsible for creating financial criteria for the Company.
- Accountability to develop and maintain the general and function-specific justification criteria resides in identified areas of NS Power.
- Capital planning, as a function, is distributed throughout NS Power, but is centrally managed. The respective functional areas of NS Power are accountable for developing, analysing and documenting projects and submitting all items to the Capital Planning group for review and approval.
- Accounting policies and procedures will be presented to the NSEB for their approval prior to implementation. These policies and criteria are presented to the Board for approval through a separate proceeding, or can be incorporated within a proceeding, such as the Annual Capital Expenditure Plan.

8.0 Financial Parameters

8.1 Introduction

The capital program is financed through a combination of debt and equity. The weighted average cost of capital (WACC) is the average of the costs of these sources of financing, each of which is weighted by its respective use to fund the activities of NS Power. The weighted average calculation identifies the cost NS Power has to pay for every dollar it finances. WACC is used to calculate Allowance for Funds Used During Construction (AFUDC) applied to eligible capital projects. The WACC used by NS Power to calculate AFUDC will be the WACC most recently approved by the NSEB. NS Power applies for approval of an AFUDC rate annually through a separate proceeding.

In making investments in capital projects, NS Power must be aware of a number of financial factors which are important in economic analysis:

- Cost of capital
- Depreciation
- Inflation
- Taxes
- Competition for investment capital in capital markets
- Investment risk

The rationale for each factor and the basis for its use in determining the economics of capital projects is presented below.

8.1.1 Cost of Capital

NS Power finances capital expenditures through:

- Debt
- Preferred shares
- Common shares
- Retained earnings

Each of these sources of financing has a cost. Debt-holders require semi-annual payments of interest, preferred shareholders expect quarterly dividends, and common shareholders require both a quarterly dividend as well as a future return on the earnings reinvested in the business as retained earnings. The cost associated with each source of financing varies according to the financial risk represented by each type of capital.

The weighted average cost of capital in today's financial markets for NS Power represents the minimum acceptable return the Company must earn on its capital investments to compensate investors for the use of their funds to finance capital projects.

NS Power Capitalization Structure

The mid-point of capital structure ranges approved by the NSEB is used as the basis for calculation of Cost of Capital.

Long Term Debt Structure

The debt structure is based on the target structure accepted by the Board of Directors of NS Power. The annual rates for new debt capital will be calculated from the Treasury Division's long term forecast of the cost of debt.

Equity Structure

NS Power's equity structure consists of common equity with a range of allowed return established by the NSEB and preferred equity with a return established by the prevailing market conditions at the point in time when it was issued. The cost of new common equity used in the calculation of the weighted average cost of capital is the point of the range used to set rates on common equity allowed by the NSEB. The cost of preferred equity used is the Treasury Division's long term forecast of the cost of new preferred equity issues.

Cost of Capital

The Cost of Capital is calculated as the weighted average cost of capital (WACC) based on the capitalization structure.

The Cost of Capital is the rate of return on capital investments that is required by NS Power to pay for the use of the investors' capital employed by the Company. It is NS Power's long term Cost of Capital.

NS Power revises its Cost of Capital annually. NS Power submits the revised WACC calculation as part of the AFUDC rate approval request. Economic Analysis Models for projects included in the ACE Plan will also incorporate NS Power's proposed WACC.

8.1.2 Depreciation

When NS Power acquires financing for its capital program, it takes on an obligation to repay the investment. This is accomplished through the setting aside, from an accounting perspective, of a certain amount of funds annually for the purpose of repayment of the investment. This amount is called depreciation. The estimated useful life of the capital asset forms the basis for calculating the annual depreciation rate.

Two general approaches are used to establish the annual depreciation rate – life span (production plant) and mass property (transmission, distribution and general plant). The life span approach applies generally to large single investments such as a thermal generating plant. The mass property approach applies generally to such assets as distribution lines that, through interim replacements, might be expected to have an indefinite life.

In the latter instance the characteristics of the on-going failures of the materially significant components of the asset are important to calculating the depreciation rate. NS Power uses the Iowa Curves to establish annual depreciation rates that account for the dispersion characteristics of plant failures.

The specifics of the depreciation rates employed for each type of plant are provided in NS Power's Accounting Policies and Procedures Manual, Section 5300.

8.1.3 Inflation

The cost of goods and services tend to increase over time, an effect called inflation. This is taken into account in calculating future costs for economic analyses. NS Power will estimate the general inflation rate and escalate the costs used in its analyses accordingly. Special inflation rates may be developed for particular costs (e.g. fuel) and these escalations will be justified individually.

8.1.4 Taxes

NS Power is subject to Provincial and Federal income tax on its earnings, and Federal Part VI.1 tax on its preferred dividends. The economic analysis must include the effects of these taxes.

In addition NS Power pays annual grants to municipalities of Nova Scotia, in lieu of all municipal taxation other than Deed Transfer Tax. These grants bear no relationship to NS Power's capital assets and they are not included in the economic analysis of the alternatives.

NS Power also pays the Harmonized Sales Tax on certain goods and services. Because this tax is fully refundable, it is not a relevant cost for capital budgeting purposes since it does not result in any differential costs to NS Power.

8.1.4.1 Taxes in Economic Analyses

Income tax is included in the economic analysis of capital projects.

Taxes on the earnings associated with the capital expenditure are included in the economic analysis of alternative projects. The Federal and Provincial taxes on earnings are calculated on taxable income. This is derived from gross income by allowing certain deductions. These deductions include operating and maintenance expenses, capital cost allowance (tax depreciation), preferred dividend tax credits and interest on debt.

Depreciation expense is treated differently for tax purposes than for rate-making purposes.

Depreciation

For rate making purposes, depreciation is the process by which capital invested is recovered. The useful life estimations and other significant assumptions are periodically reviewed and the results filed with the NSEB for approval. Depreciation expense is not included in the calculation of taxable income or cash flows. It is recognized in the calculation of revenue requirement.

Capital Cost Allowance

CCA is depreciation for tax purposes. CCA is a deduction against taxable income. Capital Cost Allowance is based on the classification of the asset for tax purposes

Allowance

As per Schedule II - Capital Cost Allowances, of the Income Tax Regulations, CCA is established on the basis of specific classifications for tax purposes, whereas depreciation expense is based on the useful life of the plant.

8.1.5 Competition for Capital

NS Power must compete in the financial markets for the investment capital that it needs to fund its capital program. It must maintain the confidence of investors so that it has access to capital at attractive rates. The market will demand increased returns, either through higher coupon rates or lower share prices, for investments in which it has less confidence (perceives higher risk). Decisions regarding the individual projects in which NS Power invests, and the total capital investment made by the Company, must respect this market confidence. Because of their larger impact, each significant individual capital investment will receive a thorough financial analysis to satisfy NS Power that, in addition to being economic, it is a financially sound investment.

In evaluating any particular capital project, it is helpful to create a hierarchy to provide a preliminary ranking of prospective projects. As all projects can be classified as being either essential or discretionary, essential capital projects will receive first priority in the allocation of capital. Refer to Section 6.11 - Additional Perspectives On Capital - for further information regarding these classifications.

8.1.6 Investment Risk

Risk exists in capital budgeting when more than one outcome may occur. A quantitative evaluation of a capital expenditure proposal requires that several predictions be made, often far into the future. As a general rule, the risk associated with achieving an expected cash inflow or outflow in a given year increases as one moves further into the future, as there are more factors in the long term which cannot be foreseen but which will affect cash flows.

There are essentially two types of project investment risk:

Inherent Risk: varies with the nature of the project and generally relates to unknowns about successful performance.

Traditional Risk: results from errors in estimates and assumptions that affect the probable revenue requirement associated with the project.

In addition, the decision to undertake a project may involve certain corporate strategic risks where the outcomes of the decision could affect business flexibility or create other costs not directly related to the project.

In order to minimize NS Power's exposure to inherent risk, the Company may establish a project-level cut-off rate for individual discretionary projects. This will occur if the perceived investment risk for the project differs substantially from the general risk levels of NS Power. This limits the overall investment risk exposure of NS Power from the project level perspective. However, corporate priorities may dictate that individual projects will be accepted at cutoff rates as low as the cost of capital despite the investment risks at the project level.

9.0 Economic Analysis of Alternatives

9.1 Introduction

The guiding principle of economic analysis is to seek the most economic alternative based on establishing which alternative, among a number of alternatives that satisfy basic requirements, yields the best value for customers and NS Power. Within the analysis, both traditional and non-traditional alternatives are reviewed prior to initiating a capital item. This guideline will review relevant factors and their use in identifying the most economic alternative.

An outcome of the analysis is that, when estimates of revenues are included, an estimate of the amount of contribution towards lower costs offered by the alternative is produced. Certain investments required of NS Power may have no lower cost contribution; that is, they return no revenues beyond that required to exactly recover costs. The minimum revenue requirement method serves, in this case, to identify the alternative that results in the least amount of cost to NS Power and its customers.

The essentials of conducting an economic analysis of alternatives may include, when appropriate:

- Analysis methodology
- Financial parameters
- Cost components for analysis
- Analysis period
- Calculating the net present value
- Sensitivity analysis

9.1.1 Analysis Methodology

Production-costing models are used by NS Power to estimate replacement energy costs and generator capacity factors in the EAMs for a period of five years. NS Power uses an estimate of inflation as an escalator for years six (6) onward to determine future year avoided costs.

On an annual basis, NS Power will compare its estimated inflation escalator to fuel forecasts for years 6 onward. If results materially vary, the continued use of inflation as an escalator will be more closely examined and discussed with stakeholders.

9.1.2 Financial Parameters

Certain financial parameters are required to undertake an economic evaluation of capital expenditures. They are:

AFUDC:	The cost-of-capital invested in construction work in progress is included in an allowance for funds used during construction ("AFUDC") as an addition to the cost of property constructed using a weighted average cost-of- capital.
Book Depreciation:	The difference between the amount of book value for an asset and how much depreciation is assessed on the asset.
Cost of Capital:	The weighted average cost of all capital employed by NS Power.
Taxes:	The taxes payable by NS Power on its earnings and the capital it employs to finance projects.
Capital Cost Allowance:	Depreciation expense for tax purposes (also known as the CCA).
Inflation Rates:	The rates to be used to establish the future prices of goods and services.
Discount Rate:	The cost of capital rate adjusted by other factors such as risk premiums.

9.1.3 Cost Components for Analysis

The cost components of the economic analysis are as follows:

1. Relevant costs
2. Cost estimates
3. Receipts from the sale of by-products
4. Unequal lives

9.1.3.1 Relevant Costs

The estimate of the costs and benefits of a capital project should show the difference in revenue requirement as a result of undertaking the project.

9.1.3.2 Cost Estimates

Reliable estimates and forecasts are vital to the capital investment decision. A sophisticated process of analyzing financial information and managing the decision related to a project is of little value if a casual approach is taken to development of these estimates. Effective management of capital expenditure decisions, therefore, requires that controls be designed and operated to ensure that projections are realistic at the time decisions are made.

When estimating costs for capital expenditures, the following guidelines should be applied:

1. Only future revenues and costs after the payment of tax on income are relevant. Historical costs may be useful in terms of providing a basis for prediction, but they do not represent what future costs will be. A cost that occurs before the decision is implemented, that is, a past or “sunk" cost, cannot be influenced and must therefore be ignored.

2. Only differential revenues and costs are relevant. This means that only the difference in revenue requirement between implementing or not implementing a proposal need be considered.

3. Opportunity costs are relevant. If a resource can be used more than one way, it has an opportunity cost. In general terms, an opportunity cost is the benefit lost by taking one action as opposed to another.

It is the revenue requirement generated by an investment project that is of primary importance in an economic analysis. As used in the context of this guide, payment means a cash flow from NS Power to an outside entity, and non-cash

payments including items such as AO and depreciation. The date of payment, as well as the magnitude of these payments, must be estimated.

Cost allocations, charges and transfers between different parts of NS Power are not payments to an outside entity, and must not be used for economic cost comparisons unless they can be shown to accurately reflect such payments (e.g. internal labour used in achieving the required result is included in the estimated costs of alternatives). Items withdrawn from stores or spares do create payments to an outside entity when they are replaced and must be included in the estimate.

9.1.3.3 Receipts from the sale of by-products

A by-product is any physical result of an alternative which is not a part of the required result. Some examples of by-products are: assets which become surplus to requirements, electricity sold outside Nova Scotia, and flyash used for making concrete. Receipts from the sale of by-products are included in the determination of the minimum revenue requirement by including them as credits to operating & maintenance costs.

9.1.3.4 Unequal Lives

Alternative capital investments can have different useful lives. To make a valid comparison when the future payments are not equal it is necessary to equalize the lives of the projects. One method is to assume a chain of replacements where the analysis covers the same number of years.

Alternatively, terminal values can be used to shorten the period in an economic cost comparison to avoid some of the effort required to include all the significant cash flows under the chain replacement method. Terminal values must not be used to shorten the period to less than the expected life of any major asset required by the alternatives. The terminal values of capital expenditures can be determined using the following techniques:

1. When an active market exists for a capital asset, such as an automobile, the potential net receipts from sale of the asset must be used as the terminal value.

2. When no active market exists for a retained asset, such as a distribution line, the replacement value to NS Power must be considered. Unless in the judgement of the estimators a better criterion of this value is available, the terminal value should be a straight line proration of the replacement cost based on remaining service life.

For example, if a distribution line is expected to have a third of its service life remaining at the end of the comparison period, and to have a replacement cost of $450,000 at that time, it should be assigned a terminal value of $150,000.

Terminal values, also called retention or residual values, are included in economic cost comparisons as receipts.

9.1.4 Analysis Period

Depending on the nature of the capital investment, the analysis timelines will vary.

9.1.4.1 The Planning Horizon - Economic Life

The criterion to estimate the life of a project is the continued ability to generate satisfactory cash flows or other intangible benefits. The economic life of a project is the least of its physical life, technological life, or product market life, or the point where cost differences between discounted alternatives are so small they are insignificant.

9.1.4.2 Physical Life

Physical life represents the time taken for an asset to become physically worn, or consumed so that it can no longer be efficiently maintained and must be replaced. However, equipment will often be disposed of before its physical life has expired.

9.1.4.3 Technological Life

Technological life is the period of time that elapses before an even newer machine or process becomes available which would make the proposed machine or process obsolete. Improvements will almost certainly be made sometime in all machines or processes now in existence, but questions of which machines or processes will be improved, and how soon they will be on the market, are most difficult to answer. To ignore a product or machine's technological life is to imply that the technological life is the same as the physical life.

9.1.4.4 Product Market Life

Although a machine may be in excellent physical condition, and there may be no better machine on the market, its economic life has ended for the organization as soon as the manufacturer ceases to produce the product, market the product, or provide spares and services.

9.1.5 Calculating the Net Present Value (Worth)

The estimates prepared for economic cost evaluations must include, as a relevant cost, the time value of money. Capital investment decisions require investing money now to bring more money in the future. The time value of money is an opportunity cost; by making a particular investment now, we give up the opportunity to make other investments.

The common time is called the present and the process of converting future costs to the present is called discounting. Discounting changes the magnitude of an estimate according to a compound interest formula. The degree of change depends on the time interval involved and on the compound interest rate, that is, the discount rate.

Interest, principal repayments, and dividend amounts are not included in the cash flows for discounting purposes. The investment decision is based on the revenue requirement of the project, regardless of how it is financed. Using the cost of capital as the discount rate automatically provides for not only the recovery of the investment, but also a return on the investment at least equal to the cost of capital.

After the estimates have been converted to their present worth equivalents, they are totalled and cash receipts and terminal values are subtracted from costs.

In the Economic Analysis Model the net present value (worth) differences between alternatives are then calculated, the alternatives ranked according to their net present value (worth), and the alternative with the lowest present cost (or highest present value, in the case of economic projects) is identified.

9.1.6 Sensitivity Analysis

An economic cost comparison cannot be given its proper weight in a decision without some indication of its sensitivity to input assumptions; that is, of the confidence that can be placed in its results. The potential sources and likelihood of error in the ranking of alternatives can be determined by a sensitivity analysis.

Sensitivity analysis gives NS Poweran idea about how unfavourable variance occurrences like lower volumes, shorter useful lives or higher costs affect the economics of a project. It is a technique which is used to identify those estimates which are the principal contributors (key factors) to the risk that an inferior alternative will be chosen. In this technique, the estimates which have the greatest impact on the comparison are identified, usually by changing each one in turn by a given proportion, e.g. 10%. Then, the effect of varying these estimates through a range of values (e.g. from a minimum to a maximum) based on possible inaccuracies in forecasts and assumptions is evaluated. Those estimates that significantly change the comparison, when varied through this range

of possible values, are candidates for additional estimating effort directed toward reducing the range.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

10.0 NS Power Capital: Types of Capital Applications Submitted for NSEB Approval

- Capital projects submitted to the Board in the Annual Capital Expenditure Plan (ACE).
- Capital projects identified in the ACE Plan requiring subsequent submission to the Board.
- Capital projects included in the ACE Plan, but for which the Board has withheld approval in the ACE Decision (typically requires a filing by NS Power of additional supporting information, in a separate, or revised capital application).
- Unforeseen and Unbudgeted (U&U) capital projects. These projects are not included in the ACE Plan and are filed separately for Board approval.
- Planned and Advanced (P&A) capital projects. These projects are not included in the ACE Plan and are filed separately for Board approval.
- Authority to Overspend (ATO) applications. These applications represent request for NSEB approval of over-expenditure on a capital project or routine.
- Scope Change applications. These applications represent request for NSEB approval of scope changes within a previously NSEB approved capital project. This is independent of any variances in costs.
- Final Cost (FIN) applications. These applications are required for NSEB approval if final costs of the project are over or under the specified spend thresholds. They consist of final cost details and variance analysis.

11.0 Requirements for NSEB Approval

11.1 General Requirements

NS Power is a public utility, subject to the provisions of the *Public Utilities Act* (the Act). NS Power is subject to general supervisory oversight of the NSEB. Section 35 and Section 35AA (October 30, 2019) of the Act provide the following:

> 35 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.
>
> 35AA (1) In this Section, "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.

The Board may approve, or disallow capital projects requested by NS Power. The Board's approval may be in the amount applied for by NS Power or another amount the Board considers appropriate. The form of Board review is determined by the Board and may involve direct review by the Board, its staff and consultants and/or a public hearing, either oral or written.

NS Power retains the discretion to defer or cancel capital projects submitted and/or approved by the Board based on condition reassessment and reprioritization in accordance with engineering, business judgment and resource availability. Any projects cancelled or deferred are reported in the Quarterly Capital Reports.

11.2 Capital Application Requirements

Supporting documentation is provided with each capital work order application. The following information will be filed with each capital application in the project description, as relevant:

- Project Start Date
- Project In Service Date
- Project Final Cost Date
- Utility Function
- Forecast Amount
- Project's Estimated Useful Life

- Depreciation Class
- Retirement Information
- Contingency Information

Project Description, that clearly defines the intended scope of the project.

Justification Criteria Including:

- Sub Criteria (when applicable)
- Description of why the project is being undertaken (i.e. Why do this project?)
- Description of why the project is necessary at the time proposed (i.e. Why do this project now?)
- Description of why the project will be carried out in the manner proposed (i.e. Why do this project this way?)
- Whether the work will be undertaken by an affiliate and reason for affiliate involvement

Summary of Related Capital Items

- Related Projects approved or having taken place in the past 2 years, current year or anticipated for the next 2 years including the projects' estimated costs. When multiple projects relate to the same asset, or initiative they should be grouped as a package.
- A project can be considered related if it meets the following parameters:

  Steam/Gas Turbine – Work completed on the same asset (turbine, boiler, etc.) and on the same unit (Lingan Unit #3, for example).

  Hydro – Work completed on the same generating unit and dam structures, but not necessarily the same asset.

  Wind – Work completed on the same Wind Farm site.

  Transmission & Distribution – Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line).

  General Plant – Work completed on the same asset (application, building, etc.).

Retirement Information

- The categorization of retirement (as either under Accounting Policy 6420 - Retirement and Disposal of Capital Assets OR 6350 - Assets Not Used or Useful), and the percentage of the asset pool it represents.

Moved down [1]: Related Projects approved or having taken place in the past 2 years, current year or anticipated for the next 2 years including the projects' estimated costs. When multiple projects relate to the same asset, or initiative they should be grouped as a package.¶

Moved (insertion) [1]

Deleted: A list of related capital projects that have been or are scheduled to be completed within +/- 2 years of the submitted project will be included in capital applications.¶
¶

Contingency Information

- Project maturity classification checklist
- Statement of the basis for the contingency guidelines including, as applicable:
  - a. Predetermined guidelines - reference to or statement of documented basis for use of a standard "single contingency" or other referenced practice;
  - b. Subject matter expert judgement - documented reasons for the determination, including a supporting risk register; and
  - c. Other, more technical reasoning - Supporting analysis as described in the Contingency Guidelines.

Cost Support - This may include but is not limited to:

- Supplier quotes, or estimates
- Significant contract terms & conditions
- Management's best estimate based on previous experience or related projects

Additional Information required to justify the project - This may include but is not limited to:

- Engineering/condition assessment reports
- Independent consultant reports
- Planning studies
- Business cases

Cost Benefit Analysis - This may include but is not limited to:

- The Economic Analysis Model; including inputs, assumptions, and results for all alternatives
- The Levelized Cost Model; including inputs, assumptions, and results for all alternatives
- Production Costing Modelling Results
- NS Power procurement documentation and recommendations; (i.e. Requests for Expressions of Interest and Requests for Proposals)

Project Due Diligence Summaries

Industry Information

Real Estate Information - This may include but is not limited to:

- Lease agreements
- Property evaluations and assessments

NS Power Performance Data - This may include but is not limited to:

- Load statistics
- Outage performance data
- Annual maintenance schedules
- Historical results for multi-year projects
- Internal NS Power reviews
- Operating performance indicators

Technical Details - This may include but is not limited to:

- Substation drawings
- Line drawings
- System Impact Studies
- Generation Interconnection Agreement

Stakeholder Information - This may include but is not limited to:

- Government legislation
- Letters of project support
- Stakeholder engagement communication

11.3 Capital Costs Incurred Prior to Application

NS Power strives to submit all capital applications to the NSEB for review and approval on a timely basis. Capital costs incurred prior to application submission will be subject to the criteria noted below with respect to their inclusion into rate base.

Preliminary Engineering Projects

Each quarter, any spend above $1,000,000 associated with a preliminary engineering project that has been inactive (i.e. no internal or external engineering or scoping work, exceeding $10,000, being carried out within the last 12 month period) will be removed from rate base until such time as the preliminary engineering becomes active again or these costs are submitted for approval to the NSEB.

Under $1,000,000 Projects Subsequently Exceeding $1,000,000

Projects originally budgeted at less than $1,000,000, but subsequently exceeding that threshold during project execution, must be filed with the NSEB for approval no later than within six months of the project exceeding $1,000,000. Any projects that do not get filed within this timeframe will have all costs in excess of $1,000,000 removed from rate base in the quarter after the six month timeframe until these costs are submitted for approval to the NSEB.

Capital Projects in ATO Position

If a previously approved capital project exceeds the allowable variance of the greater of 5% or $250,000 and is not filed within six months of exceeding the approved amount, then the costs in excess of Board approval will be removed from rate base each quarter until these costs are approved by the NSEB.

Unapproved Plant in Service Spending

Any capital item with unapproved plant in service above $1,000,000 that does not fall under any of the above categories, and where a capital work order has not been filed with the Board within 6 months of the project's completion, the spend to date on that project in excess of $1,000,000 will be excluded from rate base each quarter until such time as the work order is filed.

12.0 Authorization to Overspend (ATO) Requirements

12.1 Individual Capital Item ATO

Approval to Overspend (ATO) applications are intended to request Board approval prior to incurring additional expenditures above the approved amount. Individual capital items (non-routine) that are tracking final costs with a variance of more than the greater of 5% or $250,000 must be submitted as ATO applications, within 6 months, if NS Power intends to include costs in excess of Board approval in its regulated rate base.

The reporting included with the Quarterly submission of capital project applications will provide the budget, forecast and actual financial details in a one line format for all projects. Those projects that are tracking final costs with a variance of more than the greater of 5% or $250,000 will be specifically identified.

The following documentation shall be filed with the Board in an individual capital item ATO application:

- Updated NSEB approval sheet reflecting the revised project amount;
- Revised Capital Item Description Page reflecting the revised project amount;
- Cost support for the ATO request; and
- Updated economic analysis and / or production costing modelling results (if applicable).

12.2 Individual Capital Item Scope Change

Scope Change applications are intended to request Board approval prior to proceeding with a change in scope, when feasible, as compared to the previously Board approved scope. Scope Change applications may experience cost variances from the original application, but are submitted regardless of whether the thresholds for ATO and FIN applications have been exceeded when the stated intent from the original capital application of the project description has been changed. In the event a project has exceeding the ATO and FIN cost thresholds and has also experienced a scope change, the project will be submitted as a combined ATO or FIN and Scope Change application.

Examples of what a scope change may include are as follows:

- The refurbishment (component replacement) of an asset is changed to a full asset replacement. (i.e. a Steam Turbine Refurbishment project intended to replace / refurbish individual turbine blades is changed to a full turbine replacement).

- A technology project that intended to replace / upgrade a system with a specified application changes to a different application from what was listed in the project description.
- A distribution project such as a feeder rebuild through component replacement changes to a new line in an alternative locations (i.e. changing to a "Build to Roadside" approach).

A scope change is not considered to have occurred when the quantity of units within a project changes (i.e., replacing 6 turbine blades instead of 5, or completing more / fewer kilometres of New Distribution Rights-of-Way through vegetation management). In both instances the stated intent of the project is still being completed.

The following documentation shall be filed with the Board in an individual capital item Scope Change application:

- Updated NSEB approval sheet reflecting the revised project amount if applicable;
- Revised Capital Item Description Page reflecting the revised Scope Change;
- Cost support for the Scope Change request (if applicable); and
- Updated economic analysis and / or production costing modelling results (if applicable).

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12.3 Routine Capital ATO

Routine capital ATOs are based on the annual budget of individual sub-routines noted in the preceding ACE Plan.

Those sub-routines with variances compared to the annual budget of more than the greater of 5% or $250,000 will require submission to the NSEB for review and approval in the first half of the following year. If, however, the sub-routine budget and its total actual incurred cost is less than the $1 million threshold, then no sub-routine ATO filing is required as it falls outside of the 35AA approval threshold for the NSEB.

The following documentation shall be filed with the Board in a sub-routine capital ATO application:

- NSEB approval sheet including the sub-routines subject to overspend, the revised sub-routine amount, variance amounts, and detailed variance explanations for each in the comments section.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

13.0 Final Cost Application (FIN) Requirements

Individual capital item projects that have final costs with a variance of more than the greater of +5%/+$250,000 or -10%/-$500,000 will require that a final cost application be submitted to the Board for approval.

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Projects not falling within this threshold may require final cost applications as requested by the NSEB. If the final cost of a project falls below the $1 million approval threshold, no FIN application would be required as it falls outside of the 35AA approval threshold for the NSEB.

The information provided in these submissions includes:

- Updated NSEB approval sheet reflecting the Final Cost amount;
- Revised Capital Item Description Page reflecting the Final Cost of the project;
- Line by line project account variance explanations will be provided for those accounts with material variances; and
- Project scope variances.

All projects should be final costed within twelve months of their in-service date. Exceptions to this requirement will be required on occasion. A final cost submission may be delayed due to certain circumstances or unique projects. Circumstances may include not receiving final vendor invoicing in a timely fashion. Unique projects may include projects for which in-service dates are well in advance of project completion. In all cases where final costing capital work orders are submitted past twelve months after their in-service, justifications for the delay will be provided. Projects that are completed in an ATO position remain subject to the rate base rules outlined in **Section 11.3**, which requires costs to be removed from rate base if not filed in accordance with the stated rules.

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14.0 Retirement of Capital Assets

NS Power retires capital assets for various reasons, including:

Normal Wear and Tear

This is referred to as normal deterioration of physical plant caused by use over time and usually occurs because of the physical deterioration of the asset. This type of retirement usually causes an asset to be scrapped.

Inadequacy

This usually occurs because of such items as customer safety, employee safety, public safety, increased customer demand.

The asset can no longer be used safely or cannot supply the customers adequately. The asset is retired but could be reused in another location.

Technical and Economic Obsolescence

The asset is technically obsolete or becomes redundant and no longer economically supplies customers' needs. The asset is retired but could be reused in another location.

Public Authority Requirements

The asset is required to be removed and or replaced for some of the following reasons:

- Environmental regulations (e.g. PCBs)
- Regulatory requirements (e.g. meter replacement)
- Highway relocations

The asset is retired but could be reused in another location.

Customer Requirements

The asset currently serving the customer does not meet customer requirements in a manner other than adequacy and efficiency of supply (e.g. customer requests underground service).

The customer usually pays for any of these requests but the assets must be retired. However they could be reused elsewhere.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

Procedures

When capital assets reach the end of their useful life and are no longer able to contribute to the service of customers, they must be retired from the Plant in Service records at their original cost. In doing so, they are removed from rate base.

For retirements of property, plant and equipment other than land and entire production plants, the original cost plus any costs of removal less salvage proceeds is charged to accumulated depreciation, with no immediate gain or loss recognized.

Gains or losses on capital assets, with the exception of land, are deferred and depreciated over the remaining life of the assets, in accordance with depreciation rate filings with the Nova Scotia Utility and Review Board.
The only exception to this policy concerns the sale of land, in which the resulting gain or loss is recognized immediately.

In those cases where the disposal of land requires expenditures to address environmental issues, then this transaction will be viewed on its own merit, as per approved financial policies.

15.0 Routine Expenditures

15.1 Foreword

NS Power's Routine Program (the Program) is organized and managed through a subset of capital items (Routines) which are provided below. The Program provides for recurring annual allocations of funds for high volume, repetitive, like-for-like capital replacements, enhancements, or additions that are expected to continue into the foreseeable future.

The Program is held to the same standards as individual ACE Plan projects with regards to compliance with Capital Expenditure Justification Criteria and NS Power's Financial Policies and Procedures.

On an annual basis NS Power requests NSEB approval for the Program and its component Routines through NS Power's ACE Plan. Within the approval request further context and justification is provided to support the annual funding levels of the Routines. This information includes specific project budget details, historical trending and year over year variances.

15.2 Definition

Routines include recurring annual capital expenditures for:

- Replacement of worn out or technologically deficient stand-alone equipment.
- Additions/improvements to existing capital assets to raise or improve productivity levels and asset value.
- Additions to existing equipment base resulting from system growth.
- Addition of customers to the system.

15.3 Unit Cost Materiality Limits

The threshold for capitalizing smaller asset purchases is to be consistent with the materiality limits contained in the financial policies. Expenditures for amounts less than the stated capitalization limits should be charged to operations as they are incurred, regardless of the volume purchased.

Exceptions:

Where smaller components are implicit within the scope of a capital project they will be capitalized as part of the overall project.

IT Infrastructure:

NS Power's computer platforms are made up of the following components:

- Keyboards
- Monitors
- Docking stations
- Peripheral communication devices
- Desktop and laptop computers
- Software
- Licenses
- Servers
- Networks
- Data Storage

Each of these assets is integral to the operation of the computer systems which allow employees to perform their daily work functions. NS Power's annual IT capital investment allows for the periodic refresh of certain components to ensure that each platform is functioning at its intended potential. As these purchases are included in and required to ensure the adequate performance of each employee's computer system, the investments will be capitalized.

15.4 Routine Classification

Routines are classified into four functional categories:

- Generation
- Transmission
- Distribution
- General Plant

The Routines included in the Program are as follows:

Generation Routines

Generation Equipment Replacements
Generation Other Hydro
Generation Other Thermal

Transmission Routines

Transmission Substation Replacements, Additions, Modifications
Primary Equipment Spares
Protection Modification & Replacement
Transmission Line Replacements, Additions, Modifications

Distributions Routines

Meters
Distribution Upgrades and Replacement
New Customers
Joint Use
Right-of-Way Widening

General Plant Routines

Work Vehicles
Tools and Test Equipment
Telecommunications
Computing Asset Management
Property Improvements and Furniture
Other

15.5 Approval

Routines are provided for Board approval on an annual basis through the ACE Plan. As part of the ACE Plan proceeding, stakeholders are provided the opportunity to evaluate each Routine. If a new Routine is required, NS Power will file for Board approval of the Routine prior to or by including it in the ACE Plan. If there are new projects added to an existing Routine, NS Power will identify the projects within the ACE Plan documentation.

Over-expenditure

Please refer to section 12.2.

Limits

All individual expenditures are tracked separately within the routine.

Routine Expenditure Reporting

The Board is kept apprised of the actuals incurred during a given year through the ACE Plan process and in the Q4 capital reports provided to the Board.

Projects within Routines

Descriptions of the individual routine projects included in NS Power Routine Program are provided in **Appendix A**.

16.0 Confidentiality

Where the above documentation packages provide confidential information (e.g. commercially sensitive information such as vendor quotes, cost estimates, and internal procurement recommendations; proprietary third party information such as consultant reports and standards documentation; and security sensitive information such as transmission one-line diagrams), NS Power will justify and request the Board, in accordance with Rule 12 of the Board's Rules, maintain portions of the capital filings as confidential. NS Power will minimize such requests for increased transparency and to support the Board's objective in issuing transparent, non- confidential, public decisions.

17.0 Capital Expenditure Justification Criteria

17.1 Introduction – General Considerations

The following considerations are used to evaluate the economic justification for procurement and replacement of equipment, materials and services on the NS Power system.

- Examination of basic needs and alternatives (e.g. why is this required, why now, what other options are available, what are the consequences of doing nothing?).
- Examination of suitable technologies to provide an appropriate solution(s).
- Evaluation of alternative means of acquiring technologies including: design and build NS Power owned facilities and provide services using NS Power staff; rent or lease facilities and provide services using NS Power staff; rent or lease facilities and contract to others for services; and variants of the above as appropriate.
- The alternatives will be ranked using the most appropriate measure (e.g. Revenue Requirement or Net Present Value (NPV)), and the best alternative will be chosen (i.e. lowest Revenue Requirement or highest NPV or lowest Net Present Cost, etc.)
- Capability to meet industry norms for performance, such that NS Power's ability to provide its customers with the required levels of service are not compromised.
- Obsolescence and/or lack of support from facility, spare parts and service suppliers, such that NS Power incurs unacceptable risk of financial loss and/or liability.
- Ability to provide the lowest overall operating costs to NS Power.
- Required to ensure compliance with NPCC and, or NERC Reliability Standards.

The least cost option meeting the requirements and constraints specified above shall be selected.

17.1.1 Integrated Resource Plan

An Integrated Resource Plan (IRP) assesses various supply and demand scenarios to determine the best ways for NS Power to meet future requirements (including emission standards) in a cost-effective and reliable manner, while maintaining a minimum 20% capacity reserve margin above firm loads. The IRP is an important resource document used in the development of the capital plan.

NS Power's IRP is:

- A strategic document;
- A planning document that helps NS Power and governing bodies create long-term sustainable plans based on in-depth analysis;
- A result of broad consultation with stakeholders;
- A roadmap that outlines the primary demand and supply options to be used by NS Power to meet future electricity and emission requirements;
- An analysis framework that integrates demand and supply options to meet future electricity requirements reliably and cost effectively in compliance with current and emerging operational and environmental constraints;
- A reference against which to assess demand and supply-side applications;
- A living document that will be updated as conditions change materially; and
- Developed using models that incorporate the best information available at the time of planning, as well as predictions about potential decisions that are subject to change as societal and technology priorities evolve.

NS Power's IRP:

- Is based on current information about basic assumptions;
- Sources include:
    - Recognized experts and consultants
    - NSEB staff and NSEB consultants
    - Proprietary information sources
    - Publicly available trends
    - Stakeholders / suppliers
    - NS Power's professional experience and judgment;
- Has a 25-year planning horizon;
- Provides ranges of realistic values based on current information.

NS Power's IRP is not:

- An application for NSEB approval of specific NS Power initiatives;
- A commitment by NS Power to undertake specific initiatives;
- A prohibition against specific third-party initiatives; or
- A review of regulatory or accounting treatment for NS Power assets or costs.

17.2 Innovation

General

The electricity industry, along with customers' needs and expectations, is changing. It is subject to governments mandating increasingly stringent environmental legislation and regulation; increased adoption of distributed energy resources; and increased participation in feed-in-tariff programs, also implemented through government policy. All of these impact the delivery and affordability of electricity to customers. This is changing the way in which electric utilities generate and deliver electricity.

These developments require proactive and timely adaptation by electric utilities, so that they can continue to provide safe, reliable and affordable electricity to customers in a way that adapts to the changing electricity landscape and the evolving expectations of customers. This means doing things in new ways, so adaptation, by definition, requires utilities to invest in, test, and deploy non-traditional, innovative technologies.

In some cases, the efficacy of these innovative technologies is subject to many variables including region-specific application, and therefore can only be determined through their practical application locally via corresponding capital investments and demonstration projects. These must be pursued to develop core knowledge of the technology, and determine whether they will lead to feasible long-term solutions.

These innovation projects assist with the determination of whether certain innovative capital investments will achieve customer value in the future. The value of these demonstration projects goes beyond the deployment and use of the capital assets by providing data and learnings, allowing for testing before deploying at scale, or aiding in the development of business cases, where applicable.

For greater certainty, this category applies to capital projects that are responsive to the above evolution of the electric system. Innovation projects justified under this criterion will propose to use innovative technologies or use established technologies in innovative ways. Innovation projects are not projects that propose incremental upgrades or improvements to established

technologies, except to the extent that such upgrade or improvement involves innovative technologies or use of established technologies in innovative ways.

Justification Criteria

Innovation capital projects are justified on the basis that there is a reasonable expectation that they will provide customer value in some or all of the areas of reducing upward pressure on revenue requirement, reliability and grid stability, government policy compliance, and customer experience, through the deployment of proven technologies in innovative ways. In addition, innovation capital investments may be justified on the basis that they are reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable.

Sub-Justification Criteria

Innovation capital projects may be justified under one or more of the following sub-criteria:

- reduce upward pressure on revenue requirement
- reliability and grid stability
- environmental and other compliance
- customer experience improvements

Reduce Upward Pressure on Revenue Requirement

Capital investments under this sub-criterion may contribute to understanding how emerging impacts to NS Power's system may affect revenue requirement, or reduce upward pressure on NS Power's revenue requirement. This reduction can be achieved a number of different ways, including by increasing fixed costs contributions, decreasing operational costs, decreasing capital investment, decreasing fuel cost, or increasing the output of cost effective forms of renewable generation.

Innovation capital projects justified under reducing upward pressure on revenue requirement must (1) be reasonably expected to reduce upward pressure on revenue requirement, based on known issues increasing pressure on revenue requirement, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learning, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in reducing upward pressure on revenue requirement.

Reliability and Grid Stability

Intensifying weather events, customer reliance on electricity and service expectation, and decreasing power quality caused by increasing wind and solar generation, are all creating reliability and grid stability challenges that are difficult to address with traditional grid

technologies and practices. Capital investments under this sub-criterion may mitigate these issues by allowing NS Power to test new technologies and techniques which may allow further integration of solar, wind and other impactful technologies without compromising system stability and potential growth, as well as ways to reduce outage frequency or duration through the incorporation and optimization of technologies such as grid automation, electricity storage, distributed generation and energy management technologies.

Innovation capital projects justified under reliability and grid stability must (1) be reasonably expected to improve reliability and grid stability, based known issues affecting the same, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in improving the reliability of the system.

Environmental and Other Compliance

The Nova Scotia Renewable Energy Standards provide that 40 percent of NS Power's generation must come from renewable resources starting in 2020. Moreover, NS Power must comply with four air emission hard caps for CO2, NOx, Hg, and SO2, and potential future federal cap and trade requirements. Capital investments under this sub-criterion may contribute to achieving these renewable generation and emissions requirements through the testing or deployment of innovation technologies such as battery storage, which can store excess variable renewable energy to be utilized when the renewable resource is not producing energy.

Innovation capital projects justified under environmental and other compliance must (1) be reasonably expected to support environmental or other compliance, based on environmental compliance or other legislation and regulation, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in complying with environmental or other policy.

Customer Experience

Rapid advances in technology, the offerings customers receive from other service providers, and the availability and control of information 24 hours a day are driving changing customer expectations. As customer expectations continue to evolve, using innovative technologies in new ways may contribute to meeting them. Customer experience projects are driven by the reasonable expectation they may lead to improvements to customer experience exclusive of other justifications, but may also provide benefits under the other sub-criterion noted above.

Innovation capital projects justified under customer experience must (1) be reasonably expected to improve the customer experience, based on either stated or predicted needs of customers, through the deployment of proven technologies in innovative ways; or (2) be reasonably expected

to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases where applicable, regarding the efficacy of innovation technology in improving the customer experience.

17.3 Health & Safety

NS Power conducts all of its business in a manner which is both health and safety conscious. Health and/or safety are one of the many reasons why a capital expenditure might be required. In cases where health and safety is not the principal justification for the project and other criteria (e.g. pole retreatment, transmission plant replacement etc.) are used to justify the project, health and safety is not used as sub-justification criteria even if health and safety is a secondary driver for the project.

This criterion applies to capital projects undertaken to comply with applicable laws and accepted industrial practices, including but not restricted to:

- Nova Scotia Occupational Health and Safety Act and Regulations
- NS Power standards and work practices
- Orders issued by the N.S. Department of Labour, or Environment
- Accepted industrial practice or codes
- Exercise of due diligence

As well as applying to active NS Power sites, the Health and Safety criterion is applicable to temporarily or permanently decommissioned NS Power sites. Examples of such expenditures include the following:

- Demolition of physical plant to eliminate all liability
- Alterations to a site or physical plant to render it secure against public intrusion in order to limit liability (e.g. Signage, fencing, boarding of windows and doors, electrical isolation, etc.)
- Security devices to alarm intruders
- Alterations to a site or physical plant in preparation for sale or disposal

Projects where compliance with such requirements is the primary driver for the investment will utilize the Health and Safety justification criteria. There are often projects where other (discretionary) asset management criteria may be major drivers in addition to Safety improvements that will be accomplished through a capital upgrade. The intent is to code the project to its primary driver but judgment is often required to ensure consistency.

17.4 Environment

As an industrial enterprise, NS Power is obligated to act in a manner which is respectful and protective of the environment in accordance with Company policy, environmental legislation and regulations and agreements with governments. Subsequent to appropriate analysis of its existing and proposed operations, NS Power may need to make capital expenditures to achieve the required environmental performance. NS Power is committed to an environmental ethic which supports environmental and economic sustainability.

The environmental justification criteria include the following:

Environmental Permit, License, Regulation Criteria

These criteria refer to the specific law(s) and the enabling legislation which is enacted to provide for processes, project approvals, environmental monitoring, and standards of performance.
Resulting from regulations, laws and legislation are instruments which require a certain level of environmental performance. They can significantly impact capital expenditures.

These instruments are:

- permits
- licenses
- regulations

NS Power's capital expenditure criteria will include justification based on the type of instrument placing the requirements.

Environmental Agreement, Guidelines, International Standards and Voluntary Action Criteria

These criteria respond to agreements between governments, government guidelines, international standards developed for various industrial sectors and voluntary action that bind the owner/operator to carry out its business in a certain way so as to meet agreed environmental performance.
These instruments may be more flexible than those described in section 1.0 above. However, there is usually little choice given the expectations of performance under international trade agreements. These agreements have provisions which can be used to punish and/or reward industries, economic sectors and countries based on environmental performance.

NS Power’s capital expenditure criteria will include justification to make such an expenditure by reference to the specific instrument in question.

17.5 Land and Right-Of-Way

NS Power needs to occupy and access land to enable the Company's operations. Land can be held as a fee simple title or through some other interest or type of right over land. Fee simple ownership is normally taken for facilities where permanent exclusive occupation is required, for example a thermal generating plant. Where these requirements are lessened in some way, NS Power can acquire interests which are less than the fee simple interest in land, including rights-of-way or easements for power lines, or utility corridors and leases or licences for the occupation of land.

Land and Rights owned by NS Power are managed according to their use, with the main distinction being between those in current use for company operations and those where there is no operational use. Sites without an operational use can be held to mitigate or protect adjoining operational uses, allow management of the remnants of past use, or to allow for future activities or to generate revenue.

The criteria governing NS Power land transactions are as follows:

Land Acquisition

Land is normally acquired as part of a capital project associated with the five year capital budget. Occasionally land that will satisfy the requirements of a future capital project that is beyond the five year capital budget will become available on the open market. In such instances the property may be acquired if no economically practical alternative property is available to satisfy the requirements of the future project in question.

Land Disposal

NS Power can dispose of, lease or grant rights over surplus land. Land associated with hydro projects is generally retained to protect the safety and usability of the whole system. Land to be disposed of will be investigated to ensure compliance with NS Power environmental criteria and provincial regulations.

Land and Building Disposal

A building, land or rights surplus to NS Power requirements and which can be sold will be sold with its associated lands assuming all environmental criteria have been met. If the land and building cannot be sold as one entity, then the building or facility will be removed or retired under NS Power retirement of capital asset criteria and, depending upon requirements, the land will be retained or sold.

Abandoned Rights-of-Way

NS Power normally retains rights-of-way which are not in current use to allow for future use. If a right-of-way is determined to be surplus to NS Power requirements, then the right-of-way may be released, usually to the owner of the property over which the right-of-way exists.

17.6 Hydro, Wind and Biomass

The principles set out hereunder shall be used by NS Power in determining the methods used and timing of purchase and replacement of its hydro, wind and biomass production assets.

These production assets shall be purchased, replaced, or modified for any of the following conditions:

- To eliminate conditions which, in the opinion of NS Power, constitute hazards to operating personnel or the general public.
- To meet NS Power's obligations to third parties or to conform to applicable laws and regulations - including Nova Scotia's Renewable Electricity Standards and Canadian Dam Safety Guidelines.
- To produce an economic benefit by reducing or minimizing operating costs, or improving generating equipment efficiency.
- To maintain reliability and quality of supply to the bulk power system.
- When the probability of failure is high enough that:
    - Making the proposed capital investment reduces the costs compared to continuing to repair the existing asset;
    - The estimated cost reduction is of significant magnitude to meet NS Power's financial criteria; and
    - The timing of investment is optimized to maximize customer net benefits.

Hydro - Economic Justification Procedure

The following procedure is used to evaluate replacement, refurbishment or upgrades to NS Power's hydro production assets.

The least cost option meeting all the requirements and constraints specified shall be selected.

- Wood stave pipelines shall be replaced when an engineering assessment indicates a high risk of failure exists. The engineering assessment takes into consideration near end of life annual inspection reports, stave sampling (where appropriate), performance reports (leakage and stave failure) and risk assessment.

- Turbine runners shall be replaced on the basis of runner degradation or potential efficiency improvements. Turbine runners under consideration for replacement due to runner degradation will be based on a qualitative and quantitative assessment following annual inspections. An engineering analysis will examine potential improvement for efficiency improvement.

- Capital improvements and replacement of dams and hydraulic structures will be initiated where formal engineering investigation and risk assessment find that the structures do not comply with accepted national standards of stability and flood management capability for existing structures, or where accepted criteria of "due diligence" for public and environmental safety cannot be met.

- Generator stators will be rewound when there is a high probability of insulation failure or when failure has occurred. All generation station windings are tested under a regular inspection program. Units having older type insulating materials or those whose windings are exhibiting insulation deterioration are tested annually. The tests provide insulation resistance values, dissipation indices and polarization indices. Station winding replacement is justified taking into consideration measured test values, age, type of insulating material and trends in insulation performance suggested by test results.

- In all instances, it must be demonstrated that the value of energy to the system is greater than the cost of the capital project in question or the next most cost effective renewable energy option to replace the hydro generation. The latter is required to ensure NS Power remains compliant with Nova Scotia's Renewable Electricity Standards.

17.7 Thermal

The principles set out hereunder shall be used by NS Power in determining the methods used and timing of purchase and replacement of its thermal production assets.

Equipment Replacement/Refurbishment

Capital expenditures to purchase, replace, or refurbish equipment must be justified by an engineering and/or economic evaluation which incorporates information from planned inspection/performance programs and industry standards. An economic analysis is carried out such that the least cost option meeting all the requirements and constraints specified shall be selected.

Thermal production assets shall be purchased, replaced, or modified when the probability of failure is high enough that:

- Making the proposed capital investment reduces the costs compared to continuing to repair the existing asset;
- The estimated cost reduction is of significant magnitude to meet NS Power's financial criteria; and
- The timing of investment is optimized to maximize customer net benefits.

Heat Rate

For capital expenditures resulting in Unit heat rate improvements, an annual cost saving is calculated using the system dispatch production models (i.e. production costing model) (for major improvements) or calculated on a BTU/kWh basis using current production forecasts and current cost of fuel forecast (for minor improvements < 1% improvement in heat rate).

Capacity

For capital expenditures that result in an increase in net Unit capacity, the value of a kW is calculated using system planning models.

Labour

Impacts on present or future labour requirements are calculated on an annual savings/cost basis taking overtime and fringe benefits into account.

Forced Outage Rate

Unplanned outages result in replacement generation, often at a higher cost than the existing generation. These costs are estimated using the probabilistic production model and incorporated into the Economic Analysis Model.

17.8 System Design

Nova Scotia Power's transmission system is divided into several classifications, each of which is governed by different design criteria.

These classifications are as follows:

- Primary Transmission
- Secondary Transmission
- Electrically Remote Transmission

- Transformation

NS Power is a member of the Northeast Power Coordinating Council (NPCC). Those portions of the NS Power Bulk Power System, wherein single contingencies can potentially adversely affect the interconnected NPCC system, are designed and operated in accordance with NPCC Directory #1, Design and Operation of the Bulk Power System.

NS Power is required to follow the standards of the North American Electric Reliability Corporation (NERC). NERC is a non-government organization which regulates Bulk Power System users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices. NERC standards are filed with the NSEB through a regulatory approval process where they become mandatory and enforceable in the province of Nova Scotia. NS Power designs its Bulk Electric System to meet the requirements of the in-force NERC standards. NS Power utilizes a set of criteria for its transmission system that combines protection performance specifications with system dynamics and steady state performance requirements. The NS Power Bulk Electric System is planned, designed, and operated in accordance with single contingency criteria.

NS Power System Design Criteria are applied for all other portions of the interconnected system.

NERC standards and NPCC criteria are continually evolving. NS Power system design practices are constantly updated to meet the requirements of new and evolving standards.

The System Design criteria are provided and maintained in report #NS Power-TPR-003-6. The current version of this report is provided in **Appendix C**.

Definitions

Primary Transmission is defined as 230kV and above and any other NPCC Bulk Power System transmission.

Prime clearance times are defined to be 4 cycles first zone and 6 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 12 to 16 cycles for both three-phase and line-to- ground faults.

Secondary Transmission System includes all other transmission facilities which are not included in the Primary Transmission nor the Electrically Remote Transmission categories.

Prime clearance times are defined to be 6 cycles first zone and 8 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 14 to 18 cycles for both three-phase and line-to-ground faults.

Electrically Remote Transmission is defined by the buses at which the maximum fault levels do not exceed 1000 MVA three phase.

Normal system conditions are defined to include all of the following:

- Expected load conditions.
- All transmission facilities in service (no line or transformer maintenance).
- Economically scheduled and dispatched generation allowing for planned generator maintenance outages (non-firm generation is not included as economically dispatched generation). Economic dispatch may be influenced by environmental or regulatory restrictions.
- Stable steady-state operation of the Interconnected Transmission System.
- All system voltages within 95% to 105% of nominal, unless otherwise noted.
- All system elements operating within their continuous thermal ratings, unless otherwise noted.

A system element is defined to be any one generator, transmission line, transformer or bus section.

Breaker back-up is defined to be protection against a local breaker's failure (mechanical or electrical) to trip when initiated by an associated protection operation.

17.9 Transmission Plant

The principles and criteria set hereunder shall be used by NS Power in determining the methods used and timing of purchase and replacement of its transmission plant.

Conditions for Purchase

Transmission plant shall be upgraded, rerouted, or otherwise modified for any of the following conditions:

- To eliminate conditions which, in NS Power's opinion, constitute hazards to operating personnel or to the general public.

- To meet NS Power's obligation to third parties or to conform to the provisions of applicable laws and regulations.
- To reduce or minimize operating costs of the transmission system.
- To maintain reliability and quality of supply to the distribution bus.

Conditions for Replacement

Transmission plant shall be replaced, if still required to meet system design requirements, as follows:

- Transmission poles which fail the test for resistance to overturning moment in accordance with Transmission Maintenance Practice TMP 475C.1.
- Certain insulators with cemented joints are failing due to the composition of the cement used in the manufacture of the insulators. The manufacturers of the insulators are no longer in existence. These insulators include:
    - Suspension insulators in strain positions.
    - Pin type insulators manufactured with two or more parts of porcelain cemented together.
    - Cap and pin insulators manufactured with two or more parts of porcelain cemented together.
    - Multicone insulators.
    - Suspension insulators in tangent positions when a history of failure has been established by outage statistics.
- Substation apparatus which fails or is predicted to fail due to; insulation degradation, out of calibration or capacity limitation. Apparatus is inspected and tested at regular intervals to ensure reliability of purpose, security of the electrical system, and safety of operating personnel and general public. Programs for determining the current and predicted performance are as follows:
    - Substations are visually inspected every month.
    - Insulating oils are tested every year.
    - Other insulations are tested every four to six years.

- SF6 interrupters are tested every eight years and oil interrupters are tested every six years.
- NPCC protection is tested every two years.
- Batteries are visually inspected every year.
- Insulation degradation as confirmed by internal testing; intervals varying by equipment and performance and asset age.

Transmission Plant Replacement – Economic Justification Procedure

The following procedure will be used to evaluate the replacement, modification or upgrade of Transmission Plant at NS Power:

- Any transmission plant which fails or is predicted to fail will be evaluated firstly as to NS Power's current and future requirements.
- An economic evaluation will then be completed such that the least cost option meeting all the requirements and constraints specified shall be selected. Included in these alternatives will be the costs to:
  - Repair the transmission plant to such a state as to meet NS Power's requirements.
  - Upgrade or modify other transmission plant so as to eliminate NS Power's requirement for the plant in question.
  - Replace the transmission plant as to maintain NS Power's transmission system.
- Any repairs, upgrades or modifications will be costed as per the manufacturer's and NS Power's specifications and standards. The costs for completing this work will include and compare NS Power's costs and/or manufacturer's operating and maintenance labour, material, expenses, shipping and all other relevant costs or factors which may affect these costs (i.e. availability of labour, material, revenue, etc.).

17.10 Distribution System

Nova Scotia Power's Distribution System connects the majority of NS Power's customers to the Transmission System. (Some of the larger customers are supplied directly from the transmission network.) As such the Distribution System criteria bridge the gap between the Transmission System and the customer's service entrance. The need for distribution projects is driven by the criteria provided below.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

Requirement to Serve

The provision of electrical service to customers, as well as street lighting and other unmetered services is a requirement of NS Power. The least cost option to extend the system will be undertaken unless the customer requests to contribute the incremental cost difference. Extension of service will conform to the latest version of the NS Power Rates, Regulations and Procedures Manual.

Pole Strength Compliance with Standard CAN/CSA-C22.3 No. 1-10 – Overhead Systems

Principles and Criteria for Replacement of Distribution Pole Lines

- The principles and criteria set out hereunder shall be used by NS Power in determining the methods used and timing of replacements of its distribution poles lines.

- Conditions for change or replacement:

  Pole lines shall be replaced, upgraded, rerouted and otherwise modified for any of the following purposes:

  - To eliminate conditions which, in NS Power's opinion, constitute hazards to operating personnel or to the general public.

  - To meet NS Power's distribution planning criteria.

  - To meet NS Power's obligation to third parties or to conform to the provisions of applicable laws and regulations thereunder.

  - To minimize distribution cost in the absence of any requirement to alter the distribution system under the provisions noted above.

- Criterion for select pole replacement:

  - Poles found to fail the test for resistance to overturning moment, as set out in the NS Power report entitled, "Distribution Line Inspection Procedures and Pole Replacement Criteria", 1993-09-28, shall be replaced. It is noted that the specified criterion is based on existing CSA standards.

  - Where a pole is found to fail the stated strength test, it shall be replaced immediately if, in the opinion of NS Power, it constitutes a hazard to operating personnel or the general public. Otherwise, it shall be replaced in a least cost manner.

- Under least cost planning, an option involving timing of replacements which differs from that obtained by application of a distribution planning study may be found to provide the minimum cost. In this case, if hazards are not incurred, the global minimum shall be selected.

Service Voltage Outside CSA Standard CAN3-C235-83 (C2010)

CSA sets national voltage level standards at customer's service entrance, utilization points, and the point of sale to a municipal utility.

When it is determined from measurement or computer models that the voltage will be over or under these standards then various alternative solutions to these problems will be identified and the least cost option meeting all the requirements and constraints specified shall be selected.

- Service Voltage Outside Standards – Economic Justification Procedure

  The following procedure is used to evaluate alternative solutions to correcting voltage conditions to CSA Standards on the Nova Scotia Power Inc. distribution system.

- Local Voltage

  For local voltage issues the costs are identified to determine a least cost solution. These costs include: relocating the single phase transformer tap to another phase, replacing a transformer with a larger size, relocating the transformer closer to the load, reconductoring secondary on service conductors, other similar options. All costs are included for labour, material, expenses, interest, removal and salvage.

  These costs are totalled in current year dollars and represent the costs to resolve local voltage problems.

- Feeder/Substation

  For feeder or substation issues relating to low voltage the costs are identified to determine the least cost solution. These costs include: adjusting regulator settings, addition of line regulators, addition of shunt capacitors, reconductoring, conversion of the system in question to a higher voltage, addition of another feeder, addition of a substation or other unforeseen options. All costs are included for labour, material, expenses, interest, removal, salvage, losses, maintenance, and any other related costs. These costs are totalled in current year or present worth dollars, and represent the costs to resolve feeder/substation voltage problems.

Overloaded Equipment

- Transformers

  Transformers used as step-downs from one primary voltage to another are considered to be overloaded when they have reached a peak load in excess of 133% of their top nameplate rating. If the transformer load peaks in the summer and has a high daily load factor, a criteria of 110% top nameplate rating is used. Padmount and vault installed transformers should be loaded according to DEP 3.03 “Loading Guide – Padmount Transformers”.

  “Single Phase Transformer Capacity Selection Chart for 120/240V Domestic Services” T-1, from “Overhead Distribution Standards Manual” should be used for pole mounted transformer loading.

- Cables and Overhead Substation Exits

  Cables or overhead distribution feeder circuits emanating from a supply substation will be considered to be overloaded when the peak load exceeds 325 amps or thermal capacity whichever is less and transfer capability with adjacent feeders has been fully utilized.

  In addition, cable ratings for normal and emergency conditions should be determined by reference to the “Underground Standards Manual”.

- Conductors

  Overhead conductors are considered to be overloaded when they have reached the loadings as per the report “Conductor Current Carrying Capabilities” and the “Overhead Distribution Standards Manual”.

  Variables considered were: conductor resistance, dissipation, wind velocity, atmospheric pressure, emissivity, etc. In addition, a conductor carrying a current of 325 amps is considered to be at its load limit.

- Equipment

  Equipment, such as reclosers, regulators and switches are considered to be overloaded when they exceed their continuous current rating as provided by the manufacturers.

- Overloaded Equipment – Economic Justification Procedure

  The following procedure is to be used to evaluate alternative solutions to correct overloading equipment problems on the Nova Scotia Power Inc. distribution system.

For overloading equipment problems the costs are identified such that the least cost option meeting all the requirements and constraints shall be selected. These costs include: replacing the equipment in question with higher rated equipment, reduction in load by reconfiguring the power system, converting to a higher voltage for equipment other than transformers and other unforeseen options. All costs are included for labour, material, expenses, removal, salvage and any otherrelated costs. These costs are totalled in current year or present worth dollars, as appropriate, and represent the cost of resolving the overloaded equipment problem.

Deteriorated Conductor

Overhead conductor shall be replaced on the basis of:

- deterioration sufficient to constitute a safety risk to powerline technicians or the public at large;
- deterioration sufficient to result in an unacceptable level of outages to customers;
- least cost economics.

It is sufficient justification for replacement that the conductor fail to meet any one of the criteria outlined below.

The criteria that establish the basis for conductor replacement are as follows:

- Powerline Technician Safety – Live Line Procedures

  When safety considerations for live line procedures as per the NS Power Safety Manual are evaluated, they shall be based on evidence of conductor deterioration as established by 5.2, or 5.3 but may include other factors permitted by the NS Power Safety Manual when assessed by a fully qualified powerline technician assigned to the job. If the conductor is deteriorated to the extent that it is not deemed safe to work live then conductor replacement would be considered in conjunction with the earliest pole replacement program on that line.

- CSA Safety Standard

  When tests indicate that the conductor tensile strength for conductors size #2 and larger has deteriorated to less than 60%, or for conductors sized #4 and smaller has deteriorated to less than 80% of the ultimate tensile strength specified for design loading conditions as stipulated in CSA Standard C22.3 NO. 1-10 “Overhead Systems”. (Note 1) Testing to support this recommendation will be conducted on representative samples of conductor.

- Lineworker Safety – General Linework

  When tests indicate that the torsional ductility of individual supporting strands of the conductor is reduced below 4 turns when tested according to ASTM Standard E558-83 “Standard test method for torsion testing of wire” for a test conductor length of 120 wire diameters. (Note 1) Testing to support this recommendation will be conducted on representative samples of conductor.

- Economics

  At times it is economical under least cost planning to establish an earlier replacement date. The economic analysis will include the value of energy losses in combination with other significant operating cost considerations (e.g. maintenance and customer costs due to outages) for the existing conductor as compared with the capital and operating costs of the replacement conductor. The economics will be calculated over the remaining life of the conductor which will, in the absence of more specific information, be established by evaluating the point in time when it will fail to meet technical requirements such as electrical load, voltage, protection or conductor strength.

- When direct measurement shows loss of the galvanizing coating on the reinforcing strands over a significant portion of the circuit. Conductor replacement will be planned on the basis of predicted remaining life as established from experienced deterioration rates.

  Note 1 – A database of conductor test results will be established. This database will be analysed to support the longer term objective of developing additional, cost-effective conductor replacement criteria founded on direct observation of specific characteristics of the conductor that pertain to its life expectancy. These will include, besides the test results, the conductor type, age, aggressiveness of environmental conditions at installation site (or distance from coast) failure history and splices per conductor per km.

Outage Performance

In evaluating methods of achieving reliability targets, analysis of the interruption data will be undertaken annually to direct the spending in the areas which will have the greatest impact on provincial reliability without sacrificing the regional reliability to a level below that warranted by the customer density. Transmission as well as distribution alternatives will be coordinated.

Distribution System Protection

The protection of the distribution plant and public and employee safety is provided in Distribution Engineering Practice "6.02 Overcurrent Protection Guidelines". The specific objectives of the criteria are to:

- Protect electrical plant from thermal and electromagnetic damage which can be caused by excessive current flow.
- Limit hazards to public and operating personnel.
- Maintain service continuity to customers through the selective coordination of overcurrent devices.

Distribution System Protection – Economic Justification Procedure

The following procedure is to be used to evaluate alternative solutions to protection problems on the Nova Scotia Power Inc. distribution system.

For protection problems the costs are identified such that the least cost option meeting all the requirements and constraints shall be selected. These costs include: addition of protective devices, uprating protective devices, reconductoring, addition of phases, converting to a higher voltage, reconfiguring the power system, addition of a feeder, addition of a substation, increase a substation transformer or other possible unforeseen options. All costs are included for labour, material, expenses, interest, removal, salvage, maintenance, losses and any other related costs. These costs are totalled in current year or present worth dollars and represent the costs to resolve distribution system protection problems.

Prevention of Catastrophic Failure of Distribution Transformers/Capacitors

Maximum symmetrical fault levels of 8000 amps at 24.94 kV and 9000 amps at 12.47 kV govern the Distribution System design. In addition to these levels, so as to prevent catastrophic failure, distribution equipment subject to symmetrical fault levels exceeding 4000 amps at 12.47 kV and 3000 amps at 25 kV should be protected by current limiting fuses as outlined in Distribution Engineering Practice 5.30.

Grounding Criteria

Grounding of the distribution system should ensure that the system neutral to ground (earth potential)[2] shall not exceed 10 volts. Methodology is contained in the "Overhead Distribution Standards Manual", Section G – Relocation.

[2] Ground or earth refers to the reference point in an electrical circuit from which other voltages are measured, or a common return path for electric current, or a direct physical connection to the Earth.

- Grounding – Economic Justification Procedure

  To reduce the earth potential the costs are identified such that the least cost option meeting all the requirements and constraints shall be selected. These costs include: insuring the neutral integrity, addition of grounding, reducing current flow, increasing size of neutral conductor, adding phases or other unforeseen options. All costs are included for labour, material, expenses, interest, removal, salvage, outage costs and customer outage costs as well as any other related costs. The costs are totalled in current year dollars and represent the cost of fixing a grounding problem.

Joint Use Agreement

Expenditures required in accordance with our Joint Use Agreement with Bell Aliant. This agreement is established to reduce costs to both NS Power and Bell Aliant customers, by sharing poles.

Highway Relocation

Poles located on highway, city street, town and municipal rights of way are installed based on pole permits and must normally be relocated at NS Power’s cost when requested by the right-of-way owner.

Radio Interference Voltage

The Radio Interference Regulations under the Radio Communication Act Chapter 1374 regulate the radio noise limits being emitted from our distribution lines. Alternative methods of reducing noise involve tightening hardware or replacing insulators or other similar methods.

Voltage Unbalance

Expenditures may be required due to violation of the criteria outlined in DEP 5.50 "Distribution Feeder Balancing" on NS Power's system.

Alternative methods of solving this problem would include phase current balancing, addition of phases, replacing conductor.

Voltage Flicker Due to Motor Starting

Allowable flicker is governed by DEP 3.04 "Voltage Flicker Due to Motor Starting".

Flicker caused by customer equipment should be mitigated by the customer with NS Power solutions requiring contribution from the customer such as reconductoring, voltage conversion, new feeders, new substation, etc.

CATV Agreement

CATV contracts with various Cable Television companies throughout Nova Scotia govern our expenditures.

17.11 Pole Retreatment

The principles and criteria set out hereunder shall be used by NS Power in determining the methods used and the timing of retreatment of its transmission and distribution wood poles.

Conditions for Retreatment

Wood poles originally treated with pentachlorophenol and creosote preservatives shall be retreated with approved wood preservatives to reinforce the preservative retention levels in the ground line area thereby maintaining acceptable toximetric thresholds necessary for protection against fungal and insect attack.

Criteria for Wood Pole Retreatment

Wood pole species found on the transmission and distribution systems include various kinds of Pine, Douglas Fir, and Western Red Cedar. NS Power undertakes on a line basis, retreatment of those poles that have been in service for 15 years or more in the following manner:

- Transmission class poles are tested for resistance to overturning moment in accordance with Distribution Engineering Practice (DEP) 7.51.Poles found to have an effective circumference equal to or greater than the minimum required circumference and a shell thickness of 3 inches or more are scheduled for retreatment.
- Specified failure criterion is based largely on existing CSA standards for required pole strength and to some extent on utility industry practice.
- Some poles though meeting strength and treatment criteria may not be retreated due to various reasons. These include landowner requests, poles in proximity to agricultural lands or domestic gardens and poles inside water buffer zones established by the Nova Scotia Department of the Environment and included in the yearly ministerial permit.
- Appropriate personnel are informed of poles that fail criteria.
- All pole tests and retreatment data will be maintained on a computerized database for future reference.

Pole Retreatment - Economic Justification Procedure

The management plan for retreatment of transmission class poles is based on studies which consider the age, species, original treatment and structural integrity of the lines comprising the transmission system. NS Power carries out a pole retreatment program on transmission class poles. The least cost option meeting all the requirements and constraints shall be selected.

17.12 Metering Equipment

The principles and criteria set hereunder shall be used by NS Power in determining what types of metering equipment to purchase and timing of replacements.

Conditions for Purchase and Service

Metering equipment shall be purchased and placed into service under the following conditions:

- For revenue metering, NS Power purchases only those meters having Measurement Canada (MC) TYPE APPROVAL. These are the only approved apparatus for measuring AC energy and power in Canada, and upon whose readings a legal bill may be rendered by the supplier to the customer.

- Meters are sealed by NS Power, or accredited verifier, to the Standard proclaimed in document S-E-02, "Specifications for Verification and Re-verification of Electricity Meters", before being placed in service. Meters are also brought in from active service on a periodic basis for re-verification according to this standard.

- Meters being purchased at the present time for kWh measurement will be of the standard type because these have been determined to be the most economic choice when all factors related to metering cost have been considered. The determining factor in this economic choice is the costs associated with meter re-verification.

MC allows selective sampling of standard induction type meters both in verification and re-verification. MC requires each register to be tested fully, as must any load control device, and the meter once sealed, cannot be updated electronically, unless the seal is broken at the meter shop and the whole calibration process repeated. The multitude of readouts causes delays in re-verification, and the special features required for Industry Canada TYPE APPROVAL makes these meters much more expensive on a unit for unit basis.

Conditions for Replacement

Metering equipment shall be replaced, upgraded or otherwise modified for any of the following reasons:

- When meters fail the criteria specified in the Standard, depending upon the economics (i.e. labour/material charges, availability of spare parts) of overhauling, and whether or not a directive to discard is received from MC, they are either repaired and returned to service or retired and replaced by new meters.

- When a rate class for a given customer changes, requiring a meter with greater or lesser capability.

Metering Equipment - Economic Justification Procedure

The following procedure is used to evaluate the replacement of meters on the Nova Scotia Power Inc. system.

- Any meter(s) which has been ordered to be discarded as a result of an order from Measurement Canada (MC) shall be replaced with a type approved by the MC.

- Any meters of a particular lot which are known to have a defect will require action. This may require a meter replacement or repair.

- An economic evaluation will be completed to determine the least cost alternative. Included in these alternatives are the costs to replace the meter, the costs to repair the meter at a NS Power facility, the costs to repair the meter at a manufacturer's facility. Included in these costs are labour, material, expenses, overhead, shipping and any other relevant costs.

- Meters which fail re-verification according to the document S-E-02, "Specifications for Verification and Re-Verification of Electricity Meters", shall be repaired or replaced. Appropriate action is taken based on the least cost alternative. In determining the cost to repair or replace the meter the expected life is calculated from standard electric utility depreciation practices.

17.13 Work Support Facilities

Building Facilities/Furniture

NS Power owns and operates buildings and associated systems, equipment and furniture to support the delivery of service to customers (i.e. other than that associated with generation facilities, the costs of which are included in the related function costs). These facilities are operated in a manner which provides the most suitable environment for employees to carry out their work in a safe and efficient manner and protects the asset and extends its original useful life.

Facilities may be constructed, replaced, upgraded, renovated, leased, retired or otherwise modified for any of the following purposes;

- To eliminate conditions which, in NS Power's opinion, constitute hazards to NS Power's personnel or to the general public;
- To meet NS Power's obligations to third parties or to conform with the provision of applicable laws and regulations there under;
- To protect facility assets by maintaining them in a reasonable operating condition;
- To comply with regulations and legislation.

Building Facilities/Furniture - Economic Justification Procedure

The following procedure will be used to evaluate the construction, replacement, renovation, modification or retirement of NS Power facilities. In all cases financial analysis will be conducted on the basis of least cost over the facility life cycle.

Facility Audits

- Periodic audits will be carried out on all facilities. These audits will identify any operating issues, deficiencies, inefficiencies, potential hazards, code compliance, or any opportunities for improvements to the facilities. Aspects examined will include the building structure, the electrical, lighting, mechanical (including heating ventilating and air conditioning), communications and safety systems, as well as interior appointments including finishes, furniture and signage. Examination of the grounds will encompass all aspects of the compound, any out-buildings and all environmental considerations.
- Capital work identified from these audits will be examined for its positive impact on the productivity and working conditions of employees, elimination of hazards, code and regulations compliance, or its ability to extend the life of the building asset. Applicable projects will be cost justified over the life of the building and all costs taken into account (labour, material, expenses, administrative overhead, interest and all other relevant costs).
- Furniture and equipment will be replaced on an equivalent and suitable basis when existing items are no longer serviceable or when safety or ergonomic issues dictate. Additions to inventory will be made on the basis of new human resource requirements or the support of a valid business case.

Building Replacement/Modifications

Capital projects which involve building replacements, new buildings, or the renovation or modification of a major portion of the building space will consider the following factors in the economic analysis when pertinent:

- Operating costs of the building (heat, lights, rentals, general maintenance, etc.)
- Relevant operating costs of the functions carried out by employees (e.g. travel time)
- Capital costs necessary to continue to operate the existing facility (e.g. roof replacement, code compliance)
- Effect on staffing levels (e.g. reduced staff due to reorganization or relocation)
- Construction costs (land purchase and preparation, building design, project supervision and management, temporary relocations, contractor costs, retirement of old facilities)
- Cost of preliminary investigation, study and engineering
- Relevant safety and environmental issues
- Long range needs (business requirements of the investment for the useful life of the asset)

The least cost option meeting all the requirements and constraints specified above shall be selected.

Telecontrol & Telecommunications

The principles and criteria set hereunder shall be used by NS Power in determining the methods used and timing of procurement and replacement of its Telecontrol and Telecommunications facilities and services.

Definitions

- Telecontrol Facilities includes equipment which is used to provide supervisory control and data acquisition (SCADA), remote control, special protection systems and teleprotection.
- Telecommunication Facilities includes broadband transport mediums such as: fibre optics, microwave radio, UHF and VHF radio, metallic-pair cable, power line carrier, and systems which employ these mediums to transfer voice and data communications from one location to another such as: telephone, mobile radio, telecontrol equipment, computer networks, video, etc.

General

Telecontrol and telecommunications are essential for the protection and control of the Bulk Power System. They allow for remote monitoring and control of the power system through SCADA and provide for high speed protection of generation and transmission facilities through

teleprotection and special protection systems (SPS). Telecontrol and telecommunications are also required to ensure compliance with Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC) Reliability Standards. Telecontrol and telecommunication facilities are not used directly for the supply of electricity to NS Power customers. They are enabling technologies which help to satisfy NS Power's business requirements to serve its customers in the most economical, effective and safe manner possible. The need for the application of this technology is driven by the above requirements.

Telecontrol & Telecommunications - Economic Justification Procedure

The following considerations are used to evaluate the economic justification for procurement and replacement of telecontrol and telecommunication facilities and services on the Nova Scotia Power Inc. system.

Procurement of Facilities and Services

The procurement of telecontrol/telecommunication facilities and services shall be made according to the following process:

- Examination of basic needs and alternatives (e.g. why is this required, why now, what other options are available, what are the consequences of doing nothing?).

- Examination of suitable technologies to provide an appropriate solution(s).

- Evaluation of alternative means of acquiring the above technologies including: design and build NS Power owned facilities and provide services using NS Power staff; rent or lease facilities and provide services using NS Power staff; rent or lease facilities and contract to others for services; and variants of the above as appropriate.

  Each alternative will be subject to full life cycle economic analysis which will include: capital costs, lease/rental costs, NS Power operating costs, contract costs and taxation.

- The alternatives will be ranked using the most appropriate measure (e.g. Net Present Value (NPV)), and the best alternative will be chosen (i.e. highest NPV or lowest Net Present Cost, etc.).

- Replacement of Facilities and Services.

- Capability to meet industry norms for performance, such that NS Power's ability to provide its customers with the required levels of service are not compromised.

- Obsolescence and/or lack of support from facility, spare parts and service suppliers, such that NS Power incurs unacceptable risk of financial loss and/or liability.

- Ability to provide the lowest overall operating costs to NS Power.

- Required to ensure compliance with NPCC and, or NERC Reliability Standards.

17.14 Information Technology Application and Hardware System

Information Technology (IT) is subject to rapid evolution, obsolescence, and evolving customer expectations. Accordingly, categories and justifications for IT capital investments vary, from mitigating risks associated with obsolescence to meeting customer needs and expectations. IT projects can be broadly justified under the following sub-criteria:

- Technical
- Economic
- Customer Experience

IT capital projects may be justified primarily under one of these sub-criteria or under a combination of them all. These categories and their justifications are expanded upon below.

Technical

Technical projects are driven by criticality and condition based risk assessments of in-service assets. They are most frequently associated with mitigating risks associated with obsolescence, security, and system performance to meet requirements of the utility to serve customers. Technical projects are ranked according to the ranking matrix and methodology outlined in Section 6.2.

Economic

Economic projects are driven by opportunities to operate in a more cost effective manner. Economics may also be associated with Technical, and Customer Experience projects.

Customer Experience

Customer experience projects are driven by either stated or predicted needs of customers, and are reasonably expected to provide improvements to their experience and interactions with NS Power.

Information Application and Hardware Systems - Economic Justification Procedure:

The following procedures will be used to evaluate the purchase, replacement or upgrade of Information Application and Hardware Systems at NS Power:

- Any Information Application and Hardware System which fails or is predicted to fail NS Power's requirements for capacity, security or service levels will first be evaluated as to NS Power's current and future requirements.

- An economic evaluation will then be completed to determine the most cost effective alternative. Included in these alternatives will be the cost to:

    - Repair the Information Application and Hardware System to such a state as to meet NS Power's requirements.

    - Upgrade or modify other Information Application and Hardware Systems so as to eliminate NS Power's requirement for the plant in question.

    - Replace the Information Application and Hardware System as to maintain current business requirements.

- Any repairs, upgrades or modifications will be costed as per the manufacturer's and NS Power's specifications and standards. The costs for completing this work will include and compare NS Power's total cost of ownership (TCO) and/or manufacturer's costs. Included in these costs will be all capital, operating and maintenance labour, material, overheads, expenses, shipping and all other relevant costs or factors over the asset’s expected useful life, which may affect these costs (i.e. availability of labour, material, revenue, etc.). Please refer to Section 6.7.5 for more information on TCO.

- New Information Application and Hardware System will be evaluated on a least cost basis considering the total cost of ownership (TCO) which satisfied NS Power's current and future requirements. Alternatives to purchasing new systems will include: modifications to existing systems, technological availability, capital, operating and maintenance costs such as labour, material, overheads, expenses, shipping and all other relevant costs or factors over the asset’s expected useful life.

- The least cost technically acceptable option meeting all the requirements and constraints specified above shall be selected. The Total Cost of Ownership, as defined in Section 6.7.5, should be considered in the analysis.

17.15 Vehicles

Nova Scotia Power requires vehicles for the effective delivery of its services. There are two broad classifications used for vehicle identification; transportation and work vehicles.

Transportation vehicles are primarily used for transportation of personnel. Vans, cars, sport utility vehicles and trucks are considered transportation vehicles.

Work vehicles provide Nova Scotia Power personnel with the means to conduct their day-to-day work. Bucket aerial trucks, digger trucks, cranes, off road equipment, pole and wire trailers make up the majority of vehicles in this classification.

Vehicle Replacement Process

The first step in the review of any vehicle for potential replacement is that it meet the life cycle costing methodology initial screening criteria.

Vehicles proposed for replacement based on the screening criteria of vehicle age, kilometres and maintenance history are then subject to a mechanical inspection and analysis.

As part of this exercise, a Vehicle Standardization Committee made up of user group members establishes that the type of vehicle is still the most appropriate for the work use. As job functions change and new technologies evolve, a different vehicle may be specified.

Vehicle expenditures and decisions on vehicle maintenance and replacement are the responsibility of Fleet Services.

The Fleet Services group provides predictive maintenance information on each class of vehicle, along with individual vehicle records. This group also provides technical support and guidance for the selection of the appropriate vehicle for each class. The premise of vehicle replacement is to achieve the most economical decision based on life cycle costing, which includes predictive maintenance, age and kilometres.

NS Power follows the life cycle costing methodology to establish units that are a potential for replacement. Vehicle replacements are ranked and scheduled based on the overall benefits to all operating units.

Appendix A: Capital Projects within the NS Power Routine Program

Generation Routines

Generation Equipment Replacements

Each generating unit forecasts projects relating to capital replacements for repair and/or refurbishment of equipment that are not large enough in scope and magnitude to be justified as individual capital projects. The value of the equipment replacement routines will vary from year to year.

Upon identification of failure or deterioration in performance, a like for like replacement is completed immediately in the case of failure or at the next scheduled maintenance outage for the affected unit.

Generation Other Hydro

This routine provides for the costs associated with managing/reducing the risk of environmental events and security requirements for the hydro facilities. It also includes the acquisition of new land properties for business support activities and/or retiring land properties that are no longer business viable or required.

Annual condition-based analysis will dictate the scope of work required for each hydro facility.

Generation Other Thermal

This routine provides for the costs associated with efficiency-driven projects. These projects must directly impact and improve the Unit heat rate.

Transmission Routines

Transmission Substation Replacements, Additions, Modifications

This routine provides for the replacement of deteriorated or failed circuit breakers, bushings, instrument transformers, arrestors, batteries, chargers, switches, breakers, etc; modification or upgrade of existing equipment to prevent damage, extend serviceable life or reduce customer outages; replace primary equipment spares; and the retirement of failed or deteriorated transmission substation plant.

The replacement of deteriorated or failed equipment is immediate. Modifications are initiated as a result of identified system problems following a review of options. The least cost option meeting the requirements and constraints specified shall be selected.

Deleted: These are minor in nature.

Primary Equipment Spares

This routine provides for the costs associated with ensuring an adequate level of spare substation equipment is maintained for high voltage system components.

Protection Modification & Replacement

This routine provides for transmission substation protective relays, under frequency load shedding, automatic line reclosing, metering, fault and sequence of event recorders along with spare relays and components that fail or are damaged during the year. It also covers minor modifications to inadequate protection and control logic schemes.

Minor modifications result from a change in system protection design criteria and can be traced back to the inadequacy from standard. This work is carried out in a planned manner with other work being carried out in the substation.

Damaged and failed equipment are replaced as soon as possible to maintain the operation of the substation.

Transmission Line Replacements, Additions, Modifications

This routine provides for the reactive and planned replacement / improvement of transmission line components.

Poles, structures and insulators which have deteriorated condition are replaced or modified to maintain or extend the life of the transmission lines. Visual inspection or accident reports are used to identify the required replacement.

Deleted: been damaged or broken

Deleted:

To maintain the service level, such failures are replaced immediately. The transmission line inspection program prioritizes circuits for component replacements on an annual basis.

Distribution Routines

Meters

This routine provides for the costs of purchasing and installing all classes of meters for customers.

Please refer to Capital Expenditure Justification Criteria: Metering Equipment for the justification criteria relating to metering.

Distribution Upgrades and Replacement

This routine covers the costs associated with reactive distribution plant replacement, planned distribution plant replacement, upgrades to the distribution system to achieve system performance improvements, the replacement of distribution assets as a result of damage caused by storms, and the replacement or addition of distribution assets that are required to accommodate government regulations.

Reactive distribution plant replacement is a result of equipment failing due to age, deterioration or destruction by outside forces (vehicles, vandalism, etc.). Planned distribution plant replacement is undertaken as a result of inspection programs.

The routine is estimated based on a combination of units to be replaced at an average unit cost and project costs as a result of inspection programs.

New Customers

This routine covers the utility's cost of adding new customers to the electrical system. Capital contributions required in aid of construction are governed by the Regulations approved by the Nova Scotia Utility and Review Board.

This routine is submitted on a Province wide basis based on historical actual costs and/or forecasts.

Deleted: an estimated number of new customers and on average per customer cost

The vast majority of new customer connections result in a request for service. This initial contact established the timing, cost and complexity of the addition. Primary customers served at higher voltages require NS Power discussions regarding transformation, location, timing and detailed plans including costs.

Joint Use

There are three components which provide the funding level of the Joint Use Routine. Local field district work, Provincial sale of distribution poles under the Joint Use agreement to Bell Aliant and all other Joint use work contribute to the annual budget.

During the preparation of NS Power's ACE Plan, Bell Aliant may not have not prepared their province wide priorities for work to be carried out. As a result, NS Power identifies the total value of work it is prepared to do and sub-divides this work into field district level upon priority setting. This exercise combined with NS Power priorities for Joint Use work provides the basis for the annual budget development.

Right-of-Way Widening

This routine provides for costs associated with right-of-way widening for both the distribution and transmission systems. Provincial Right of Way Widening often requires acquiring additional easements and is equivalent to newly purchased land. NS Power proactively widens right-of-ways where it is deemed that vegetation issues could result in a degraded reliability performance on the power system.

General Plant Routines

Work Vehicles

This routine covers the replacement and any additions to the transportation vehicle fleet. The item is prepared Province wide and managed by the Fleet Services group.

Please refer to Capital Expenditure Justification Criteria: Vehicles for the justification criteria relating to vehicle purchases.

Tools and Test Equipment

This routine covers tools and test equipment for field and plant operations. Customer Service, Hydro and Thermal each submit a province wide budget for tools and equipment which meet materiality and criteria requirements.

Telecommunications

This routine covers replacements and modifications in six areas, when the equipment has failed or is unserviceable.

- Mobile Radio Network & Systems Routine

  This includes mobile radios, portable radios, or remote control units, repeaters, gap filler repeaters, or base stations, cards and components, antennas, waveguides and power supplies.

- Voice Network & Systems

  This includes PBX Cards, disk drives, power supplies, software & component upgrades, telephone sets, fax machines, and wiring due to office moves.

- Telecom Systems Broadband Network & Systems
    - Broadband Network and Systems: Includes multiplexor, radio, and related system cards, power supplies, antennas, waveguides, fibre optic splice components, patch panels, and connectors.
    - Cable System and Circuits: Includes NS Power metallic and fibre cables and related termination equipment, positron cable protection installations as jointly identified by NS Power & Bell, individual communication channels and related materials.
    - Voice Networks and Systems: Includes system operations voice system (SOPS), SOPS telephone sets, telecom site phones and order wire.
    - Network Management Systems: Includes network management servers and software, telecom alarm monitoring devices and site monitoring equipment.
- Telecommunications Spares

  Includes: Maintenance Spares for telecommunication equipment and facilities, broadband networks and systems, cable systems and circuits, voice networks and systems and network management systems.
- Telecommunications Sites

  Includes: Upgrades and improvements to NS Power radio sites and telecommunication sites (i.e. backup generators), HVAC replacements, fences, buildings, etc.
- SCADA/Telecontrol Network & Systems

  Includes: Teleprotection, telemetry, and SCADA system, cards, components and power supplies, etc. (includes Ragged Lake Facility)

Computing Asset Management

This routine provides for the acquisition of hardware and software products to maintain the cost effective, secure and efficient operation of NS Power's computer and network facilities. The computer and network facilities are used for the development and operation of the financial, customer, human resources and engineering information processing applications for NS Power.

This routine includes the purchase of hardware and software products required for the continuing operation of the file servers distributed across the province, the midframe and mainframe platforms located at the main computer facility at Ragged Lake, and the computer data network which links these.

Property Improvements and Furniture

This routine provides for improvements to NS Power property. These improvements can include environmental compliance work, or infrastructure replacement such as door, window and roof replacement. The routine work is based on on-going review of the state of NS Power land and buildings as identified by field and facilities staff evaluation.

This Routine also provides for the replacement of office and warehouse furniture and equipment. Furniture and equipment purchased as part of a new facility are not included in this item.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

Appendix B: Capital Item Documentation Policy & Review Requirements

Objective

To specify the documentation required to provide reasonable assurance that capital expenditures at Nova Scotia Power Inc. are incurred for the maximum benefit of the customer while ensuring compliance with applicable laws, regulations, and internal policies and processes.

Purpose

Documentation is prepared and retained for every capital project for the following reasons:

- To provide assurance that the capital expenditure(s) were necessary, that alternatives (including the status quo) were evaluated, that cost data was analyzed, and that an economic analysis was performed (if applicable);
- To demonstrate compliance with applicable laws, code of conduct, regulations and internal policies and processes;
- To communicate employee responsibility and accountability for the planning, management and control of spending activities relating to capital;
- To provide a source of historical information which can be referenced for future budgeting and spending; and
- To facilitate the transfer of project responsibilities and to assist in training.

Scope

This policy applies to all capital spending including routine and non-routine spending.

Accountability

Each capital project owner (person responsible for the project) is accountable for maintaining the appropriate level of documentation to support capital decisions, including development, justification, cost analysis and spending.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
Detailed Document

Analysis of Alternatives

All alternatives must be reviewed prior to initiating a capital project. Generally, alternatives are developed through self-generated ideas, discussions with suppliers and consultants, technical articles, general utility trends, or a combination of the above. Some of these alternatives may not be feasible for various reasons and, in the end, usually several alternatives are examined using the Economic Justification Criteria. However, proper documentation shall be provided outlining the reasons why certain alternatives were not considered feasible (see Exhibit 'A').

Review and Approval Process

There will be two levels of review:

Level 1 Review (*See Table 1*)

This review is performed by:

- Person(s) responsible for planning, budgeting, controlling and managing the project (person responsible for the project),

- Person(s) responsible, within the Division/Department, for initial approval of the project. Approval is subject to the item meeting the Capital Expenditure Justification Criteria in place at the time the project is approved.

Documentation Requirements:

Sufficient documentation will be maintained to support the financial and technical content of the item from the ACE Plan, including the project in rate base and continues until the project is complete and received final cost approval. All documentation which provides assurance that the capital program is executed for the maximum benefit of the customer, while ensuring compliance with applicable laws, regulations, and internal policies and processes, will be accessible by or directed to those person(s) who have the authority to act on it, including NS Power Management and Internal Audit, Revenue Canada, and the Nova Scotia Utility and Review Board (see Exhibit 'A' for guidance).

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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Level 2 Review (*See Table 1*)

This review is performed by:

- Person(s) responsible for final corporate approval of the capital item and confirming that the item meets the technical and financial criteria contained in the Capital Expenditure Justification Criteria at the time the project is approved.

Documentation Requirements:

Sufficient documentation will be maintained to provide reasonable assurance that the item meets NS Power's financial and technical justification criteria as contained in the Capital Expenditure Justification Criteria Document. All documentation which provides reasonable assurance that the criteria have been met will be accessible by or directed to those person(s) who have the authority to act on it, including NS Power Management and Internal Audit, Revenue Canada, and the Nova Scotia Utility and Review Board (see Exhibit 'A' for guidance).

Table 1

Process	**Level of Review**
ACE Plan Initiation & Approval	Level 1 & 2
Capital Spending Approval (Activation)	Level 1 & 2
Capital Monitoring (Cost Control)	Level 1
Capital Forecasting	Level 1
Capital Item Authority to Overspend (ATO)	Level 1 & 2
Rate Base Inclusion	Level 1 & 2
Final Costing	Level 1 & 2

File Content Guidelines

Exhibit 'A' provides a guideline for the documentation to be maintained in the capital file(s).

Records Retention Period

All capital files should be maintained for a minimum of six years from the in-service date of the asset to meet the Taxation Authorities requirements. Prior to six years a letter of permission must be obtained from the Taxation Authorities before the capital file(s) is (are) destroyed. The Corporate Tax Services Department and the Secretary and General Counsel Division should be contacted for assistance if required. Retention beyond the minimal requirement of six years should be based on other requirements. For example, due to the long term nature of capital expenditures, certain support documentation contained in the capital file(s) may provide a source of information for future capital expenditures or may be required to support several expenditures over a specified planning period. In addition, certain legal, safety or environmental issues associated with particular capital projects may warrant a longer retention period than six years. In these and other instances, the retention period will be based on the particular situation.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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Exhibit A

Note: The descriptions provided are intended to be used as guidelines. The actual file contents will vary depending on the capital item.

Description	Contents	Level	
		1	2
A) Authorization Details	Authorization - Divisional approval If >$1M or U&U: Executive committee approval NSEB approval - Corporate approval (approval detail can be found on Capital Item Detail Report)		x
B) Analysis of Alternatives	Includes : - Description of the possible alternatives associated with the capital project - Reasons why certain alternatives required no further analysis - Reasons for choosing the accepted alternative	x	
C) Capital Item Detail Information	Includes: Annual spending requirements - ACE Plan - Approved spending - Additional spending - Forecast - Final cost Online recommendations/approvals - Item recommendation - Item approval - Item activation Description - Scope - Project components/costs	x	x

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Description	Contents	Level	
		1	2
	Account listing - Account numbers - Responsibility codes - Amounts		

	Justification
	- Criteria & sub-criteria
	- Document(s) name & location
	- Person responsible
	- Memo
	  - Why do the project?
	  - Why now?
	  - Why this way?
	- References - legislation, regulations		

	Reason for over or under expenditure, final costing - Description		
D) Economic Analysis	Analysis output including: - Supporting documentation for revenue, capital & operating costs - All calculations & major assumptions - Recommendation - Qualitative factors - All other relevant support documentation	x	x
E) Correspondence	- NSEB - Other	x	x

F) Technical & Financial Criteria (*See Capital Expenditure Justification Criteria*)	Working papers supporting
	- Derivatives & calculations
	- Explanation of changes in scope or amount
	- Source of costs
	  - Historical, standard
	  - Manufacturer quotes
		x	

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Description	Contents	Level	
		1	2
	Budget estimates	x	
	Other relevant information - (*content will vary*) Examples include: - Regulations, acts, codes - Permits, licences, guidelines, agreements - Engineering studies & assessments - Pole test results - Planning reports - Outage reports - Retreatment data - Insulating oil, insulations, circuit interrupter, electrical protection, battery tests - Annual inspection reports, stave sampling, performance reports - Production models - Joint use information	x	
G) Cost Control, Final Costing	Cost monitoring, forecasting & final costing - Reports (eg. work scheduling) - Supporting worksheets and analysis	x	
	Retirement Information	x	
	Tenders and bid evaluations	x	
	Financial reports, including - Power Plant Information- General ledger - Purchasing & Accounts Payable - Labour Distribution - Documentation to support assumptions, decisions, or other factors which change the expected cost and/or scope of the project.	x	

NS Power

System Design Criteria

Report number NSPI-TPR-003-6

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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REVISION RECORD

Date	Version Number	Approver , Date Signature		Comments
1995/01/12	0			Initial document
2010/10/07	1	T. Leopold	7-Oct-10	Updated to align with changes to System Design Criteria and better align with NERC/NPCC standards
2013/05/10	2	P. Zinck	10-May-13	Revised fault clearing time requirements for Primary and Secondary Transmission, contingency loading for Remote Transmission, and system transformer loading.
2016/03/24	3	D. Stanford	24-Mar-16	Updated to include Looping Policy
2016/07/21	4	D. Stanford	21-Jul-16	Updated to correct version of Looping Policy
2022/11/15	5	C. Milligan	29-Aug-23	Updated definition of Primary, Secondary, and Electrically Remote transmission systems.
2024/02/20	6	C. Milligan	10-Apr-24	Updated to include Transient Voltage Criteria per NERC TPL-001

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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PURPOSE

The purpose of this document is to state the Nova Scotia Power Inc. (NS Power) planning and development criteria to be applied to new additions to NS Power transmission system planned or constructed after the effective date of this document. NS Power's transmission system is divided into four classifications, each of which is governed by different design criteria. Where and when applicable, NS Power criteria will be superseded by the Northeast Power Coordinating Council (NPCC) criteria.

The NS Power classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Transformation

The NS Power System Design Criteria combine protection performance specifications with system dynamics and steady state performance requirements. When system expansions are undertaken, facilities are to be constructed such that the criteria are met. The specified speed of protection systems must be achieved unless faster speeds are specified or slower speeds are accepted based on system studies. System studies to determine adequacy and investment requirements must be conducted using the actual characteristics (setting and operating time) of existing protection systems.

DEFINITIONS

1. **Normal system conditions** are defined to include all of the following:

    a. Expected load conditions.
    b. All transmission facilities in service (no line or transformer maintenance).
    c. Economically scheduled and dispatched generation allowing for planned generator maintenance outages (non-firm generation is not included as economically dispatched generation). Economic dispatch may be influenced by environmental or regulatory restrictions.
    d. Stable steady-state operation of the Interconnected Transmission System.
    e. All system voltages within 95% to 105% of nominal, unless otherwise noted.
    f. All system elements operating within their continuous thermal ratings, unless otherwise noted.
2. A **system element** is defined to be any one generator, transmission line, transformer or bus section.

3. **Breaker back-up** is defined to be protection against a local breaker's failure (mechanical or electrical) to trip when initiated by an associated protection operation. The term "**Breaker failure protection**" is used interchangeably in this document.
4. **Single contingency** is defined as loss of one **system element** with or without a fault.

Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria
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1. PRIMARY TRANSMISSION SYSTEM

Primary Transmission is defined as 230kV and above and any other NPCC Bulk Power System transmission.

The protection system must be designed with redundancy to cater to any single element failure, in keeping with good utility practice and conform to industry standards.

Unless otherwise specified, and determined appropriate by transient stability studies, the following fault clearing times will be applied to the Primary Transmission system. Any deviations from these criteria must be submitted to the system planning group for approval.

a. For a three phase or phase to ground fault on the local bus or on any element directly connected to the local bus such that it is within the instantaneous protection zone for that element (e.g. 21Z1, 87, 50) the fault contribution clearing time will be 4 cycles.
b. Where breaker failure protection is required to trip local breakers to isolate the fault described in item (a), the fault clearing time will be 12 cycles.
c. Where breaker failure protection is required to trip remote breakers to isolate the fault described in item (a), the fault contribution clearing time will be 14 cycles.
d. For a three phase or phase to ground fault on any element directly connected to the local bus such that it is outside the instantaneous protection zone for that element (e.g. 21Z2, 51) the fault contribution clearing time will be 6 cycles.
e. Where breaker failure protection is required to trip local breakers to isolate the fault described in item (d), the fault contribution clearing time will be 14 cycles.
f. Where breaker failure protection is required to trip remote breakers to isolate the fault described in item (d), the fault contribution clearing time will be 16 cycles.

Breaker failure protection will be applied to all Primary Transmission.

The design criteria are:

1. From **normal system conditions**, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one system element cleared in prime time. No cascade tripping shall occur.
2. From **normal system conditions**, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element cleared in prime time. No cascade tripping shall occur.
3. From **normal system conditions**, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to ground fault on any one system element cleared in breaker back-up time.

No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From **normal system conditions**, following loss of any one system element with or without fault, all system elements shall be within 110% of their thermally limited ratings under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.
5. From **normal system conditions**, for the loss of any one system element with or without fault, steady-state post-contingency Interconnected Transmission System bus voltages shall be not less than 90% or greater than 110% of nominal following correction by automatic tap-changers. In addition no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap-changers.
6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.
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.

2. SECONDARY TRANSMISSION SYSTEM

This category includes all other transmission facilities which are not included in the Primary Transmission nor the Electrically Remote Transmission categories.

The protection system must be designed with sufficient redundancy to cater to any single element failure, in keeping with good utility practice and conform to industry standards. The following fault clearing times will be applied to the Secondary Transmission system. Any deviations from these criteria must be submitted to the system planning group for approval.

a. For a three phase or phase to ground fault on the local bus or on any element directly connected to the local bus such that it is within the instantaneous protection zone for that element (e.g. 21Z1, 87, 50) the fault contribution clearing time will be 6 cycles.

b. Where breaker failure protection is required to trip local breakers to isolate the fault described in item a), the fault contribution clearing time will be 14 cycles.

c. Where breaker failure protection is required to trip remote breakers to isolate the fault described in item a), the fault clearing time will be 16 cycles.

d. For a three phase or phase to ground fault on any element directly connected to the local bus such that it is outside the instantaneous protection zone for that element (e.g. 21Z2, 51) the fault contribution clearing time will be 8 cycles.

e. Where breaker failure protection is required to trip local breakers to isolate the fault described in item d), the fault contribution clearing time will be 16 cycles.

f. Where breaker failure protection is required to trip remote breakers to isolate the fault described in item d), the fault contribution clearing time will be 18 cycles.

Breaker failure protection will be applied to Secondary Transmission if system studies determine the requirement.

The design criteria are:

1. From **normal system conditions**, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one **system element** cleared in prime time. No cascade tripping shall occur.

2. From **normal system conditions**, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent

line-to-ground fault on any one **system element** cleared in prime time. No cascade tripping shall occur.

3. From **normal system conditions**, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to ground fault on any one **system element** cleared in **breaker back-up** time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From **normal system conditions**, following loss of any one system element with or without fault, all system elements shall be within 110% of their thermally limited ratings in steady state, under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.

5. From normal system conditions, for the loss of any one system element with or without fault, steady-state post-contingency Interconnected Transmission System bus voltages shall be not less than 90% or greater than 110% of nominal following correction by automatic tap-changers. In addition no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap-changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

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.

3. ELECTRICALLY REMOTE TRANSMISSION SYSTEM

This category is defined by the buses at which the maximum fault levels do not exceed 1,000 MVA three-phase.

1. The Interconnected Transmission System dynamic response shall be stable and positively-damped following a fault on any one **system element**.

2. From normal system conditions, following a **single contingency**, all system elements shall be within 110% of their thermally limited ratings under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.

3. From **normal system conditions**, for any **single contingency**, steady-state post-contingency system bus voltages shall not be less than 90% and not be greater than 110% of nominal following correction by automatic tap-changers. In addition, no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap changers.

4. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

5. **Breaker back-up** will be applied to Electrically Remote Transmission if system studies determine the requirement.

4. TRANSFORMATION

Capacity for any individual transformation point shall, under **normal system conditions**, be sufficient to meet the daily load requirements after due consideration is given to the following:

a. Economic dispatch or outage of generation.

b. Loading of transformer(s) to their (or their associated equipment) thermally limited ratings.

Reinforcement is required in all cases when a single contingency results in either thermal damage to equipment in attempting to continue to supply the load, or inability to meet the daily load requirements in whole or in part after due consideration is given to the following:

a. The capacity of the underlying interconnection(s) with another supply point(s) when applicable.

b. Out-of-merit running of generation when applicable.

c. Loading of remaining station(s) transformer(s) to their (or their associated equipment) thermally-limited ratings as per the Notes below. (This in conjunction with (a) and (b) above as applicable.)

d. Largest available **suitable** mobile transformer loaded to its nameplate rating. (This in conjunction with (a) and (b) above as applicable.)

Notes:

1. Reinforcement may be the economic choice even if (a), (b) and (c) or (d) result in satisfaction of the load supply criterion because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. In accordance with methods accepted within North America, and particularly with reference to "C57.91-1995 IEEE Guide for Loading Mineral-Oil-Immersed Transformers", it is NS Power practice to permit the loading of transformers to exceed the nominal or nameplate value.

3. For distribution load serving transformers to exceed the nominal or nameplate value, where calculations are not specifically conducted, overload capability assumptions based on normal cyclic daily loading may be made, but shall not exceed 133% of the top nameplate rating. In any case the maximum overload capability is not to exceed the current NS Power SCADA Alarm limits. In special circumstances, such as **single contingency** situations where some means of reducing the overload exists, a thermal

rating based on a loss of life of 2 1/2% may be applied to distribution load serving transformers, in accordance with the above and engineering judgment. The loss of life permitted is measured over the time required to reduce the loading on the transformers. This may be done by switching low voltage circuits or relieving load by use of a mobile transformer.

4. For system power transformers, where calculations are not specifically conducted:

   a. Under system normal, loading is limited to 100% of the 65°C manufacturer nameplate MVA for summer and 110% for winter;

   b. Under contingency, the 15 minute short time rating is limited to 110% of the 65°C manufacturer nameplate MVA for summer and 120% for winter, provided that the system operator has the means to reduce the overload to system normal rating within 15 minutes;

   c. Consideration should be given to the ratings of the auxiliary equipment such as CTs, PTs, bushings and tap changers.

   When no means of reducing the overload exists, a 0% loss of life is used.

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ATTACHMENTS

A. NOVA SCOTIA POWER INC. RADIAL TRANSMISSION POLICY

A radial load is a load center, such as a substation, that provides power to a large population, connected to the power grid via a single transmission line. Loss of a radial transmission line results in loss of supply with no other way to connect the radial load to the grid. A single transmission line may have more than one radial load connected to it.

A lone substation, which is dedicated to a single customer, is not considered a radial load in this context. Any load, which is tapped from a transmission line connected between two supply points, is not considered a radial load since this load can be fed from either supply location.

Where a radial load exceeds 40 MW, a planning study will be undertaken. The planning study will examine options of reducing the size of the load by load transfer to other substations, by considering local generation in the vicinity, and by other practical load reduction methods.

The planning study will also examine options to improve the line performance such as: vegetation control, lightning mitigation, line upgrade, and other practical technological methods.

In the case of multiple radial loads, which are connected to one radial transmission line, the planning study will examine the option of installing remote switching at the upstream substations to provide fast restoration to the radial loads upstream from the faulted line section.

Implementation of the above "stepped" approach will be the first mitigation measure for any radial load above 40 MW. After implementation of these measures, should the radial load remain above 40 MW and should the existing transmission supply exhibit deterioration in reliability, then a second transmission line will be evaluated to provide loop feed to improve the reliability.

When radial load grows past 60 MW, a second transmission line will be evaluated regardless of performance.

NS Power

Mersey Hydro Update

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1.0 INTRODUCTION

NS Power owns and operates the Mersey Hydro System (MHS), a series of six hydroelectric stations and a lake storage diversion along a 21km reach of the Mersey River. The 2026 ACE Plan focuses on sustaining capital investments required to ensure safe and reliable operation of the system while long-term options are evaluated through the upcoming Integrated Resource Plan (IRP). This update provides details on current sustaining investments, ongoing stakeholder engagement, and preliminary planning activities to support future decisions regarding the MHS.

In its 2025 ACE Plan Order, the Board provided the following direction:

> 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.[1]

[1] M12012, NS Power 2025 Annual Capital Expenditure (ACE) Plan, NSEB Order, August 19, 2025.

The sections below provide NS Power's response, including:

- An update on the incremental sustaining investments that have been incorporated into the Hydro Interval Plan (HIP);

- An update on the ongoing work associated with continued engagement on the MHS with Kwilmu'kw Maw-klusuaqn (KMK), Wasoqopa'q (Formerly "Acadia"), Bear River and Sipekne'katik First Nations, DFO, and the Nova Scotia Government;

- A net present value (NPV) analysis of the capital costs that compares redevelopment, partial decommissioning and full decommissioning, including the details of the assumptions that form that analysis; and

- A detailed description of the cost estimates for preliminary engineering, Mi'kmaq and stakeholder engagement, environmental studies, detailed engineering and procurement costs required for the Mersey Redevelopment to begin in 2028.

2.0 SUSTAINING INVESTMENT

The deferral of the Mersey Redevelopment is aligned with NS Power's asset management methodologies. Deferring projects when safety, environmental and economic risks, as well as social implications associated with the project can be managed is in the best interest of customers. To support the safe deferral, NS Power has implemented a series of incremental sustaining investments to ensure the continued safe operation of the MHS in the interim. These investments were first incorporated into the Hydro Investment Plan (HIP) in 2023 and have been updated annually through 2025.

The HIP is a dynamic planning tool that reflects evolving asset conditions, regulatory requirements, and stakeholder input. As such, sustaining costs across the 40-year planning horizon may vary year-to-year. These investments are designed to maintain safe and reliable operation of MHS while NS Power continues planning and engagement activities required to support the future scope of work.

The forecast capital investment for Mersey Redevelopment included in Appendix G of the 2025 ACE Plan was approximately $1.2 billion. The most current forecast, included in Attachment 1, remains consistent, at approximately $1.2 billion, with a NPV of $559.9 million.

The total capital required for sustaining investment (2026-2065) increased from $160.7 million in Appendix G of the 2025 ACE Plan to $172.4 million, included in Attachment 1. The increase in total investment is attributed to ongoing review of historical project costs to bring future project cost estimates more in line with actual costs on more recent similar projects. The NPV for sustaining investment has increased from $68.1 million in Appendix G of the 2025 ACE Plan to the current forecast of $79.2 million. NS Power continues to revise the profile of the investment in accordance with its asset management principles to ensure projects are scheduled at appropriate intervals.

The most recent update includes $45.1 million in sustaining investment between the years of 2026–2030, compared to the prior year forecast of $40.6 million over the same period. Attachment 1 outlines the current MHS investment profile included in the HIP for 2026–2065.

The sustaining capital plan prioritizes investments across four key categories outlined in the table below. Unless otherwise noted, the work provided in the table reflects typical capital projects completed or initiated in 2025.

Category	Scope
Safe and Reliable Management of Water	Planned turbine overhaul on Unit 12 at Cowie Falls (CI C0038126) to provide reliable operation of the turbine until the next major refurbishment
Safe and Reliable Management of Water	Planned generator refurbishment on Unit 12 at Cowie Falls (CI C0053654) to provide reliable operation of the generator until the next major refurbishment
Safe and Reliable Management of Water	Rotor re-insulation on Unit 6 at Big Falls (CI C0080112) to provide reliable operation of the generator rotor until the next major refurbishment
Safe and Reliable Management of Water	Exciter refurbishment on Unit 6 at Big Falls (CI C0059785) to reliably regulate voltage output and ensure stable power generation
Safe and Reliable Management of Water	Stoplog refurbishments, minor spillway refurbishments, and trash-rack replacements at Lower Great Brook (CI C0070486) and preparation for drawdown at Deep Brook in 2026 (CI C0080219)
Safe and Reliable Management of Water	Hoist replacement for stop logs at Cowie Falls to safely and reliably manage water (CI C0049032)
Dam Safety and Powerhouses	Concrete Assessments & Minor Refurbishments, including laser scanning (CI C0060245): Completed at Upper Lake Falls, Lower Lake Falls, and Big Falls
Dam Safety and Powerhouses	Crane column refurbishments at Upper Lake Falls Powerhouse (CI C0080116) to provide safe and reliable operation of the powerhouse crane
Dam Safety and Powerhouses	Crane column refurbishments at Big Falls Powerhouse (CI C0076222) to provide safe and reliable operation of the powerhouse crane

Category	Scope
Dam Safety and Powerhouses	Powerhouse roof refurbishment at Lower Great Brook (CI C0060569) to address leaks, protect internal assets, and protect structural integrity of the powerhouse
Environmental Compliance	Fish Passage: Initiated RFP process for refurbishment of three existing fish ladders (Cowie Falls, Deep Brook, and Lower Great Brook) and installation of new eel passage systems (all sites) to meet Federal Fisheries Act requirements.
Substations Reliability & Electrical Safety	Switchgear Remote Racking: Completed at Lower Great Brook (CI C0036368) to mitigate arc flash hazards and improve personnel safety

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3.0 ONGOING PROJECT DEVELOPMENT AND MI'KMAQ AND STAKEHOLDER ENGAGEMENT

While active project work on the Mersey Redevelopment remains paused, NS Power continues to build an understanding of requirements resulting from the recent shifts in the environmental regulatory landscape, as well as Mi'kmaq interest and concern with respect to environment, fish passage, and archaeology. NS Power continues to have meaningful conversations with Kwilmu'kw Maw-klusuaqn (KMK), Wasoqopa'q, Bear River and Sipekne'katik First Nations as well as the Department of Fisheries and Oceans (DFO) and the Nova Scotia Government including Nova Scotia Departments of Environment (NSECC), Natural Resources (NSDNR) and Communities Culture Tourism and Heritage (CCTH). NS Power's goal is to achieve a common understanding and agreement on an approach with respect to expectations for archaeology and environment as it relates to the project prior to moving forward and submitting an application for approval.

NS Power's recent experience continues to help define the additional requirements and conditions set out by DFO with respect to continued compliance with the modernized *Fisheries Act* (2019), which will result in material project impacts. In order to move forward with the Mersey Redevelopment, NS Power must have a clear understanding of the conditions associated with continued compliance with the *Fisheries Act* and requirements for permit approval. In particular, NS Power is continuing conversations with DFO in order to understand requirements associated with fish passage that may not have been in place previously. Recent hydro projects elsewhere in NS Power's fleet have experienced increased requirements associated with fish passage, which has resulted in subsequent impacts to project timing, cost and scope. NS Power has maintained 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 Roseway Asset Decommissioning and Ruth Falls Main Dam Refurbishment, which required engagement with DFO, Mi'kmaw communities and other stakeholders.

Recently, efforts have been made to collaborate with DFO and the Mi'kmaq on developing hydro system specific work plans to mitigate impacts to fish and fish habitat across NS Power's hydro fleet, and to address compliance to the modernized *Fisheries Act*. This includes possible mitigations to potential impacts to fish and fish habitat on the MHS, including improvements to fish passage as part of the Mersey Redevelopment. As feedback received from these conversations and engagements is integrated into the overall strategy for the watershed, NS Power is improving its understanding of the broader impacts on the long-term planning, development, and execution of the overall Mersey redevelopment efforts. NS Power will continue to engage with government, the Mi'kmaq, and external stakeholders as these items are further defined and will provide preliminary project planning details to the Mi'kmaq communities and DFO prior to submitting capital items associated with the Mersey Redevelopment to the NSEB.

Recent hydro projects also indicate that environmental and archaeological costs and scope requirements typically impact project alternatives similarly, i.e., if archaeological or environmental costs or scope increase for a redevelopment alternative, they will also increase with a decommissioning or naturalization alternative within the construction footprint. In addition to this, recent experience has also revealed complexities and sensitivities with drawing down reservoirs, beyond the focus of the project activities. For example, consideration of impacts to communities and exposure of Mi'kmaw archaeological resources are hard to quantify, which highlights the challenges of re-naturalization. As with all capital projects, NS Power will continue to evaluate and assess project alternatives based on the most current available information to ensure that the selected project alternative remains the lowest cost option for customers.

4.0 NET PRESENT VALUE (NPV) ANALYSIS

As directed in the 2025 ACE Plan Order, NS Power has undertaken an NPV analysis of the capital costs that compare redevelopment, partial decommissioning and full decommissioning (renaturalization), including the details of the assumptions that form that analysis. The NPV analysis provides a comparison of three scenarios for the Mersey Hydro System: redevelopment, full decommissioning, and partial decommissioning investments. The basis of these estimates are included in Sections 4.1, 4.2 and 4.3 below, and reflect current assumptions about project timing and scope. Profiles for each scenario, including total capital cost estimate and NPV calculation, are provided in Attachment 1. The NPV analysis for each scenario is summarized in the following table:

Scenario	NPV	Class of Estimate
Full Decommissioning	($196M)	Unclassed
Partial Decommissioning	($346M)	Class 4
Redevelopment	($164M)	Class 4

Several assumptions were required when compiling the NPV analysis, which are outlined below:

- An average annual MHS production of 190,000MWh, was used, which was based on 2015-2024 data
- Marginal cost of electricity values are consistent with the values used in NS Power's Economic Analysis Model
- Marginal cost of capacity from 2026-2050 was calculated using the Evergreen IRP models, and was escalated two (2) percent annually 2051-2065
- During redevelopment, Power Production capacity on the Mersey would be reduced to 10 of 12 units in service during 2031-2050, reducing power production capacity during that period

The NPV figures presented in this update reflect capital costs only and are not a full economic analysis of the Mersey Redevelopment. They should not be used in isolation to determine the

future of the Mersey Hydro System (MHS). While the analysis includes simplified assumptions for replacement energy and capacity costs, these do not represent a comprehensive system level evaluation. A complete review combining decommissioning and redevelopment capital estimates with detailed system modeling of replacement fixed and variable costs is required to fully understand the economic impact of each option. This broader analysis will be undertaken as part of the upcoming IRP process to ensure decisions are based on accurate and integrated cost comparisons.

4.1 Redevelopment Costs

The redevelopment estimates were developed using a variety of sources, including consultant estimates, contractor bids and NS Power estimates. The major scopes of work for Big Falls, including the civil scope, turbine and generator scope and step-up transformer were based on Contractor estimates. Most of the remaining scope was based on consultant estimates. The switchyard re-configuration, and project costs estimates were developed by NS Power. This year, the estimate has been updated to include preparatory work leading up to construction. The cost of this work is roughly estimated to be $8.5 million. Activities include completion of detailed engineering design and preparation of IFC packages, procurement of Contractors, carrying out environmental studies, applying for permits as well as associated Administrative Overhead (AO) / Allowance for Funds Used During Construction (AFUDC). This number does not include spend for early procurement of major long lead items. Except for the three years leading up to the start of the first phase of the work, the estimated spend profile assumes that each phase will take approximately five years to complete, where the first year will focus on preparation and procurement.

The total combined estimate to redevelop the MHS is **$1.2 billion CAD.**

4.2 Partial Decommissioning Costs

The MHS partial decommissioning cost estimate was based on detailed work completed in 2021, leveraging the Big Falls rebuild scenario as a baseline due to significant overlap in scope. Under this option, the decommissioning scope includes removal of the powerhouse, concrete water control and retaining structures, and associated electrical and mechanical equipment. The rebuild and refurbishment of concrete water control structures and dams remain unchanged, as do the new fishways and the Big Falls switchyard upgrade. The primary exclusion is the construction of a new powerhouse and generation equipment.

Consistent with the redevelopment estimate, the 2025 forecast has been updated to incorporate preparatory activities ahead of construction. These activities, estimated at approximately $6.5 million, include procurement, permitting, and planning, but exclude detailed design packages associated with a new powerhouse. The spend profile assumes a three-year preparation period followed by phased execution, with each phase taking roughly four years to complete and overlapping by two years. The first year of each phase will focus on preparation and procurement.

The total combined estimate to partially decommission the MHS is $512 million CAD.

4.3 Decommissioning Costs

In 2024, NS Power commissioned updates to the 2018 Hydro Asset Study (HAS) to support ongoing depreciation and decommissioning planning for the MHS. These updates were led by Boreas Heritage Consulting Inc. and Hatch Ltd., and reflect evolving archaeological resources and environmental regulatory expectations, cost escalations, and lessons learned from recent decommissioning projects.

Boreas Heritage revisited the 2018 archaeological costings and assumptions for all hydro assets in the MHS. The revised study incorporated updated hourly rates, field methodologies, and regulatory

guidance from CCTH, as well as KMK. All Mersey assets were classified as having high archaeological potential, which would trigger reconnaissance shovel testing, and excavation in a decommissioning scenario. Dewatering events, particularly at Lake Rossignol, were flagged for intensive shoreline surveys due to the presence of multiple registered and unregistered archaeological sites, including petroglyphs and precontact Mi'kmaq settlements. The total archaeological cost estimate for the MHS was revised to $352.2 million. Given the deep history and size of the region, any additional work in the reservoirs could result in a significant escalation of this estimate.

Hatch also updated its 2018 HAS decommissioning cost model using 2024 Canadian dollars and expanded empirical datasets. The MHS was reassessed using updated infrastructure removal metrics, sediment management classifications, and environmental scoring matrices. While no major asset changes occurred since 2018, cost escalation and refined sediment allowances increased the total estimated decommissioning cost for the MHS to $155.6 million. This includes $128.6 million for infrastructure removal, $19.1 million for environmental mitigation, and $7.5 million for sediment management.

The total combined cost for the MHS, based on the Boreas archaeological study and Hatch decommissioning report, is $507.8 million. This estimate does not include NS Power internal costs, including internal labour and associated AO/AFUDC and does not consider the socioeconomic impacts of decommissioning, which have not yet been quantified. Additionally, as previously noted, recent experience has revealed the complexities and sensitivities with drawing down reservoirs. Consideration of impacts to communities and exposure of Mi'kmaw archaeological resources are hard to quantify in a decommissioning (re-naturalized) scenario. Decommissioning estimates are indicated as not classified due to these complexities and would present a much higher contingency requirement.

5.0 UPCOMING IRP CONSIDERATIONS

NS Power's 2020 Integrated Resource Plan included a detailed evaluation of the MHS using both the NS Power Decision Analysis (DA) Model and E3's RESOLVE capacity expansion model. The analysis compared the cost of rebuilding Mersey versus decommissioning it and replacing its energy and capacity contributions with alternative resources. Across all scenarios - including reference cases, low-cost sensitivities, high electrification, and accelerated GHG reduction pathways - the conclusion was consistent: rebuilding Mersey was more economic than decommissioning.

The Evergreen IRP process (2022–2023) reaffirmed these findings, highlighting Mersey's role as a zero-emission, firm, and flexible resource that supports system reliability and decarbonization goals. The analysis also showed that Mersey's value increases under scenarios with higher electrification and more stringent GHG constraints.

Importantly, the NPV values (provided as part of this Mersey update) alone cannot be used for decision-making on the path forward. These values do not include the full system replacement costs, which account for both replacement fixed costs (capital investments in new resources) and replacement variable costs (ongoing operational and energy production costs). A more complete and integrated review is required to assess the true economic impact of decommissioning versus redevelopment. This full cost comparison - combining decommissioning and redevelopment capital estimates with broader system modeling - is essential for informed decision-making.

NS Power is expected to support the 2025/2026 IRP process being initiated by the Nova Scotia Independent Electricity System Operator (IESO Nova Scotia). This next IRP will provide an updated framework for evaluating the MHS, incorporating refreshed assumptions on load growth, emissions targets, resource costs, and system integration. NS Power will contribute input to ensure the Mersey evaluation reflects current planning priorities and stakeholder expectations.

No final decisions on decommissioning or redevelopment of MHS will be made until direction is received from the 2025/2026 IRP. The IRP process will be used to facilitate the required full-scope review, ensuring alignment with provincial energy policy, system reliability needs, and long-term decarbonization objectives.

6.0 CONCLUSION

NS Power has increased the incremental sustaining investment in the MHS to maintain safe and reliable operation of the system, while deferring a major investment for customers until the future of the MHS is determined upon the completion of the next IRP. This deferral is in the best interest of customers because it avoids committing to any long-term option, whether redevelopment of decommissioning, before confirming which path provides the greatest overall value under future system conditions. The decision to defer comes at a time when NS Power is making significant transformational investments aligned with Nova Scotia's Clean Power Plan, as outlined in Appendix F: Path to 2030, and keeping affordability at the forefront for customers. Deferral of redevelopment work, while being the lowest cost alternative, also allows NS Power to complete additional preliminary engineering work, Mi'kmaq and stakeholder engagement and environmental studies to confirm the full scope of work and ensure redevelopment remains in the best interest of customers.

The incremental investment required to support the deferral has been carefully planned to ensure the continued safe operation of the MHS and compliance with operating requirements. The investments include 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 balance of plant equipment. These investments are revisited and re-evaluated as more information is obtained, and the HIP is continuously updated as forecasts are revised as result.

NS Power reiterates that it is committed to ensuring the Mi'kmaw, stakeholders, and the Board are actively engaged prior to the submission of relevant Mersey Redevelopment projects. The Company has not to date, nor will it in the future, take any steps with respect to the Mersey Redevelopment on "short notice", and NS Power has been, and continues to be, deliberate in its

attempts to find the best approach for customers and stakeholders, which includes continued engagement with the Mi'kmaw, DFO, and third-party dam safety consultants.

NS Power acknowledges that the NPV figures presented in this update are reflective of the information currently available and do not include full system replacement costs modeled in the IRP. As such, these figures cannot be used in isolation to determine the optimal path forward. The 2025 IRP will provide a more comprehensive evaluation of Mersey's role in the future system, and NS Power will rely on its outcomes before making any decisions regarding redevelopment or decommissioning.

NS Power will continue to refine cost estimates, engage with stakeholders, and prepare preliminary engineering inputs. The Company anticipates submitting CI 39472 HYD – Mersey Redevelopment Phase 1 only once the IRP process has concluded and a full-scope review confirms the redevelopment remains the best value for customers.

NON-CONFIDENTIAL

WACC Rate	5.08%

Scenario	TOTAL or NPV	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Partial Decommissioning														
Total Capital Investment	$ 624,440,000	$ -	$ -	$ 1,500,000	$ 2,500,000	$ 2,500,000	$ 26,080,000	$ 32,590,000	$ 54,850,000	$ 48,140,000	$ 54,850,000	$ 48,140,000	$ 54,850,000	$ 48,140,000
NPV (CAPEX)	$ (346,011,445)													
Full Decommissioning														
Total Capital Investment	$ 512,276,250	$ -	$ -	$ 1,000,000	$ 1,000,000	$ 2,500,000	$ 13,583,360	$ 13,583,360	$ 11,353,735	$ 11,353,735	$ 18,994,027	$ 18,994,027	$ 16,764,402	$ 16,764,402
NPV (CAPEX)	$ (196,107,720)													
Redevelopment														
Total Capital Investment for Redevelopment	$ 1,202,480,000	$ -	$ -	$ 2,500,000	$ 3,500,000	$ 2,500,000	$ 11,500,000	$ 36,730,000	$ 65,770,000	$ 56,990,000	$ 41,060,000	$ 63,710,000	$ 72,490,000	$ 64,330,000
NPV (CAPEX)	$ (559,893,305)													
Sustaining CAPEX Through Redevelopment														
Total Capital Investment	$ 172,362,402	$ 9,673,500	$ 15,210,000	$ 7,109,750	$ 6,409,750	$ 6,700,000	$ 3,997,877	$ 4,996,783	$ 5,741,131	$ 3,525,523	$ 1,950,391	$ 994,699	$ 887,769	$ 905,525
NPV (CAPEX)	$ (79,222,501)													
Total Redevelopment and Sustaining	$ 1,374,842,402	$ 9,673,500	$ 15,210,000	$ 9,609,750	$ 9,909,750	$ 9,200,000	$ 15,497,877	$ 41,726,783	$ 71,511,131	$ 60,515,523	$ 43,010,391	$ 64,704,699	$ 73,377,769	$ 65,235,525
NPV (CAPEX)	$ (639,115,806)													
Total Value of Energy	$ 1,042,075,305	$ 15,498,300	$ 15,988,500	$ 16,543,300	$ 19,986,100	$ 20,385,822	$ 17,258,637	$ 17,603,810	$ 17,955,886	$ 18,315,004	$ 18,681,304	$ 19,054,930	$ 19,436,028	$ 19,824,749
NPV (Value of Energy)	$ 376,550,690													
Total Avoided Capacity Cost	$ 267,274,027	$ 4,802,500	$ 4,887,500	$ 4,972,500	$ 5,100,000	$ 5,185,000	$ 4,374,100	$ 4,479,925	$ 4,550,475	$ 4,656,300	$ 4,762,125	$ 4,832,675	$ 4,938,500	$ 5,044,325
NPV (Avoided Capacity Cost)	$ 97,952,233													
Total Benefit	$ 1,309,349,331	$ 20,300,800	$ 20,876,000	$ 21,515,800	$ 25,086,100	$ 25,570,822	$ 21,632,737	$ 22,083,735	$ 22,506,361	$ 22,971,304	$ 23,443,429	$ 23,887,605	$ 24,374,528	$ 24,869,074
NPV (Total Benefit)	$ 474,502,923													
Overall NPV - Redevelopment	**$ (164,612,883)**													
Assumptions:	190,000	2015-2024 average Mersey production (MWh)												
	2%	Inflation rate (matches HIP)												
	Marginal cost of elec	$ 81.57	$ 84.15	$ 87.07	$ 105.19	$ 107.29	$ 109.44	$ 111.63	$ 113.86	$ 116.14	$ 118.46	$ 120.83	$ 123.25	$ 125.71
	Marginal cost of capacity	$ 113.00	$ 115.00	$ 117.00	$ 120.00	$ 122.00	$ 124.00	$ 127.00	$ 129.00	$ 132.00	$ 135.00	$ 137.00	$ 140.00	$ 143.00

NON-CONFIDENTIAL

WACC Rate	5.08%

Scenario	TOTAL or NPV	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Partial Decommissioning														
Total Capital Investment	$ 624,440,000	$ 54,850,000	$ 48,140,000	$ 54,850,000	$ 48,140,000	$ 28,770,000	$ 15,550,000							
NPV (CAPEX)	$ (346,011,445)													
Full Decommissioning														
Total Capital Investment	$ 512,276,250	$ 16,900,806	$ 16,900,806	$ 14,671,181	$ 14,671,181	$ 20,834,700	$ 20,834,700	$ 18,605,075	$ 18,605,075	$ 9,256,371	$ 9,256,371	$ 7,026,746	$ 7,026,746	$ 22,944,922
NPV (CAPEX)	$ (196,107,720)													
Redevelopment														
Total Capital Investment for Redevelopment	$ 1,202,480,000	$ 73,830,000	$ 68,710,000	$ 51,010,000	$ 54,960,000	$ 75,520,000	$ 68,890,000	$ 54,960,000	$ 75,520,000	$ 68,890,000	$ 54,960,000	$ 75,520,000	$ 58,630,000	
NPV (CAPEX)	$ (559,893,305)													
Sustaining CAPEX Through Redevelopment														
Total Capital Investment	$ 172,362,402	$ 923,635	$ 1,345,868	$ 960,950	$ 2,100,362	$ 1,142,597	$ 2,476,579	$ 891,568	$ 3,637,599	$ 1,082,186	$ 1,103,829	$ 3,699,406	$ 2,953,091	$ 5,187,596
NPV (CAPEX)	$ (79,222,501)													
Total Redevelopment and Sustaining	$ 1,374,842,402	$ 74,753,635	$ 70,055,868	$ 51,970,950	$ 57,060,362	$ 76,662,597	$ 71,366,579	$ 55,851,568	$ 79,157,599	$ 69,972,186	$ 56,063,829	$ 79,219,406	$ 61,583,091	$ 5,187,596
NPV (CAPEX)	$ (639,115,806)													
Total Value of Energy	$ 1,042,075,305	$ 20,221,244	$ 20,625,669	$ 21,038,182	$ 21,458,946	$ 21,888,125	$ 22,325,887	$ 22,772,405	$ 23,227,853	$ 23,692,410	$ 24,166,258	$ 24,649,583	$ 25,142,575	$ 30,898,104
NPV (Value of Energy)	$ 376,550,690													
Total Avoided Capacity Cost	$ 267,274,027	$ 5,150,150	$ 5,255,975	$ 5,361,800	$ 5,467,625	$ 5,573,450	$ 5,679,275	$ 5,785,100	$ 5,890,925	$ 6,032,025	$ 6,137,850	$ 6,278,950	$ 6,384,775	$ 7,846,350
NPV (Avoided Capacity Cost)	$ 97,952,233													
Total Benefit	$ 1,309,349,331	$ 25,371,394	$ 25,881,644	$ 26,399,982	$ 26,926,571	$ 27,461,575	$ 28,005,162	$ 28,557,505	$ 29,118,778	$ 29,724,435	$ 30,304,108	$ 30,928,533	$ 31,527,350	$ 38,744,454
NPV (Total Benefit)	$ 474,502,923													
Overall NPV - Redevelopment	**$ (164,612,883)**													

Assumptions:														
	190,000													
	2%													
	Marginal cost of elec	$ 128.23	$ 130.79	$ 133.41	$ 136.07	$ 138.80	$ 141.57	$ 144.40	$ 147.29	$ 150.24	$ 153.24	$ 156.31	$ 159.43	$ 162.62
	Marginal cost of capacity	$ 146.00	$ 149.00	$ 152.00	$ 155.00	$ 158.00	$ 161.00	$ 164.00	$ 167.00	$ 171.00	$ 174.00	$ 178.00	$ 181.00	$ 184.62

NON-CONFIDENTIAL

WACC Rate	5.08%

Scenario	TOTAL or NPV	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064
Partial Decommissioning														
Total Capital Investment	$ 624,440,000													
NPV (CAPEX)	$ (346,011,445)													
Full Decommissioning														
Total Capital Investment	$ 512,276,250	$ 22,944,922	$ 20,738,200	$ 20,738,200	$ 20,738,200	$ 20,738,200	$ 20,738,200	$ 20,738,200	$ 20,738,200	$ 20,738,200				
NPV (CAPEX)	$ (196,107,720)													
Redevelopment														
Total Capital Investment for Redevelopment	$ 1,202,480,000													
NPV (CAPEX)	$ (559,893,305)													
Sustaining CAPEX Through Redevelopment														
Total Capital Investment	$ 172,362,402	$ 5,291,348	$ 4,178,458	$ 7,893,630	$ 3,260,451	$ 8,129,391	$ 4,334,443	$ 1,730,008	$ 5,882,028	$ 1,199,934	$ 7,547,583	$ 9,155,014	$ 1,910,069	$ 10,390,775
NPV (CAPEX)	$ (79,222,501)													
Total Redevelopment and Sustaining	$ 1,374,842,402	$ 5,291,348	$ 4,178,458	$ 7,893,630	$ 3,260,451	$ 8,129,391	$ 4,334,443	$ 1,730,008	$ 5,882,028	$ 1,199,934	$ 7,547,583	$ 9,155,014	$ 1,910,069	$ 10,390,775
NPV (CAPEX)	$ (639,115,806)													
Total Value of Energy	$ 1,042,075,305	$ 31,516,066	$ 32,146,388	$ 32,789,315	$ 33,445,102	$ 34,114,004	$ 34,796,284	$ 35,492,210	$ 36,202,054	$ 36,926,095	$ 37,664,617	$ 38,417,909	$ 39,186,267	$ 39,969,993
NPV (Value of Energy)	$ 376,550,690													
Total Avoided Capacity Cost	$ 267,274,027	$ 8,003,277	$ 8,163,343	$ 8,326,609	$ 8,493,142	$ 8,663,004	$ 8,836,264	$ 9,012,990	$ 9,193,250	$ 9,377,115	$ 9,564,657	$ 9,755,950	$ 9,951,069	$ 10,150,090
NPV (Avoided Capacity Cost)	$ 97,952,233													
Total Benefit	$ 1,309,349,331	$ 39,519,343	$ 40,309,730	$ 41,115,925	$ 41,938,243	$ 42,777,008	$ 43,632,548	$ 44,505,199	$ 45,395,303	$ 46,303,209	$ 47,229,274	$ 48,173,859	$ 49,137,336	$ 50,120,083
NPV (Total Benefit)	$ 474,502,923													
Overall NPV - Redevelopment	**$ (164,612,883)**													
Assumptions:	190,000													
	2%													
	Marginal cost of elec	$ 165.87	$ 169.19	$ 172.58	$ 176.03	$ 179.55	$ 183.14	$ 186.80	$ 190.54	$ 194.35	$ 198.23	$ 202.20	$ 206.24	$ 210.37
	Marginal cost of capacity	$ 188.31	$ 192.08	$ 195.92	$ 199.84	$ 203.84	$ 207.91	$ 212.07	$ 216.31	$ 220.64	$ 225.05	$ 229.55	$ 234.14	$ 238.83

NON-CONFIDENTIAL

WACC Rate	5.08%

Scenario	TOTAL or NPV	2065
Partial Decommissioning		
Total Capital Investment	$ 624,440,000	
NPV (CAPEX)	$ (346,011,445)	
Full Decommissioning		
Total Capital Investment	$ 512,276,250	
NPV (CAPEX)	$ (196,107,720)	
Redevelopment		
Total Capital Investment for Redevelopment	$ 1,202,480,000	
NPV (CAPEX)	$ (559,893,305)	
Sustaining CAPEX Through Redevelopment		
Total Capital Investment	$ 172,362,402	$ 5,851,305
NPV (CAPEX)	$ (79,222,501)	
Total Redevelopment and Sustaining	$ 1,374,842,402	$ 5,851,305
NPV (CAPEX)	$ (639,115,806)	
Total Value of Energy	$ 1,042,075,305	$ 40,769,392
NPV (Value of Energy)	$ 376,550,690	
Total Avoided Capacity Cost	$ 267,274,027	$ 10,353,092
NPV (Avoided Capacity Cost)	$ 97,952,233	
Total Benefit	$ 1,309,349,331	$ 51,122,485
NPV (Total Benefit)	$ 474,502,923	
Overall NPV - Redevelopment	**$ (164,612,883)**	

Assumptions:	190,000	
	2%	
	Marginal cost of elec	$ 214.58
	Marginal cost of capacity	$ 243.60

NS Power

The Path to 2030 – 2025 Update

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1.0 EXECUTIVE SUMMARY

This *The Path to 2030* report is submitted to the Nova Scotia Energy Board (NSEB) in compliance with the Board's direction to "[f]ile 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."[1] *The Path to 2030* presented herein is aligned with the Government of Nova Scotia's (Province) 2030 Clean Power Plan and NS Power's Evergreen IRP Action Plan & Roadmap Update.

The Province's 2030 Clean Power Plan, released in October 2023, provides a comprehensive path forward for the province, and in particular NS Power, in meeting its 2030 Decarbonization Goals (defined further below at section 3.0) of achieving 80 percent electricity sales from renewable resources and the phase-out of coal generation by 2030. The 2030 Clean Power Plan aligns with NS Power's Evergreen IRP Action Plan & Roadmap Update (M11307) completed in partnership with stakeholders in 2023. The high degree of alignment between the 2030 Clean Power Plan and the updated IRP Action Plan and Roadmap is positive, indicating there is clarity on the actions required to achieve these goals. Collectively, the 2030 Clean Power Plan and NS Power's IRP Action Plan and Roadmap outline various investments and actions required to meet the 2030 Decarbonization Goals.

In 2024, following recommendations by the Clean Electricity Solutions Task Force, the Provincial government announced a plan to create a new Independent Electricity System Operator in Nova Scotia (IESO-NS). The creation of the IESO-NS changed the electricity planning landscape in Nova Scotia including several changes to the Project Accountability Matrix.

- As described in **Section 5.0** and **Section 6.2.2**, any future Battery Storage projects will be scoped and procured by the IESO-NS.

[1] NSEB Order, 2023 Annual Capital Expenditure (ACE) Plan (M11017), September 12, 2023.

- As described in **Section 5.0** and **Section 6.4**, all Fast-Acting Generation projects will be procured by the IESO-NS, including responsibility for the first 300 MW of generation capacity.

NS Power has been and remains committed to supporting the transition of accountabilities to the IESO-NS.

The new resources identified in the 2030 Clean Power Plan were summarized in **Figure 1** below in last year's *The Path to 2030* report. These resources were updated in NS Power's 10 Year System Outlook (10YSO) report submitted to the NSEB on July 14, 2025, and the updated timelines have been added to **Figure 1** for this year's Path to 2030 update. With respect to resources, sizing, and timing, this update to *The Path to 2030* report is consistent with the 2025 10YSO report unless otherwise noted.

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
Port Hawkesbury Paper Wind	168	2025	2026
Renewable to Retail Wind	149	2024	2026-2029[1]
Green Choice Program	262	2028	2028
Future Procurement	350		2029
Community Solar	100	2025-2029	2025-2029
Commercial Net Metering	50	2024-2029	2024-2029
Energy Storage Resources			
NS Power BESS Project	150	2025-2026	2025-2026
IESO-NS Procurement	50-250[2]	2026	2027[3]
Fast Acting Generation Resources			
Stage 1	300	2027	2027[4]
Stage 2	300	2029-2030	2029-2030[4]

	Nameplate Capacity (MW)	Initial Anticipated COD (Year)	Updated Anticipated COD (Year)
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[2]		
Total New Fast Acting Generation	600		
Total Fuel Conversions	609		
Load Management Initiatives	150	2025-2029	2025-2029
Total Coal Phase Out	1,229		

[1]Timing has been updated to reflect that this wind project will come online in phases. Please refer to **Section 6.1.3.3** for further details.

[2]Stated range is as per 2023 Clean Power Plan, actual size of additional battery capacity to be determined by IESO-NS.

[3]Stated COD is as per 10 Year System Outlook, actual timing of battery capacity additions will be determined by the IESO-NS.

[4]Stated COD is as per 10 Year System Outlook, actual timing will be updated following the IESO-NS led RFP.

These resource additions form a comprehensive strategy that allows for flexibility to accommodate future uncertainties. Through the ongoing Evergreen IRP Action Plan & Roadmap items, NS Power is closely monitoring factors which may influence *The Path to 2030*, including load management initiatives, electrification, and green hydrogen development. Achieving this significant transition will require the coordination and cooperation of a broad group of partners and stakeholders, including the Government of Nova Scotia, Independent Power Producers (IPPs), EfficiencyOne (E1), Mi'kmaw partners, NS Power, and the IESO-NS. These parties will have various accountabilities in the development and execution of projects that will add and integrate both renewable and dispatchable resources to the grid.

2.0 INTRODUCTION

In its 2023 Annual Capital Expenditure (ACE) Plan Order (M11017) on September 12, 2023, the Nova Scotia Utility and Review Board (NSUARB, Board) directed Nova Scotia Power Inc. (NS Power, Company) to:

> 1) 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.
>
> 2) Use its best efforts to file such a plan with the 2024 ACE Plan. Keeping in mind the usual November filing of the ACE Plan. If this is not possible, the Board directs that a detailed plan be filed by December 31, 2023.

In its 2024 ACE Plan Order (M11458) on August 13, 2024, the NSUARB provided the following direction:

> 5. The Board directs that NS Power file an update on The Path to 2030 in the ACE Plan on an annual basis until 2030.

In its 2025 ACE Plan Order (M12012) on August 19, 2025, the NSEB provided the following direction:

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

In compliance with the Board's direction, NS Power provides herein its *The Path to 2030 – 2025 Update* report, which describes the Company's plan to achieve its 2030 obligations. This document includes information regarding the following:

- The 2030 Decarbonization Goals
- The Province of Nova Scotia's 2030 Clean Power Plan
- Creation of the Independent Energy System Operator of Nova Scotia (IESO-NS)

- Resource Development Plan elements necessary to achieve the 2030 Clean Power Plan
- NS Power Integrated Resource Plan (IRP) Action Plan and Roadmap Items supporting the 2030 Decarbonization Goals
- Project Accountabilities, Coordination, and Risk Management considerations

Details related to these topics will provide greater specificity with respect to how the Company will meet its 2030 obligations, including more specific timelines for each element of its plan to do so.

3.0 2030 DECARBONIZATION GOALS

NS Power's 2030 decarbonization goals are mandated under several legislative and regulatory frameworks. Although there are many environmental regulations that apply to NS Power's planning and operating environment, the key items relating to planning for and achieving the 2030 obligations are described below. In this year's report there is no change to the details in **Section 3.1** 80 Percent Renewable Electricity Sales and **Section 3.2** Coal Phase Out.

3.1 80 Percent Renewable Electricity Sales

The Province of Nova Scotia amended the Renewable Electricity Regulations[2] on July 9, 2021. The amendment added a Renewable Electricity Standard for 2030 which provides that:

- Beginning in calendar year 2030, load-serving entities must supply customers with 80 percent renewable electricity.

- NS Power must acquire at least an additional 1,100 GWh from independent power producers to meet this new requirement.

- NS Power may incorporate contributions from renewable low-impact electricity acquired from a source outside Nova Scotia.

This requirement was incorporated into the most recent Evergreen IRP and is considered in the 2030 Clean Power Plan.

[2] N.S. Reg. 110/2021.

3.2 Coal Phase Out

The Province of Nova Scotia introduced the *Environmental Goals and Climate Change Reduction Act*[3] on October 27, 2021, and the legislation received Royal Assent on November 5, 2021. This Act includes the following elements that influence NS Power's system planning requirements:

- To have 80 percent of electricity sales in the Province supplied by renewable energy by 2030.

- To phase out coal-fired electricity generation in the Province by the year 2030.

In addition to the provincial goal to phase out coal-fired electricity generation by 2030, the federal Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations[4] prescribe various regulations on coal generating units, including a requirement to stop generating with coal by the year 2030. The requirement to phase out coal by 2030 was incorporated into the most recent Evergreen IRP and is considered in the Province of Nova Scotia's 2030 Clean Power Plan, described below.

3.3 Clean Electricity Regulations

Commencing in 2035 the Clean Electricity Regulations (CER)[5] will regulate the electricity sector in Canada toward achieving net-zero emissions by 2050. Following the Environment and Climate Change Canada's (ECCC) engagement process, of which NS Power was a participant, the final CER was published on December 18, 2024. The final CER is in alignment with NS Power's current long-term strategy as it supports the use of emitting generation in a peaking capacity. This is accomplished through the following requirements:

[3] S.N.S. 2021, c. 20.
[4] Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (justice.gc.ca) (SOR/2012-167).
[5] Canada Gazette, Part II, Volume 158, Number 26: Clean Electricity Regulations.

- Establishing an allowable emissions limit of 65 tonnes/GWh and the opportunity to purchase additional offsets at 35 tonnes/GWh until the end of 2049

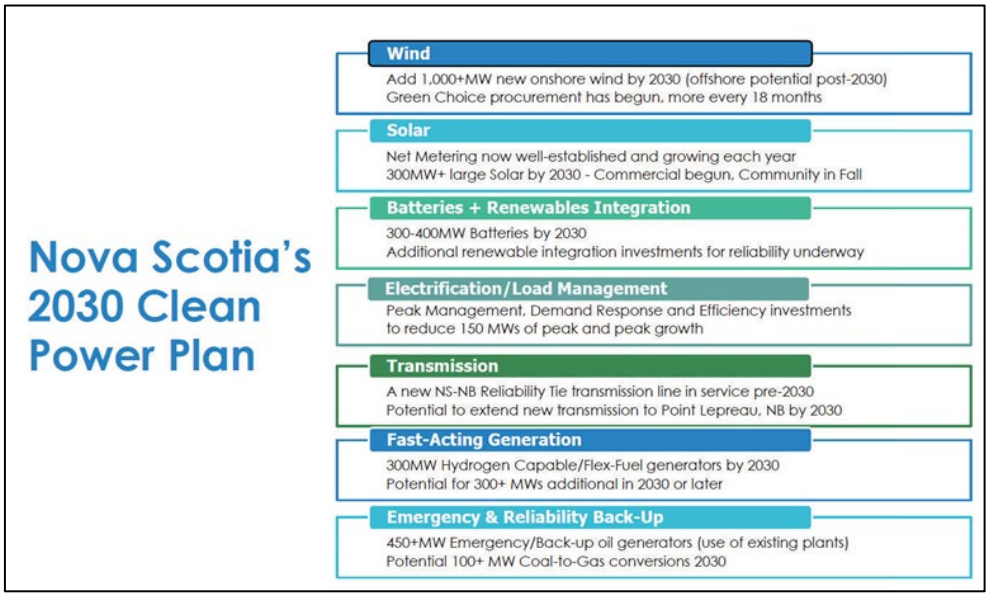
- The ability to pool the emissions for units commissioned by the end of 2029, which enables the optimized dispatch of the thermal units to minimize emissions and system costs

In addition, the CER establishes the potential for "planned unit" designation, which allows units in development that meet specific milestone criteria by the end of 2025, have started construction by 2027 and are in operation by 2035 to be exempt from the CER until the end of 2049.

4.0 NOVA SCOTIA'S 2030 CLEAN POWER PLAN

On October 11, 2023, the Province of Nova Scotia released the 2030 Clean Power Plan.[6] This release detailed the new resources that have been identified by the provincial government as being required to meet the 2030 decarbonization goals. A summary of the 2030 Clean Power Plan is shown in **Figure 2** below.

Figure 2 - Nova Scotia's 2030 Clean Power Plan (October 2023)



[6] nova-scotia-clean-power-plan-presentation-en.pdf (novascotia.ca)

5.0 NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR

In February 2024, the Clean Electricity Solutions Task Force, a task force commissioned by the Nova Scotia provincial government, submitted its final report titled, "Modernizing Energy from Transition to Transformation."[7] This report identified several recommendations for the electricity sector including the creation of an independent energy system operator and stand-alone energy regulator. On April 5, 2024, The Energy Reform Act - Bill 404 received Royal Assent in Nova Scotia, which in turn enacted the *More Access to Energy Act* (MAEA). The MAEA, amongst other things, mandates the creation of the Independent Energy System Operator of Nova Scotia (IESO-NS).

Since that time, the Province established the IESO-NS Board of Directors, and the Board of Directors has carried out various steps to further establish the structure and staffing of the IESO-NS. In particular, the IESO-NS has hired a Chief Executive Officer, begun the process of hiring various staff positions, and filed a "proposed expenditure and revenue requirements" application with the NSEB (M12412) on August 5, 2025. Accordingly, various provincial environmental mandate and Clean Power Plan responsibilities have also begun to be transferred from NS Power to the IESO-NS. As noted in the previous *The Path to 2030* update, the Department of Energy (DOE) has confirmed to NS Power that the IESO-NS will be responsible for several components of the Clean Power Plan:

- Any future Battery Storage procurements will be scoped and procured by the IESO-NS.

- All Fast-Acting Generation projects will be procured by the IESO-NS, including responsibility for the first 300 MW of generation capacity.

In its letter regarding the Decarbonization Deferral Account (DDA) – 2024 Annual Report, the Board directed NS Power to report on the particulars of the collaborative efforts made with the

[7] https://cetaskforce.ca/wp-content/uploads/2024/02/Report-February-23-2024-Final-Signed.pdf

IESO-NS to ensure the 2029 retirement dates will be met.[8] In accordance with the Board's directive, NS Power has provided an update on the transfer of work related to the procurement of fast-acting generation in **Section 6.4**. NS Power also provided an update in the Company's responses to NSEB information requests under the 2025 10 Year System Outlook Report proceeding (M12386). Please refer to M12386 NSEB IR-18 for details regarding the status and transfer of work related to procurement of future fast-acting generation and battery storage, as well as communications between NS Power and the Province confirming the transfer of responsibilities to the IESO-NS.

Furthermore, the Company notes that the IESO-NS has released a Request for Expression of Interest (REOI) for interested proponents to design, build, own and operate a fast-acting power generation facility at sites specified by the IESO-NS.[9] The REOI states a competitive Request for Proposal (RFP) process is expected to be completed by Spring 2026 for at least 300 MW with a targeted commercial operation date before the end of 2029.

The accountability Matrix in **Section 8.1** has been updated to reflect these changes. The IESO-NS is now positioned to take on its responsibilities with increased involvement, playing a significant role in planning and execution of various elements of *The Path to 2030*. NS Power continues to support the transition of accountabilities to the IESO-NS.

[8] M12303, 2024 Annual DDA Report, Board letter, October 17, 2025.
[9] IESO-Nova-Scotia-REOI-for-Capacity.pdf

6.0 RESOURCE DEVELOPMENT PLAN ELEMENTS

6.1 Wind and Solar Resources

The 2030 Clean Power Plan incorporates a significant quantity of new variable renewable generation which must be added to the grid by 2030. The required renewable energy projects will be procured by the Province of Nova Scotia, and in the future by the IESO-NS, via multiple streams, with NS Power supporting each of these as required. Updates on each procurement stream are provided below, including next steps and timing for each project stream.

6.1.1 Rate Base Procurement

The Rate Base Procurement (RBP) program was initiated by the Province of Nova Scotia in 2021. The goal of the RBP was to contract for 1,100 GWh of low-impact renewable electricity as part of meeting NS Power's 2030 Decarbonization Goals.

The RBP Program consists of four (4) projects totaling 306 MW and 1,165 GWh of wind generation. The RBP projects and their forecast commercial operation dates are summarized in **Figure 3**.[10]

Figure 3 - RBP Projects and Forecast COD

	COD
IR 673 Benjamins Mill	Dec 15, 2025
IR 669 Higgins Mountain	Jan 26, 2026
IR 668 Weavers Mountain	Dec 31, 2026
IR 677 Wedgeport	Nov 15, 2026

In 2025, NS Power collaborated with the RBP Interconnection Customers for the RBP projects, providing necessary engineering and construction support for both Network Upgrades and Transmission Provider Interconnection Facilities. There has been significant progress in these

[10] https://novascotiarbp.com/updates

projects to date: both IR-673 and IR-669 are expected to be in service in the near-term as per the forecast COD table (**Figure 3** above). In addition, both IR-668 and IR-677 are making progress in engineering and construction to achieve forecasted CODs.

6.1.2 Green Choice Program

The Green Choice Program (GCP) was established in April 2022 following amendments to the *Electricity Act*.[11] The goal of the GCP is to procure a minimum of 1,500 GWh, and up to 2,000 GWh, of new low-impact renewable electricity for which large-scale energy customers can contract to achieve their greenhouse gas emissions reduction targets while supporting the Province's 2030 decarbonization goals, per section 6B(3)(a) of the Renewable Electricity Regulations and per section 24 of the GCP Regulations.

As a voluntary corporate renewables program, GCP enables large energy consumers (with >10,000 MWh of annual load) or aggregated partnerships (with >1,000 MWh of annual load, individually, and with an annual minimum subscribed energy of 10,000 MWh) to subscribe up to 120 percent of their annual load to the renewable energy generation projects selected through the RFP process. The GCP procurement sought to solicit sufficient new renewable electricity to serve the subscribed load on an annual basis. NS Power is responsible to continue to plan and operate the system such that it has sufficient capacity available to supply the subscribed load.

NS Power will continue to support the GCP development by:

- Continuing to collaborate with DOE and their Procurement Administrator regarding details of the program administration and customer support processes.
- Verification of applicant consumption data and account status.
- Executing Participant Agreements with awarded Participants.

[11] S.N.S. 2022, c. 12.

- Submitting an annual report, on or before January 31 of each year, to the Minister and the Board as required under the Green Choice Program Regulations.[12]

In January 2025, six renewable energy projects were selected by the Procurement Administrator, COHO, under the GCP Portfolio.[13] These projects were awarded Power Purchase Agreements (PPAs), representing a total portfolio capacity of 622.5 MW. In June 2025, two of the six selected projects executed their PPAs and entered the System Impact Study phase, representing a total capacity of 262 MW. The status of these projects under the Generator Interconnection Process (GIP), along with their expected Commercial Operation Dates (COD), is summarized below:

Figure 4 - Green Choice Program Project GIP Status

	System Impact Study	Facilities Study	Generator Interconnection Agreement	Expected COD
IR 732 – Eigg Mountain Wind	In Progress	Pending	Pending	Dec 31, 2028
IR 826 – Sugar Maple Wind	In Progress	Pending	Pending	Dec 31, 2028

NS Power will continue to support the development of these projects by working with IESO-NS on the completion of System Impact Studies (SIS), and by completing the Facilities Studies, as well as planning and implementing the Transmission Provider Interconnection Facilities and associated Network Upgrades for each project.

In September 2025, the Province of Nova Scotia announced its intention to initiate a new procurement process to ensure the GCP achieves its targeted capacity.[14]

[12] Green Choice Program Regulations - Electricity Act (Nova Scotia)
[13] Green Choice Program Greening the Grid, Creating Jobs, Improving Energy Independence | Government of Nova Scotia News Releases
[14] Nova Scotia to redo wind energy procurement after 4 projects drop out | CBC News

6.1.3 Prescribed Generation Facilities

In August 2024, the Province amended the *Prescribed Energy-Storage Projects Regulations* to include prescribed generation facilities, creating the *Prescribed Generation Facilities and Energy-Storage Project Regulations* under subsections 4AA(8) and 4D(9) of the *Electricity Act (now Section 24 as amended by Powering the Offshore Act)*.[15] These Regulations were further amended in September 2025.[16] The Regulations specify commercial terms and conditions for the purchase of energy from generation facilities prescribed by the Province. Some of the facilities covered by these regulations include several wind projects included in *The Path to 2030*. October 2025 amendments to the *Electricity Act* capped the total aggregate output of generation facilities prescribed under the Regulations at 1,140 MW.[17] At present, seven wind power projects have been prescribed at an aggregate maximum nameplate capacity of 1,140 MW, three of which are listed in The Path to 2030 and have a combined nameplate capacity of 329 MW. For this year's version of the report these projects have been grouped together under a common section.

6.1.3.1 Port Hawkesbury Paper Wind (IR 618 and IR 742)

Port Hawkesbury Paper Wind (PHP Wind), a sister company to Port Hawkesbury Paper, is pursuing the development of a proposed 168 MW wind farm to support the long-term sustainable operation of the paper mill. The environmental assessment for this project was approved by the provincial government in March 2023, and groundbreaking for this project occurred in September 2024.[18] In 2025, on-site construction progressed including the building of roads, pouring turbine bases, pouring the foundation for the substation, and installing poles for the collection system.[19] PHP Wind continues to forecast commercial operation to start in the fourth quarter of 2026.

[15] Prescribed Generation Facilities and Energy-Storage Projects Regulations, N.S. Reg 179/2025. Accessed at: https://novascotia.ca/just/regulations/regs/elecpgfesp.htm
[16] Prescribed Generation Facilities and Energy-Storage Projects Regulations - Electricity Act (Nova Scotia)
[17] Bill 149, Powering the Offshore Act, Bill 149, 1st Session, 65th General Assembly, 2025 (as passed). Accessed at: https://nslegislature.ca/legc/bills/65th_1st/3rd_read/b149.htm
[18] https://www.cbc.ca/news/canada/nova-scotia/port-hawkesbury-paper-building-guysborough-county-wind-farm-1.7327216
[19] https://www.phpwind.ca/clc, September 23, 2025 Meeting Minutes

NS Power has been supporting the PHP Wind project as it moves through the GIP. There are currently two IRs associated with the project. Goose Harbour Lake I (IR 618) and Goose Harbour Lake II (IR 742). GIP status for the PHP Wind project is summarized in below:

Figure 5 - PHP Wind Project GIP Status

	System Impact Study	Facilities Study	Generator Interconnection Agreement	Expected COD
IR 618 - Goose Harbour Lake I	Complete	Complete	Executed	Dec 15, 2026
IR 742 - Goose Harbour Lake II	In Progress	Pending	Pending	Dec 15, 2026

6.1.3.2 Minas Highlands Wind Limited (IR 762)

Minas Highlands Wind Limited project is a 12.6 MW wind project located in West Hants Regional Municipality. The forecast commercial operation date for this facility is December 31, 2026.

Figure 6 - Minas Highlands Wind Limited Project GIP Status

	System Impact Study	Facilities Study	Generator Interconnection Agreement	Expected COD
IR 762 – Minas Highlands Wind	In Progress	In Progress	Pending	Dec 31, 2026

6.1.3.3 Renewable to Retail / Mersey River Wind Inc (IR 597 and IR 675)

The Renewable to Retail (RtR) electricity market was established in Nova Scotia in 2016 to enable independent licensed retailers to sell renewable energy generated within the Province directly to NS Power's retail customers. *The Path to 2030* and NS Power's 2025 10 Year System Outlook

contain 148.5 MW of new wind generation proposed to supply RtR customers (IRs 597 and 675) with first commercial operation anticipated in the fourth quarter of 2026.

On October 27, 2021, the Board approved an application by Renewall Energy Inc. (Renewall) for a Retail Supplier license to sell renewable low-impact electricity.[20] Under the terms described in Schedule A of the Board's Order, Section 71 identifies that if Renewall has not sold any renewable low-impact electricity under its license by December 31, 2024, it must apply to the Board demonstrating cause as to why the license should not be cancelled. Renewall submitted requests to the Board to extend its market entry on April 30, 2024, and again on November 1, 2024. On August 19, 2025, the Minister of Energy issued a conditional Power Purchase Agreement between Mersey River Wind Inc., and NS Power pursuant to section 4AA of the Electricity Act (now section 24), and in accordance with 7B of the Prescribed Generation Facilities and Energy-Storage Projects Regulations, to backstop the Mersey River Wind project. On September 24, 2025, Renewall wrote to the Board again, seeking to extend the deadline for first selling renewable low-impact electricity under its license to March 31, 2027. In all instances, the Board approved Renewall's request to extend its deadline for selling renewable low-impact electricity with the most recent deadline set to March 31, 2027.

In Renewall's September 24, 2025 extension request to the Board, Renewall described recent progress made in its efforts to enter the market and that construction on the Mersey River Wind Project is expected to begin soon. The Board accepted Renewall's submission that the Canadian Infrastructure Bank instructed Renewall to request a three-month extension as a contingency against unforeseen schedule delays and so the request to extend the deadline for selling renewable low-impact electricity to March 31, 2027 was approved.

Mersey River Wind Phase I (IR 597) is forecasted to reach commercial operation in Q4 2026. NS Power continues to support the project through design, engineering, and construction of Transmission Provider Interconnection Facilities (TPIF). The first 54 MW of Mersey Wind Phase

[20] M10293- Board Decision, 288061. October 27, 2021.

2 (IR 675) is forecast to reach commercial operation in Q1 2027, with the supporting operating study to be completed beforehand to assess system impact. This will bring the total installed capacity of the Mersey River Wind projects to 90 MW (36 MW from Phase I and 54 MW from Phase II). Mersey River Wind Phase II is expected to reach full commercial operation (112.5 MW) in Q1 2029.

In addition to these two interconnection requests, IR 739 (90 MW), associated with the RtR Program, has an active transmission interconnection request. NS Power is supporting its progress through the Generator Interconnection Process (GIP). IR 785 which had been included in the Path to 2030 – 2024 Update was withdrawn in 2025. The GIP status for RtR projects is summarized in **Figure 7** below.

Figure 7 - GIP Status for RtR Projects

	System Impact Study	Facilities Study	Generator Interconnection Agreement	Expected COD
IR 597 - Mersey Wind 1	Complete[1]	Complete	Executed	Sep 30, 2026
IR 675 - Mersey Wind 2	Complete	Complete	Executed	Mar 31, 2027[2]
IR 739 - Greenfield Wind	In Progress	Pending	Pending	To Be Determined
IR 785 - West Wind Farm	Withdrawn			

[1]This is a change from the 2024 update as the EMT analysis for IR 597 was incorporated into the IR 675 plant model, which was modified to include both IR 597 and IR 675 as a single plant.

[2]March 31, 2027 represents the COD for the first 54 MW of Mersey Wind 2.

6.1.4 Community Solar Program

The Community Solar Program launched in Q1 2024, following proclamation of amendments to the *Electricity Act*[21] and the registration of the Community Solar Regulations. The program was first conceived in April 2022, when the Government of Nova Scotia passed amendments to the *Electricity Act* (in SNS 2022, c 12, s 5) that enable a Community Solar Program, administered by NS Power, pending the Order in Council that came in 2024. The Province's stated goal[22] for the Community Solar Program is to enable at least 50 MW of new community solar generation and facilitate equitable access to renewable energy, including for those otherwise unable to install on-site renewables through either Commercial Net Metering or the self-generating option.

The program will encourage the development of new community solar gardens with a project nameplate capacity of between 0.5 MWac and 10 MWac. Each community solar garden project is built, owned, and operated by an eligible project owner which may include municipalities, towns, First Nations, not-for-profits, towns/townships and villages, business, co-operative, colleges and universities, or a partnership within the aforementioned. The program capacity for all community solar gardens combined is 100 MWac.[23]

The provincial DOE received NSEB approval for the Community Solar PPA (M11903) on January 30, 2025, and NS Power received NSEB approval for the Community Solar Energy Credit Rider (M11911) on February 12, 2025, which enables solar gardens to enter into PPAs with NS Power and customers to subscribe to the program.

The first project, a 0.585 MW community solar garden located at Pine Tree Park Estates in Sydney, Cape Breton has 44 residential and commercial subscribers, and enrolled in the program March 1, 2025. In March 2025, the Provincial DOE approved three additional Community Solar projects:

[21] S.N.S. 2022, c. 12, s 5.
[22] Action 18 contained within "Our Climate, Our Future – Nova Scotia's Climate Change Plan for Clean Growth" available at https://climatechange.novascotia.ca/sites/default/files/uploads/ns-climate-change-plan.pdf
[23] Nova Scotia Department of Natural Resources and Renewables, "Nova Scotia Community Solar Program Guide." February 2024. Accessed at: https://energy.novascotia.ca/sites/default/files/community-solar-program-guide.pdf

- A 4.8 MW community solar garden in Brooklyn, Annapolis County[24]
- A 1.7 MW community solar garden in Sydney[25]
- A 2.2 MW community solar garden in West Petpeswick[26]

The forecast commercial operation date for these three projects is Q3 2027. All three projects will be connected to the distribution system and it is anticipated that all future projects awarded under the Community Solar program will also be connected to the distribution system.

The Community Solar Program is a rolling application intake managed by the Provincial DOE. Once a project is approved by the Minister, the Project is awarded a PPA and can enter into a Distribution System Impact Study (DSIS) study window under the Distribution Generation Interconnection Procedures (DGIP).

As of October 7, 2025, NS Power has completed 31 preliminary assessments in 2025 for potential projects under the Community Solar program. One additional preliminary assessment is in progress. The 31 projects represent a total potential of 156 MW of installed capacity. Since commencement of the program, 79 preliminary assessments have been completed representing a total potential of 491 MW of installed capacity. Like the other renewable projects, once an application is accepted by the Minister and a PPA is awarded, NS Power will support the development of these projects via the completion of DSISs and Facilities Studies, and as required, the development of Interconnection Facilities and Network Upgrades associated with each project.

In 2027, on or before January 31, NS Power will file its first Community Solar program report with the NSEB as required by the Community Solar Program Regulations[27] and the Board Order from the Application for Approval of the Community Solar Energy Credit proceeding.[28]

[24] New Solar Garden Coming to Annapolis County | Government of Nova Scotia News Releases
[25] Second Solar Garden Coming to Sydney | Government of Nova Scotia News Releases
[26] New Solar Garden Coming to Rural HRM | Government of Nova Scotia News Releases
[27] Community Solar Program Regulations - Electricity Act (Nova Scotia)
[28] M11911, Application for Approval of the Community Solar Energy Credit Rider. Document 96741, Board Order

6.1.5 Commercial Net Metering

April 2022 amendments to the *Electricity Act (Nova Scotia)* established the framework for a new net metering program. October 2022 amendments to the *Renewable Energy Regulations*[29] required that NS Power develop and apply to the Board for approval of the new program by November 2022. NS Power received Board approval for the new Commercial Net Metering Program (CNMP) in July 2023. In August 2023, CNMP was made available for Class 1 Service (installations greater than 27 kW up to 100 kW) and, in October 2023, for Class 2 Service (installations greater than 100 kW up to 1 MW).

CNMP enables customers to generate renewable electricity from a variety of eligible sources (e.g. solar, wind, hydro) for their own use and to export excess electricity to NS Power. Energy exported to NS Power is banked and applied to the customer's next bill to offset energy drawn from the grid until the end of the calendar year. Customers participating in CNMP remain on their existing tariff and exported/banked energy is applied at a rate equivalent to the rate paid for electricity up to a maximum of the customer's total billed electricity within the same calendar year. In comparison to the legacy Net Metering program (under NS Power's Regulation 3.6), CNMP provides an expanded nameplate capacity limit (up to 1 MWac).

NS Power filed its second annual CNMP Report on March 27, 2025, which included the following highlights, as of December 31, 2024:

- 4,140.37 kW of solar PV installed with an estimated annual output of 4,528 MWh.
- 6,171.78 kW of additional solar PV pending installation with an expected annual output of 7,085 MWh.
- 82 percent of requests were for Class 1 Commercial Net Metering Service (Generators up to 100 kW).

[29] N.S. Reg. 338/2022.

- The remaining 18 percent of requests were for Class 2 Commercial Net Metering Service (Generators greater than 100 kW up to 1 MW).
- 12 percent of requests were for generators having a nameplate capacity greater than 200 kW (Nameplate capacity group 2).

As of October 10, 2025, NS Power has completed 16 preliminary assessments in 2025 for potential projects under the CNMP. The 16 projects represent a total potential installed capacity of 3.5 MW. Since commencement of the program 37 preliminary assessments have been completed for a total potential of 12.4 MW of installed capacity.

6.1.6 Additional Renewable Energy Procurements

The projects and programs identified above total approximately 800 MW of new wind generation and over 100 MW of new solar generation (depending on program uptake) beyond what is already in service on the Nova Scotia grid, all of which are anticipated to be in service by 2030. This represents a significant portion of the total resources identified in the 2030 Clean Power Plan as being required to meet 2030 Decarbonization Goals, but as identified in the 2025 10-Year System Outlook report, additional renewable energy is required to meet the 80 percent renewable standard. NS Power currently understands that the government and/or the IESO-NS are responsible for future renewable energy procurements if needed.

The Nova Scotia 2030 Clean Power Plan identifies the potential for additional procurement activities beyond those noted here to develop the remaining resource requirement needed to meet the 2030 80 percent renewable energy standard. In the 2025 10 Year System Outlook, NS Power recommended a new procurement process should be initiated targeting 1,000 – 1,200 GWh of low-impact renewable electricity in order to meet the 2030 80 percent renewable energy standard.[30] In September 25, 2025, the Nova Scotia Energy Minister announced the DOE was planning to reissue

[30] M12386, 2025 10 Year System Outlook, p. 21, lines 22 - 25

a call for new renewable energy sources and the Province was looking for a new procurement administrator to lead this initiative.[31]

6.2 Battery Storage & Renewable Integration Resources

The 2030 Clean Power Plan calls for deployments of grid-scale storage in Nova Scotia. In 2024 150 MW of 4-hour storage capacity was approved by the NSEB and additional storage capacity is anticipated to be added via future procurement activities.

6.2.1 NS Power Battery Storage Project (ECEI)

As per the Board's Decision and Order in NS Power's Battery Energy Storage System (BESS) Project (M11539), the Company filed an interim report with the NSEB on September 29, 2025 which included a high level summary of actual project costs incurred to date relative to initial estimates, the projected completion dates for the three BESS sites, and an update on external funding. The report can be accessed under Matter M12494.

As discussed in the report, the Bridgewater and Spider Lake BESS sites were reported to be on track for commercial operation in November 2025. Both sites are now expected to be in service by year end. Construction on the White Rock Road BESS site began in July 2025 and the site's control building will undergo acceptance testing at the fabricator in December 2025. The main power transformer was delivered and installed in November 2025. The White Rock Road site, which is the third and final BESS site under this project, is on track for commercial operation in July 2026.

[31] Nova Scotia to redo wind energy procurement after 4 projects drop out | CBC News

Figure 8 - Installed Battery Enclosures at Bridgewater BESS Site

6.2.2 Battery Storage Procurement

On March 22, 2023, the Province introduced amendments to the *Electricity Act*[32] that provide new procurement pathways for energy storage in Nova Scotia. Specifically, the amendments allow DOE to issue RFPs for energy storage solutions and contracts for well-developed, innovative energy storage projects that can be implemented quickly.[33]

In 2024 the Province confirmed to NS Power that all future energy storage capacity additions will be procured through a competitive process to be led by the IESO-NS. The quantity of energy storage capacity added via procurement and the timing of new energy storage additions is expected to be determined by the IESO-NS.

[32] S.N.S. 2023, c. 17.
[33] Electricity Act Amendments Allow More Energy Storage Solutions - Government of Nova Scotia, Canada

6.2.3 Grid Stability & Renewable Integration Resources

Transitioning from a traditional power system which is largely made up of synchronous generators to a power system which will rely heavily on inverter-based resources (IBRs) such as wind, solar, and battery energy storage, will require new sources of grid support for both existing and new inverter-based resources to allow for maximum integration of IBR in Nova Scotia while maintaining grid stability and reliability. These new sources include, but are not limited to, synchronous condensers, Flexible AC Transmission System (FACTS) devices, Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), switched and static capacitor banks, fast acting generation and transmission connections.

The transmission planning team, along with the system security team, have been collaborating to ensure the control system design parameters of the new IBRs aid in maintaining the stability of the grid. This is currently done by the completion of Model Quality Tests (MQTs) as well as commissioning studies.

Also, in alignment with *The Path to 2030*, NS Power is developing a synchronous condenser project. Following the directive issued to NS Power by the minister of DOE on January 16, 2024, NS Power has prioritized, for first installation, the inertial support for Benjamin's Mill and Wedgeport based on the studied grid conditions near those wind farms.

Found separately in this report are updates on BESS (see **Section 6.2.1**), Reliability Tie (see **Section 6.3**), and Fast Acting Generation (see **Section 6.4**).

6.3 NS-NB Reliability Intertie Project

The Reliability Intertie Project, a second 345 kV AC transmission line between Onslow, NS and Salisbury, NB required to improve the reliability of Nova Scotia's transmission link to the New Brunswick Power (NB Power) system and the broader Eastern Interconnection, continues to progress toward its target in-service date of Q4 2028. In Q1 2025, Wasoqonatl Transmission

Incorporated (WTI) was formed in Nova Scotia as an ownership arrangement pursuant to the *Prescribed Projects Regulations* made under the NS *Public Utilities Act*, to facilitate a low-cost equity investment in the Project by the Canada Infrastructure Bank (CIB). On April 10, 2025, WTI, a deemed utility under the *Public Utilities* Act (PUA), submitted an Application to the Board for the approval of the project cost estimate for the Reliability Intertie and the establishment of an opening rate base and return on equity for WTI. On November 20, 2025 the NSEB issued a Decision and Order approving the NS-NB Reliability Intertie Project. In its Order, the Board directed WTI to file an update about the status of the Intertie project in relation to *The Path to 2030* timeline and be a party to NS Power's annual ACE Plan proceedings. The following update is provided in fulfillment of the Board's directive.

As noted in WTI's Reply Evidence in M12217 filed August 22, 2025, land acquisition activities for the Project continue to proceed as planned in both Nova Scotia and New Brunswick. WTI currently has access to over 98 percent of the transmission line route required in Nova Scotia and is currently securing access trails required for construction. In New Brunswick, 92 percent of offers required to secure the necessary land rights in NB have been made to landowners and 22 percent of those offers have been accepted as of mid-November. Right-of-way (ROW) clearing for the Nova Scotia portion of the Reliability Intertie began in early September 2025 near the Onslow 67N substation to support the east to west linear construction of the project. As of this filing, clearing of segments one and two of the Nova Scotia ROW is complete ahead of schedule and work is advancing to clear the final NS ROW segment near the NS/NB border.

NS Power received approval for the Environmental Assessment of the Nova Scotia portion of the Reliability Intertie in December 2023. New Brunswick Power (NB Power) submitted the Environmental Impact Assessment (EIA) for the NB portion of the Project in late December 2024 and is expected to receive approval of the EIA in December 2025. Vendors have been selected for all major material and contract procurements required for the Project. This includes materials for the transmission line conductor, towers and foundations and key contracts such as ROW clearing and transmission line construction.

The Decision Gate 3 (DG3) governance milestone is planned for December 2025. Advancement of the project through DG3 enables project sanction, with kickoff of the construction contract in Q1 2026. This will be followed by the mobilization of the construction contractor, set up of the marshalling yard to receive materials and preparations for tower foundation selection. As per the Board's direction in its Decision in M12217, WTI will confirm to the NSEB and registered parties in that matter when all conditions have been satisfied to meet Decision Gate 3.

6.3.1 Stage 2

The 2030 Clean Power Plan notes the potential for the Reliability Intertie to incorporate a Stage 2 transmission build from Salisbury NB to Point Lepreau NB, to enable greater access to New Brunswick, New England, and Quebec energy imports and exports. This extension would also be accompanied by additional upgrades within Nova Scotia such as the conversion of L-7018 230 kV line to 345 kV (120H-Brushy Hill to 67N-Onslow) and additional transformation capacity at 67N-Onslow. At this time, NS Power is not engaged in discussions with NB Power regarding Stage 2 of the Reliability Tie. NS Power is committed to working with the Nova Scotia government, the IESO-NS, New Brunswick government, NB Power, and other engaged parties on further evaluating interregional transmission expansion that could benefit Nova Scotians, as opportunity presents.

6.4 Fast-Acting Generation

The 2030 Clean Power Plan identifies a need for 300MW of new fast acting generation by 2030, with the potential for 300+ MWs additional in 2030 or later, for a total of 600 MW or more of new fast-acting generation. The need for new fast-acting generation capacity was also confirmed in the Evergreen IRP analysis and it was included as part of Action Item #3c in the August 2023 update to the IRP Action Plan and Roadmap, which points to a range of 600MW to 900MW of additional fast acting generation.[34] The IRP Action Plan is clear that a significant increase in system firm

[34] Nova Scotia Power Evergreen IRP, August 8, 2023, pg. 15

capacity is required to maintain supply reliability while meeting growing peak demand requirements and replacing firm capacity that will be retired to comply with the 2030 coal phase-out policy requirements. NS Power's further study conducted in support of its 2024 and 2025 10 Year System Outlook reports identified the need for the full 600MW of fast acting generation by 2030. The 2025 10 Year System Outlook report provided, in part, the following:

> The 2024 10-Year System Outlook report included 600 MW of new fast-acting generation to be installed by 2030 to provide firm capacity to maintain supply reliability while meeting growing peak demand requirements, and to replace firm capacity that will be retired to comply with the 2030 coal phase-out policy requirements. 2030 is also a key date for the Clean Electricity Regulations (CER) as the pool size for the sharing of compliance credits is based on thermal capacity commissioned before January 1, 2030. Having new thermal capacity online before 2030 creates more flexibility for the system to maintain compliance with CER and minimizes costs for customers.[35]

In 2024, NS Power had been developing a 300 MW fast-acting generation project in alignment with both the 2030 Clean Power Plan and the IRP Action Plan with an expected in-service date of 2027. In the Fall of 2024, the Department of Natural Resources and Renewables informed NS Power that procurement of all new fast acting generation will be the responsibility of the IESO-NS, including responsibility for the first 300 MW of generation. This update in accountabilities was reflected in *The Path to 2030 – 2024 Update* filed under M12012.

Upon receiving direction from the Province that procurement of fast-acting generation would be led by the IESO-NS, NS Power worked to consolidate and transfer all relevant project materials, including preliminary engineering work, site selection studies, and technical assessments to the Province by November 28, 2024 so that the Province and IESO-NS were equipped to proceed without delay. NS Power also committed to an ongoing advisory role and has actively supported the IESO-NS in 2025 through ongoing meetings, providing technical input, clarifications, and emphasizing the urgency of maintaining project momentum.

[35] M12386, NS Power 2025 10 Year System Outlook Report, July 14, 2025, page 22.

In *The Path to 2030 – 2025 Update*, capacity and timing for new fast-acting generation has been assumed to be the same as the 2025 10-Year System Outlook report and *The Path to 2030 – 2024 update*. On October 16, 2025, the IESO-NS issued a Request for Expression of Interest (REOI) for interested proponents to design, build, own and operate a fast-acting power generation facility at sites identified by NS Power through NS Power's preliminary engineering work.[36] The REOI also states a competitive Request for Proposal (RFP) process is expected to be completed by Spring 2026 for at least 300 MW with a targeted commercial operation date before the end of 2029.

In its Expenditure and Revenue Requirement application, IESO-NS stated it was investigating a capacity contract opportunity.[37] In IR responses, the IESO-NS further stated that the capacity contract being investigated was for a 100 MW Simple Cycle Combustion Turbine (SCCT) with an expected commercial operation date in Fall 2028.[38] The addition of a capacity contract, backed by a 100 MW SCCT, is consistent with *The Path to 2030*'s need to add fast-acting generation by 2030.

NS Power anticipates that clear direction on project timelines will be available in 2026, following completion of the IESO-NS-led RFP. If it is evident following this RFP that the currently anticipated timeline is not achievable, NS Power will, in collaboration with the IESO-NS, consider the appropriate alternatives, including but not limited to options such as adjusting unit retirement dates, requesting equivalency agreements to extend the use of coal until replacement capacity is online, or converting all existing coal facilities to alternative fuels (fuel switching).

6.5 Fuel Conversions at Existing Units

The 2030 Clean Power Plan includes alternate fuel operation at four of NS Power's existing thermal units. Similarly, the Evergreen IRP identified that alternate fuel operation at four units was

[36] IESO-Nova-Scotia-REOI-for-Capacity.pdf
[37] M12412, NSIESO – Proposed Expenditure and Revenue Requirements, Exhibit N-1-(i), p. 27.
[38] M12412, NSIESO – Proposed Expenditure and Revenue Requirements, Exhibit N-9 NSIESO (Synapse) IR 4, p.7.

a common resource plan element across IRP scenarios, and these were included in the IRP Action Plan under item #3e.

6.5.1 Gas Conversion at Point Tupper Generation Station

The coal-to-natural-gas conversion of Point Tupper Generating Station Unit 2 (150 MW) emerged as a consistent outcome across all scenarios modeled in the 2023 Evergreen Integrated Resource Plan. In each case, the converted unit was identified as a cost-effective peaking resource, operating at low annual capacity factors to support system reliability during periods of net peak demand. This conversion aligns with the Clean Power Plan and the legislated phase-out of coal generation by 2030. NS Power is targeting completion of the conversion by 2028, ensuring the unit remains available to provide firm capacity as new renewable and fast-acting resources are commissioned.

The value of this conversion was first identified in the 2020 IRP, which demonstrated its economic and operational benefits in a peaking role. Following that finding, NS Power initiated a coal-to-gas conversion project, completing preliminary engineering design and economic assessments to define scope and evaluate feasibility. To meet the targeted 2028 in-service date, key activities such as detailed design and procurement are planned to advance in 2026. These efforts will maintain alignment with the Clean Power Plan and ensure the unit is available to support system reliability during the coal phase-out period.

6.5.2 HFO Operation at Lingan Generation Station

Transition to the peaking use of Heavy Fuel Oil (HFO) for Lingan units 1, 3 and 4 (approximately 450 MW total) was identified in the 2030 Clean Power Plan and emerged as a consistent outcome across all 2023 Evergreen IRP scenarios. The value of this conversion is supported by the low capital cost (these units already operate on HFO) and the ability for these units to operate in a peaking capacity during periods of net peak demand.

The 2029 timing for conversion to exclusive HFO operation for Lingan Units 1, 3, and 4 aligns with the planned phase-out of coal generation by 2030 and supports the recognized need for dispatchable capacity, including both gas and liquid-fueled resources. This need is consistent with the finalized Clean Electricity Regulations, published by the Government of Canada in December 2024, which emphasize the importance of maintaining grid reliability while reducing emissions from fossil-fueled generation.

While no major project execution activities were required to be undertaken in 2025, enabling the 2030 plan will require advancement of several supporting initiatives. Preliminary engineering work for an auxiliary boiler system intended to provide site heating during periods of low unit utilization was initiated in 2025 and will continue into 2026. This system is expected to support operational readiness while minimizing emissions. Additionally, NS Power intends to undertake a preliminary engineering review in 2026-2027 of HFO unloading and transfer capabilities at the Sydney International Pier. This review will assess the feasibility of transitioning from truck-based delivery to marine vessel unloading and rail transport to Lingan, which could improve fuel delivery logistics.

Project milestones, regulatory engagement, and design work are planned to advance in 2026 to maintain alignment with the Clean Power Plan and ensure the continued availability of these units as dispatchable generation units.

6.6 Coal Generation Phase-Out

The significant addition of new resources described above is designed to both enable coal phase-out and support the forecast of continued load growth on the system. In parallel with these resource additions, NS Power analyzed the timing of coal unit retirement and conversion as part of the Evergreen IRP process in 2023. The IRP scenarios determined it was optimal to retain coal units as late as the model allows, with retirements and/or fuel switching occurring later in the 2020s.[39]

[39] Nova Scotia Power Evergreen IRP, page 6

The 2025 10-Year System Outlook reinforces that the phase-out of coal generation continues to be dependent on the successful procurement and commissioning of new firm capacity resources. These include fast-acting generation technologies such as combustion turbines, which are essential to maintaining system reliability and meeting planning reserve margin requirements as coal units are retired.

The retirement dates in the 2025 10-Year System Outlook remain consistent with those from the 2024 10-Year System Outlook and *The Path to 2030 - 2024 Update*, which aligned the retirement of Lingan 2 and Trenton 5 with the first round of anticipated new fast acting generation additions, and the retirements of Trenton 6 and Point Aconi with the second round. These dates will continue to be evaluated as the timing of new resources, forecast for demand growth, and policy factors evolve. The forecast coal retirement and conversion dates are summarized in **Figure 9**.

Figure 9 - Coal Retirement and Conversion Dates as Reported in the 2025 10-Year System Outlook Report

Unit	Forecast Retirement/ Conversion Date	Notes
Lingan 1	2029	Converted to HFO operation (reliability resource)
Lingan 2	2027	Currently operating in Cold Reserve
Lingan 3	2029	Converted to HFO operation (reliability resource)
Lingan 4	2029	Converted to HFO operation (reliability resource)
Trenton 5	2027	
Trenton 6	2029	
Point Aconi	2029	
Point Tupper	2028	Converted to Gas operation

As new firm capacity resources are added to the system, retaining existing thermal units in cold reserve may support commissioning, testing, and the establishment of reliable operations without compromising the system's planning reserve margin. NS Power assumes this option will continue to be evaluated as part of ongoing resource planning conducted by the IESO-NS.

7.0 ADDITIONAL IRP ACTION PLAN AND ROAD MAP ITEMS

In addition to the items identified in the 2030 Resource Development Plan, there are other elements of the broader IRP Action Plan which have specific and significant impacts on resource development requirements to 2030. These are highlighted below.

7.1 Demand Side Management

In September 2022, EfficiencyOne (E1) received approval for an investment of $173.1 million for its 2023-2025 DSM Plan activities. The plan targets 412.7 GWh and 78.8 MW in energy efficiency (EE) savings over the three-year period, and 17.9 MW of available capacity from demand response (DR) programming by the end of 2025. In its Enabling Strategies component, E1 plans to support electrification strategy development. In November 2022, the Government of Nova Scotia passed amendments to the PUA under Bill 228.[40] The amendments included replacing references to "energy efficiency and conservation activities" with "demand-side management," and expanding the definition of "demand-side management" to include "strategic electrification of energy end uses […]" under Section 79A(b).[41] Further legislative changes occurred in 2025 – the creation of the Nova Scotia Energy Board with a mandate that, in addition to energy efficiency, calls for consideration of sustainable development, sustainable prosperity, and greenhouse gas emission reduction goals as part of its decision-making authority on such DSM activities. Given that DSM activities have expanded outside traditional energy efficiency, achievement of current planned investments in 2023 to 2025, and development of DSM investments in alignment with the Base DSM profile identified in the 2023 Evergreen IRP, are increasingly important to achieving the 2030 decarbonization goals.

In March 2025, further amendments to the PUA[42] extended E1's current 2023-2025 DSM Plan term for an additional year with a prescribed total DSM investment at $63.75 million in 2026 (the

[40] S.N.S. 2022, c. 53.
[41] Bill 228 also prescribed five-year terms for DSM purchase agreements and portfolio-level evaluation of proposed cost-effective DSM programs.
[42] Bill 6 – An Act Respecting Agriculture, Energy and Natural Resources. March 26, 2025.

Extension Period). As such, E1's prior five-year DSM Plan development was temporarily paused while E1 prepared and filed its 2026 DSM Plan Extension Application, which remains an open Matter before the Board.[43] E1's 2026 DSM Plan targets 116.0 GWh and 18.9 MW in EE savings over the one-year period, and 16.3 MW of available capacity from DR programming by the end of 2026. Taken as a whole, E1's 2023-2026 Performance Targets are proposed, as part of the 2026 DSM Extension, to be 528.7 GWh (of which 19.8 GWh of savings from dedicated low-income and equity programs) and 97.7 MW of EE savings, and 16.3 MW of available DR capacity at an aggregate investment of $236.8 million.[44]

On May 16, 2025, E1 filed an Application for approval of a new jurisdictional cost-effectiveness test and framework.[45] Through this, and the prior 2026-2030 DSM Plan development work, NS Power engaged with the DSMAG to update the avoided costs, using modeling built on NS Power's 2023 Evergreen IRP analysis. On October 30, 2025, E1 reviewed its Round One 2027-2031 DSM Plan model results with the DSMAG. NS Power continues to review and engage with the DSMAG on the development of the 2027-2031 Plan. It is anticipated that this will lead to an application before the Board in 2026. NS Power's focus in reviewing the plan will be affordability, peak mitigation, and strategic electrification.

7.2 Hybrid Peak / Load Management / Demand Response

As a component of NS Power's development of its electrification strategy report, it worked with consultant Energy and Environmental Economics (E3) to prepare load and system peak load forecasts for various heating electrification scenarios. Of the heating electrification load profiles considered, the hybrid peak electrification profile emerged as an opportunity for reduction of system peak load requirements and was studied as part of the Evergreen IRP. This scenario assumes the adoption of mini-split heat pumps along with the retention of existing back up heating

[43] M12249 – EfficiencyOne, Approval of the 2026 DSM Extension for Demand-Side Management Activities between EfficiencyOne and Nova Scotia Power Inc., and for Approval of the Amendment to the 2023-2025 Demand-Side Management Purchase Agreement between EfficiencyOne and Nova Scotia Power Inc. April 30, 2025.
[44] M12249 – E1 2026 DSM Extension Application, Appendix A, Table 23, page 47.
[45] M12282 – E1, Approval of a New Benefit-Cost Analysis Test for Evaluating Demand Side Management (DSM) Plans. May 16, 2025.

sources (such as oil and natural gas) to operate during the colder/peak system demand periods in the winter when heat pumps are less efficient. This potential program has been considered and discussed in NS Power's Load Forecast Reports since 2023; additional details are available as part of E3's report *The Economics of Electrification in Nova Scotia* which was shared with stakeholders via NS Power's IRP website on December 8, 2023.[46] The Evergreen IRP assumptions for this program incorporate a firm peak reduction of approximately 100 MW by 2030.

To fully assess the value of the hybrid peak scenario, NS Power committed to participating in study work to determine the corresponding cost impacts of potential customer programs (please refer to the IRP Action Plan Item 4b). This study, with engagement and participation from multiple organizations including NS Power, will provide a balanced assessment of the cost impacts of the hybrid approach and provide the necessary information to conduct a more refined assessment of the program from an electricity system cost perspective.

In the fall of 2024, Net Zero Atlantic (NZA) initiated a study to examine Hybrid Peak options on behalf of DOE. The study includes participation from key stakeholders within the province including DOE, E1, and NS Power. The scope for the study is:

- A jurisdictional scan of hybrid-heating programs in other cold climate regions
- A customer survey
- Electric-system modelling to understand system level benefits
- An outline of possible program operationalization models
- Creation of a public report

NS Power is executing resource planning modeling in support of the study objectives. The current estimated timeline for completion of the study is Q1 2026.

[46] The Economics of Electrification in Nova Scotia (nspower.ca)

In addition to the electrification strategy, the outcome of the 2020 IRP also pointed to the value of DR programming to reduce peak load requirements. NS Power (with support from E1) is progressing DR pilot programming with the intent of developing 75 MW of DR peak load reductions. This includes work in the areas of direct load control for residential, commercial, and industrial classes as well as NS Power's ongoing time varying pricing (TVP) pilot program.

During the winter 2024/25 period (December 1, 2024 – February 28, 2025), DR events were scheduled by NS Power through E1's Smart Synergy Commercial & Industrial Aggregator DR program and new Eco Shift DR pilot program. 2024/25 season enrollment, as presented in E1's Q2 2025 Demand Side Management Report, totaled approximately 175 Smart Synergy participants contributing approximately 6.6 MW BNI dispatchable capacity and approximately 4,000 Eco Shift participants, including mostly smart thermostats, domestic hot-water controllers, with provisions for and growing asset bases of managed EV charging and residential batteries, contributing roughly 0.6 MW residential dispatchable capacity. Device enrollment and installations increased significantly through early 2025, positioning the portfolio to deliver several megawatts of dispatchable capacity for the 2025/26 season through both direct-install and bring-your-own-device offerings for mini-split heat pump thermostats and residential battery systems. Together, NS Power and E1 are targeting up to 75 MW of combined DR capability across residential, commercial, and industrial sectors through the mid-term planning horizon.

As this collaborative portfolio continues to mature, NS Power's TVP Tariff pilot continues to demonstrate strong value as an effective mechanism for encouraging load shifting to improve system efficiency and for engaging customers through innovative rate options. Over the past four years, the program has consistently delivered measurable demand reductions and received positive feedback from participants.

The 2024/25 season (November 1, 2024 to March 31, 2025) built on this success by expanding participation and implementing targeted enhancements. These included internal development of the annual evaluation report and ongoing collaboration with stakeholders. On November 1, 2024, the Company also launched the Multi-Unit Residential Building (MURB) TOU pilot, co-

developed with property owners and industry stakeholders, to explore new opportunities for flexible load management in electrified multi-tenant settings.

Engagement efforts during the season included a kickoff meeting in November 2024 to present the Year Three (2023/24) evaluation findings and a draft of the 2024/25 Areas of Focus Work Plan. This was followed by the release of the updated Work Plan in January 2025 and the delivery of two scheduled Technical Sessions.

On October 1, 2025, the Company's filed its proposed approach for the upcoming TVP Season (November 1, 2025 to March 31, 2026). The Board issued its Decision on October 28, 2025,[47] directing NS Power to amend TVP Tariffs to align with standard offer rates during the temporary suspension of system functionality. In its Decision, the Board emphasized the importance of rate equity and clarified that TVP participants will remain enrolled and that full TVP functionality may resume mid-season, subject to system restoration and notification requirements.

NS Power submitted its TVP Compliance Filing, which reflects these directives, on December 8, 2025. The Company remains committed to minimizing disruption, maintaining program continuity, and preparing for the resumption of full TVP operations.

NS Power also concluded its Smart Grid Nova Scotia (SGNS) project in 2024 with proceedings continuing through 2025, confirming the technical feasibility of distributed energy resource (DER) coordination and providing evidence of its potential to deliver value across affordability, reliability, and environmental objectives. The project validated the role of a Distributed Energy Resource Management System (DERMS) in orchestrating diverse DER assets to provide measurable system benefits. Following the Board's October 2024 decision on the SGNS Final Report (M11621), NS Power initiated the Distributed Energy Resource Integration Roadmap (DERIR) (M12177), engaging Dunsky Energy + Climate Advisors to support jurisdictional scan, framework development, and stakeholder engagement.

[47] M12499 – Board Decision, 325286. October 28, 2025.

Through 2025, NS Power has made steady progress on the DERIR initiative. The initial framework, first stakeholder workshop, development of list of DER-related initiatives, second stakeholder workshop, and one-on-one interviews with participation from government, academia, advocacy organizations, and industry, were conducted by end of November 2025. Feedback from stakeholders is informing the prioritization of potential DER-related initiatives in Nova Scotia. Further stakeholder engagement sessions are planned for early 2026, after which the Company will finalize and submit a DERIR report to the NSEB. NS Power will be submitting a DERIR progress update letter to the NSEB by year-end 2025.

7.3 Green Hydrogen Projects

NS Power has had discussions with multiple potential green hydrogen project developers to understand their requirements and provide information about the Nova Scotia power system. In 2025, NS Power continued work with three project developers, EverWind Fuels (EWF), Bear Head Energy (BHE), and Nova Sustainable Fuels Ltd. (NSF, formerly Simply Blue Group) to understand the industry's needs from both operational and tariff perspectives. EWF and BHE intend to produce green hydrogen primarily for export, while NSF is looking at the production of green hydrogen as a feedstock for sustainable aviation fuel and renewable methanol.

Since The Path to 2030 resource plan described in this document is based on a load forecast that does not include additional capacity or energy requirements to support these large load customers, incremental resources to meet both the firm load and renewable energy needs of the developers will be required. Given the timelines and the significant load requirement, the following outlines the common approach by the developers:

- Developers will self-develop and supply renewable resources including a mix of wind, solar and battery storage (depending on the developer).
- Developers will require interaction with the Nova Scotia power grid under a new tariff structure for the following:

- Top up in hours when their self-supplied resources do not meet their firm load requirements or, in some cases, when additional resources are required to meet their target annual load factor. Firm load requirements range between 35 MW and 100 MW for the prospective developers.
- Energy sales when their self-supplied resources exceed their load requirements and these additional resources are a benefit to NS Power customers.

To ensure that any future developments related to hydrogen development in the province are monitored and assessed, NS Power included IRP Roadmap Item 11 (Hydrogen Tariff Impacts) to enable the assessment of the tariff impacts on the Action Plan as they develop.

On December 15, 2023, the Province of Nova Scotia released its Green Hydrogen Action Plan.[48] The plan includes seven goals and 23 actions to help develop the sector in alignment with the Province's climate change goals. It will support both domestic use and export of green hydrogen. The plan also identifies green hydrogen as a potential complementary fuel source for the electricity system that can help meet peak or emergency demand consistent with the Province's Clean Power Plan.

7.4 Offshore Wind

In September 2022, the provincial government announced a goal of leasing 5 GW of offshore wind, with specific emphasis on supporting the green hydrogen industry. Since that time, the NS DOE has established an offshore wind procurement schedule, which would see the initiation of offshore wind operations in approximately 2033 – 2035.

[48] https://novascotia.ca/green-hydrogen/docs/green-hydrogen-action-plan.pdf

The following are existing and future milestones to enable this:

- NRCan and the NS DOE designated Wind Energy Areas (WEA), which will be managed by the Canada Nova Scotia Offshore Energy Regulator (CNSOER), in July 2025.

- A strategic direction letter was provided by the Federal and Provincial Government to the CNSOER on September 18, 2025,[49] which prioritizes the development area to three WEA, identifies the range of installed capacity for offshore wind projects, and provides detail on the revenue regime and prequalification process guidelines.

- Call for bids and licensing for offshore wind projects will commence following the prequalification process, anticipated to occur in 2026.

With development timelines that currently extend beyond 2030, offshore wind does not play a role in the 2030 Clean Power Plan. However, given the potential installed capacity (5 GW) and market opportunities for offshore wind, NS Power continues to monitor industry and local developments to inform future planning exercises.

The NZA-led Atlantic Canada Offshore Wind Grid Integration and Transmission Study,[50] which was initiated in 2024, is underway and Phase 1 of the study is published and was made available by NZA. The outcomes of the Phase 1 study point to the potential value of Offshore Wind in meeting domestic long-term decarbonization goals by supporting electrification load due to economy-wide decarbonization, hydrogen development, and creating export opportunities. Phases 2 and 3 are in progress and will evaluate the resource potential/operational costs in more detail and identify a transmission expansion plan to support OSW, respectively. Ultimately, this study is anticipated to be completed in Q1 2026 and will provide a thorough understanding of the opportunities and challenges for integrating OSW into the Atlantic Canadian grid, both provincially and regionally (from both a domestic and export lens). NS Power is participating in

[49] Government of Canada and Nova Scotia Set Direction for Offshore Wind Future - Canada.ca
[50] https://netzeroatlantic.ca/research/atlantic-canada-offshore-wind-grid-integration-and-transmission-study

the study through the vetting of assumptions and outcomes of the modelling work provided by NZA and their partners.

8.0 PROJECT ACCOUNTABILITIES, COORDINATION, AND RISK MANAGEMENT

NS Power believes that the Nova Scotia 2030 Clean Power Plan is a comprehensive and appropriate clean energy transition plan. It is based on extensive studies and stakeholder engagement.

8.1 Project Accountabilities

Figure 10 below summarizes the role of NS Power, IESO-NS, and the Province of Nova Scotia in each of the major projects/elements of the 2030 Clean Power Plan. Overall, the NS Government is responsible for the renewable energy projects and load management to meet 2030 RES targets until those responsibilities are transferred to IESO-NS. NS Power is responsible for fuel conversions for existing generation units, transmission and supporting infrastructure to meet off coal targets, and integration of the procured renewable energy. IESO-NS is responsible for future battery storage and fast acting generation procurements.

Figure 10 - Project Accountabilities Matrix

2030 Projects	Accountability	NS Power Key Action Items	IESO-NS Action Items	NS Government Key Action Items	Partner Key Action Items
Wind/ Solar	NS Government	• Develop and own grid integration assets for projects serving base customers. • Transition responsibility for system impact studies to IESO-NS for transmission connected resources.	• Assume responsibility for completion of system impact studies for transmission connected resources from NS Power.	• Procure renewables from IPPs to reach RES targets.	• IPPs develop, construct, and operate renewable projects.

2030 Projects	Accountability	NS Power Key Action Items	IESO-NS Action Items	NS Government Key Action Items	Partner Key Action Items
		• Implementation of TPIF and associated Network Upgrades.			
Battery Storage	IESO-NS and NS Power	• Procure and finance 150 MW / 600 MWh storage through utility regulated model including competitive procurements for required products and services. • Integrate IPP energy storage projects into NS Power's processes and operations. • Implementation of TPIF and associated Network Upgrades.	• Procure additional Energy Storage resources, incremental to NS Power's 150 MW project. • Take over responsibility for completion of system impact studies from NS Power.	• Transfer of procurement responsibilities to IESO-NS.	• IPPs develop, construct, and operate additional grid scale storage.
Grid Stability and Renew-able Integration Resources	NS Power	• Transition responsibility to identify required assets through IPP renewable project siting and detailed system studies to IESO-NS. • Procure and finance through utility regulated model including competitive	• Take responsibility for identifying required assets through IPP renewable project siting and detailed system studies.	• Coordinate preferred IPP project siting based on detailed system studies. Incorporate into procurement processes.	• IPPs develop renewable projects in compliance with NS Power's Transmission System Interconnection Requirements (TSIR)

2030 Projects	Accountability	NS Power Key Action Items	IESO-NS Action Items	NS Government Key Action Items	Partner Key Action Items
		procurements for required products and services.			
Hybrid Peak / Load Mgmt.	NS Government	• Provide detailed load studies and forecasts. • Participate in broader sector study on Hybrid Peak opportunity. • Collaborate in development of load management initiatives.	• Participate in broader sector study on Hybrid Peak opportunity.	• Deliver load management initiatives through policies and program tools.	• E1 and other partners to support peak management, demand response, and efficiency programming. • Net Zero Atlantic to complete Hybrid Peak study.
Reliability Tie	NS Power	• Procure and finance through utility regulated model, including competitive procurements for required products and services. • Work with other parties to evaluate interregional transmission expansion opportunities.		• Ensure coordinated review and issuance of required authorizations. • Advocate for federal support and funding. • Continued engagement with NB Government on extension to Point Lepreau.	• NB Power to complete work to enable transmission connection to Salisbury, NB.
Fast-Acting Generation	IESO-NS	• Implementation of TPIF and associated Network Upgrades.	• Procure required Fast-Acting Generation resources • Take over responsibility for	• Ensure coordinated review and issuance of required authorizations.	

2030 Projects	Accountability	NS Power Key Action Items	IESO-NS Action Items	NS Government Key Action Items	Partner Key Action Items
			completion of system impact studies		
Fuel Con-versions	NS Power	• Procure and finance through utility regulated model including competitive procurements for required products and services.			

8.2 Implementation Coordination

The Province of Nova Scotia and NS Power are both committed to meeting 2030 coal phase-out and 80 Percent Renewable Energy Standard targets. NS Power will continue to participate in a Working Group for 2030 Clean Energy Targets with the Province to support cost-effective, timely, and successful program implementation. The Working Group will ensure close coordination between provincial staff and NS Power staff to support cost-effective, timely, and successful program implementation. The Working Group will also identify enabling conditions for the plan projects.

8.3 Risk Management

Delivering on The Path to 2030 will require significant capital investments and new programs over the next six years. Risk management will be integral to implementation and reaching the 2030 environmental policy goals. Individual projects/elements of the plan will be implemented with detailed risk identification and mitigation strategies.

Last year's The Path to 2030 report identified six industry wide risks to be monitored and addressed as we progress towards 2030. These risks are summarized below, and details have been added to identify how these risks are trending relative to when they were reported in the 2024 report.

1. Supply Chain
   - 2025 Trend: Increased Risk
   - There continue to be constraints in the global electricity industry supply chain due to factors such as high demand/capital build-out for both electricity supply and load facilities across the industry, extreme weather and other one-time events, general inflation, and geopolitical events. This is leading to longer lead times, price increases and volatility, and lack of equipment availability. The lead time for combustion turbines, a key component to the Path to 2030, has increased over the last 12 months. Greater clarity on the timelines for combustion turbines will be available in 2026 following the IESO-NS-led RFP and any impact will be assessed at that time.

2. Inflationary Cost Pressures
   - 2025 Trend: No Change
   - Inflation has been relatively stable in North America over the last 12 months, with inflation rates in Canada near the Bank of Canada's target inflation rate of 2 percent. Although inflation indices have declined from the highs experienced from 2021 to 2023, future inflation can lead to project cost risk and cost uncertainty as suppliers refrain from providing long-term price commitments or require indexed price commitments.

3. Human Resources
   - 2025 Trend: No change
   - The electricity industry continues to face a shortage of talent due to high demand in both the electricity industry and adjacent industries, such as housing and other construction. This is leading to cost pressures, staffing challenges, and ultimately

project delays. Talent shortages have the potential to affect NS Power, its partners across the province, and its contractors and suppliers.

4. Project Approvals

- 2025 Trend: No Change
- The 2030 Clean Power Plan requires the approval of large, capital-intensive projects such as IPP wind deployment and NS Power transmission builds. These projects will need clear First Nations, Community, and Stakeholder support to receive environmental approvals. IPP projects will require interconnection facility approvals and inclusion in fuel cost recovery. NS Power projects will require regulatory approval for cost recovery within electricity rates.

5. Transition Planning

- 2025 Trend: Increasing Risk
- Delays in procuring new fast-acting generation combined with the growing lead times seen across the industry for new combustion turbines makes it increasingly unlikely any new fast-acting generation units will be online by Winter 2027-28. If it is evident following the IESO-NS-led RFP that the 2030 timeline is not achievable, alternative plans will need to be developed. In addition, the attrition of four projects from the Green Choice procurement means a new procurement is required to secure sufficient low impact renewable energy to meet the 80 percent renewable energy standard. Given project development timelines there is a risk these projects may not be online by 2030.

6. Evolving Policy Landscape

- 2025 Trend: Reduced Risk
- The final CER was published on December 18, 2024 and is in alignment with NS Power's current long-term strategy as it supports the use of emitting generation in a peaking capacity. Other areas where policy changes could impact system planning through 2030 (and beyond) include North American Electric Reliability

Corporation (NERC) and Northeast Power Coordinating Council (NPCC) criteria and requirements as well as provincial and federal policies related to electrification (which influences load forecasts). NS Power will continue to be responsive to changes in the policy landscape via its IRP Roadmap.

9.0 CONCLUSION

The Nova Scotia 2030 Clean Power Plan and The Path to 2030 represent a comprehensive clean energy transition plan that is aligned with NS Power's most recent IRP Action and Roadmap update. Delivering on this plan will require significant investments, program activities, engagement, and coordination across multiple parties, led by the IESO-NS and the Province, and includes notable stakeholders such as NS Power, renewable procurement administrators, third party IPPs, Mi'kmaw partners, community groups, and E1 over the next five years to achieve the plan.

In 2025, considerable progress was made on the clean energy transition plan, including:

- Construction activities are in progress for the Rate Base Procurement wind farms and Port Hawkesbury Paper Wind.

- Power Purchase Agreements were executed between NS Power and two wind development projects selected through the Green Choice procurement, representing 262 MW of installed capacity with an expected in-service date of Dec 31, 2028.

- Construction has progressed at NS Power's three BESS sites, with the first two sites representing 100 MW of 4-hour storage capacity, expected to reach commercial operation before the end of 2025.

- The NSEB issued its approval of Wasoqonatl Transmission Incorporated (WTI)'s application for the Reliability Intertie project on November 20, 2025.

- The Community Solar Power Purchase Agreement and Community Solar Energy Credit Rider received NSEB approval in 2025, the first community solar project reached commercial operation, and 8.7 MW of additional projects were selected by the Province.

Nevertheless, there are growing risks with some aspects of the plan, including:

- Delays in procuring new fast-acting generation, combined with the growing lead times seen across the industry for new combustion turbines, create uncertainty about when this critical capacity and reliability resource will be available.

- The attrition of four selected projects from the Green Choice procurement will require a new procurement process to secure sufficient low impact renewable energy to meet the 80 percent renewable energy standard. Given project development timelines, there is a risk these projects may not be online by 2030.

- No timeline has been established for the procurement of energy storage solutions, beyond NS Power's 150 MW BESS project, and the potential commercial operation date for any such developments remains unclear.

Greater clarity on project timelines for new fast-acting generation and additional low impact renewable energy is expected in 2026 as IESO-NS and the Province led procurement processes conclude. Pursuant to NS Power's accountabilities under the matrix provided in **Figure 10**, the Company understands its obligations in delivering the associated capital investments, customer programs, and in assisting other parties in satisfying their respective obligations where applicable. With respect to its coal retirement obligations, NS Power has flexibility to adjust coal retirement dates up to 2030 to accommodate changes in resource development timelines, but if it is evident following the IESO-NS and Provincial procurements that the 2030 timeline is not achievable, alternative plans will need to be developed in collaboration with the IESO-NS. In the meantime, NS Power continues to support the transition of accountabilities to the IESO-NS in collaboration with the Province.

NS Power

Five-Year (2025-2029)

Reliability Plan – Update

NS Power Five-Year Reliability Plan - Update
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1.0 INTRODUCTION

The reliable and safe operation of the power system is NS Power's top priority. The Company is committed to improving the reliability and resiliency of the power grid and, in 2024, outlined its plan to achieve this in the Five-Year Reliability Plan (the Plan), which detailed $1.3 billion of investments in reliability programs, including $206 million in 2025, which builds on prior reliability investments and planning. In 2025, NS Power is on track to complete the commitments detailed in year one of the Plan. The Plan has a goal of reducing the overall duration and frequency of outages while balancing the affordability of these investments for customers.

1.1 Five-Year Reliability Plan Commitment

The Plan continues to be informed by an in-depth analysis of leading and lagging condition indicators including outage causes and inspection results. It focuses on investments in the transmission and distribution systems through three core programs outlined below:

1. **Vegetation Management & Tree Trimming** - Expanding tree-trimming programs along power lines to reduce outages. Clearing transmission and distribution corridors to enhance reliability.

2. **Storm Hardening** – Targeted Equipment Replacements and Upgrades. Replacing aging equipment, modernizing substations, and strengthening the transmission system. Installing advanced protective devices (e.g., reclosers, trip savers) to reduce outage impact. Rebuilding targeted lines, upgrading water crossings, and installing higher class poles for extreme weather.

3. **Advanced Grid Modernization -** Deploying advanced monitoring and control systems for faster outage detection and restoration. Implementing automated service restoration to improve response time. Expanding telecommunications for better grid management.

As shown in **Figure 1** below, NS Power's Plan includes approximately $1.3 billion of investment in the 2025-2029 period with a commitment to $206 million of investment in 2025 and $234 million in 2026.

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

Reliability Program	2025	2026	2027	2028	2029	Total
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**

NS Power's overall investment included in this Plan, including elements executed this past year, strive to meet the following two overarching goals by 2029:

1) Improve the customer reliability experience by reducing SAIDI by 20 percent from the five-year average (2019-2023) of 5.10 and achieving the Performance Standards SAIFI target of 2.05.

2) Continue to strengthen grid resilience to address climate change and achieve the Performance Standards for restoring service to 91.98 percent of customers within 48 hours after a Major Event Day.

This work will result in a more reliable and resilient grid that is better able to withstand and recover when the power system experiences stresses from major adverse weather events, and to a certain extent also from extreme weather events like hurricanes. The system is already responding positively to this work with an observed improvement to performance standards metrics. As of

October 31, there is a 53 percent reduction in customer interruptions and a 29 percent reduction in customer hours of interruption due to device failure in 2025 over 2023 levels.

The benefits of the program and the impact on the reliability of the system will be felt cumulatively as the combined impacts of reliability investments made over the five years are completed, resulting in a reduction of approximately one hour of SAIDI overall by 2029.

NS Power recognizes that stakeholders are seeking reassurance that the investments outlined in the Plan are effective in improving reliability. NS Power agrees with the NSEB and stakeholders that effective investments lead to the best possible balance between reliability improvements and affordability for customers.

NS Power looks forward to working with the Board appointed third party as they complete their evaluation of the Plan. In the meantime, NS Power continues to align its targeted investments with risk-based decision-making, including consideration for mitigation of the leading causes of high impact outages. Complementing this ongoing targeted asset investment approach, the Plan also includes new grid-modifying upgrades to facilitate quicker response and self-healing functionality when outages do occur. NS Power's data and risk-based approach ensures that the Company is targeting investments that are consistent with industry approaches in areas critical to reliability performance when considering reliability investment decisions.

In the Board's decision on the 2025 Annual Capital Expenditure (ACE) Plan (M12012), the Board directed the following:

> …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 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….

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In response to the Board's directive, NS Power has prepared this update on the progress of the Plan to provide the Board and Stakeholders with:

- An update on the completed progress on the Plan to date in 2025,
- A forecast of work anticipated to be complete before year end, and
- Notable updates to the Plan for future years, including an overview of projects expected to be executed in 2026.

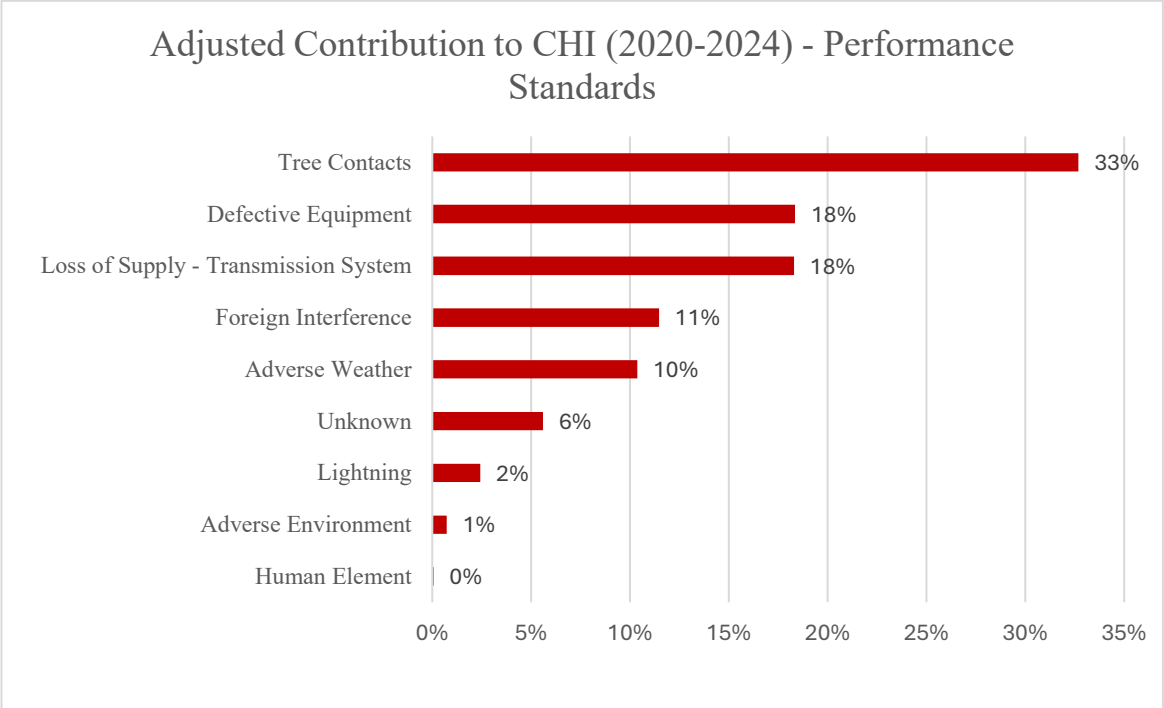
2.0 RELIABILITY PERFORMANCE ANALYSIS

NS Power has developed the Plan to deliver a 20 percent improvement in the performance standards overall average duration of outages (SAIDI) and to achieve the Performance Standards SAIFI target of 2.05 by 2029. As part of data and risk-based decision-making, analysis of system performance is an important indicator used to help ensure that the programs within the Plan are well targeted, deliver measurable benefits, and align with improving customer experience.

Tree contacts continue to be the single largest contributor to outages in Nova Scotia. In addition to events coded directly as Tree Contacts, NS Power's operations and vegetation management subject matter experts estimate that up to 40 percent of CHI coded as "Adverse Weather" can be further attributed to tree contacts based on the noted impact to trees throughout the province during severe weather. **Figure 2** shows the relative contribution to Customer Hours of Interruption (CHI) by cause code, with Tree Contacts adjusted to reflect attribution from Adverse Weather. While the Plan will positively impact each of these categories, it is particularly focused on reducing the impact of tree contacts and equipment failures on the power system and thereby improving the overall reliability of the system, including resilience to severe weather.

Grid modernization innovations such as increased integration of Remote Terminal Units (RTUs), remote connectivity to downline protective devices, and improved fault location capabilities will further mitigate the impact of these outages when they occur by reducing the customers affected by an event and allowing faults to be isolated and located faster.

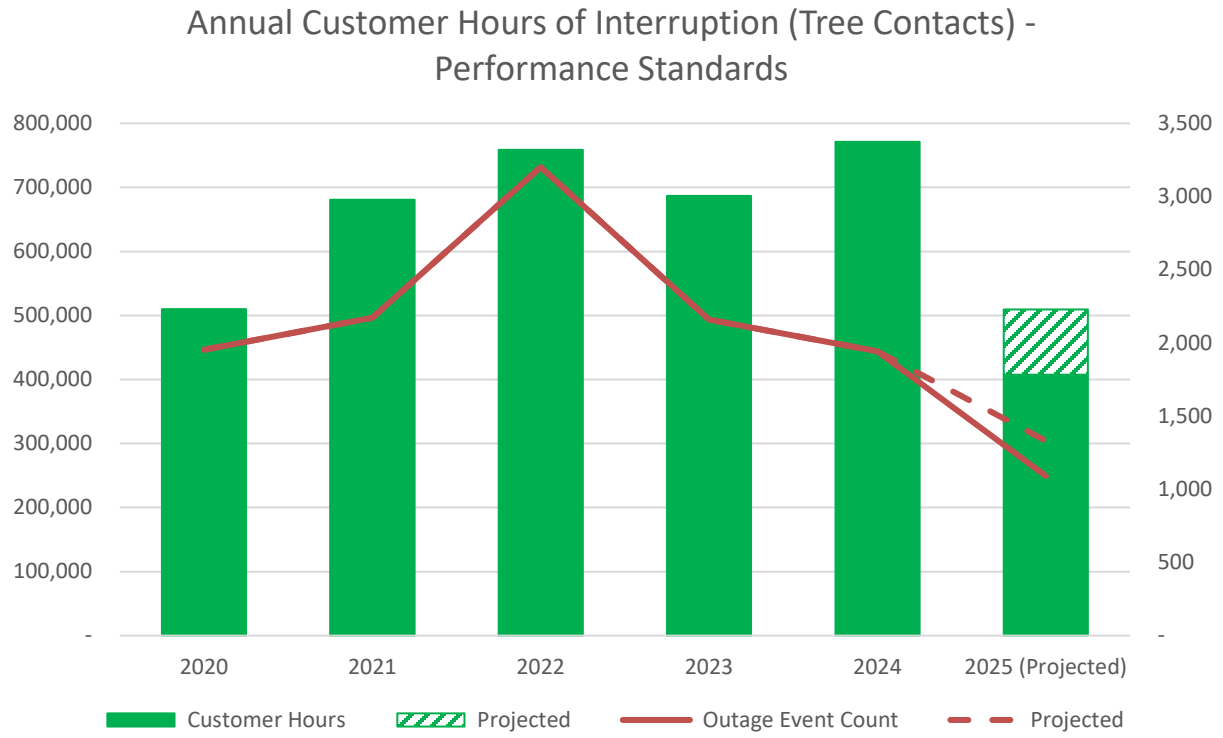
Figure 2: Contribution to CHI by Outage Cause (2020 – 2024) Performance Standards



2.1 Demonstrated Vegetation Program Impacts

Figure 3 below shows the Performance Standards annual customer hours of interruption due to tree contacts for 2020-2025 Projected Year-End and shows positive signs that vegetation management activities are contributing to reducing the overall frequency and duration of outages on the system. 2025 Projected Year-End includes actuals for October and estimates for November and December 2025 based on the prior five years' performance. The benefits of the vegetation management program will increase over time as more rights-of-way (ROWs) corridors are widened, improving clearances between trees and power lines, and enhancing overall system reliability.

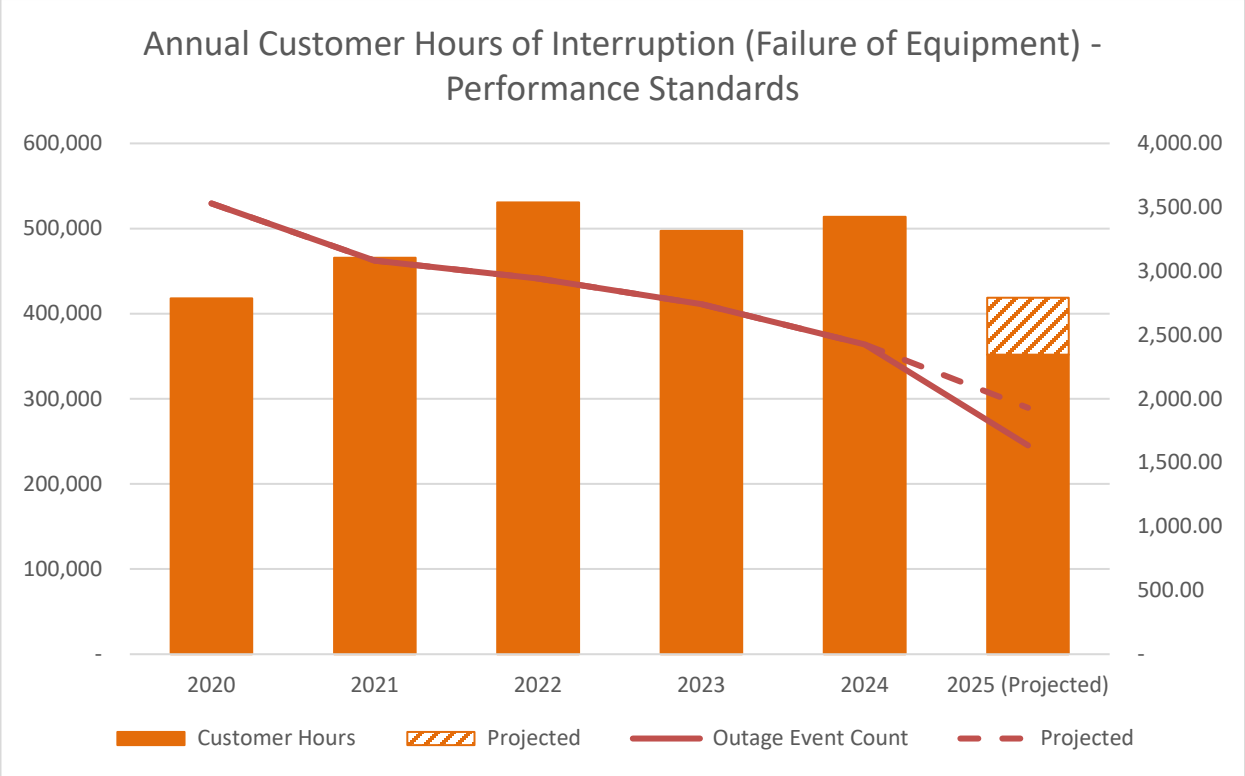
Figure 3: Annual Customer Hours of Interruption (CHI) due to Tree Contacts – Performance Standards



2.2 Distribution Targeted Devices

Figure 4 shows the contribution of device failure to Performance Standards customer hours of interruption for 2020-2025 Projected Year-End and shows positive trends in reduced overall duration and outage frequency resulting from replacements and upgrades to distribution equipment. 2025 Projected Year-End includes actuals for October and estimates for November and December 2025 based on the prior five years' performance. Storm hardening initiatives and equipment upgrades are core elements of the plan, which will continue to build on these positive trends.

Figure 4: Annual Customer Hours of Interruption (CHI) due to Failure of Equipment – Performance Standards



3.0 2025 Overview – Year One of Five Year Reliability Plan

In 2025, NS Power's Reliability team has been focused on executing the projects identified in year one of the Plan, with $206.6 million committed to strengthen the grid and enhance its resilience, enabling both improved blue-sky performance and to better withstand and recover from adverse weather events. NS Power remains on track and is forecasting to complete its $206.6 million plan by year end.

Figure 5 includes the latest forecasts of investment activity expected to be completed by year-end.

In 2025, NS Power completed targeted reliability upgrades on its Distribution system with a focus on the priority feeders identified in the initial Plan. This work includes but is not limited to:

- Application of robust coastal framing standards in areas of concern to better withstand extreme winds and severe ice loading conditions.
- Over 2500 legacy porcelain insulators have been upgraded to new, polymer devices.
- 73.7 kilometers of primary distribution conductor has been replaced, reducing the likelihood of conductor failure and enabling the system to deliver on growing load.
- 64 padmount transformers have been replaced to address identified deterioration and improve the reliability of the underground distribution system.
- 8.8 kilometers of distribution circuit has been built to roadside, further reducing the percentage of the system with offroad construction.
- Trees have been cleared from approximately 617 kilometers of distribution line ROW and approximately 105 kilometers of transmission line ROW.
- 118 hazard tree locations in addition to the 617 kilometers of corridor widening have been proactively identified and addressed from beyond cleared rights-of-way. This work involves coordination with customers and landowners to remove each individual tree. Some of these locations include the removal of multiple trees.

- Addition of six RTUs improving substation communication and control, supporting quicker response and restoration of service in the event of an outage.
- Completed replacement of two substation transformers in 2025 with three additional substation transformer replacements in progress. These replacements are improving substation condition and contributing to increased reliability and reduced outage frequency.
- Construction and energization of a new substation in Mount Uniacke by year-end, enhancing winter peak capacity and supporting continued growth in the community.
- Worked on approximately 500 transmission structures from January – October through replacement and upgrade projects.
- Upgraded 33.7 kilometers of transmission line through reconductoring to enhance system reliability and improve grid resilience.

Figure 5: Reliability Program Detailed 2025 Investment Breakdown

Reliability Program	Targeted Strategy	2025 Planned Investment	2025 Completed to Date	2025 Planned to Complete in Remainder of Year	Anticipated YE Result	Program Status
Distribution Vegetation Management	Distribution Corridor Widening with Managed ROWs	297 kms	183 kms	59 kms	242 kms (Revised due to Wildfire Mitigations)[1]	☑
	Establish New ROWs	330 kms	229 kms	89 kms	318 kms (Revised due to Wildfire Mitigations)	☑
	Trimming and Removal of Trees	177 kms	205 kms	55 kms	260 kms*	☑
Transmission Vegetation Management	Transmission Corridor Widening	120 kms	105 kms	15 kms	120 kms	☑
Targeted Equipment Replacements and Upgrades	Distribution System Equipment Additions	23 devices	18 devices	5 devices	23	☑

[1] Additional controls implemented by the Department of Natural Resources for fire mitigation purposes led to a reduction in work efficiency due to the downtime at site. Details of the controls are outlined in the Storm Hardening – Vegetation Management section below.

Reliability Program	Targeted Strategy	2025 Planned Investment	2025 Completed to Date	2025 Planned to Complete in Remainder of Year	Anticipated YE Result	Program Status
	Distribution System Build-To-Roadside	8 kms	8.8 kms	2.0 kms	10.8 kms	☑
	Distribution System Conductor Upgrades	39 kms	73.7 kms	4.5 kms	78.2 kms	☑
	Distribution System Underground Upgrades	50 padmounts	64 padmounts	Program Complete	64 padmounts	☑
	Transmission System Upgrades	37 lines	30 lines	7 lines	37 lines	☑
	Substation Upgrades and Replacements	4 Transformers	2 Transformers	3 Transformers	5 Transformers	☑
Advanced Grid Modernization	Remote Terminal Units (RTUs)	11 devices	6 devices	5 devices	11 devices	☑
	Downline Connectivity	35 devices	-	Multi-Year execution ongoing in 2026	On-going**	☑
	Fault Location Isolation and Service Restoration (FLISR)	24 devices	-	Multi-Year execution ongoing in 2026	On-going**	☑

* Due to careful management of resources, vegetation management team was able to exceed the planned kms while remaining within the $45 million overall budget.

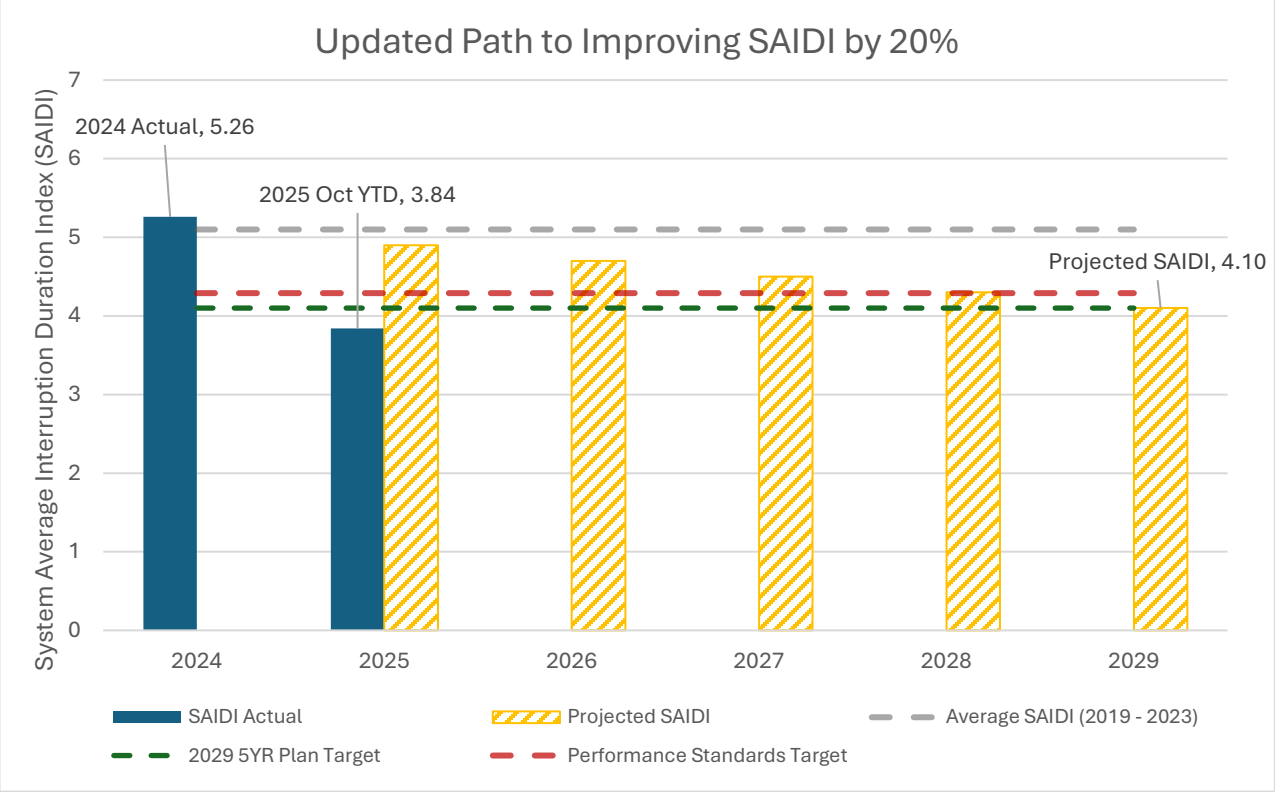
** This project is on track for completion in 2026 as per its intended multi-year execution approach.

3.1 Demonstrated Reliability Impact/Benefit

As detailed in the Reliability Performance Analysis section above, the trends in 2025 YTD SAIDI performance reflect early outcomes from the overall reliability tracks as outlined in the Five-Year Reliability Plan and the specific investments detailed previously. NS Power recognizes that this Plan is still in the initial phase of its five-year implementation and while these preliminary figures

provide a snapshot of reliability performance to date, including positive trends for vegetation and defective equipment, it is important to recognize that the full impact of the program will take time to materialize. Meaningful trends and improvements in SAIDI will be more accurately assessed over the full duration of the program at a network level, as upgrades are completed and benefits accumulate across the system. **Figure 6** below demonstrates the projected path these reliability improvements will have in achieving the goal to meet SAIDI target of 4.10 by 2029.

Figure 6: Updated Path to Improving SAIDI by 20%



3.2 2025 Priority Feeders Update

Please refer to **APPENDIX A: 2025 Highest Priority Distribution Feeders**, which shows the list of priority feeders for 2025. A data-driven and targeted program of reliability improvement work was developed in consideration of the priority feeders, their condition, and previous performance.

All feeder plans for 2025 are underway or complete; work will continue on all in progress work until completed.

APPENDIX B: Work Completed (C) and In Progress (P) on 2025 Priority Feeders presents a summary of the work completed or currently underway on each feeder as of filing, along with a preliminary indication of whether the feeder remains on the priority list for 2026. These initiatives are intended to mitigate feeder risks and reduce future outage impacts. While the work completed to date helps to address the primary outage drivers for each feeder, in several cases, additional multi-year projects are necessary and planned for select feeders to further enhance reliability performance.

4.0 STORM HARDENING – VEGETATION MANAGEMENT

2025-2029 Forecast Investment: $265.0 million

Estimated Performance Standards SAIDI Reduction: 0.70 to 1.25 hours

2025 Anticipated Year End Investment: $45 million

Proactive storm hardening vegetation management work is a critical component of NS Power's reliability strategy, aimed at reducing tree contacts with the electrical system. Across Nova Scotia, approximately 75 vegetation management crews are actively deployed each day on average to clear trees and branches from distribution and transmission ROWs.

Tree contacts are the largest single cause of outages and can contribute significantly to extended restoration times when outages occur. The vegetation management program employs several targeted strategies to mitigate these risks, including:

- Distribution Corridor Widening with managed Rights-of-Way (ROW)
- Transmission Corridor Widening with managed Rights-of-Way (ROW)
- Establishment of New Rights-of-Way
- Trimming and removal of trees around existing lines

An overview of the year-to-date progress and the year-end forecast for each of these programs is detailed in **Figure 7** with additional detail on each program found in the sections below.

Figure 7: Vegetation Management Year One Reliability Plan Results

	$ Planned (M)	Kms Completed	Additional Kms Forecast to be Completed by YE	Program Status
Distribution Corridor Widening	12.5	183	59	☑
Transmission Corridor Widening	3.0	105	15	☑
Establishment of New Rights-of-Way	16.4	229	89	☑
Trimming and removal of trees	6.9	205	55	☑

As of October 31, 2025 NS Power has completed approximately 617 kilometers (approximately 11,100 spans) of distribution vegetation management across the province and approximately 105 kilometers of transmission vegetation management. This work includes a combination of activities aimed at improving system reliability and reducing vegetation-related outages. Key components of the program include:

- Establishing and widening of distribution rights-of-way
- Hazard tree identification and removal
- Aerial pruning to maintain safe clearances
- Ongoing right-of-way maintenance

These efforts are part of a strategic approach to vegetation management that enhances system resilience and reduces the risk of tree-related outages. NS Power's assessment of overall vegetation condition is informed by its ongoing use of satellite-image based assessment of distribution ROWs.

This enhanced detail of vegetation condition is used to improve the Company's risk-based decision-making on where to target its interventions. **Figure 8** below provides a regional breakdown of the spans cleared and kilometers of ROW treated representing all distribution vegetation management work programs.

Figure 8: 2025 (YTD End of October) Distribution Vegetation Management Completed by Region

Region	Distribution Vegetation Management	
	Spans	Kms
Metro	1,114	61
NE	3,913	217
CB	1,874	104
West	4,230	235
Total	11,131	617

Due to provincial restrictions imposed by the Department of Natural Resources, stemming from drought conditions and heightened wildfire activity across the province in Summer and Fall 2025, NS Power was obligated to revise the planned scope of vegetation management originally anticipated for this year.

Under these restrictions, if the Actual Daily Fire Weather Index reached "Extreme," all heavy equipment operations must cease, and no work was permitted after 1:00 p.m. Additionally, NS Power was required to conduct a two-hour fire watch at each work site to ensure no ignition occurred as a result of any vegetation management activities. These constraints resulted in adjustments to work prioritization and scheduling to maintain reliability while ensuring compliance with fire safety protocols.

Operating under the DNR restrictions resulted in a safe, managed approach to working in forested areas during the period of heightened wildfire risk but did result in a reduction in the number of

kms of vegetation managed under the program in 2025 as detailed in **Figure 9** and **Figure 12**. This work will be reprioritized for completion in 2026.

4.1 Wildfire Mitigation

NS Power actively engages with wildfire risk stakeholders across Nova Scotia to inform and prioritize reliability and vegetation management initiatives. As part of NS Power's Wildfire Mitigation Plan, which is integrated within the broader Climate Adaptation Plan, NS Power collaborates with municipal leaders, emergency management officials, and community representatives through regional forums such as the Halifax Wildfire Advisory Committee and the Nova Scotia Fire Smart and Prevention Committee to share data, review risk mapping, and align on mitigation strategies.

These engagements have led to the development of community-specific wildfire risk assessments, such as the Glen Haven Wildfire Risk Assessment, providing actionable insights into local hazards, infrastructure vulnerabilities, and vegetation conditions. NS Power incorporates this input into its reliability planning process to understand the potential needs for vegetation management efforts in high-risk areas and support community resilience against wildfire threats.

In 2025, approximately 11 kilometers of rights-of-way management was accelerated in the communities of Glen Haven (circuit 92H-331) and Grand Lake (circuit 82V-402) through this reliability and wildfire assessment and prevention collaboration.

Additionally, in August 2025, NS Power's vegetation management team temporarily redirected resources to support emergency response efforts in response to the Long Lake wildfire. Crews were deployed along West Dalhousie Road, Morris Road, and Thorne Road to conduct targeted vegetation management activities. This originally unplanned work focused on removing fire-compromised trees at risk of falling into conductors and widening over 6.5 kilometers of

distribution rights-of-way to enhance fire breaks. These actions supported the protection of infrastructure and reduced the potential for further wildfire-related outages.

4.2 Distribution Corridor Widening with Managed Rights-of-Way (ROW)

2025-2029 Forecast Investment: $66 million
2025 Anticipated Year End Investment: $12.5 million

Corridor widening activities improve reliability by increasing the physical separation between overhead conductors and the forest edge, thereby reducing the likelihood of tree contacts and consequently, vegetation-related outages.

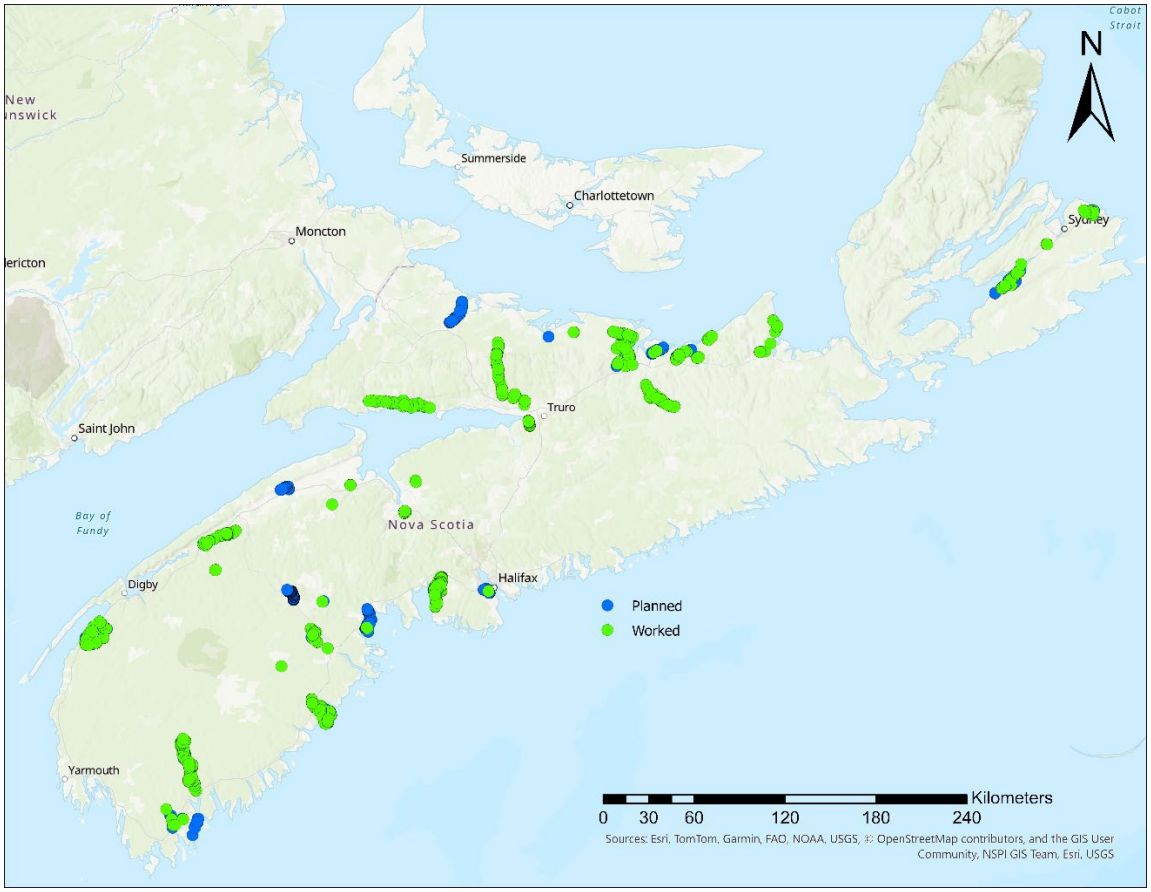
To date, 183 kilometers of distribution corridor widening has been completed. NS Power expects to complete approximately 59 additional kilometers of distribution corridor widening by year-end. Details provided in **Figure 9**. This work is projected to positively impact reliability in 35 communities across the province.

Figure 9: Distribution Program Corridor Widening with Managed ROW

Distribution Program	2025 Planned Kms	Kms Completed YTD	2025 Revised Plan (Due to Wildfire Mitigation) Kms	Project on Track (Y/N)
Distribution Corridor Widening with Managed Rights-of-Way	297	183	242	☑

Figure 10 below illustrates the locations where distribution rights-of-way have been widened year to date and areas scheduled for completion later this year.

Figure 10: Completed Distribution Corridor Widening with Managed Rights-of-Way



4.3 Transmission Corridor Widening with Managed Rights-of-Way (ROW) > 69KV

2025-2029 Forecast Investment: $15 million

2025 Anticipated Year End Investment: $3.0 million

Similarly to distribution corridor widening activities, expanding transmission ROWs impact reliability by increasing separation distance between transmission conductors and the forest edge, thereby reducing the likelihood of tree contacts and consequently, vegetation-related outages.

As of October 31, approximately 87 percent of the 2025 program has been completed and is on track to have the full project work completed by year-end. **Figure 11** below outlines the 2025 vegetation transmission widening projects, including the kilometers completed year to date.

Figure 11: Transmission Corridors Targeted for Widening (2025)*

Transmission Line	Geographic Location of the Line	2025 Planned Kms	YTD Completed Kms	On Track Y/N
L-6503-**added**	Onslow to Trenton	0	17	☑
L-6002-**added**	Sackville to Bridgewater	0	12	☑
L-7005	Onslow to Hopewell	16	9	☑
L-7003	Onslow to Port Hastings	29	22	☑
L-7004	Dalhousie Mountain to Port Hastings	23	18	☑
L-7009	Brushy Hill to Bridgewater	18	15	☑
L-7008	Brushy Hill to Bridgewater	15	12	☑
L-6511	New Glasgow to Glen Dhu	19	0	Reprioritized

Note: As per NS Power's asset management practices, specific targeted lines were updated throughout the year to reflect ongoing shifts in priorities (identified above as lines that were added and reprioritized).

4.4 Establish New Rights-of-Way (ROW)

2025-2029 Forecast Investment: $86 million

2025 Anticipated Year End Investment: $16.4 million

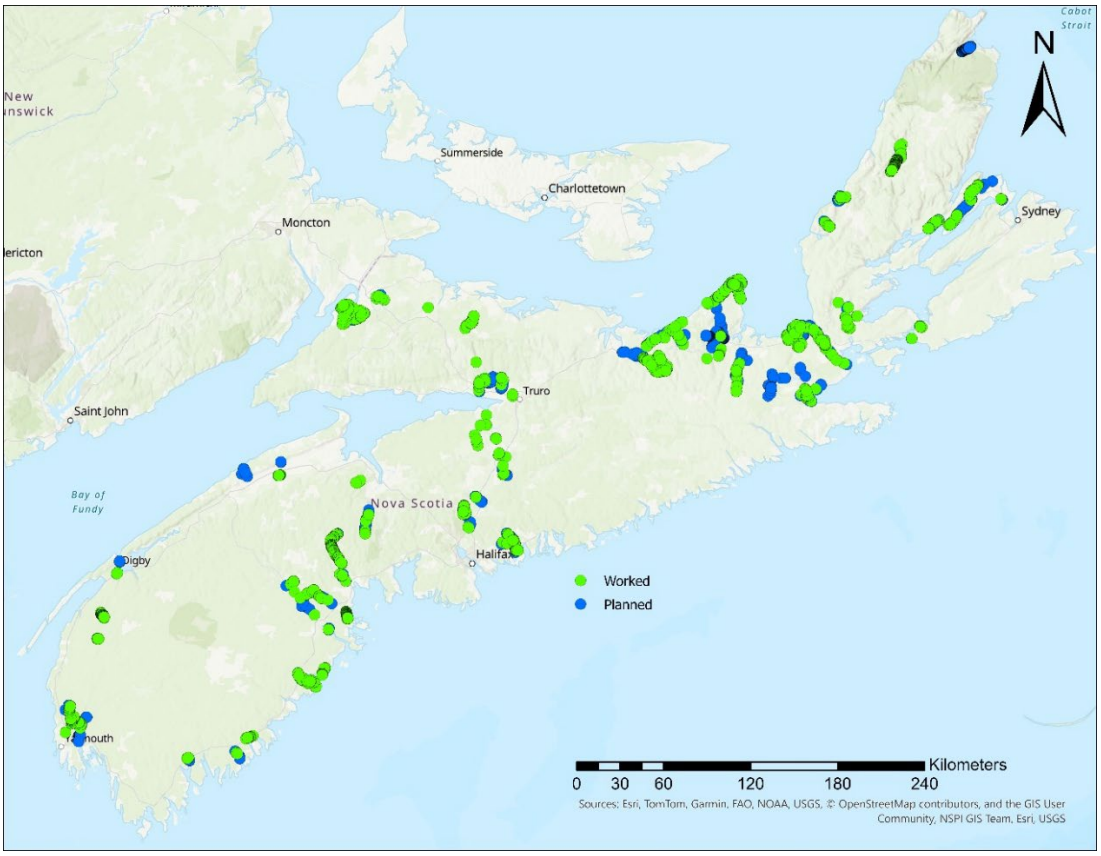
This program focuses on establishing new distribution rights-of-way, creating clearance on either side of the existing conductor for feeders where no managed corridor previously existed. To date, 229 kilometers of new rights-of-way have been created, with approximately 89 additional kilometers in new distribution rights-of-way created by year end. Details provided in **Figure 12**.

Figure 12: Establish New Rights-Of-Way - 2025

Distribution Program	2025 Planned Kms	Kms Completed Year to Date	2025 Revised Plan (Due to Wildfire Mitigation) Kms	Project on Track (Y/N)
Establish New Rights-of-Way	330	229	318	☑

Figure 13 illustrates the locations across the province where this new clearance has been implemented.

Figure 13: Map of 2025 Completed and Planned Establishment of New Rights-of-Way



4.5 Trimming and Removal of Trees Around Existing Power Lines

2025-2029 Forecast Investment: $98 million

2025 Anticipated Year End Investment: $6.9 million

Beyond the three ROW programs detailed previously, the remainder of NS Power's vegetation management efforts in 2025 focused on aerial pruning and trimming in urban areas where right-of-way expansion is not feasible, customer-requested tree trimming (CRTT), and the maintenance of existing corridors through mechanical mowing and manual ground cutting. To date, NS Power has completed approximately 205 kilometers of tree trimming and removal around existing distribution circuits under these three categories.

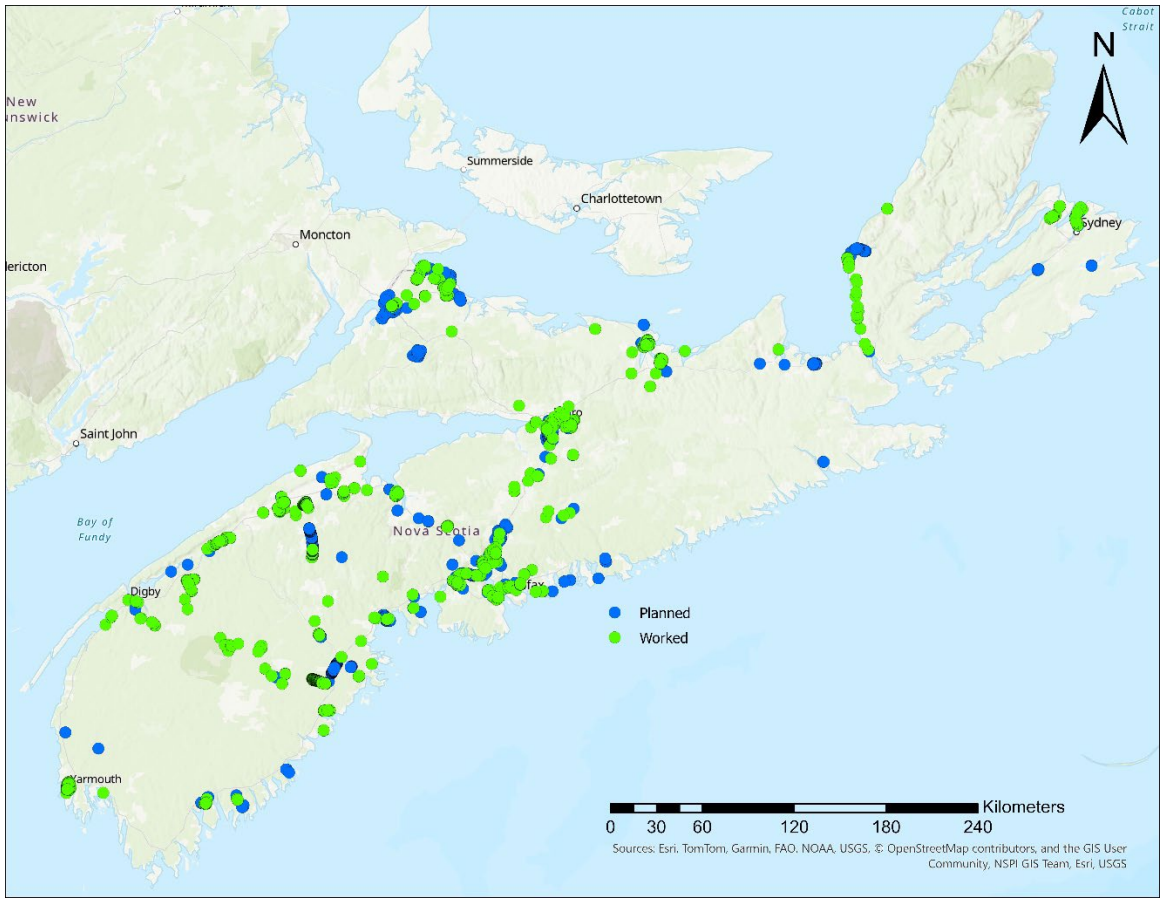
By year-end, NS Power anticipates completing an additional 55 kilometers under this program, exceeding the original target and further mitigating vegetation-related reliability risks. Details provided in **Figure 14**.

Figure 14: Trimming and Removal of Trees Around Existing Powerlines - 2025

Distribution Program	2025 Planned Kms	Kms Completed Year to Date	2025 Revised Plan Kms	Project on Track (Y/N)
Trimming and Removal of Trees Around Existing Powerlines	177	205	260	☑

Figure 15 illustrates the geographic distribution of completed vegetation work in this category, with a significant concentration in urban areas where ROW widening is largely constrained. These efforts are critical to maintaining safe and reliable service in these urban regions.

Figure 15: Completed Trimming and Removal of Trees Around Existing Power Lines



As described in the previous sections, NS Power expects to see improvement in tree-related outages on feeder segments that have received targeted vegetation management investment. **Figure 16** and **Figure 17** illustrate the impact of establishing or expanding distribution ROWs using examples recently completed in Shelburne, Trenton, and Little Harbour where the distances to tree edges have been increased. These improved ROWs not only reduces the likelihood of tree contacts with lines but also enhances the visibility to overhead equipment during feeder inspections and outage restoration efforts, supporting both reliability and safety objectives.

Figure 16: Rockland Rd, Shelburne (left: Before, right: After)

Figure 17: Egypt Rd, Between Trenton and Little Harbour- InProgress and Completed

5.0 STORM HARDENING – TARGETED EQUIPMENT REPLACEMENTS AND UPGRADES

2024-2029 Forecast Investment: $916 million

Forecasted Performance Standards SAIDI Reduction: 0.13 to 0.24 hours

2025 Anticipated Year End Investment: $152.4 million

To support continued reliability and resilience across the electrical grid, targeted investments are planned and have been made to address equipment risks. **Figure 18** outlines recently completed and planned upgrades and replacements across three critical system components:

- **Distribution System Equipment Upgrades and Replacements** – Improvements aimed at enhancing reliability by reducing outage frequency through the replacement of aging conductors, transformers, and other overhead distribution assets.

- **Transmission System Equipment Upgrades and Replacements** – Upgrades focused on strengthening the backbone of the grid, increasing capacity, and mitigating risks associated with equipment failure.

- **Substation Upgrades and Replacements** – Upgrading efforts including the replacement of aging components and integration of advanced monitoring technologies to improve operational efficiency and fault response.

These initiatives are aligned with broader asset management strategies and regulatory compliance objectives, ensuring the system remains robust and adaptable to evolving demands.

Figure 18: 2025 Targeted Equipment Upgrades Progress Overview

Program	Planned $	On Track (Y/N)
Distribution System Equipment Upgrades and Replacement	81.0	☑
Transmission System Equipment Upgrades and Replacement	32.6	☑
Substation Upgrades and Replacements	38.8	☑
Total	152.4	☑

5.1 Distribution System Equipment Upgrades and Replacements

2024-2029 Forecast Investment: $487 million

2025 Anticipated Year End Investment: $81 million

NS Power continues to replace and upgrade aging distribution infrastructure across Nova Scotia. This work can be grouped within several key initiatives, including:

- Replacing and upgrading deteriorated assets identified through inspection and maintenance programs;
- Expanding the deployment of protective devices to isolate faults more effectively and reduce the number of customers impacted by outages; and
- Ensuring continued compliance with environmental regulations and standards.

These efforts are part of NS Power's ongoing commitment to improving system reliability, enhancing customer experience, and supporting a more resilient energy future for the province.

5.1.1 Upgrade and Replace Aging Equipment

The program includes plans to further upgrade the system by replacing aging assets with new, modern equipment that aligns with current utility standards. Consistent with the asset management strategy for Energy Delivery, targeted assets are prioritized should condition and criticality factors indicate they pose reliability, environmental, and/or safety risks if left in service. Replacing these assets including poles, transformers, regulators, and other critical distribution components ahead of failure will contribute to reduced outages, limit oil spills due to failures, as well as improve worker and public safety. The PCB program exemplifies this approach and continues to progress on schedule, remaining compliant with federal regulations and timelines.

5.1.2 Power Line Protective Devices

Recloser Installations

Reclosers are automated protection devices that detect and respond to faults on the distribution system, isolating affected segments and reducing the number of customers impacted by outages. By interrupting fault currents and restoring service when possible (such as in the case of transient faults), reclosers help reduce outage frequency and durations.

In 2025, NS Power planned to install seven new reclosers across the province, with three units installed to-date and a further four scheduled for installation before end of year. **Figure 19** provides a summary of the planned recloser locations and the current status of each installation.

Figure 19: 2025 Recloser Installation Plan and Progress

Region	Feeder	Communities Impacted	Installation Status
Northeast	24C-442	Canso and surrounding area	On Track
Northeast	50N-410	Merigomish and surrounding area	Completed
Cape Breton	22C-404	Isle Madam	On Track
Cape Breton	81S-303	Glace Bay, Port Morien	On Track
Metro	127H-411	Waverley and Fall River	Completed
West	55V-314	Berwick, Aylesford and Burlington	On Track
West	55V-314	Berwick, Aylesford and Burlington	Completed

Trip Saver Installations

Trip Savers are protective devices installed on smaller segments of the distribution system where traditional fuses have historically been used. Like reclosers, Trip Savers rapidly detect and isolate faults, enabling quicker restoration of service to unaffected areas and reducing overall outage duration.

To date, NS Power has completed the installation of 15 of the 16 trip savers planned for deployment in 2025. The remaining unit is scheduled for installation in December 2025 and remains on track to be completed before year-end. **Figure 20** provides a specific update by region (detailed below).

Figure 20: 2025 Planned Trip Saver Installations

Region	# Additional Trip Savers Planned in 2025	# Trip Savers Installed 2025	Trip Saver Installation Target Status
East	3	3	Completed
Northeast	3	2	On Track
Metro	1	1	Completed
West	9	9	Completed

New Distribution Feeders

NS Power planned for the addition of two new distribution feeders in 2025 to address future capacity constraints and to support reliable service for two growing communities. Earlier this year, NS Power commissioned a new distribution feeder to help serve the Shannon Park, Wyse Road, and downtown Dartmouth areas. This infrastructure enhancement is part of the Company's ongoing efforts to maintain system reliability in regions experiencing increased customer demand.

In addition, the construction of a fourth feeder to service West Bedford and surrounding areas, initiating at the Kearney Lake substation is underway. This feeder is anticipated to be complete and commissioned by year end.

NS Power continues to progress the addition of a second distribution feeder to help serve customers along Prospect Road in the Halifax area and anticipates construction to begin in 2026.

Updated Overhead Standards

NS Power has updated its overhead distribution design standards to align with the current CSA C22.3 overhead line standards. In the Board's decision on the 2025 Annual Capital Expenditure (ACE) Plan (M12012), the Board directed the following:

> ...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…

In alignment with the Board's directive, NS Power has developed a table, provided in **APPENDIX C– Pole Monitoring Projects – New Pole Class Standard**, that identifies the region, feeder, location, and the number of poles scheduled for upgrade to the new class standard. These assets will be monitored on an ongoing basis following storm events.

5.1.3 Distribution System Build to Roadside

This program is designed to improve reliability and accessibility by relocating distribution lines from off-road areas to roadside locations. Re-routing infrastructure to roadside helps reduce the likelihood of tree-related contacts, as roadways are kept clear of vegetation, leaving only one forest edge of the ROW to manage. Improved roadside access also facilitates more efficient inspection and maintenance of associated equipment and enables more work to be completed using energized work methods, reducing the number of planned outages.

In 2025, NS Power planned to relocate approximately 8 kilometers of distribution line to roadside locations. To date, with careful allocation of resources, NS Power has advanced the execution of several sections originally planned for future years and exceeded the original target, with 8.8 kilometers of distribution line already relocated, and an additional 2.0 kilometers scheduled for completion or currently in progress before year-end. **Figure 21** outlines the specific locations where work has been completed and where it is ongoing.

Figure 21: 2025 Build to Roadside Projects by Region

Region	2025 Planned BTR kms	YTD Completed BTR kms	BTR Project Comments	BTR Project Status
East	3.2	0.7	On Track – Ongoing Projects In Progress	☑
Northeast	2.9	2.6	On Track – Projects Re-Prioritized	☑
Metro	2.0	0.7	On Track – Projects Re-Prioritized	☑
West	1.0	4.8	Exceeded – Ongoing Projects In Progress	☑

5.1.4 Distribution System Conductor Upgrades

The Distribution Conductor Upgrades program is a proactive initiative aimed at replacing aging infrastructure to reduce the risk of outages and enhance the reliability and resilience of the distribution system.

In 2025, NS Power set a target to reconductor approximately 39 kilometers of distribution line. Following a detailed review of reliability projects, the reporting of kilometers reconductored includes projects addressing both deteriorated conductors as well as upgrades required to support load growth. As of this reporting period, 73.7 kilometers have been successfully reconductored, exceeding the original target. An additional 4.5 kilometers is scheduled for completion by year-end. **Figure 22** provides a breakdown of the regions, number of feeders, and kilometers reconductored.

Figure 22: 2025 Distribution System Conductor Upgrades

Region	Feeders Planned to be Reconductored	Km Planned to be Reconductored	# Feeders Reconductored	Kms Reconductored	Feeder Reconductor Target Status
East	2	5.4	4	17.1	☑
West	5	9.7	13	28.4	☑
Metro	18	10.6	12	15.0	☑
Northeast	7	12.8	10	13.2	☑

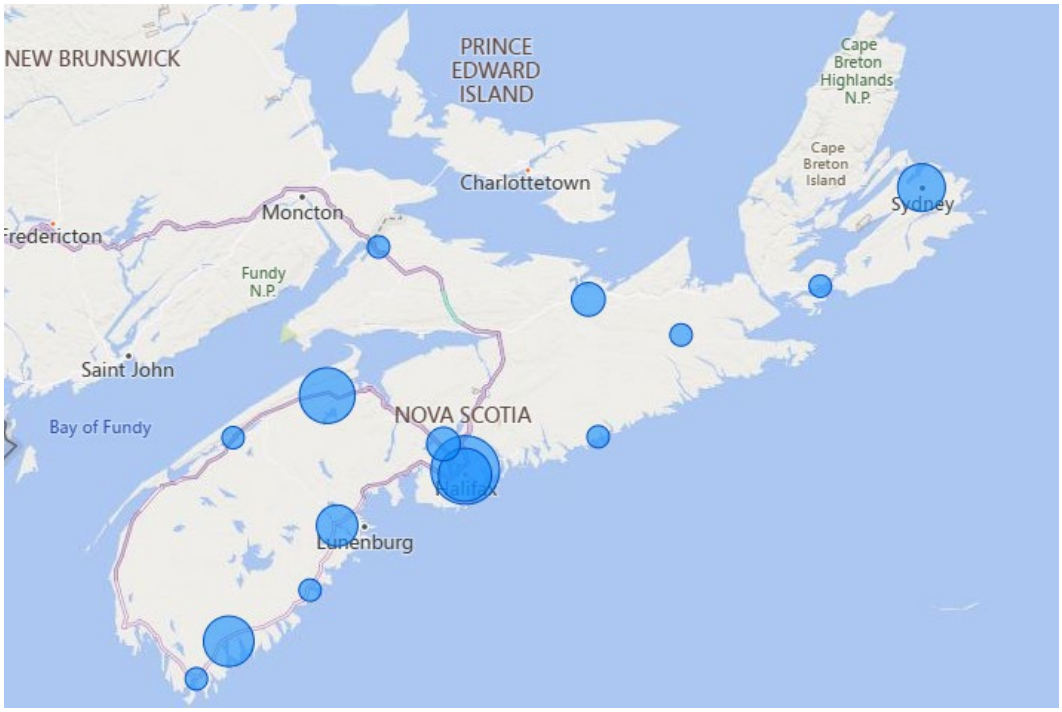
5.1.5 Distribution System Underground Upgrades

The Distribution Underground Program focuses on the targeted replacement and upgrade of aging underground infrastructure, including padmount transformers, switches, vaults, and manholes. These upgrades are essential to maintaining system reliability, improving safety, and reducing the risk of equipment failure in areas served by underground distribution.

In 2025, NS Power set a target to replace 50 padmount transformers. As of November, 64 padmount transformer replacements have been completed, already exceeding the 2025 target. NS Power analyzed the results of the padmount inspections and chose to prioritize completing padmount replacements this year. In addition, NS Power has completed three vault upgrades, and plans to complete one manhole upgrade before the end of the year.

Figure 23 below illustrates the general locations where padmount transformer replacements and upgrades have been completed or are currently underway. The larger the indicator on the map, the greater the number of padmount transformer replacements that have been completed in that area.

Figure 23: 2025 Completed Padmount Transformer Replacements and Upgrades



5.2 Transmission System Upgrades and Replacements

2025-2029 Forecast Investment: $196 million

2025 Anticipated Year End Investment: **$**32.6 million

In 2025, NS Power continues to focus on enhancing the resiliency and reliability of its transmission system. This investment and work plan is informed by the Company's transmission risk profiles, including inputs from transmission inspection programs and past reliability performance, with projects focused on replacing and upgrading transmission structures, reinforcing conductor systems, and executing targeted realignments and rebuild. **Figure 24** below outlines the number of transmission lines upgraded by transmission program.

Figure 24: Transmission System Program - 2025 Overview

Category	# Transmission Line Upgraded
Replacements and Upgrades	29
Line Rebuilds	3
Asset Life Extension	Province Wide
Water Crossing Upgrades	3
Line Realignment	2

These investments are part of NS Power's continued commitment to maintaining and strengthening the transmission system across the province. Through asset replacement and upgrade projects, steel tower refurbishment program, including anode installation and life-extension work, and wood pole retreatment initiatives, NS Power is proactively managing infrastructure to support long-term system reliability. **Figure 25** illustrates the locations across the province where targeted project work, as outlined in the 2025 ACE Plan, in addition to work prioritized through inspections, has been completed or is currently underway.

Figure 25: Transmission Work Completed or In Progress (2025)

5.3 Substation Upgrades and Replacements

2025-2029 Forecast Investment: $233 million

2025 Anticipated Year End Investment: 38.8 million

In 2025, NS Power continues to implement a range of initiatives targeting substations, supporting both system reliability and long-term asset sustainability. These investments included upgrades and replacements of existing substation assets, advancement in the design and construction of new substations, and the addition of a new transformer to strengthen NS Power's fleet of spares. Notably in 2025, NS Power has replaced two substation transformers, with three additional transformer replacements in progress, to be completed before year end. The transformer replacements that have been completed are at the Whycocomagh (67C-T64) and Cobequid (101H-T62) locations. The transformer replacements at Maitland Bridge (76V-T1), Nictaux (10V-T1), and Pugwash (7N-T3) are currently in progress.

NS Power has purchased and received a spare substation transformer. Replenishing this spare unit supports the overall NS Power Transformer spare strategy improving NS Power's ability to respond in the event of an unforeseen failure across the Company's transformer fleet while keeping inventory levels cost-effective.

NS Power continues to advance its multi-year substation development projects as part of its broader reliability strategy. The Bayers Lake substation project remains in the engineering and design phase, while construction is actively underway at the Stellarton site. The new Mount Uniacke substation (see **Figure 26**) has been completed and energized, marking a key milestone in strengthening system capacity and reliability in the Mount Uniacke community.

Figure 26: In Progress Construction of New Mount Uniacke Substation

6.0 ADVANCED GRID MODERNIZATION PROGRAMS

2025-2029 Forecast Investment: $78 million

Forecasted Performance Standards SAIDI Reduction: 0.06 to 0.11 hours

2025 Anticipated Year End Investment: $9.2 million

NS Power's Advanced Grid Modernization program is a strategic initiative designed to enhance system reliability, resiliency, and operational efficiency through the targeted installation and integration of intelligent technologies and data-driven infrastructure. The program is structured around three core elements:

- **Connected Assets**, which focuses on enabling real-time visibility and control of field devices through secure communications and SCADA integration;

- **Fault Location, Isolation, and Service Restoration (FLISR)**, which aims to reduce outage durations and improve restoration times by automating fault response; and

- **Distributed Energy Resources (DERs)**, which support grid flexibility and reliability by integrating customer-owned generation and storage assets into system operations.

Together, these elements contribute to a more responsive, efficient, and resilient Nova Scotia grid.

Figure 27: 2025/2026 Advanced Grid Modernization Progress Overview

Program	Devices Complete	Remaining Devices Forecast 2025/2026	On Track (Y/N)
RTUs	6	5	☑
Downline Connectivity	-	35 downline devices to be connectivity enabled	☑
FLISR	-	24 devices	☑
Total	6	64	☑

Note: Downline connectivity refers to the integration of field devices with NS Power's Energy Control Center, facilitated by telecommunications infrastructure.

6.1 Connected Assets

2025-2029 Forecast Investment: $65 million

6.1.1 Remote Terminal Units (RTUs)

2025-2029 Forecast Investment: $ 21 million
2025 Anticipated Year End Investment: $2.2 million

Remote Terminal Units (RTUs) enhance substation reliability by enabling real-time monitoring, remote control, and faster fault detection, supporting quicker isolation and restoration of service during outages. As of this reporting period, NS Power has completed the installation of six of the 11 RTUs planned for deployment in 2025. The remaining units are in progress and remain a priority to have two completed before year-end, and the final three installations to be completed early in

2026. The 2025 RTU Phase 6 project is presently undergoing regulatory review.[2] NS Power will participate fully with the project review and respects the Board's role in ensuring each project represents value for customers. The RTU plan will be updated to reflect the outcome of the review. **Figure 28** provides a specific update by substation.

Figure 28: 2025 Planned Remote Terminal Unit Installations

Region	Area/Community	Substation	Installation Status
Cape Breton	Southwest Margaree	58C	Complete
Cape Breton	Cleveland	22C	On Track
Northeast	Tatamagouche	4N	Complete
West	Hebron	16W	On Track
West	Bridgewater East	89W	On Track
West	Bridgewater Rural	70V	Complete
West	Kingston	63V	Complete
West	Ohio Road	25W	Complete
West	Central Argyle	19W	On Track
West	Wolfville Ridge	83V	Complete
West	Indian Path	80W	On Track

6.1.2 Downline Connectivity

2025-2029 Forecast Investment: $44 million

2025 Anticipated Year End Investment: $5.2 million

[2] M12588, To obtain a cost reasonableness review of NS Power CI C0051815 - RTU Replacements Program – Phase 6, as outlined in Section 2.1 of the 2025 Annual Capital Expenditure Plan decision (M12012).

As outlined in NS Power's Five-Year Reliability Plan, establishing a communications path between downline reclosers and the Advanced Distribution Management System (ADMS) offers significant reliability and safety benefits. These include accelerated fault location during outages, reduced restoration delays by enabling remote SCADA operation, particularly in areas with long driving distances between devices, and enhanced asset management through improved data visibility. Additionally, remote operation reduces line-of-fire exposure for field crews, supporting safer work practices. In 2025 and continuing into 2026, NS Power set a target to integrate up to 35 downline devices with the ADMS environment. **Figure 29** provides a detailed update on the implementation status of these communication paths and identifies the specific devices and feeders involved.

Figure 29:2025/2026 Planned Communications Path with Downline Reclosers Installation

Region	Area/Community	Feeder/Substation	Installation Status
West	Three Mile Plains	79V-401	In Progress/On Track
Metro	Musquodoboit Harbour	87H-313	In Progress/On Track
Metro	Musquodoboit Harbour	87H-313	In Progress/On Track
Northeast	Dickie Brook	24C-442	In Progress/On Track
Northeast	Ruth Falls	96H-412	In Progress/On Track
Northeast	Ruth Falls	96H-412	In Progress/On Track
Northeast	Ruth Falls	96H-412	In Progress/On Track
West	Waterville	55V-313	In Progress/On Track
Metro	Lucasville	131H-422	In Progress/On Track
Metro	Lakeside	103H-434	In Progress/On Track
East	Ingonish & Cape North	85S-401(multiple devices)	In Design. Planned for 2026 Execution
East	Coxheath & Eskasoni	11S-411 (multiple devices)	In Design. Planned for 2026 Execution
Metro	Lakeside	103H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Kearney Lake	129H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Hammonds Plains	137H	In Design.

Region	Area/Community	Feeder/Substation	Installation Status
		(multiple devices)	Planned for 2026 Execution
Metro	Armdale	2H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Kempt Rd	104H (multiple devices)	In Design. Planned for 2026 Execution

6.2 Fault Location Isolation and Service Restoration

2025-2029 Forecast Investment: $13 million

2025 Anticipated Year End Investment: $1.6 million

Fault Location, Isolation and Service Restoration (FLISR) is a system of distribution protection devices sited to allow automatic and remote re-configuration of the distribution grid to improve feeder reliability by reducing interruption impacts to the minimum number of customers possible.

In 2025, NS Power advanced its FLISR initiatives through key preparatory and planning activities. Progress included the submission of the Capital Work Order (CI C0071528 FLISR Implementation, which is currently being considered by the NSEB under matter M12417) including responding to information requests, supporting project momentum. Engineering teams also focused on standardization, producing material specifications and installation standards, while also advancing foundational work to support connected assets and the broader FLISR initiative.

6.3 Distributed Energy Resources (DERs)

As the country moves towards a net-zero future, the increasing penetration of Distributed Energy Resources (DERs) is changing the dynamics of electricity generation and consumption. Energy can now be produced and utilized based on customer behavior and variable conditions, rather than traditional centralized dispatch as evidenced by growing numbers of net-metered connections. This shift introduces new complexities for power utilities, particularly with respect to maintaining

reliability and operational flexibility. To address these challenges, enhanced visibility, automation, and control of DERs is important. Coordinated integration of DERs will be critical to mitigating adverse grid impacts and ensuring continued reliability as the system evolves.

Building on the Intelligent Feeder and Smart Grid Nova Scotia (SGNS) projects, NS Power has demonstrated the technical feasibility of DER coordination and the value of a Distributed Energy Resource Management System (DERMS) in orchestrating diverse assets within system constraints. As outlined in "The Path to 2030 – 2025 Update," (included as Appendix F in the 2026 ACE Plan) and following the Board's 2024 decision on the SGNS Final Report (M11621), NS Power initiated the Distributed Energy Resource Integration Roadmap (DERIR) (M12177).

This initiative, supported by Dunsky Energy + Climate Advisors, is guiding the development of a jurisdictionally informed framework for DER integration. Through 2025, NS Power has advanced stakeholder engagement and is actively evaluating a DERMS project to support the integration and orchestration of DERs (C0068718 - IT - DERMS Solution Project is listed as a project for subsequent submission in the 2026 ACE Plan). This work is aligned with the province's 2030 Clean Power Plan, and is intended to ensure DERs are deployed in a manner that enhances system reliability, supports decarbonization, and delivers customer value.

7.0 2026 – YEAR TWO – FIVE-YEAR RELIABILITY PLAN

2026 is year two of the Five-year Reliability Plan. NS Power has committed to an overall reliability investment of $234 million in 2026 (please refer to **Figure 30** and **Figure 31**), building upon the $206 million invested in reliability improvements in 2025 and the over $185 million on average annually in the previous five year period.

The following sections will outline the reliability projects planned for year two of the Five-Year Reliability Plan and the specific feeders prioritized in 2026.

Figure 30: 2026 Reliability Program Investment Overview

Reliability Program	2026 Anticipated Spend
Storm Hardening – Targeted Equipment Replacement and Upgrades	$178.9
Storm Hardening – Vegetation Management	$45.0
Advanced Grid Modernization	$10.7
Total	$234.6

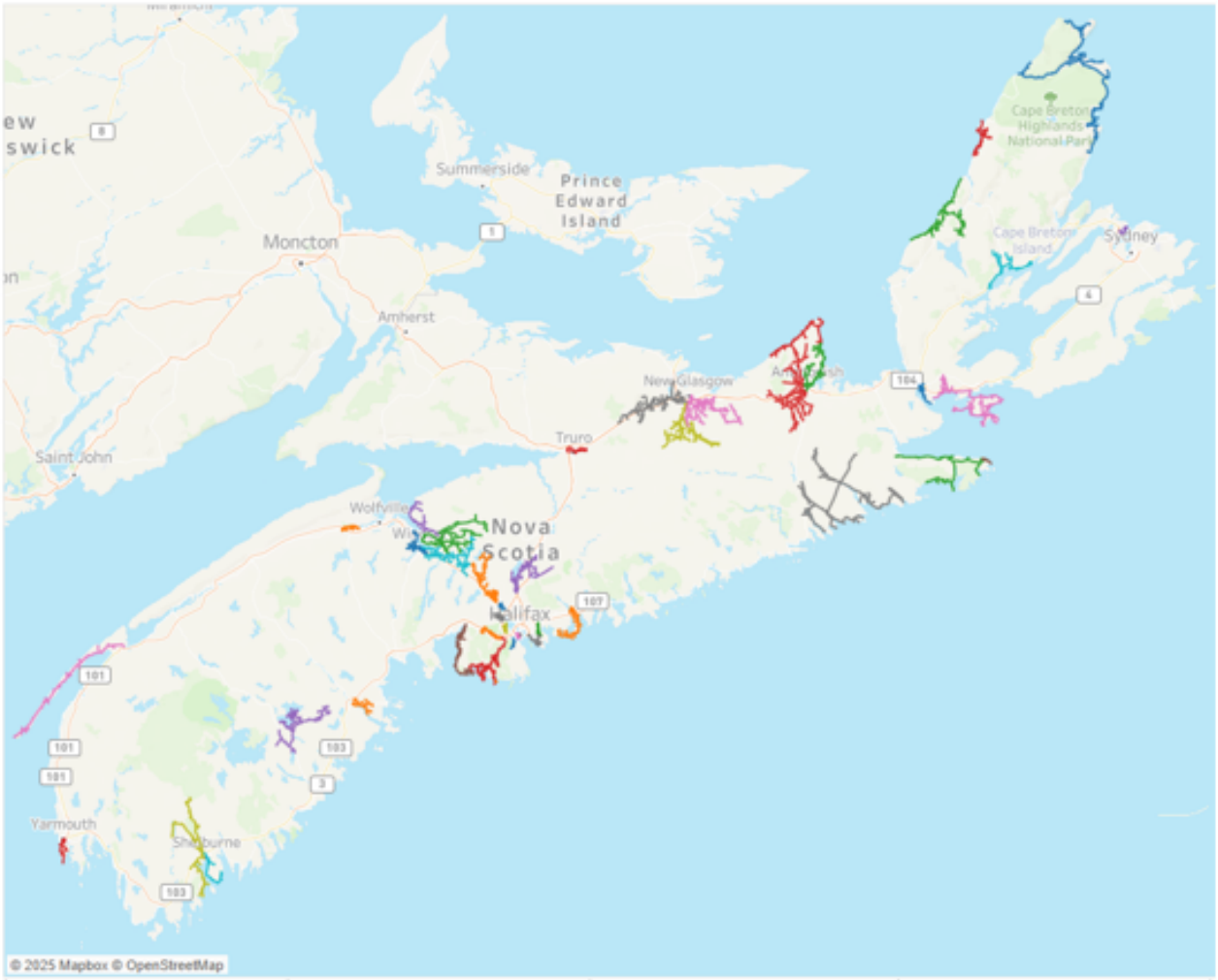
Figure 31: Reliability Program Detailed 2026 Investment Breakdown

Reliability Program	Targeted Strategy	Commitment
Distribution Vegetation Management	Distribution Corridor Widening with Managed ROWs	293 kms
	Establish New ROWs	377 kms
	Trimming and Removal of Trees	192 kms
Transmission Vegetation Management	Transmission Corridor Widening	121 kms
Targeted Equipment	Distribution System Equipment Upgrades and Replacements	15 Trip Saver Additions 10 Downline Recloser Additions 50 Padmount Replacements

Reliability Program	Targeted Strategy	Commitment
Replacements and Upgrades	Distribution System Build-To-Roadside	7.1 kms
	Distribution System Conductor Upgrades	80.9 kms
	Distribution Line and Phase Extensions	30.9 kms
	Transmission System Upgrades	28 lines
	Substation Upgrades and Replacements	8 Transformers
Advanced Grid Modernization	Remote Terminal Units (RTUs)	8 RTUs
	Downline Connectivity	35 Devices
	Fault Location Isolation and Service Restoration (FLISR)	24 Devices

The priority investment areas for 2026 include the feeders listed in **Figure 32**. These feeders have been identified based on outage events observed both in the current year and in previous years, and through engineering analysis of current feeder condition and projected load growth. This 2026 priority feeder list comprises 40 feeders, 31 newly identified and 9 carried over from the 2025 list. It is important to note that this list is subject to revision following a comprehensive analysis of the full-year 2025 outage data. The continued inclusion of some feeders from the 2025 list is expected, as several reliability and resiliency improvements require a multi-year implementation approach.

Figure 32: Highest Priority Distribution Feeders in 2026



Western Region	Metro Region	Northeast Region	Cape Breton Region
50V-402 88W-312	129H-412 131H-422	62N-413 4C-430	22C-404 85S-401
77V-401 89W-302	137H-413 104H-411	57C-426 62N-415	58C-403 104S-311
91W-411 25W-301	103H-432 103H-434	1N-421 4C-424	3S-302 103C-314
25W-302	79V-402 113H-441	19C-204 62N-414	1C-411
	82V-402 58H-421	24C-442	
	20H-306 79V-401		
	92H-331 126H-312		
	101H-412 18V-413		
	18V-411		

7.1 STORM HARDENING – VEGETATION MANGEMENT

2026 Forecast Investment: $45 million

In 2026, NS Power has committed $45 million to remove trees from near power lines. This investment will improve the reliability performance of over 860 kilometers of the power system by reducing the opportunity for trees to contact power lines. In 2026 NS Power will continue to execute on the established vegetation management reliability program as previously outlined.

Figure 33 outlines the estimated summary of spans and kilometers for all distribution vegetation programs by region, providing transparency into regional planning and resource allocation.

Figure 33: 2026 Distribution Vegetation Work Plan by Region

Region	Distribution	
	Spans	Kms
Metro	1,770	97
Northeast	2,576	145
East	4,020	224
West	7,125	396
Total	15,491	862

The 2026 vegetation management plan will be reviewed and updated following analysis of 2025 year-end system performance, with potential refinements to address emerging priorities.

7.1.1 Distribution Corridor Widening with Managed Rights-of-Way (ROW)

2026 Forecast Investment: $13.2 million

In 2026, NS Power plans to complete approximately 293 kilometers of distribution corridor widening within areas that have a defined, existing right-of-way, as detailed in the regional breakdown and forecasted kilometers shown in **Figure** 34.

Figure 34: 2026 Distribution Corridor Widening with Managed Rights-of-Way (ROW)

Region	Spans	Kms
Central/Metro	560	30
East	1,465	82
Northeast	847	48
West	2,389	133
Total	5,261	293

7.1.2 Transmission Corridor Widening with Managed Rights-of-Way (ROW) > 69KV

2026 Forecast Investment: $3.3 million

NS Power's transmission vegetation management plan is strategically prioritized using a suite of advanced tools and modeling techniques designed to optimize the focus of forestry crews. This includes:

- **Growth modeling**, which evaluates transmission corridors as sectionalized polygons based on site index data, allowing for predictive planning.

- **Integrated Vegetation Management (IVM)**, which incorporates historical treatment records and applies growth analytics to forecast future control methods. These may include mechanical, manual, biological, or chemical treatments, depending on site-specific conditions.

- **LiDAR analysis**, used on select lines, provides more precise vegetation measurements to identify potential hazards within transmission corridors.

- **Inspection data**, gathered through foot patrols, informs current vegetation conditions.

In 2026, NS Power is forecasting an investment of $3.3 million to widen approximately 121 kilometers of transmission rights-of-way by five meters. This initiative is part of a broader effort to enhance storm hardening and reliability by increasing clearance between vegetation and transmission infrastructure. **Figure 35** outlines the approximate spans, kilometers, and associated investment by provincial work region. **Figure 36** illustrates the locations across the province where targeted project work, as outlined in the 2026 ACE Plan, is planned to occur.

Figure 35: Transmission Right-of-Way Widening

Year	Line	Total Widen (KM)
2026	L-7003	27
	L-7004	36
	L-6503	31
	L-7009	27
	Total	121

Figure 36: 2026 Transmission Capital Widening Plan

7.1.3 Establish New Rights-of-Way (ROW)

2026 Forecast Investment: $18.5 million

The 2026 Vegetation Management Reliability program will continue to leverage satellite imagery technology to spatially identify areas where vegetation is in closest proximity to conductors. This data-driven approach enables a more precise and targeted vegetation management strategy for the 2026 work plan, improving efficiency and risk mitigation.

In 2026, NS Power plans to establish approximately 377 kilometers of new rights-of-way in areas where no defined corridor currently exists, with specific regions and forecasted kilometers outlined in **Figure** 37.

Figure 37: 2026 Planned KMs to Establish New Rights-of-Way (ROW)

Region	Spans	Kms
Central/Metro	817	45
East	1,436	80
Northeast	1,271	71
West	3,258	181
Total	6,782	377

7.1.4 Trimming and Removal of Trees Around Existing Power Lines

2026 Forecast Investment: $6.9 million

NS Power plans to complete hazard tree identification and removals, rights-of-way maintenance, and customer-requested tree trimming along approximately 192 kilometers of distribution line in 2026. **Figure 38** provides a detailed breakdown of the communities and circuits where this work is scheduled to take place

Figure 38: Ongoing Maintenance Around Existing Power Lines

Region	Spans	Kms
Central/Metro	393	22
East	1,119	62
Northeast	458	26
West	1,478	82
Total	3,448	192

7.2 STORM HARDENING – TARGETED EQUIPMENT REPLACEMENTS AND UPGRADES

2026 Forecast Investment: $178.9 million

7.2.1 Distribution System Equipment Upgrades and Replacements

2026 Forecast Investment: $83.9 million

7.2.1.1 Modernize and Replace Aging Equipment

NS Power anticipates that by the end of 2025, approximately 99 percent of assets will be confirmed to contain less than 50 ppm of PCBs. NS Power will continue its sampling and targeted replacement of downline devices into 2026, aligned with updated federal environmental regulations and guided by ongoing test results and environmental risk assessments.

Going forward, NS Power will continue to renew system infrastructure with modern equipment through existing programs fueled with prioritized data from the feeder inspection program.

7.2.1.2 Distribution System Build to Roadside

To improve accessibility and reduce outage duration, NS Power is planning to relocate 7.1 kilometers of distribution lines to roadside in 2026. This investment aligns with NS Power's broader reliability strategy by targeting areas, listed in **Figure 39,** where access limitations have historically contributed to extended outages.

Figure 39: 2026 Build-to-Roadside Projects

Region	Feeder	Project Name	Build to Roadside kms
Cape Breton	85S-401	Wreck Cove Rebuild	0.4
Cape Breton	103C-314	Grand Étang Water Crossing	0.9
Northeast	57C-426	Country Harbour Cell Tower Build to Roadside	2.6
Northeast	33N-201	Canaan Road Conversion	1.3
Northeast	4C-432	Loch Katrine Build To Roadside	1.9

7.2.1.3 Distribution System Conductor Upgrades

In 2026 NS Power plans to advance a series of reconductoring projects aimed at improving system reliability and performance. **Figure 40** below details the number of feeders and kilometers to be reconductored by region.

Figure 40: 2026 Conductor Upgrades by Region

Region	Total Km of Line (Conductor Upgrade Program)
Cape Breton	20.1
West	34.0
Metro	9.6
Northeast	17.2

In 2026, NS Power plans to complete approximately 30.9 kilometers of line and phase extensions to enhance system reliability and operational flexibility. These projects are designed to improve load balancing, reduce voltage drops, and provide alternate pathways for power flow during outages or maintenance. By extending lines and adding phases, NS Power can better support growing customer demand, reduce the risk of overloading existing infrastructure, and improve service continuity in rural and developing areas. These targeted investments contribute to a more resilient and adaptable distribution network. Details of these projects are outlined in **Figure 41** below.

Figure 41: 2026 Distribution Line and Phase Extension Projects by Region

Region	Total Km of Line/Phase Extension
Northeast	5.5
Metro	10
West	15.4

7.2.1.4 Distribution System Underground Upgrades

In 2026, a planned investment of $10.2 million will support the Distribution Underground program, aimed at strengthening and modernizing NS Power's underground electrical system. This funding will enable the continued replacement and upgrade of aging infrastructure, while also advancing strategic initiatives designed to enhance the resiliency of the underground network. Details of these initiatives are outlined in the project descriptions further below.

As part of NS Power's ongoing efforts to strengthen system reliability, this investment includes the replacement of approximately 1 kilometer of direct-buried primary cable in the Town of Kentville, along feeder 50V-202 between Duncan Avenue and Carmen Drive. This work will convert the area to 25 kV and establish a looped configuration with adjacent subdivisions. The upgrade will significantly enhance service reliability by eliminating a frequent source of outages and removing the existing single-point-of-failure configuration.

Additionally, NS Power will be replacing a critical underground switch in downtown Halifax that currently interconnects three feeders. The new switch will be SCADA-enabled, allowing for remote monitoring and operation, and will be installed during a planned vault shutdown to minimize customer impact. This upgrade will improve operational flexibility and reduce outage duration in a high-density urban area.

As approved by the NSEB, NS Power is partnering with the QEII Health Sciences Centre to construct a high-capacity underground ductbank between Jubilee Road and Bell Road. This infrastructure enhancement is designed to support system growth in high-density areas by enabling the extension of existing three-phase circuits. Additionally, the project will establish new feeder ties, contributing to improved reliability and operational flexibility in the distribution network. For further details, refer to CI C0074130 (matter M12456).

7.2.2 Transmission System Upgrades and Replacements

2026 Forecast Investment: $43.0 million

In 2026, NS Power plans to invest approximately $43.0 million in targeted initiatives to enhance the reliability and resiliency of the transmission system, representing a substantial increase over the 2025 investment levels. Of this, $29.3 million is allocated to traditional infrastructure replacements and upgrades, reinforcing the core components of the transmission network. An additional $8.3 million will support unique, site-specific projects such as water crossing upgrades and targeted line rebuilds. Furthermore, $5.1 million is dedicated to ongoing upgrade programs and asset life extension efforts. These investments are designed to address aging infrastructure, mitigate reliability risks, and support long-term system performance.

Figure 42 below highlights the planned locations for targeted transmission project work. The Company continues to execute defined programs focused on sustaining system performance through ongoing upgrades and asset life extension. Key activities include province-wide wood pole retreatment and steel tower refurbishment, both of which are prioritized based on condition assessments and risk-based planning to ensure long-term reliability of the transmission network

Figure 42: Illustration of Targeted NS Power Transmission Projects Planned for 2026

7.2.3 Substation Upgrades and Replacements

2026 Forecast Investment: $52.0 million

In 2026, NS Power plans to invest approximately $52.0 million in substation programs aimed at strengthening system reliability and supporting regional growth. This investment will focus on the upgrade and replacement of aging substation assets, as well as advancing the engineering design and construction of new substations across the province. These projects are strategically aligned with NS Power's asset management framework and are intended to meet evolving community needs and anticipated load growth in key regions.

NS Power plans to invest approximately $19 million in the replacement and addition of substation transformers. **Figure 43** lists the transformers NS Power plans to replace or add into the electrical grid, and the areas serviced by these substations.

Figure 43: 2026 Substation Transformers Planned Replacement/Additions

Transformer	Location	Region	Activity
91H-T11	Dartmouth	Metro	Replacement
10H-T1	Halifax	Metro	Replacement
10H-T2	Halifax	Metro	Replacement
96H-T1	Sheet Harbour	Northeast	Replacement
1N–T66	Onslow	Northeast	Addition
77V-T1	Conway	West	Replacement
76W-T1	Mahone Bay	West	Replacement
70W–T52	Bridgewater	West	Addition

The investment in substation initiatives also includes the progression of the engineering design and construction work of new substations across the province. NS Power's expectation is that the new Stellarton substation will be energized in 2026, and there will be further progress with a new substation in Bayers Lake. In addition, NS Power plans to enhance the system capacity and reliability with additional substations in the Wellington, Stillwater, Bridgewater and Dartmouth communities. Engineering and procurement activities for these new substations will continue in 2026.

7.3 ADVANCED GRID MODERNIZATION PROGRAMS

2026 Forecast Investment: $10.7 million

7.3.1 Connected Assets

In the second year of the Five-Year Reliability Plan, NS Power will continue to expand and implement telecommunications connectivity across the grid. This includes the integration of telemetry and control capabilities for intelligent field devices, as well as the addition and

replacement of RTUs and enhanced communications with distributed protection equipment, strengthening real-time visibility, operational responsiveness, and overall system reliability.

7.3.1.1 Remote Terminal Units (RTUs)

In 2026, NS Power will prioritize the replacement and upgrade of end-of-life RTUs to maintain and enhance grid reliability. The details of the devices planned for replacement are listed in **Figure** 44 below. Planning is underway to continue RTU additions and replacements through 2027 to 2029, supporting improved system visibility, control, and operational resilience.

Figure 44: 2025/2026 Planned Remote Terminal Unit replacements

RTU Replacement Project Sites	Estimated Year of Completion	Installation Status
91V-RTU1 Fourth Lake	2025	Completed
74N-RTU1 Springhill	2025	Installation in Progress
2V-RTU1 Avon 2	2026	
15V-RTU1 Sissiboo	2026	
85S-RTU2 Wreck Cove Sub	2026	
50N-RTU1 Trenton GS	2026	
87W-RTU1 Hubbards	2026	
14H-RTU1 Burnside Gas Turbine	2026	

7.3.1.2 Downline Connectivity

NS Power remains committed to enhancing grid reliability by expanding connectivity to downline devices. In 2026, the focus will continue to be on integrating advanced telemetry and remote control capabilities into intelligent field equipment, as outlined in **Figure** 45 below.

Figure 45: 2025/2026 Planned Communications Path with Downline Reclosers Installation

Region	Area/Community	Feeder/Substation	Installation Status
West	Three Mile Plains	79V-401	In Progress/On Track
Metro	Musquodoboit Harbour	87H-313	In Progress/On Track
Metro	Musquodoboit Harbour	87H-313	In Progress/On Track
Northeast	Dickie Brook	24C-442	In Progress/On Track
Northeast	Ruth Falls	96H-412	In Progress/On Track
Northeast	Ruth Falls	96H-412	In Progress/On Track
Northeast	Ruth Falls	96H-412	In Progress/On Track
West	Waterville	55V-313	In Progress/On Track
Metro	Lucasville	131H-422	In Progress/On Track
Metro	Lakeside	103H-434	In Progress/On Track
Cape Breton	Ingonish & Cape North	85S-401(multiple devices)	In Design. Planned for 2026 Execution
Cape Breton	Coxheath & Eskasoni	11S-411 (multiple devices)	In Design. Planned for 2026 Execution
Metro	Lakeside	103H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Kearney Lake	129H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Hammonds Plains	137H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Armdale	2H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Kempt Rd	104H (multiple devices)	In Design. Planned for 2026 Execution

7.3.2 Fault Location Isolation and Service Restoration

NS Power continues to advance its grid modernization efforts through the deployment of FLISR technology, which enhances system reliability by automating fault detection and service restoration. The FLISR implementation follows a structured, multi-step approach including the following:

- **Device Deployment**: The first phase involves ensuring the necessary field devices are in place. While most of the required devices already exist on the system, some will be newly installed, and others will replace older, less capable equipment to support FLISR functionality.

- **Connectivity Enablement**: The second phase focuses on installing telecommunications and communications infrastructure to enable real-time connectivity with the field devices. This step is critical for enabling remote monitoring and control.

- **FLISR Configuration**: In the final phase, devices designated to participate in the FLISR scheme will be configured with the necessary intelligence and automation logic. This enables them to detect faults, isolate affected segments, and restore service to unaffected areas with minimal human intervention.

All FLISR projects detailed in **Figure** 46 below, are targeted to be in service by the end of 2026, contributing to improved reliability performance and faster outage response across the distribution network Please refer to CI C0071528 FLISR Implementation, which is currently being considered by the NSEB under matter M12417.

Figure 46: 2026 Planned FLISR Implementation Projects

Region	Area/Community	Feeder/Substation	Installation Status
Cape Breton	Ingonish & Cape North	85S-401(multiple devices)	In Design. Planned for 2026 Execution
Cape Breton	Coxheath & Eskasoni	11S-411 (multiple devices)	In Design. Planned for 2026 Execution
Metro	Lakeside	103H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Kearney Lake	129H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Hammonds Plains	137H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Armdale	2H (multiple devices)	In Design. Planned for 2026 Execution
Metro	Kempt Rd	104H (multiple devices)	In Design. Planned for 2026 Execution

7.3.3 Distributed Energy Resources (DERs)

As the presence of Distributed Energy Resources (DERs) such as solar, wind, and battery storage continues to grow, effectively managing these assets becomes critical to maintaining grid reliability, stability, and efficiency. A DERMS provides the necessary software platform to monitor, coordinate, and optimize the performance of DERs across the network. By enabling real-time visibility and control, DERMS supports load balancing, voltage regulation, and improved outage response, while also facilitating the integration of renewable energy. NS Power plans to advance this capability by initiating a capital work order (CI C0068718) in 2026 to implement a DERMS platform, marking a significant step toward a more resilient and intelligent grid.

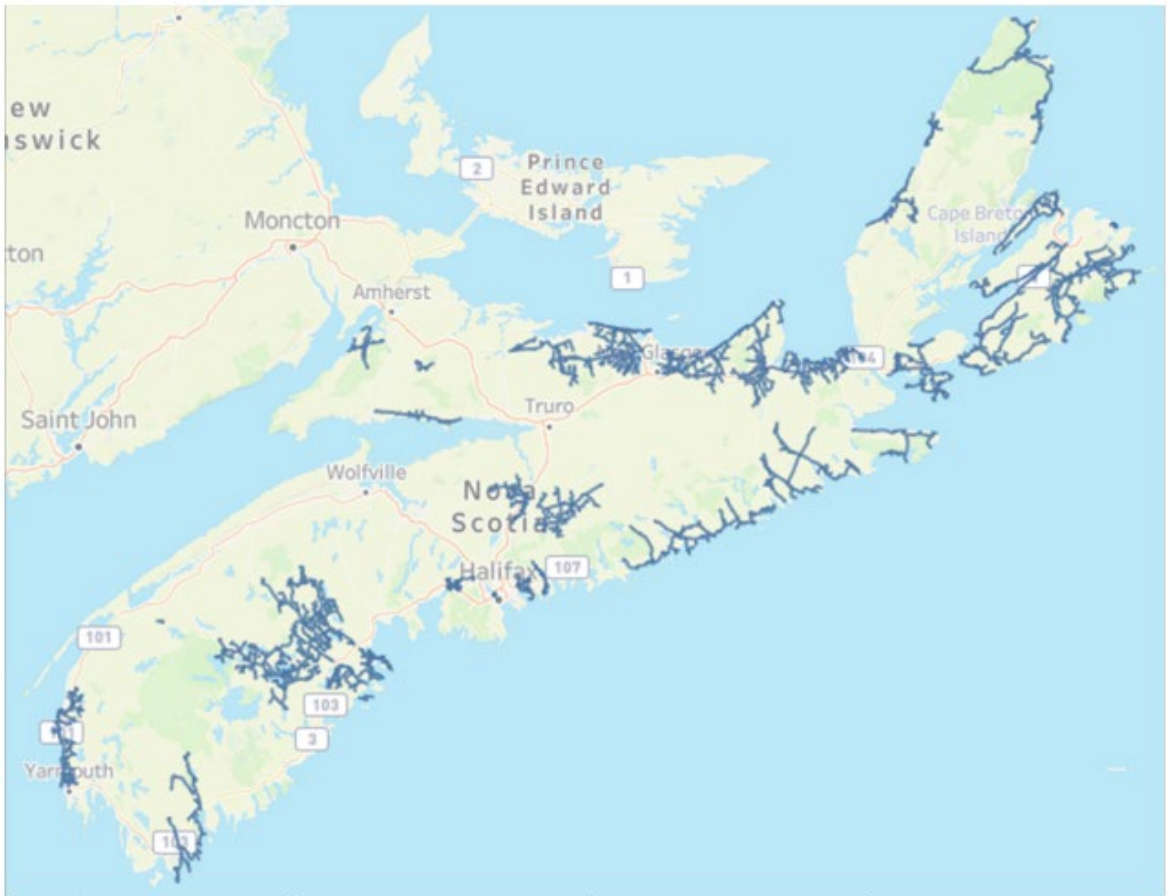
8.0 CONCLUSION

NS Power's Five-Year Reliability Plan represents a significant, sustained commitment to improving system reliability and resilience for customers across Nova Scotia. Year one of the Plan is delivering meaningful progress, and remains on track to invest $206 million in 2025 in targeted initiatives including vegetation management, storm hardening, and advanced grid modernization. These efforts have already produced measurable benefits, such as reductions in outage frequency and duration, and enhanced system performance.

Looking ahead, the full impact of the program will continue to build as investments accumulate over the five-year horizon. By 2029, NS Power expects to achieve a 20 percent improvement in Performance Standards SAIDI, equivalent to approximately one hour of reduced outage duration, and continue to meet Performance Standards SAIFI, while continuing to prioritize affordability for customers. Continued focus on risk-based decision-making, data-driven prioritization, and innovative technologies will ensure that reliability improvements are aligned with customer needs and industry best practices.

NS Power remains committed to transparency and collaboration with stakeholders and the Board throughout the implementation of this plan, aided by the third-party review starting in early 2026. Annual updates will provide visibility into progress, performance trends, and refinements to future-year work plans. Through these efforts, NS Power will deliver a stronger, more resilient grid capable of meeting the challenges of climate change, supporting electrification, and improving the customer experience.

APPENDIX A: 2025 Highest Priority Distribution Feeders



Western Region	Metro Region	Northeast Region	Cape Breton Region
14V-303 70W-311 80W-301	137H-412 104H-421 82V-402	100C-421 30N-412 4C-441	57S-401 57S-402 11S-411
16W-301 70W-313 91W-411	113H-433 126H-311	4N-313 57C-426 82V-401	3S-403 59C-402 103C-314
23W-302 73W-411 93V-313		88H-401 50N-410 56N-414	22C-403 22C-404 81S-305
25W-301 76V-301		6N-302 96H-411 96H-412	85S-401 58C-403
57W-401 78W-301		24C-442 4C-430 37N-411	
57W-402 78W-302			

NS Power Five-Year Reliability Plan - Update
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APPENDIX B: Work Completed (C) and In Progress (P) on 2025 Priority Feeders

	Region	Depot	Targeted Equipment Replacements	Protection Upgrade	Upgrades for Load Growth	Build to Roadside	Vegetation Work	2026 Priority Feeder? (Y/N)
100C-421	Cape Breton	PHA				P	C	N
103C-314	Cape Breton	CHC	C					Y
11S-411	Cape Breton	SYD					P	N
22C-403	Cape Breton	PHA		P				N
22C-404	Cape Breton	PHA	P	P				Y
3S-403	Cape Breton	SYD					P	N
57S-401	Cape Breton	SYD	C	C			P	N
57S-402	Cape Breton	SYD	C				P	N
58C-403	Cape Breton	CHC	P	C	C		P	Y
59C-402	Cape Breton	RIB					P	N
81S-305	Cape Breton	SYD	C					N
81S-307	Cape Breton	SYD	C					N
85S-401	Cape Breton	ING		P		P	P	Y
104H-421	Metro	HFX	C					N
113H-433	Metro	DAR	P	C	P		P	N
126H-311	Metro	DAR	C		C		P	N
137H-412	Metro	BAY	C				P	N
82V-402	Metro	SAC	P				P	Y
24C-442	Northeast	GUY	P				P	N
30N-412	Northeast	AMH	P				P	N
37N-411	Northeast	PAR	P				C	N
4C-430	Northeast	ANT	P				P	Y
4C-441	Northeast	ANT	C		C		P	N
4N-313	Northeast	AMH	C	C			P	N
50N-410	Northeast	STE	C				P	N
56N-414	Northeast	STE	C	P			C	N
57C-426	Northeast	GUY	P			P		Y

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	Region	Depot	Targeted Equipment Replacements	Protection Upgrade	Upgrades for Load Growth	Build to Roadside	Vegetation Work	2026 Priority Feeder? (Y/N)
6N-302	Northeast	AMH	P					N
82V-401	Northeast	SAC	C					N
88H-401	Northeast	TRU	P				P	N
96H-411	Northeast	TRU			C			N
96H-412	Northeast	TRU	P		C			N
16W-301	West	YAR	C	P				N
23W-302	West	SHE	C					N
25W-301	West	SHE	P	C			P	Y
57W-401	West	LIV	C	C	C			N
57W-402	West	LIV	C				P	N
70W-311	West	DIG	C	C				N
70W-313	West	DIG	P					N
73W-411	West	BRW	P				P	N
76V-301	West	LIV				C		N
78W-301	West	BRW		C	C		P	N
78W-302	West	BRW	C		C		P	N
80W-301	West	BRW	P	C			C	N
91W-411	West	LIV		C			P	Y
93V-313	West	CLA	C					N

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APPENDIX C– Pole Monitoring Projects – New Pole Class Standard

Summary of Pole Monitoring Project Locations

Region	Feeder	Location	Pole Removals	Pole Installs
West	12V-302G	Karsdale (3471 Granville Rd)	40 ft CL4 Quantity: 10	45 ft CL3 Quantity: 2 45 ft CL1 Quantity: 8 40 ft CL3 Quantity: 1
Metro	2H-411	Ragged Lake Blvd to Exhibition Park Exhibition Park to Irving at Evergreen PL	50 ft CL2 Quantity: 1 40 ft CL4 Quantity: 9 45 ft CL3 Quantity: 4	60 ft CL2 Quantity: 6 55 ft CL2 Quantity: 45 50 ft CL2 Quantity: 3 45 ft CL3 Quantity: 3 40 ft CL4 Quantity: 1 35 ft CL4 Quantity: 10
Northeast	26N-211	Joggins, Cumberland County	40 ft CL4 Quantity: 15 35 ft CL4 Quantity:2	55 ft CL H1 Quantity: 2 50 ft CL H1 Quantity: 2 45 ft CL3 Quantity: 5 45 ft CL1 Quantity: 8 35 ft CL4 Quantity: 2
Cape Breton	85S-401	Wreck Cove (41817 Cabot Trail)	40 ft CL4 Quantity: 5 35 ft CL4 Quantity: 1	50 ft CL2 Quantity: 1 45 ft CL1 Quantity: 2 45 ft CL3 Quantity: 3 40 ft CL1 Quantity: 1 35 ft CL4 Quantity: 3

Capital Project Approval Process

Project Delivery Model (PDM) Documentation Review

Purpose:

This document should be used as a guide during capital project review to ensure that all relevant PDM documentation that is utilized to develop a capital project scope and estimate has been filled out properly and has been appropriately considered throughout the capital project documentation. This only includes PDM documentation that is intended to inform project planning and execution.

The following lists the relevant PDM documentation, and what should be reviewed:

Contingency Assessment (if applicable)

Review this document to ensure it's aligned with the Non-Binding Contingency Guidelines, and that the justifications included in the assessment are aligned with the contingency amount / percentage used in the application. Refer to similar projects as applicable.

Estimate Maturity Matrix

Review this document to ensure that the project is advanced in its planning enough to request the type of approval it is seeking. The resultant class of estimate that is shown in this matrix is to be reviewed against the contingency percentage used in the project.

Economic Analysis Model (EAM) (if economic)

Review the EAM to ensure that all feasible alternatives are being tested, and that this analysis is consistent with the "Why do this Project This Way" section of the project description. Ensure that the project manager has properly inputted all capital costs, operating expenses and avoided expenses if applicable.

Risk Register

Review this document against the Project Description, including the contingency statement to ensure that all risks are properly considered when applying a contingency percentage. Discuss with project manager to confirm that any risks included in the risk register are more appropriate to be considered within the project contingency or included as an explicit cost estimate if the risk of occurrence is high.

Post Project Review (to be completed post project completion)

This cannot be reviewed until after the project is complete, but ensure project manager has considered lessons learned from prior capital projects in developing the project scope and detailed cost estimate.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Long Title	(i)Approval Mechanism	(ii)Approved Budget (no Contingency)	(iii)Approved Contingency	(iv)Actual Cost	(v)
C0031069	L6020 Replacements and Upgrades	ACE 2021	1,681,215	144,085	1,520,929	Under budget. FIN approved by NSEB
C0031085	L6516 Line Replacement and Upgrades	ACE 2021	2,513,760	216,832	2,542,897	Over budget by < 5%
C0041789	L5550 Replacements and Upgrades Phase 2	ACE 2022	2,392,219	306,296	2,094,295	Under budget. FIN approved by NSEB
C0041793	L7002 Replacements and Upgrades Phase 2	ACE 2022	3,640,960	417,551	3,856,785	Over budget. Increased costs are due to more difficult access to the strucures.
C0041796	L6020 Replacements and Upgrades Phase 2	ACE 2022	2,232,473	285,770	3,281,196	Over budget. Additional structure replacements were required. FIN/ATO filed and approved by NSEB
C0041800	L5537 Replacements and Upgrades	ACE 2022	1,126,404	144,294	648,216	Under budget. FIN approved by NSEB
C0041805	L7005 Replacements and Upgrades Phase 2	ACE 2022	2,818,777	363,741	2,910,505	Over budget by < 5%
C0041810	L5022 Replacements and Upgrades	ACE 2022	1,927,707	244,494	1,618,003	Under budget. FIN approved by NSEB
C0011339	**L6549 Replacements and Upgrades Phase 2**	**ACE 2019**	**2,041,364**	**168,543**	**3,904,481**	**Over budget. ATO filed and approved by NSEB**
C0043010	**2022-2023 Wood Pole Retreatment Program**	**ACE 2022**	**1,300,037**	**98,320**	**791,054**	**Under budget. FIN filed with NSEB**