Nova Scotia Utility and Review Board

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

2023 10-Year System Outlook

NS Power

June 30, 2023

NON-CONFIDENTIAL

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1.0 INTRODUCTION

Delivering clean, reliable and lowest cost energy is NS Power's commitment to customers. NS Power is committed to supplying 80 percent clean energy and phasing out coal generation by 2030. The Company has made great strides towards these goals by more than tripling the amount of renewable energy on the grid over the last decade. In order to achieve its commitment to customers, NS Power performs planning and resource adequacy assessments while adhering to the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

In accordance with the 3.4.2.1[1] Market Rule requirements, this report provides the 10-Year System Outlook on behalf of the Nova Scotia Power System Operator (NSPSO) for 2023. The 10-Year System Outlook is not an integrated resource planning exercise. It is the NSPSO's annual assessment of Nova Scotia Power Incorporated's (NS Power, Company) system capacity and adequacy.

The Report contains the following information:

- A summary of the NS Power load forecast and an update on the Demand Side Management (DSM) forecast in **Section 2.0**.
- A summary of generation expansion anticipated for facilities owned by NS Power and others in **Section 3.0**. NS Power's generation planning for existing facilities, including retirements as well as investments in upgrades, refurbishment or life extension, and new generating facilities committed in accordance with previously approved NSPSO system plans.

[1] Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules (as amended 2016 06 10), Market Rule 3.4.2 states, "The NSPSO system plan will address: (a) transmission investment planning; (b) DSM programs operated by EfficiencyOne or others; (c) NS Power generation planning for existing Facilities, including retirements as well as investments in upgrades, refurbishment or life extension; (d) new Generating Facilities committed in accordance with previous approved NSPSO system plans; (e) new Generating Facilities planned by Market Participants or Connection Applicants other than NS Power; and (f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services)."

- A summary of environmental and emissions regulatory requirements, as well as forecast compliance in **Section 5.0**. Section 5.0 also includes projections of the level of renewable energy forecast and discusses anticipated policy changes.
- A Resource Adequacy Assessment in **Section 6.0**.
- A discussion of transmission planning considerations in **Sections 7.0 and 8.0**.

The previous (2022) 10-year System Outlook report relied on outcomes of the 2020 NS Power Integrated Resource Plan (IRP), which evaluated a robust set of future planning scenarios, with modeling assumptions that incorporated stakeholder input. 2020 IRP Scenario 3.1C was chosen as the basis for the 2022 10YSO as it best reflected the load and policy landscape at the time[2], as opposed to the original 2020 IRP reference plan (Scenario 2.0C).

Since that time and in accordance with NS Power's IRP Action Plan Update[3] and 2022 Evergreen IRP Study Scope and Timeline,[4] NS Power has completed a focused evaluation and refinement of the long-term electricity strategy[5] developed as part of the 2020 IRP that reflects the current planning environment. The results of the evergreen IRP work[6] have assessed a range of future planning scenarios reflecting various potential system planning outcomes. Evergreen IRP scenario CE1-E1-R2 (net zero 2035, current policy and trends for electrification, no Atlantic Loop) has been selected as the basis for the 2023 10-year System Outlook report. Please refer to **Section 3.0** for a more detailed discussion of the evergreen IRP and the selected reference scenario.

[2] 2020 IRP Scenario 3.1C reflected the mid-electrification load profile, base demand side management assumptions, access to a Regional Interconnection, and retirement of coal by 2030.
[3] M10504, Nova Scotia Power IRP Action Plan Update, January 21, 2022.
[4] M10504, Nova Scotia Power IRP Evergreen Study Scope. April 6, 2022.
[5] M10504, Nova Scotia Power IRP Action Plan Roadmap.
[6] 2022 Evergreen IRP - NSP Integrated Resource Planning (nspower.ca)

2.0 LOAD FORECAST

The NS Power load forecast provides an outlook on the energy and peak demand requirements of customers in the province. The load forecast forms the basis for fuel and power-purchase supply planning, investment planning, and overall operating activities of NS Power. The figures presented in this Report are the same as those filed with the NSUARB in the 2023 Load Forecast Report[7] on April 29, 2023, and were developed using NS Power's statistically adjusted end-use (SAE) model to forecast the residential and commercial rate classes. The residential and commercial SAE models are combined with an econometric-based industrial forecast and customer-specific forecasts for NS Power's large customers to develop an energy forecast for the province, also referred to as the Net System Requirement (NSR).

Figure 1 shows historical and forecast NSR which includes in-province energy sales plus system losses. Compared to the 2022 Load Forecast, the 2023 Load Forecast shows accelerated growth in the near term due to increased customer addition forecasts and higher average use when adjusted for weather. Mid to long-term growth is driven by sustained customer growth and higher Electric Vehicle (EV) sales driven by the federal government's goal of achieving 60 percent zero-emissions vehicle sales by 2030 and 100 percent by 2035. Sales through the Renewable to Retail (RTR) market are forecast to reduce load in the 2024-2025 timeframe by approximately 136 GWh. In the long term, energy sales will be reduced by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside structured DSM programs, as well as increased behind-the-meter solar installations. The net result is an average annual increase in Net System Requirement of 0.7 percent.

[7] M11108, Nova Scotia Power 2023 Load Forecast Report, April 28, 2023.

Figure 1: Net System Requirement with Future DSM Program Effects (actuals not weather adjusted)

Year	NSR (GWh)	Growth (%)
2013	11,194	6.9
2014	11,037	-1.4
2015	11,099	0.6
2016	10,809	-2.6
2017	10,873	0.6
2018	11,250	3.5
2019	11,077	-1.5
2020	10,723	-3.2
2021	10,902	1.7
2022	11,134	2.1
2023*	11,288	1.4
2024*	11,168	-1.1
2025*	11,199	0.3
2026*	11,327	1.1
2027*	11,416	0.8
2028*	11,531	1.0
2029*	11,616	0.7
2030*	11,720	0.9
2031*	11,838	1.0
2032*	11,998	1.4
2033*	12,113	1.0

*Forecast value

NS Power also forecasts peak hourly demand for future years. The system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads. Due to the weather-sensitive load component in Nova Scotia, the system peak occurs in the period from December through February.

The peak demand forecast is developed using end-use energy forecasts combined with peak-day weather conditions to generate monthly peak demand forecasts through an estimated monthly peak demand regression model. The peak contribution from large customer classes is calculated from historical coincident load factors for each of the rate classes. Peak savings related to Demand Response (DR) activities, adjusted for Effective Load Carrying Capability (ELCC) as outlined in the 2020 IRP and including critical peak pricing and direct load control components, are included in the firm peak. Customer growth and increased EV sales will increase the peak, while DSM activities will reduce the peak. As a result, the system peak demand is expected to increase by 2.3 percent annually over the forecast period. The firm contribution to peak demand is expected to increase by 2.2 percent annually over the forecast period. **Figure 2** shows the historical and forecast net system peak.

Figure 2: Coincident Peak Demand with Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)
2013	136	-	1,897	2,033	8.0
2014	83	-	2,036	2,118	4.2
2015	141	-	1,874	2,015	-4.9
2016	98	-	2,013	2,111	4.8
2017	67	-	1,951	2,018	-4.4
2018	80	-	1,993	2,073	2.7
2019	111	-	1,949	2,060	-0.6
2020	96	-	1,954	2,050	-0.5
2021	94	-	1,875	1,968	-4.0
2022	155	4	2,061	2,216	12.6
2023*	146	12	2,105	2,256	1.8
2024*	147	24	2,111	2,271	0.7
2025*	148	36	2,119	2,291	0.9
2026*	156	39	2,148	2,340	2.1
2027*	157	39	2,198	2,395	2.3
2028*	157	39	2,259	2,454	2.5
2029*	157	38	2,325	2,520	2.7
2030*	156	38	2,395	2,589	2.8
2031*	156	38	2,468	2,662	2.8
2032*	156	38	2,545	2,738	2.9
2033*	156	37	2,627	2,819	3.0

*Forecast value

As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, energy efficiency program effectiveness, the health of the economy, government policy, the impact of electrification, changes in large customer loads, the number of electric appliances and end-use equipment installed, and changes in technology.

3.0 GENERATION RESOURCES

3.1 Existing Generation Resources

NS Power's generation portfolio is composed of a mix of fuel and technology types that include coal, petroleum coke, light and heavy fuel oil, natural gas, biomass, wind, hydro and solar. In addition, NS Power purchases energy from Independent Power Producers (IPPs) located in the province and imports power across the NS Power/NB Power intertie and the Maritime Link. Since the implementation of the *Renewable Electricity Standards* (RES) discussed in Section 5.1, an increased percentage of total energy is produced by variable renewable resources such as wind. However, due to their intermittent nature, these variable resources provide less firm capacity, as a percentage of net operating capacity, than conventional generation resources. Therefore, the majority of the system requirement for firm capacity is met with NS Power's conventional units (e.g. coal, gas) while their energy output is displaced by renewable resources when they are producing energy. This is discussed further in **Section 3.3** below.

Figure 3 lists NS Power's and the IPPs' verified and forecast firm generating capability for generating stations/systems along with their fuel types up to the filing date of this Report. The changes and additions over the 10-year period to this total capacity are shown in **Figure** . The firm generating capability for the wholesale market participants is set out in **Figure 4.**

Figure 3: 2023 Firm Generating Capability for NS Power and IPPs

Plant/System	Fuel Type	Winter Net Capacity (MW)[8]
Avon	Hydro	6.4
Black River	Hydro	21.4
Lequille System	Hydro	23.0
Bear River System	Hydro	35.5
Tusket	Hydro	2.3
Mersey System	Hydro	33.9
St. Margaret's Bay	Hydro	10.3
Sheet Harbour	Hydro	10.2
Dickie Brook	Hydro	3.6
Wreck Cove	Hydro	201.4
Annapolis Tidal[9]	Hydro	0.0
Fall River	Hydro	0.5
Maritime Link NS Base Block	Hydro	145.4
Total Hydro		**493.8**
Tufts Cove	Heavy Fuel Oil/Natural Gas	318
Trenton	Coal/Pet Coke/Heavy Fuel Oil	304
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	150
Lingan[10]	Coal/Pet Coke/Heavy Fuel Oil	607
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	168
PH Biomass		43
Total Steam		**1590**
Tufts Cove Units 4, 5 & 6	Natural Gas	144
Total Combined Cycle		**144**
Burnside	Light Fuel Oil	132
Tusket	Light Fuel Oil	33

[8] Wind, Hydro and solar are Effective Load Carrying Capability (ELCC) values. Please refer to Section 6.3 for further information.
[9] Annapolis is assumed to be out of service. Please refer to Section 3.2..
[10] Lingan Unit 2 will be retained in cold reserve in order to provide firm capacity for the upcoming winter (2023/2024). Please refer to Section 3.

Plant/System	Fuel Type	Winter Net Capacity (MW)[8]
Victoria Junction	Light Fuel Oil	66
Total Combustion Turbine		**231**
Pre-2001 Renewables	Independent Power Producers (IPPs)	25.7
Post-2001 Renewables (firm)	IPPs	64.9
NS Power wind (firm)	Wind	14.5
Community-Feed-in-Tariff (firm)[11]	IPPs	29.6
Solar	Solar	0.1
Tidal	Tidal	0.1
Total IPPs & Renewables		**134.9**
Total Capacity		**2593.7**

Figure 4: Firm Generating Capability for Wholesale Market Participants

Wholesale Market Participant	Fuel Type	Winter Net Capacity [12] (MW)
Backup Top-Up (BUTU)[13]	Wind [Ellershouse[14]]	4.2
Backup Top-Up (BUTU)	Municipal Tariff[15]	0
Total		**4.2**

[11] Existing Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) wind projects are assumed to have a firm capacity contribution of 18 percent as detailed in Section 6.3.1.
[12] M09940, UARB Backup/Top-up Service (BUTU) decision to use 18 percent ELCC for wind and 0 percent for non-firm Imports to align with current NS Power planning practices (page 38).
[13] Wholesale Market Backup/Top-up Service (BUTU) Tariff participants currently include the Municipal load for Berwick, Mahone Bay, Antigonish and Riverport.
[14] Ellershouse wind farm owned by Alternative Resource Energy Authority (AREA).
[15] Energy requirement needs now met by NS Power under the Municipal Tariff (2023), previously met by imports delivered via the Nova Scotia/New Brunswick Intertie.

3.1.1 Maximum Unit Capacity Rating Adjustments

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NS Power meets the requirement for generator capacity verification as outlined in North American Electric Reliability Corporation (NERC) Standard *MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability*[16] which was approved by Federal Energy Regulatory Commission (FERC) on March 20, 2014 and approved by the NSUARB for effect in the province on July 1, 2016.

The Net Operating Capacity of the thermal units and large hydro units covered by the NERC criteria are current. NS Power will continue to update unit maximum capacities in the 10-Year System Outlook each year as operational conditions change.

3.1.2 Mersey Hydro

NS Power continues to assess options to address current concerns on the Mersey Hydro System. Degradation of the powerhouses and water control structures after nearly a century of service has necessitated the need for future significant redevelopment work. The Mersey Hydro System is an important part of NS Power's hydro assets and is responsible for approximately 25 percent of annual domestic hydroelectric production. The Company has increased its sustaining capital from now until 2030 to reflect the shifted start of the larger Mersey Hydro System redevelopment project.

In the current Evergreen IRP study, the Mersey hydro system is modeled as being retained throughout the planning horizon. To account for the status of the redevelopment project work, the derated adjusted forced outage rate (DAFOR) has been increased to account for potential additional outage hours on the Mersey Hydro System. In addition, the modeled Effective Load

[16] https://www.nerc.com/pa/Stand/Pages/Project2007-09-Generator-Verification.aspx

Carrying Capability (ELCC) has been reduced to 85 percent; this is reflected in the firm generating capacity table (please see **Figure 3**).

3.1.3 Wreck Cove Hydro

The Wreck Cove Hydro system is an important asset for NS Power, providing critical and renewable generation for peak demand periods. With the ability to quickly provide 212 MW of peak capacity from two operating units and average annual generation of 300 GWh, Wreck Cove is NS Power's largest hydroelectric system. As part of the Life Extension and Modernization (LEM) Project, the two unit turbines will be replaced with newly designed turbine runners which will have increased efficiency and a wider operating range over the existing ones. While the change in turbine runners will not change the peak capacity of 212 MW, it will provide a forecast increase of 5 percent to the annual generation from Wreck Cove. The completion of this project will bring the average annual generation at Wreck Cove to 315 GWh per year.

3.2 Changes in Capacity

3.2.1 NS Power IRP Process

Since the completion of the 2020 IRP, there have been significant changes to the electricity planning environment, which include the following (please refer to the February 2023 IRP Action Plan Update for more details[17]):

- 2030 targets including 80 percent renewable energy standards and phase-out of coal generation (please see **Section 6.0**).
- Nova Scotia Output-Based Pricing System implementation and the associated Federal carbon price trajectory to $170/tonne in 2030 (please refer to **Section 6.0** for further discussion).

[17] PowerPoint Presentation (nspower.ca)

- The pausing of the Eastern Clean Energy Initiative (ECEI) project investments as an outcome of the passage of Bill 212, which limits non-fuel rate increases to 1.8 percent to the end of 2024.
- Announcement of the Federal Investment Tax Credit for qualifying renewable energy, storage and delivery resources.
- The accelerating pace of load growth in the province as discussed in **Section 2.0**.
- The awarding of PPAs associated with the Provincial Rate Base Procurement program.[18]

The Evergreen IRP process is NS Power's approach to assess and refine its IRP Action Plan and Roadmap items. The Evergreen modeling aligns NS Power's electricity strategy with the current planning and policy environment.

For the purposes of the 2023 10 Year System Outlook Report, NS Power has selected scenario CE1-E1-R2 (net zero 2035, current policy and trends electrification, no Atlantic Loop) as the resource plan that is representative of the range of scenarios evaluated in the 2023 evergreen IRP and aligned with the current planning environment. This scenario is among the lowest cost plans evaluated which achieves the 2030 decarbonization targets and the Federal target of a net zero electricity system in 2035. The remainder of the Report uses scenario CE1-E1-R2 as the reference resource plan.

NS Power will continue to be responsive to ongoing changes in the electricity planning environment, including but not limited to potential advancement of the Atlantic Loop[19], the pace of economy-wide electrification, and development of alternative peak mitigation strategies. NS Power will also monitor developments in emerging technologies in alignment with Federal policy discussion papers which point to these technologies as part of the path to a net zero electricity system. The emerging technologies considered in the evergreen IRP include hydrogen fueled

[18] Nova Scotia Rate Base Procurement (novascotiarbp.com)
[19] In the evergreen IRP analysis, scenario CE1-E1-R1 BD, which includes a bidirectional Atlantic Loop in 2030, was the lowest cost plan modeled. The addition of the Atlantic Loop and associated wind offset the need for approximately 300MW of alternative firm capacity resources cumulatively through 2030. The balance of the resource mix through the period is similar; accordingly CE1-E1-R2 continues to be representative of the overall system resource mix anticipated for this 10-year period.

combustion turbines, small modular reactors, tidal, natural gas generation with carbon capture & storage, and long duration energy storage. These resources are not currently commercially available but were evaluated as potential future resources in the evergreen IRP modeling. Although they were not economically selected in the evergreen IRP modeling, NS Power will continue to monitor the development of these potential resources and reassess as needed.

Figure 5 below shows the anticipated DSM and firm capacity changes over the ten-year period starting in 2024.

Figure 5: Firm Capacity Changes & DSM

New Resources 2024-2033	Net MW
DSM Peak reduction	245
Demand Response (Firm contribution)[20]	37
Total Demand Side MW Change Projected Over Planning Period	**282**
Maintenance/Repairs:	
Hydro derates during Wreck Cove LEM	-101
Wreck Cove LEM completion	101
Additions:	
Biomass	43
Tidal	2
New Wind Build (Rate Base Procurement) (Firm capacity)	37
Battery (Firm capacity)	114
Fast Acting Generation	870
Point Tupper 2 Coal-to-Gas conversion	150
New Wind Build (Firm capacity)	160
Other Wind (Firm capacity)[21]	13

[20] Represents the firm contribution of demand response programs in 2033 assuming an ELCC of 48 percent. Refer to Section 2.0, Figure 2 for the annual DR totals from 2024 to 2033.
[21] Represents the Pirate Harbour Wind project

New Resources 2024-2033	Net MW
Lingan 1, 3 & 4 HFO Operation	459
Retirements:	
Trenton 5 & 6	-304
Lingan 1, 2, 3 & 4 (Coal Operation)	-607
Point Tupper (Coal Operation)	-150
Point Aconi	-168
Total Firm Supply MW Change Projected Over Planning Period	**635**

3.2.2 Brooklyn Power

Brooklyn Power owns a 24 MW firm dispatchable renewable energy Biomass facility located in Liverpool, Nova Scotia. NS Power purchases energy from Brooklyn Power under a long-term power purchase agreement (PPA). On February 18, 2022 high winds caused damage to the unit's power stack and warehouse, ultimately taking the unit offline. Repairs to the facility have since been completed and the facility was brought back online in early 2023.

3.2.3 Lingan Unit 2

Effective August 15, 2022, Lingan Unit 2 was laid up and not made available for economic dispatch. The unit was placed into cold reserve and available to be recalled on two weeks' notice. Over winter 2022/2023, the unit was recalled to service eight times by the NSPSO to support firm customer load, generating a total of 404 GWh.

During the Wreck Cove LEM project scheduled outages, Lingan Unit 2 will be available, if needed, to provide firm capacity and maintain an adequate planning reserve margin (**Section 6.2**) for the upcoming winter (2023/2024).

In NS Power's Wreck Cove LEM capital application,[22] the single-unit winter outages were identified as requiring an offsetting capacity replacement. At the time of the application, NS Power estimated the costs of replacement capacity and included this cost in its LEM project application. As discussed in the February 2023 IRP Action Update, near-term firm import opportunities over existing transmission interfaces are unavailable for winter 2023/2024. With Lingan Unit 2 phased out of economic dispatch for energy provision but available to provide firm capacity for winter 2023/2024 (recallable on two weeks' notice), NS Power maintains sufficient capacity to meet its planning reserve margin requirements.

As new firm capacity resources are added to the system, retaining existing thermal units in cold reserve can support commissioning, testing and establishment of reliable operations without compromising the planning reserve margin requirements. This will be considered and assessed as plans for new resources are progressed.

3.2.4 Annapolis Tidal

The Annapolis Tidal Generating Station ceased generation in January 2019 following the failure of a crucial station component. Subsequently, NS Power completed an analysis to determine whether continued reinvestment in the facility was the lowest cost option for customers. Ultimately, NS Power made the determination that the facility should be retired. In February 2021, NS Power applied to the NSUARB[23] for approval to treat the generating station as Not Used and Not Useful in accordance with approved accounting policies, and for approval to amortize the unrecovered net book value of the assets over a 10-year period. On January 14, 2022 the NSUARB concluded that it was not yet in a position to find the asset Not Used and Not Useful. The NSUARB will reconsider the application for the requested accounting treatment if NS Power resubmits it with a decommissioning application. NS Power is continuing capital planning activities with respect to the generating station and is engaging in discussions with Fisheries and Oceans Canada.

[22] M09596, NS Power Wreck Cove Life Extension and Modernization – Unit Rehabilitation and Replacement, CI 13838, February 28, 2020.

[23] M10013, NS Power Application re Annapolis Tidal Generation Station Retirement: Request for Accounting Treatment and Net Book Value Recovery (P-111.6), February 22, 2021.

NS Power provided a status update to the NSUARB on March 9, 2023 indicating that the Company, along with the relevant environmental regulators (DFO), continues to assess the Annapolis Tidal Generating Station. Another update will be provided to the NUARB on July 31, 2023. For the purposes of the 2023 10-Year System Outlook, NS Power has assumed no capacity or energy contribution from the Annapolis Tidal Generating Station.

3.3 Unit Utilization Forecast

The Company typically forecasts 10 years of utilization and investment projections in this Report. These projections inform NS Power's asset planning approach and are used to guide investment strategies. There are many operational factors, such as the prices of fuel and power or changes in policy, electricity demand, or regulation that could trigger a significant shift in the utilization forecast to provide the most economic system dispatch for customers. A summary of the anticipated system additions and retirements is set out below in **Figure 6**.

Figure 6: Additions and Retirements as in the 10-Year System Outlook Resource Plan

Winter	Additions	Retirements
2024/2025	• New wind additions (Rate Base Procurement) (Installed capacity 194 MW, firm 19.4MW based on marginal ELCC of 10%) • New wind additions (Installed capacity 130MW, firm 13MW based on marginal ELCC of 10%)	
2025/2026	• New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%) • Battery Storage (Installed capacity 30MW, firm 25.6MW)	Lingan 2 (-148 MW)
2026/2027	• New wind additions (Rate Base Procurement) (Installed capacity 178.2 MW, firm 17.8 MW based on marginal ELCC of 10%) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%)	

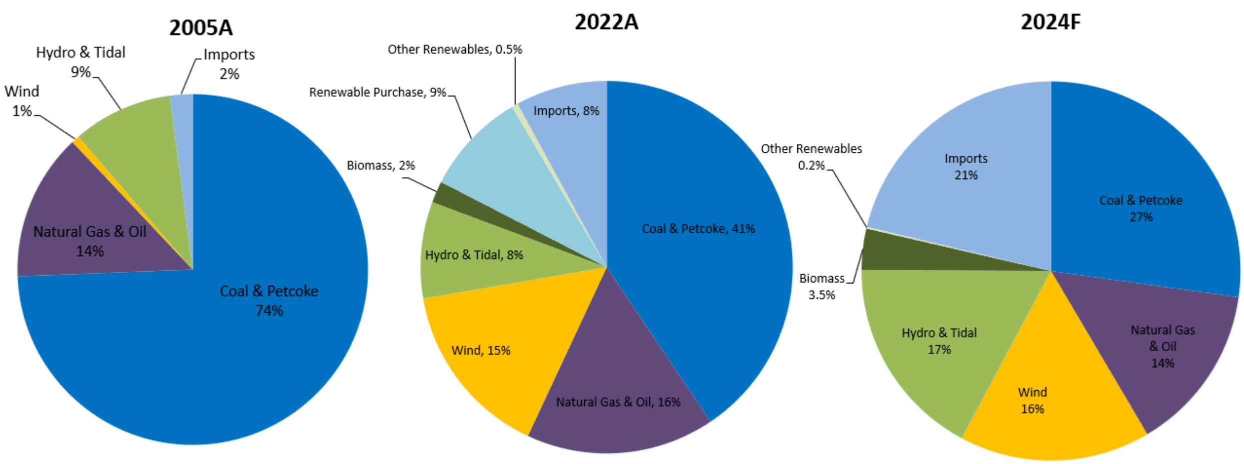
Winter	Additions	Retirements
	• Battery Storage (Installed capacity: 10MW; firm capacity: 8MW) • Combustion turbine (50 MW)	
2027/2028	• Combustion turbines (200 MW) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%) • Battery Storage (Installed capacity: 50MW; firm capacity: 33MW)	Trenton 5 (-150 MW)
2028/2029	• Combustion turbines (350 MW) • Point Tupper 2 coal-to-gas conversation (150 MW) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%) • Battery Storage (Installed capacity: 50 MW; firm capacity: 25MW)	Point Aconi, Point Tupper 2 & Trenton 6 (-472 MW)
2029/2030	• Combustion turbines (50 MW) • Coal to HFO operation (Lingan 1, 3, 4; 459MW) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%)	Lingan 1, 3, 4 (- 459 MW)
2030/2031	• Combustion turbines (50 MW) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%) • Battery Storage (Installed capacity: 60MW; firm capacity: 23MW)	
2031/2032	• Reciprocating engine (20 MW) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%)	
2032/2033	• Combustion turbines (150 MW) • New wind additions (Installed capacity 200 MW, firm 20 MW based on marginal ELCC of 10%)	

Since many of the resource additions listed are currently in the development stage, there may be adjustments in timing for planned in-service dates and corresponding retirement dates. NS Power will continue to make adjustments as required.

3.3.1 Evolution of the Energy Mix in Nova Scotia

NS Power's energy production mix has undergone significant changes over the last 15 years. Since the implementation of the RES, an increased percentage of energy sales is produced by variable renewable resources such as wind. However, due to their intermittent nature, variable resources provide less firm capacity, as a percentage of net operating capacity, than conventional generation resources. Therefore, the majority of the system requirement for firm capacity and other ancillary services is met with NS Power's conventional units (i.e. coal, gas, diesel, hydro) as discussed in Sections 3.1, while the energy output of conventional units is being displaced by renewable resources. **Figure 7** below illustrates this change with the actual energy mix from 2005 and 2022 and the updated forecast for 2024.

Figure 7: 2005, 2022 Actual and 2024 Forecast Energy Mix



3.3.2 Projections of Unit Utilization

NS Power's projected utilization of each of the units in the thermal generating fleet is set out below in **Figure 8**.

Figure 8: NS Power Steam Fleet Unit Utilization Forecast

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Lingan 1[24]	Capacity Factor (%)	31	38	29	28	32	11	1	1	2	1
	Unit Cycles	12	24	23	24	24	23	6	4	5	5
	Service Hours	3,201	4,438	3,540	3,301	3,968	1,344	116	103	183	142
Lingan 2[25]	Capacity Factor (%)	0	0	0	0	0	0	0	0	0	0
	Unit Cycles	0	0	0	0	0	0	0	0	0	0
	Service Hours	0	0	0	0	0	0	0	0	0	0
Lingan 3[24]	Capacity Factor (%)	30	14	14	11	17	8	1	2	2	2
	Unit Cycles	48	24	22	24	23	24	7	8	10	7
	Service Hours	3,238	1,734	1,685	1,250	1,880	957	171	209	273	242
Lingan 4[24]	Capacity Factor (%)	35	23	26	15	22	10	2	2	2	2
	Unit Cycles	18	24	21	22	24	24	5	6	7	7
	Service Hours	3,495	2,632	3,101	1,651	2,607	1,191	176	182	247	222
Point Aconi	Capacity Factor (%)	32	10	1	4	2	0	0	0	0	0
	Unit Cycles	9	8	4	6	3	0	0	0	0	0
	Service Hours	3,289	1,015	160	488	226	0	0	0	0	0

[24] Lingan units operate on HFO from 2030-2033.
[25] See Section 3.2.4

Point Tupper[26]	Capacity Factor (%)	39	59	41	55	53	7	2	1	2	2
	Unit Cycles	40	21	24	24	21	12	8	9	10	5
	Service Hours	4,722	5,831	4,071	5,391	5,235	862	254	161	270	219
Trenton 5	Capacity Factor (%)	16	17	12	14	0	0	0	0	0	0
	Unit Cycles	4	15	12	9	0	0	0	0	0	0
	Service Hours	1,769	1,896	1,244	1,514	0	0	0	0	0	0
Trenton 6	Capacity Factor (%)	64	44	37	50	21	0	0	0	0	0
	Unit Cycles	11	19	21	21	7	0	0	0	0	0
	Service Hours	6,802	4,920	4,333	5,649	2,386	0	0	0	0	0
Tufts Cove 1	Capacity Factor (%)	24	5	5	1	2	1	5	3	5	4
	Unit Cycles	16	23	20	8	6	4	14	7	12	11
	Service Hours	2,443	591	482	139	189	125	447	285	467	367
Tufts Cove 2	Capacity Factor (%)	25	18	8	5	3	16	20	16	17	12
	Unit Cycles	29	60	44	32	11	63	62	65	46	45
	Service Hours	2,960	2,351	1,087	763	324	1,763	2,142	1,676	1,679	1,240
Tufts Cove 3	Capacity Factor (%)	41	21	14	12	7	26	30	23	28	21
	Unit Cycles	27	65	72	65	31	74	89	83	80	79
	Service Hours	4,829	2,865	2,018	1,803	926	3,081	3,340	2,525	3,067	2,322
Tufts Cove 4	Capacity Factor (%)	73	68	57	61	61	68	62	56	57	43
	Unit Cycles	92	100	174	149	142	205	222	214	209	206
	Service Hours	7,135	6,810	5,426	5,705	5,756	6,420	5,822	5,240	5,355	4,051
Tufts Cove 5	Capacity Factor (%)	71	63	56	60	58	65	62	55	57	44
	Unit Cycles	104	112	193	147	154	222	237	221	206	218
	Service Hours	7,024	6,440	5,247	5,694	5,459	6,091	5,827	5,186	5,379	4,120

[26] Point Tupper is converted to Natural Gas in 2028.

Tufts Cove 6	Capacity Factor (%)	54	44	37	37	39	46	45	40	41	34
	Unit Cycles	100	57	128	87	87	137	161	159	145	161
	Service Hours	5,734	6,799	5,868	6,257	6,020	6,111	5,598	5,074	5,225	4,082

3.3.3 Steam Fleet Utilization Outlook

Unit utilization and reliability objectives have long been the drivers for unit investment planning. Traditionally, in a predominantly base-loaded generation fleet, it was sufficient to consider capacity factor as the source for utilization forecasts for any given unit. This is no longer the case; integration of variable renewable resources on the NS Power system has imposed revised operating and flexibility demands to integrate wind generation on previously base-loaded steam units. Therefore, it is also necessary to consider the effects of unit starts, operating hours, flexible operating modes (e.g. ramping and two-shifting) and asset health along with the forecast unit capacity factors.

NS Power created the concept of utilization factor (UF) for the purpose of providing a directional understanding of the future use of each generating unit. This approach enables the Company to better demonstrate the demands placed upon NS Power's generating units given their planned utilization. The UF for each unit is evaluated by considering the forecast capacity factor, annual operating hours, unit starts, expected two-shifting, and a qualitative evaluation of asset health. By accounting for these operational capabilities, the value brought to the power system by these units is more clearly reflected. Please refer to **Figure 9** below.

Figure 9: Utilization Factor

The UF parameters are assessed to more completely describe the operational outlook for the steam fleet and direct investment planning. The four parameters are described below.

- Capacity factor reflects the energy production contribution of a generating unit and is a necessary constituent of unit utilization. It is a part of the utilization factor determination rather than the only consideration, as it would have been in the past.

- Service hours have become a more important factor to consider with increased penetration of variable-intermittent generation, as units are frequently running below their full capacity while providing load following and other essential reliability services for wind integration. For example, if a unit operates at 50 percent of its capacity for every hour of the year, then the capacity factor would be 50 percent. In a traditional model, this would suggest a reduced level of investment required, commensurate with decreased capacity factor. However, many failure mechanisms are a function of operating hours (e.g. turbines, some boiler failure mechanisms, and high energy piping) and the number of service hours (which in this example is every hour of the year) is not reflected by the unit's capacity factor. Additionally, some failure mechanisms can be exacerbated by reducing load operation (e.g. valves, some pumps, throttling devices).

- Unit cycling increases damage mechanisms on many components (e.g. turbines, motors, breakers, and fatigue in high energy piping systems) and accelerates failure mechanisms; therefore, these must also be considered to properly estimate the service interval and appropriate maintenance strategies.

- Asset health is a critical operating parameter to keep at the forefront of all asset management decisions. For example, asset health may determine if a unit is capable of two-shifting (unit is shut down during low load overnight and restarts to serve load the next day). Although it does not necessarily play directly into the UF function, it can be a dominant determinant in allowing a mode of operation; therefore, it influences the UF function.

While the UF rating provides a directional understanding of the future use of each generating unit, the practice of applying it has another layer of sophistication as system parameters change. NS

Power utilizes the PLEXOS dispatch optimization model to derive utilization forecasts and qualitatively assess the UF of each unit by evaluating the components described above**. Figure 10** below provides the UF by each unit on an annual basis.

Figure 10: Forecast Unit Utilization Factors

Unit***	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
LIN-1**	M	M	M	M	M	M	M	UL	UL	UL	UL
LIN-2	UL	-	-	-	-	-	-	-	-	-	-
LIN-3**	M	M	M	M	M	M	M	UL	UL	UL	UL
LIN-4**	M	M	M	M	M	M	M	UL	UL	UL	UL
POA-1	M	L	UL	UL	UL	UL	UL	-	-	-	-
POT-2*	M	M	H	M	H	H	UL	UL	UL	UL	UL
TRE-5	L	L	L	L	L	-	-	-	-	-	-
TRE-6	H	H	M	M	H	L	-	-	-	-	-
TUC-1	L	L	UL	UL	UL	UL	UL	UL	UL	UL	UL
TUC-2	M	M	H	M	M	L	H	H	H	M	M
TUC-3	M	M	H	H	H	M	H	H	H	H	H
TUC-4	H	H	H	H	H	H	H	H	H	H	H
TUC-5	H	H	H	H	H	H	H	H	H	H	H
TUC-6	H	H	H	H	H	H	H	H	H	H	H
PHB-1	H	H	H	H	H	H	H	H	H	H	H

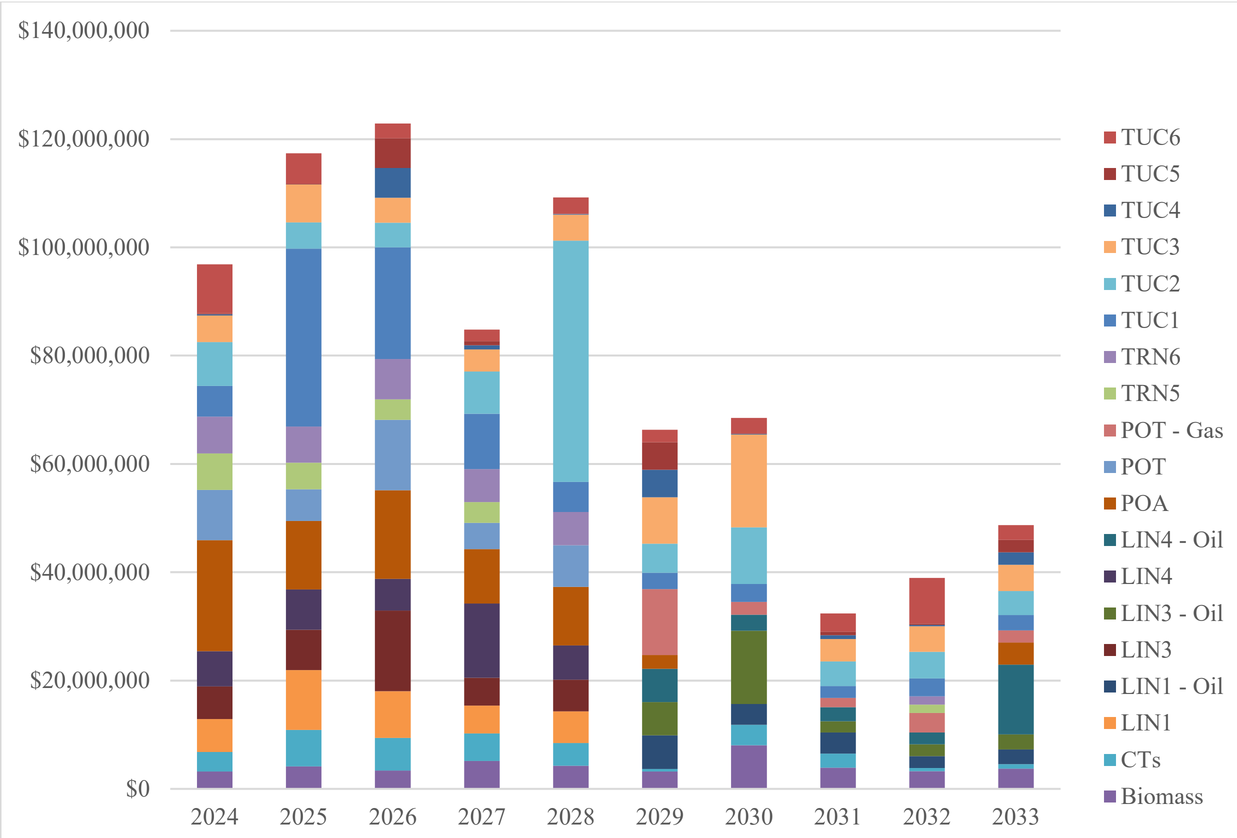
*POT-2 values from 2029 onwards reflect operation post natural gas conversion
**LIN-1, 3 and 4 values from 2030 onwards reflect operation on Heavy Fuel Oil (HFO)
***H = High, M = Medium, L = Low, UL = Ultra Low

Figure 11 below provides the projected sustaining investments based on the anticipated utilization forecast in **Section 3.3.2**. Estimates of unit sustaining investment are forecast by applying the UF, related life consumption and known failure mechanisms. NS Power does not include unplanned failures in sustaining capital estimates. These estimates are evaluated at the asset class level; some asset class projections are prorated by the UF and others have additional overriding factors. For example, the use of many instrument and electrical systems is a function of calendar years, as they operate whether a unit is running or not. Investments for coal and ash systems are a direct function of capacity factor, as they typically have material volume-based failure mechanisms. In contrast, the UF is directly applicable to the investment associated with turbines, boilers and high energy piping. Major assets are regularly reassessed in terms of their condition and intended service as NS Power's operational data, utilization plan, asset health information, and forecasts are updated.

The overarching investment philosophy is to maintain unit reliability cost effectively while minimizing undepreciated capital. Mitigating risks by using less intensive investment strategies is a method executed throughout the thermal fleet. Major outage intervals are extended where possible to reduce large investments in the thermal fleet.

1 **Figure 11: Forecasted Sustaining Capital Investment (in 2023$) by Unit**

2



3

4 Note: Forecast investments are subject to change arising from asset health and actual utilization. Changes in
5 currency value, escalation and inflation can also have significant effect on actual cost.

6

4.0 QUEUED SYSTEM IMPACT STUDIES

Figure 12 below provides the location and size of the generating facilities currently in the Combined Transmission & Distribution (T&D) Advanced Stage Interconnection Request Queue. Active transmission and distribution requests not appearing in the Combined T&D Advanced Stage Interconnection Request Queue are considered to be at the initial queue stage, as they have not yet proceeded to the system impact study (SIS) stage of the Generator Interconnection Procedures (GIP) or Distribution Generator Interconnection Procedures (DGIP).

The Port Hawkesbury Biomass generating unit (63.8 MW gross / 45 MW net output) is presently an energy resource interconnection service (ERIS)-classified resource which will be converted to network resource interconnection service (NRIS) following the system upgrades associated with Transmission Service Request 400 which is discussed further in Section .

Figure 12: Combined T&D Advanced Stage Interconnection Queue as of June 28, 2023

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Inter-connection Point	Type	In-Service date DD-MMM-YY[27]	Status	Service Type
1-T	426	27-Jul-12	Richmond	45	45	47C	Biomass	01-Sep-18	Generation Interconnection Agreement (GIA) Executed	NRIS
2-T	516	5-Dec-14	Cumberland	1.26	1.26	37N	Tidal	31-May-20	GIA Executed	NRIS
3-T	540	28-Jul-16	Hants	14.1	14.1	17V	Wind	31-Oct-23	GIA Executed	NRIS
4-T	542	26-Sep-16	Cumberland	3.78	3.78	37N	Tidal	30-Jun-25	GIA Executed	NRIS
5-D	557	19-Apr-17	Halifax	5.6	5.6	24H	CHP	01-Sep-18	SIS Complete	N/A
6-T	517	15-Dec-14	Cumberland	4	4	37N	Tidal	01-Oct-2019	GIA In progress	NRIS
7-D	569	26-Jul-19	Digby	0.6	0.6	509V-302	Tidal	30-Jul-21	GIA Executed	N/A

[27] The In-Service dates listed reflect the milestone dates specified in the interconnection agreement with the Interconnection Customer associated with each individual Interconnection Request or as last specified by the Interconnection Customer in interconnection study related agreements.

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Inter-connection Point	Type	In-Service date DD-MMM-YY[27]	Status	Service Type
8-D	566	16-Jan-19	Digby	0.7	0.7	509V-301	Tidal	30-Apr-22	GIA Executed	N/A
9-T	574	27-Aug-20	Hants	58.8	58.8	L-6051	Wind	30-Jun-23	Facilities Study (FAC) in Progress	NRIS
10-T	598	13-May-21	Cumberland	2.52	2.52	37N	Tidal	01-Dec-22	SIS Milestones Met	NRIS
11-D	604	7-Jun-21	Cape Breton	0.45	0.45	11S-303	Solar	15-Jan-22	GIA Executed	N/A
12-T	597	07-May-21	Queens	36	36	50W	Wind	31-Aug-23	FAC Complete	NRIS
13-T	647	6-Oct-21	Cumberland	1.5	1.5	37N	Tidal	31-Dec-23	GIA in progress	NRIS
14-D	653	19-Jan-22	Halifax	0.09	0.09	24H-406	Solar	30-Oct-22	SIS in progress	N/A
15-D	654	16-Feb-22	Halifax	0.125	0.125	127H-413	Solar	20-Sep-22	SIS in progress	N/A
16-T	664	26-Jul-22	Lunenburg	50	50	99W	Battery	15-Dec-23	SIS in progress	NRIS
17-T	662	26-Jul-22	Halifax	50	50	132H	Battery	15-Dec-24	SIS in progress	NRIS
18-T	663	26-Jul-22	Colchester	50	50	1N	Battery	15-Jun-24	SIS in progress	NRIS
19-T	670	05-Aug-22	Colchester	97.98	97.98	L-7005	Wind	28-Feb-26	SIS in progress	NRIS
20-T	671	05-Aug-22	Halifax	88.96	88.96	L-6004	Wind	28-Feb-26	SIS in progress	NRIS
21-T	669	04-Aug-22	Cumberland	99	99	L-6613	Wind	31-Dec-25	SIS in progress	NRIS
22-T	668	03-Aug-22	Antigonish	94.4	94.4	L-7003	Wind	01-Dec-25	SIS in progress	NRIS
23-T	618	21-Jul-21	Guysborough	130.2	130.2	L-7003	Wind	01-Jan-25	SIS in progress	NRIS
24-T	673	09-Aug-22	Hants	33.6	33.6	L-6054	Wind	31-Dec-24	SIS in progress	NRIS
25-T	675	10-Aug-22	Queens	112.5	112.5	50W	Wind	01-Dec-24	SIS in progress	NRIS
26-T	677	23-Sep-22	Yarmouth	80	80	L-6024	Wind	31-Dec-25	SIS in progress	NRIS
27-D	676	15-Aug-22	Halifax	0.74	0.6475	103H-431	Solar	01-Jun-22	SIS in progress	N/A
28-T	697	28-Mar-23	Kings	50	50	43V	Battery	15-Mar-26	SIS Agreement in Place	NRIS
D-29	699	21-Apr-23	Halifax	0.625	0.625	58H-431	Solar	31-Dec-24	SIS Agreement in Place	N/A
30-D	700	21-Apr-23	Cape Breton	0.585	0.585	82S-303	Solar	30-Sep-23	SIS Agreement in Place	N/A
31-D	701	28-Apr-23	Halifax	0.5625	0.5625	139H-412	Solar	01-Nov-23	SIS Agreement in Place	N/A
32-T	686	23-Jan-23	Cumberland	340	340	L-8002	Wind	01-Dec-25	SIS in progress	N/A

4.1 System Impact Studies (SIS)

As outlined in **Figure 12**, a significant number of SIS have been completed or are in progress. Of the SIS either in progress or complete, the majority are studying wind generation facilities. With the associated increase in variable renewable invertor-based generation on the system and the anticipated decrease in synchronous generation related to the coal-fired generation phase-out requirement by 2030, GIP SIS analyses are being expanded to include Electromagnetic Transient (EMT) Analysis in addition to Load Flow and Dynamic Analysis to understand the impacts of generator interconnections and requirements to support system reliability. Each transmission SIS initiated after March 3, 2023 will have a phase 2 EMT study completed for each SIS grouping to determine if additional equipment/network upgrades are required to support the integration of new wind resources. This will be completed in parallel with the facilities study and will inform the overall system requirements for each interconnection customer.

4.2 OATT Transmission Service Queue

As of June 20, 2023 there are two active requests in the Open Access Transmission Tariff (OATT) Transmission Queue as shown in **Figure 13**.

Figure 13: Requests in the OATT Transmission Queue as of June 28, 2023

Item	Project	Date & Time of Service Request	Project Type	Project Location	Requested In-Service Date	Project Size (MW)	Status
1	TSR 400	July 22, 2011	Point-to-point	NS-NB*	May 2019	330	System Upgrades in Progress
2	TSR 411	January 19, 2021	Point-to-point	NS-NB*	January 1, 2028	550	Facilities Study in Process

*Indicates project as being located near provincial border.

Information in **Figure 13** under Project Location reflects the non-confidential information provided in the customer's application. Details regarding the location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted are deemed confidential under Section 17.2 of the OATT[28] and not available to the public on the Open Access Same-Time Information System (OASIS). As such, there is limited further information the Company can include in this Report on a non-confidential basis.

The design for the remaining system upgrades related to Transmission Service Request (TSR) 400 was completed in 2022. The execution of the remaining upgrades (increase the rating of lines L-8004 and L-6613) is planned for 2024/2025.

A Facilities Study (FAC) is currently being performed for TSR 411, with a forecast completion date of Q3 2023.

[28] Nova Scotia Power Inc. Open Access Transmission Tariff As approved by the UARB May 31, 2005 and As Amended June 10, 2016. The OATT is available on NS Power's website at https://www.nspower.ca/docs/default-source/pdf-to-upload/revised-oatt-june-10-2016.pdf?sfvrsn=7d69fd73_0

5.0 ENVIRONMENTAL AND EMISSIONS REGULATORY REQUIREMENTS

5.1 Renewable Electricity Requirements

On July 9, 2021 the Province of Nova Scotia amended the *Renewable Electricity Regulations* to add a RES of 80 percent of energy sales beginning in 2030. NS Power was directed to meet this requirement, in part, through the acquisition of 1,100 GWh of new renewable energy from independent power producers. The Province also announced on July 10, 2021 that it was initiating a procurement targeting 1,100 GWh of electricity from renewable sources as part of its Rate Base Procurement program. The procurement administrator identified the portfolio in August 2022, awarding 372 MW of total installed wind capacity. The selected projects will all be in service by December 31, 2026.[29]

On April 8, 2016 the Province amended the *Renewable Electricity Regulations* to allow NS Power to include COMFIT projects in its RES compliance planning. It also amended the Regulations to remove the "must-run" requirement of the Port Hawkesbury biomass generating facility.[30] From 2015 to 2019 the Company served 26.6 percent (2015), 28 percent (2016), 29 percent (2017), 30 percent (2018) and 30 percent (2019) of sales using qualifying renewable energy sources.

The Nova Scotia block of the Muskrat Falls energy from Newfoundland & Labrador began delivery over the Maritime Link on August 15, 2021. However, ongoing issues prevented the full delivery of energy from Muskrat Falls, and the Company was unable to meet the 40 percent renewable energy standard over the three calendar years (2020-2022). For the years 2020, 2021 and 2022, the Company served 29 percent (2020), 30.4 percent (2021) and 36 percent (2022) of sales using qualifying renewable energy sources. NS Power is now receiving the full NS block.

[29] Timeline | Nova Scotia Rate Based Procurement (novascotiarbp.com)
[30] *Renewable Electricity Regulations*, made under Section 5 of the *Electricity Act* S.N.S. 2004, c. 25 O.I.C. 2010-381 (effective October 12, 2010), N.S. Reg. 155/2010 as amended to O.I.C. 2020-147 (effective May 5, 2020), N.S. Reg. 74/2020 s. 5(2A).

The near-term RES Compliance Forecast in **Figure 14** illustrates the full amount of RES-eligible energy forecast to be available to the Company for 2024-2026.

Figure 14: RES Compliance Forecast

RES Compliance Forecast[31]			
	2024	**2025**	**2026**
Energy Requirements (GWh)			
NSR including DSM effects	11,168	11,199	11,327
Losses	734	741	741
Sales	10,434	10,458	10,586
RES (%) Requirement	40%	40%	40%
RES Requirement (GWh)	**4,174**	**4,183**	**4,232**
Renewable Energy Sources (GWh)			
NS Power Wind	239	260	234
Post-2001 IPPs*	739	2130	2543
PH Biomass	289	208	212
COMFIT Wind Energy	508	532	499
COMFIT Non-Wind Energy	17	26	26
Eligible Pre-2001 IPPs	111	16	16
Eligible NSPI Legacy Hydro	919	918	957
REA procurement (South Canoe/Sable)	328	344	296
Compliant Renewable Import	2346	2362	2364
Forecast Renewable Energy (GWh)	**5,496**	**6,797**	**7,147**
Forecast Surplus or Deficit (GWh)	**110**	**2,614**	**3,517**
Forecast RES Percentage of Sales	**53%**	**65%**	**68%**

*Includes Rate Base Procurement

[31] NSR and Losses are provided in the 2022 NS Power Load Forecast Report, Table A1, April 29, 2022 (M10109).

5.2 Environmental Regulatory Requirements

The Nova Scotia *Greenhouse Gas Emissions Regulations*[32] specify emission caps for 2010-2030, as outlined in **Figure 15**. The net result is a hard cap reduction from 10.0 to 4.5 million tonnes over that 20-year period, which represents a 55 percent reduction in CO_2 release over 20 years. Carbon emissions in Nova Scotia from the production of electricity in 2030 are forecast to have decreased by 58 percent from 2005 levels.

Figure 15: Multi-year Greenhouse Gas Emission Limits

Year	GHG Cumulative Million tonnes (CO_2)
2014-2016	26.32
2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

Further discussion of the *Environmental Goals and Climate Change Reduction Act* (EGCCRA) is provided in **Section 5.2**.

On January 1, 2019, Nova Scotia's cap-and-trade program came into effect. The *Cap-and-Trade Program Regulations* included the annual free allowances for GHG emissions for NS Power.

[32] *Greenhouse Gas Emissions Regulations* made under subsection 28(6) and Section 112 of the Environment Act S.N.S. 1994-95, c. 1, O.I.C. 2009-341 (August 14, 2009), N.S. Reg. 260/2009 as amended to O.I.C. 2013-332 (September 10, 2013), N.S. Reg. 305/2013.

Under the GHG cap-and-trade system, NS Power is allowed to purchase no more than 5 percent of GHG credits offered for auction by the province. Although the free GHG allowance under the GHG cap-and-trade system was specified for each year from 2019 to 2022 as noted in **Figure 16**, the allowances can be redistributed in a four-year compliance period between 2019 and 2022 in order to reduce the cost of compliance. NS Power met the requirements of the program through reduced emissions and the amendment to the Cap-and-Trade Regulations, which provided NS Power with 2,600 additional kilotonnes.

Figure 16: Greenhouse Gas Free Allowances 2019-2022

Year	GHG Free Allowances Million tonnes
2019	6.334
2020	5.517
2021	5.120
2022	5.087

The Nova Scotia *Air Quality Regulations*[33] specify emission caps for sulphur dioxide (SO_2), nitrogen oxides (NOx), and mercury (Hg). These regulations were amended to extend from 2020 to 2030, effective January 1, 2015. The amended regulations replaced annual limits with multi-year caps for the emissions targets for SO_2 and NOx.

The Province introduced amendments to the Air Quality Regulations respecting the SO2 cap for a three-year period from 2020 to 2022, effective January 21, 2020. The regulations also provide local annual maximums, as well as limits on individual coal units for SO2. The revised emissions requirements are shown below in **Figure 17**.

[33] *Air Quality Regulations* made under Sections 25 and 112 of the Environment Act S.N.S. 1994-95, c. 1 O.I.C. 2005-87 (February 25, 2005, effective March 1, 2005), N.S. Reg. 28/2005 as amended to O.I.C. 2020-016 (effective January 21, 2020), N.S. Reg. 8/2020.

Figure 17: Emissions (SO_2, NOx, Hg)

Multi-Year Caps Period	SO_2 (t)	SO_2 (t) Annual Max	NOx (t)	NOx (t) Annual Max	Hg (kg)
2020	60,900		14,955		35
2021-2022	90,000			14,955	35
2023-2024	68,000		56,000		35
2025	28,000		11,500		35
2026-2029	104,000	28,000	44,000	11,500	35
2030	20,000		8,800		30

By 2030 SO_2 emissions from generating electricity will have been reduced by 80 percent from 2005 levels. NOx emissions will have decreased by 73 percent and mercury emissions will have decreased 71 percent from 2005 levels.

SO_2 reductions are being addressed mainly by reduced thermal generation and changes to fuel blends. NOx reductions are being addressed through reductions in thermal generation and the previous installation of Low-NOx Combustion Firing Systems. Mercury reductions are being accomplished through reduced thermal generation, changed fuel blends, and the use of Powder Activated Carbon (PAC) systems. NS Power offered a mercury recovery program from 2015 through to the end of January 2020. The program involved recycling light bulbs or other mercury-containing consumer products, which reduced the amount of mercury going into the environment through landfills. Credits approved by Nova Scotia Environment and Climate Change (ECC) may be used to compensate from the deferred emissions by 2020, and a limited number of credits approved by ECC (30 kg in 2020, 10 kg per year for subsequent years) may be used for compliance from 2020 to 2029.

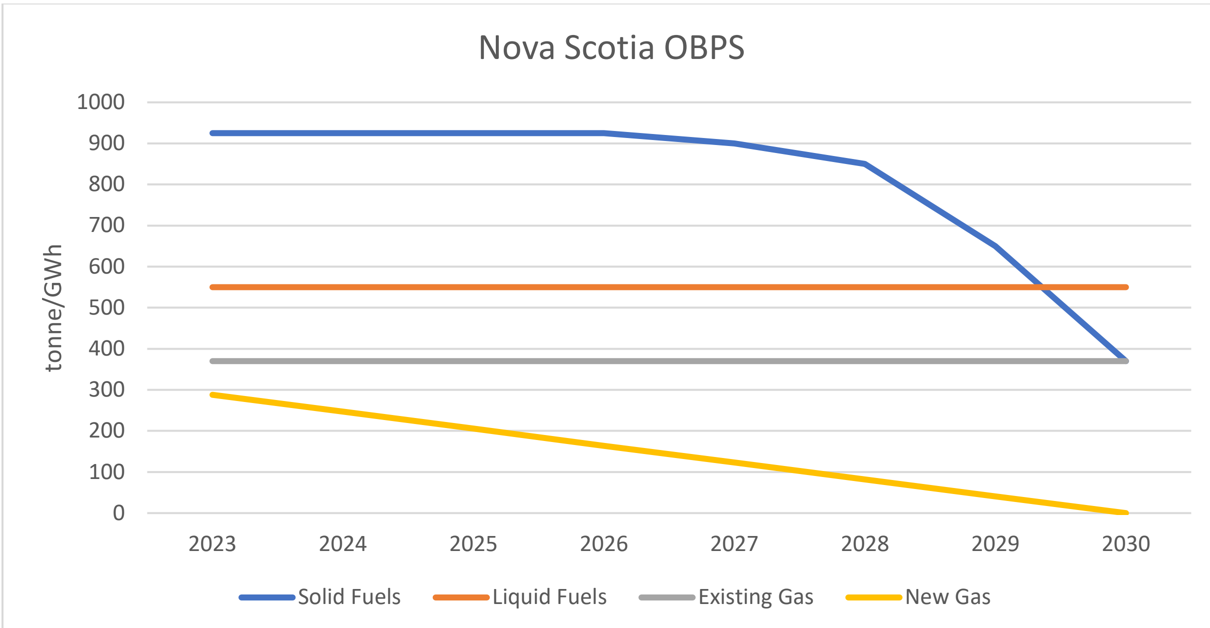
In December 2020, as part of the report titled A Healthy Environment and a Healthy Economy,[34] the Federal Government proposed a carbon price trajectory of $65/tonne starting in 2023 and rising $15 annually to $170/tonne in 2030 ("Federal Backstop"). Following this report, additional information from both the Federal Government and the Province provided further guidance on the carbon policy requirements related to both the carbon price and how this would be enabled in the provinces. In July 2021, the Federal Government confirmed the Federal Backstop and referenced potential requirements for a provincial system to be found equivalent to the Federal Backstop. In January 2022, the Federal Government confirmed the program options for the Province to enact the carbon policy which include meeting the Federal Backstop carbon pricing for emissions produced, extending the cap-and-trade program or enabling a hybrid model in which a performance target is established, which retains a marginal price signal to incent emissions reductions.

In October 2022, the Province updated the *Environment Act*,[35] moving from a then current cap-and-trade system to a provincial output-based pricing system (Nova Scotia OBPS, referred to as the "NS OBPS"). The NS OBPS sets emissions intensity limits for various types of generating facilities. Facilities covered under the NS OBPS program include solid fuels, liquid and gaseous fuels, and the emissions limit is calculated using an emissions-intensity performance standard for electricity generation by facility. Facilities that emit more than the applicable emission intensity limits must provide compensation for the excess emissions, which are priced according to the federal carbon price.

The Province received federal approval late in 2022 for the NS OBPS, which establishes a performance standard by facility type for the electricity sector beginning in 2023. The performance standards for the NS OBPS by fuel type are shown in **Figure 18**.

[34]https://www.canada.ca/en/environment-climate-change/news/2020/12/a-healthy-environment-and-a-healthy-economy.html
[35] Nova Scotia Legislature – Bill No. 208: c046.pdf (nslegislature.ca)

Figure 1814: NS OBPS Emission Intensity Standards



As noted above, the province introduced the EGCCRA on October 27, 2021.[36] The EGCCRA includes the 80 percent RES 2030 requirement in addition to the requirement to phase out coal-fired electricity generation in the Province by 2030. It also includes provincial GHG reduction targets of 53 percent below 2005 levels by 2030, Net Zero by 2050 (discussed further in **Section 5.3**) and a zero-emission vehicle mandate that will require 30 percent of new vehicle sales of all light duty and personal vehicles in the Province by 2030 to be zero-emission vehicles.

5.3 Anticipated Policy Changes

In the spring of 2022, the Federal Government (Environment and Climate Change Canada, ECCC) produced a discussion paper on a potential Clean Electricity Standard (CES).[37] The focus of the discussion paper was on the Federal Government's commitment to target net-zero electricity production by 2035, in support of achieving net-zero emissions economy-wide by 2050.

[36] *Environmental Goals and Climate Change Reduction Act*, S.N.S. 2021, c. 20, s. 1.
[37] A clean electricity standard in support of a net-zero electricity sector: discussion paper - Canada.ca

Offsets/credits are being considered as an element of the CES framework, which would serve to offset emissions from electricity generation in support of economy wide electrification. In parallel, the OBPS emissions performance standards will be reviewed within the context of meeting the 2035 targets and beyond.

Following the discussion paper and a period of industry engagement, ECCC released a proposed frame[38] for a Clean Electricity Regulation under the Canadian Environmental Protection Act (CEPA) in July 2022, which will establish the performance standards and operating parameters for emitting generation in 2035 and beyond. NS Power participated in the consultation phase leading up to the fall of 2022 and ECCC ended the initial phase of consultation in advance of Canada Gazette 1 publication. NS Power anticipates continued stakeholder engagement ahead of Canada Gazette 2 and will continue to be engaged.

In response to both the existing and anticipated policy changes, NS Power is assessing, refining, and enabling the electricity strategy to continue the path to meet the 2030 targets (80 percent RES, coal phase-out, carbon pricing) and beyond (net-zero electricity 2035) through the transformation of the generation fleet. This is supported by the NS Power Evergreen IRP process which will refine the IRP Action Plan and Roadmap items identified as part of the 2020 IRP.

NS Power continues to engage with both levels of government to explore opportunities to accelerate the Company's carbon reduction strategy in a way that is affordable for customers, maintains reliability, and supports NS Power's customers and the communities where they live and work. As the governments' announced policy changes become legislative and regulatory requirements, NS Power will reflect these changes in future planning studies.

[38] Proposed Frame for the Clean Electricity Regulations - Canada.ca

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

Operating Reserves are resources which can be called upon by system operators on short notice to respond to the unplanned loss of generation or imports or unanticipated changes in load. These assets are essential to the reliability of the power system.

As a member of the Maritimes Area of NPCC, NS Power meets the operating reserve requirements as outlined in *NPCC Regional Reliability Reference Directory #5, Reserve.* These criteria are reviewed and adjusted periodically by NPCC and subject to approval by the NSUARB. The criteria require that:

> Each Balancing Authority shall have ten-minute reserve available that is at least equal to its first contingency loss…and,
>
> Each Balancing Authority shall have thirty-minute reserve available that is at least equal to one half its second contingency loss.[39]

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*[40] NS Power and New Brunswick Power (NB Power) have agreed to share the reserve requirement for the Maritimes Area on the following basis:

> The Ten-Minute Reserve Responsibility, for contingencies within the Maritimes Area, will be shared between the two Parties based on a 12CP [coincident peak] Load-Ratio Share… Notwithstanding the Load-Ratio Share the maximum that either Party will be responsible for is 100 percent of its greatest, on-line, net single contingency, and, NSPI shall be responsible for 50 MW of Thirty-Minute Reserve.

[39] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories

[40] New Brunswick's Electricity Act (the Act) was proclaimed on October 1, 2013. Among other things, the Act establishes the amalgamation of the New Brunswick System Operator (NBSO) with New Brunswick Power Corporation ("NB Power").

The Ten-Minute Reserve Responsibility for NS Power is typically 32 MW[41] of spinning reserve on the system. Additional regulating reserve is maintained to manage the variability of customer load and generation.

6.2 Planning Reserve Criteria

The Planning Reserve Margin (PRM) is intended to maintain sufficient resources to reliably serve firm customers. Unit forced outages, higher than forecast demand, and lower than forecast wind generation are all conditions that could individually or collectively contribute to a shortfall of dispatchable capacity resources to meet customer demand.

NS Power is required to comply with the NPCC reliability criteria that have been approved by the NSUARB. These criteria are outlined in *NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System* which states:

> Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year. [This evaluation shall] make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.[42]

The PRM is a long-term planning assumption that is typically updated as part of an IRP process. NS Power studied the appropriate calculation of its PRM as part of the 2020 IRP[43] which confirmed that a 20 percent PRM target was appropriate for long-term planning.

[41] This is a fixed 32MW at all times based on an interim operating agreement with New Brunswick.
[42] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories
[43] M08929, Nova Scotia Power, IRP Final Report, November 27, 2020, page 40.

The PRM provides a basis for the minimum required firm generation NS Power must plan to maintain to comply with NPCC reliability criteria; it does not represent the optimal or maximum required capacity to serve other system requirements. The optimal capacity requirement is determined through a long-term planning exercise such as the Evergreen IRP, as discussed in **Section 3.2.1.**

From February 3-4, 2023, Nova Scotia experienced a severe cold weather event, which tested the limits of the system capacity to meet demand requirements. NS Power served a record hourly peak load of 2455 MW, which is 217 MW over the previous all-time peak (recorded in January of 2004). This peak exceeds the current firm planning peak by approximately 400 MW. With adequate planning for firm peak and PRM requirements, good performance from all available units and anticipatory reduced loads from Large Industrial Interruptible Rider (LIIR) customers, NS Power was able to meet the demand.

6.3 Capacity Contribution of Renewable Resources in Nova Scotia

Due to their variability, renewable energy resources such as wind and solar are not always available to contribute during peak demand hours. The Effective Load Carrying Capability (ELCC), or "capacity value" of a resource represents the statistical likelihood that it will be available to serve the firm peak demand, and as a result, what percentage of its capacity can be counted on as firm for system planning. Loss of Load Expectation (LOLE) studies are the industry standard used to calculate the ELCC or capacity value of these renewable resources.

In a letter dated October 5, 2018[44] the NSUARB directed NS Power to complete certain pre-IRP analyses by July 31, 2019. One of the pre-IRP deliverables directed by the NSUARB was a Capacity Study to calculate the ELCC of wind and other renewable energy generators, both for the existing wind resources as well as potential new resources. The study was undertaken by Energy+Environmental Economics (E3)[45] on behalf of NS Power and the results determined the

[44] M08059, UARB Decision Letter, Generation Utilization and Optimization, October 5, 2018.
[45] M08929, Integrated Resource Planning and Generation Utilization and Optimization (P-884)

average ELCC of the wind currently installed on the NS Power system to be 19 percent. The declining marginal ELCC value of adding new wind to the NS Power system was determined to be 11 to 9 percent. In the 2020 IRP, the Company used 10 percent for the ELCC value of new wind. For the purposes of this Report, NS Power has used the 18 percent capacity value of existing wind to account for the wind farm serving wholesale market participants under the Back-up / Top-up (BUTU) Tariff (referred to at lines 13-16 below), 10 percent capacity value of new wind, and 95 percent for hydro. Solar has very limited ELCC in Nova Scotia due to poor correlation with the net peak load hours, which primarily occur on winter evenings. Beyond initial penetrations of solar capacity, the marginal capacity value declines to 0 percent.

Please refer to **Section 3.1** regarding the inclusion of ERIS wind resources.

Municipal load for Berwick, Mahone Bay, Antigonish, and Riverport is served by a wind farm owned by Alternative Resource Energy Authority (AREA). This generation is not included in NS Power's sourced wind generation but contributes to operational considerations of the total amount of wind generation on the Nova Scotia system.

6.4 Load and Resources Review

The 10-year load and resources outlook in **Figure 19** is based on the capacity changes and DSM forecast from **Figure 5**, and provides details regarding NS Power's required minimum forecast PRM equal to 20 percent of the firm peak load. Since the CE1-E1-R2 Evergreen IRP scenario is based on the 2022 Load Forecast, the firm capacity additions have been slightly modified to account for additional firm peak requirements reflected in the 2023 Load Forecast.[46] This requirement is met by an increase in new fast-acting combustion turbine capacity in the latter part of the 10-year horizon (please refer to **Figure 19**).

Energy+Environmental Economics, Planning Reserve Margin and Capacity Value Study, July 2019, Attachment 18 to NS Power's Pre-IRP Final Report at https://irp.nspower.ca/documents/pre-irp-deliverables/

[46] M11108, NS Power 2023 Load Forecast, April 28, 2023

The current forecast indicates a small PRM deficit from 2023 to 2026. NS Power will continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve and will adjust decisions accordingly.

Figure 19 is intended to provide a medium-term outlook of the capacity resources anticipated to be available to the Company compared to expected customer demand.

Figure 19: NS Power 10-Year Load and Resources Outlook[47]

Load and Resources Outlook for NSPI - Winter 2023/2024 to 2032/2033 (All values in MW except as noted)											
		2023/ 2024	**2024/ 2025**	**2025/ 2026**	**2026/ 2027**	**2027/ 2028**	**2028/ 2029**	**2029/ 2030**	**2030/ 2031**	**2031/ 2032**	**2032/ 2033**
A	Firm Peak including effects of DSM & DR	2,111	2,119	2,148	2,198	2,259	2,325	2,395	2,468	2,545	2,627
B	Required Reserve (A x 20%)	422	424	430	440	452	465	479	494	509	525
C	Required Capacity (A + B)	2,534	2,542	2,578	2,638	2,711	2,790	2,874	2,962	3,054	3,152
D	Existing Resources (NS Power and IPPs)	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551
E	Existing Resources (Wholesale Market Resources)	4	4	4	4	4	4	4	4	4	4
F	Total Existing Resources (D + E)	2,555	2,555	2,555	2,555	2,555	2,555	2,555	2,555	2,555	2,555
	Firm Resource Additions:										
G	Biomass		43								
H	Hydro	-101	101								
I	Tidal	2									
J	New Wind - Rate Base Procurement		19		18						
K	Other Wind Projects		13								
L	Additions - Wind			20	20	20	20	20	20	20	20
M	Additions - Coal to Gas Conversion						150				
N	Additions - New Fast Acting CTs				50	200	350	50	50	20	150
O	Additions - Battery			25.6	8	33	25		23		
P	Additions - Coal to HFO Operation							459			
Q	Retirements			-148		-150	-472	-459			

[47] Resource additions must first demonstrate reliable performance before corresponding retirements are fully decommissioned.

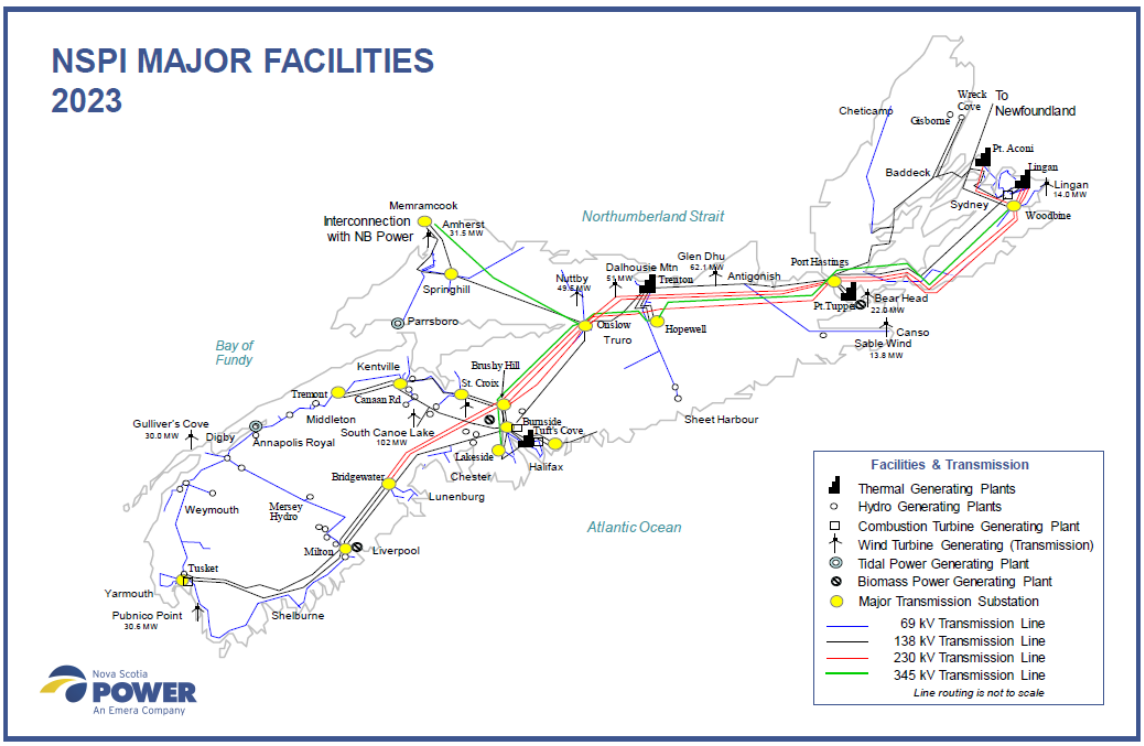
Load and Resources Outlook for NSPI - Winter 2023/2024 to 2032/2033 **(All values in MW except as noted)**											
R	Total Annual Firm Additions (Sum of rows G thru Q)	-99	176	-102	95	103	73	70	93	40	170
S	Total Cumulative Firm Additions (R + S of the previous year)	-99	77	-25	70	173	246	316	409	449	619
T	Total Firm Capacity (F + S)	2,456	2,632	2,530	2,625	2,728	2,801	2,871	2,964	3,004	3,174
	+ Surplus / - Deficit (T - C)	-78	90	-48	-13	17	11	-3	3	-50	22
	Reserve Margin % [(T - A)/A]	16%	24%	18%	19%	21%	20%	20%	20%	18%	21%

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has approximately 5,220 km of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels. The configuration of the NS Power transmission system and major facilities is shown in **Figure 20**.

Figure 20: NS Power Major Facilities in Service 2023



The 345 kV transmission system is approximately 468 km in length and comprises 372 km of steel tower lines and 96 km of wood pole lines.

The 230 kV transmission system is approximately 1,271 km in length and comprises 47 km of steel/laminated structures and 1,224 km of wood pole lines.

The 138 kV transmission system is approximately 1,871 km in length and comprises 303 km of steel structures and 1,568 km of wood pole lines.

The 69 kV transmission system is approximately 1,560 km in length and comprises 12 km of steel/concrete structures and 1,548 km of wood pole lines.

Nova Scotia is interconnected with the New Brunswick electric system through one 345 kV and two 138 kV lines providing up to 505 MW of transfer capability to New Brunswick and between 0 and 300 MW of transfer capability from New Brunswick, depending on system conditions. As the New Brunswick system is interconnected with the province of Quebec and the state of Maine, Nova Scotia is integrated into the NPCC bulk power system.

Nova Scotia is also interconnected with Newfoundland via a 500 MW, +/-200 kV DC Maritime Link. The Maritime Link is owned and operated by NSP Maritime Link Inc., a wholly-owned subsidiary of Emera Newfoundland & Labrador.

7.2 Transmission Design Criteria

Consistent with good utility practice, NS Power utilizes a set of deterministic criteria for its interconnected transmission system that combines protection performance specifications with system dynamics and steady state performance requirements. The approach used has involved the subdivision of the transmission system into various classifications, each of which is governed by the NS Power System Design Criteria. The criteria require the overall adequacy and security of the interconnected power system to be maintained following a fault on and disconnection of any single system component.

7.2.1 Bulk Power System (BPS)

The NS Power bulk transmission system is planned, designed and operated in accordance with North American Electric Reliability Corporation (NERC) Standards and NPCC criteria. NS Power is a member of the NPCC; therefore, those portions of NS Power's bulk transmission network where single contingencies can potentially adversely affect the interconnected NPCC system are designed and operated in accordance with the NPCC *Regional Reliability Directory 1: Design and Operation of the Bulk Power System*, and are defined as Bulk Power System (BPS).

7.2.2 Bulk Electric System (BES)

The NERC Bulk Electricity System (BES) definition encompasses any transmission system element at or above 100 kV with prescriptive inclusions and exclusions that further define BES. System Elements that are identified as BES elements are required to comply with all relevant NERC reliability standards.

NS Power has adopted the NERC definition of the BES and an NS Exception Procedure for elements of the NS transmission system that are operated at 100 kV or higher for which contingency testing has demonstrated no significant adverse impacts outside the local area. The NS Exception Procedure is used in conjunction with the NERC BES definition to determine the accepted NS BES elements and is equivalent to Appendix 5C of the NERC Rules of Procedure.

The BES Definition and NS Exception Procedure were approved by NSUARB Order dated April 6, 2017. Under the BES definition and NS Exception Procedure approved by the NSUARB, elements classified as NS BES elements are required to adhere to all relevant NERC standards that have been approved by the NSUARB for use in Nova Scotia.

7.2.3 2022 Bulk Electric System Exception Requests

Since the filing of the 2022 10 Year System Outlook Report, no new BES Exception Requests have been received.

7.2.4 Special Protection Systems (SPS)

Special Protection Systems (SPS) are also referred to as Remedial Action Schemes (RAS) in NERC documentation. Both terms are valid.

NS Power makes use of SPS in conjunction with the Supervisory Control and Data Acquisition (SCADA) system to enhance the utilization of transmission assets. These systems act to maintain system stability and remove equipment overloads, post-contingency, by rejecting generation and/or shedding load. The NS Power system has several transmission corridors that are regularly operated at limits without incident due to these SPS.

7.2.5 NPCC Directory 1 Review

A Working Group under the NPCC Task Forces on Coordination of Planning (TFCP) and Coordination of Operation (TFCO) is presently conducting a review of the NPCC Directory 1 Document: Design and Operation of the Bulk Power System. Membership was solicited from the NPCC Task Forces on Coordination of Planning, and Coordination of Operation and other interested representatives of NPCC Member Companies.

At present, Directory 1[48] provides a "design-based approach" to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the contingencies referenced. NS Power has representation from both Operations and Planning on the Directory 1 Working Group that is performing the review. The Directory 1 Working Group anticipates the review will be complete in Q3 2023.

[48] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories

7.3 Transmission Life Extension

NS Power has a comprehensive maintenance program in place for the transmission system focused on maintaining reliability and extending the useful life of transmission assets. The program is centered on detailed transmission asset inspections and associated prioritization of asset replacement (i.e. conductor line, poles, cross-arms, guywires, and hardware replacement).

Transmission line inspections consist of the following actions:

- Visual inspection of every line once per year via helicopter, or via ground patrol in locations not practical for helicopter patrols.
- Foot patrol of each non-BPS line on a three-year cycle. Where a Lidar survey is requested for a non-BPS line, the survey replaces the foot patrol in that year.
- For BPS lines, Lidar surveys every two years out of three, with a foot patrol scheduled for the third year.

These inspections identify asset deficiencies or damage and confirm the height above ground level of the conductor span while recording ambient temperature. This enables the NSPSO to confirm that the rating of each line is appropriate.

7.4 Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NS Power transmission system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria and other standards. NS Power has sought to upgrade existing transmission lines and utilize existing plant capacity, system configurations, and existing rights-of-way and substation sites where economic.

Major projects included in the plan have been included based on a preliminary assessment of need. The projects will be subject to further technical studies, internal approval at NS Power, and approval by the NSUARB. Projects listed in this plan may change because of final technical studies, changes in the load forecast, changes in customer requirements or other matters determined by NS Power, NPCC/NERC Reliability Standards, or the NSUARB.

7.5 New Large-Load Customer Interconnection Requests

NS Power continued to receive large numbers of new large-load requests in 2022 with respect to proposed commercial, mining, aquaculture and government projects. In particular, NS Power is seeing increased interest in large-load requests from prospective Hydrogen production developers.

Since June 30, 2022, approximately twenty-five (25) Preliminary Assessments were performed in the range of 1-9 MVA, leading to the completion of two (2) formal Load Impact Studies on the distribution system. In some instances, Preliminary Assessments determined that a Load Impact Study was not required. Not all these assessments translate into near-term load, as some projects have multi-year construction or are not completed. In addition, six (6) formal Load Impact Studies on the transmission system were completed, with a range of values between 4-250 MW.

NS Power has received four (4) additional formal Load Impact Studies on the transmission system, all of which are currently underway and range in size from 6-900 MW.

8.0 TRANSMISSION DEVELOPMENT 2022 TO 2033

Investments in transmission infrastructure can be affected by energy policy and the changing sources of energy and capacity. Proposed transmission development plans and projects are subject to reconsideration and alignment with current policy goals. Items described below are current as of the date of this report.

8.1 Impact of Proposed Load Facilities

As noted in Section 7.5 of this Report, there are several system upgrades required to serve load facilities greater than 1 MW that were proposed in 2020 and 2021. These projects have precipitated the need for the following system upgrades:

1. Construction of new 15/20/25 MVA, 138 kV-25 kV substation at 101W-Bowater. This substation is currently under construction with an expected completion date in 2023.
2. Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in 2023/24. The design of this substation is currently in progress.
3. Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow. Area load continues to be monitored to determine the appropriate timing of this installation.
4. Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Susie Lake Crescent in 2024/25. Property acquisition for this site is currently underway.
5. Installation of a new 10MVA, 69-25kV portable dead-front transformer on-line L-5510 required to provide a 25kV supply to a new mine site in 2024.

8.2 129H-Kearney Lake Relocation

Detailed inspection of the proposed two land parcels for relocation of 129H revealed that site development costs would be much higher than expected to grade the property and provide a suitable access route into the site for a mobile transformer unit. Subsequent negotiations with the owners of the existing site resulted in a new option to swap the existing Kearney Lake Substation site (plus sufficient property to enable an expansion for a second transformer and new approach structure) with the NS Power-owned land parcels across the street. The owners of the Kearney Lake site have extended the existing lease to complete this option. This option also involves surrendering a small portion of the existing L-6038 ROW, resulting in re-alignment of the 129H transmission approaches so that L-6038 will be in the same corridor as the existing L-5004. Once complete (transfer forecasted for completion in 2023), the existing 129H-Kearney Lake substation site will be suitable for the future addition of a second transformer. The transmission structure re-alignment is scheduled and planned for completion in 2024.

8.3 Transmission Development Plans

Transmission development plans are summarized below. As noted above, these projects are subject to change. For 2023, most of the projects listed are included in NS Power's 2022 ACE Plan. As a result of the growth in the 2023 load forecast, and as coal phase-out planning continues to advance and replacement resource are identified, additional projects are anticipated to be identified.

2023

- Completion of 5P 25 MVA Mobile Substation Replacement [carry-over from 2022].
- Completion of 101W-Port Mersey Expansion to include a new 138 kV-25 kV, 15/20/25 MVA transformer and two feeders (C0011261) [carry-over from 2022].
- 78W-Martins Brook substation relocation and transformer replacement (C0010956).
- Line structure replacements and upgrades [carry-over from 2022].
- Resolution of the Aulds Cove 345kV crossing line deration (parallel existing lines vs disconnection and grounding of lower three lines) [carry-over from 2022].
- 2021 Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 7 of 8).
- Receipt of new large spare auto-transformer (C0031050) for substation in Stellarton.
- Purchase suitable lot for establishing a new 138kV–25kV Suzie Lake Substation.
- Complete land transfer to enable the retention of 129H-Kearney Lake Substation.

- Construct new 25/33/42 MVA 138 kV–25 kV 98N Substation complete with three 25 kV distribution feeders in Stellarton.
- Purchase new 138 kV–25 kV, 15/20/25 MVA transformer and site at the intersection of 138 kV line L-6051 and Highway 1 (near Brushy Hill) for new Lacey Lake substation. Install temporary substation near site until permanent substation is complete in 2024.

2024

- Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 8 of 8).
- Re-align transmission structures on approach to the 129H-Kearney Lake Substation.
- Replacement of 9W-B53 support structure [carry-over from 2022].

2025

- Construct new 25/33/42 MVA 138 kV-25 kV Suzie Lake Substation complete with four 25 kV distribution feeders.
- Add a second 15/20/25 MVA 69 kV-12.5 kV transformer at 70W-High Street (Bridgewater). Retire the 69 kV-4.16 kV transformer 70W-T51 and install a 2.5 MVA 12.5kV-4.16kV padmount transformer to pick up remaining 4.16 kV load.
- Build a new 15/20/25 MVA 138kV-25kV substation tapped to line L-6002 in Bridgewater.
- Replace existing 50/66.7/83.3 MVA 138 kV-69 kV Tufts Cove auto-transformer with a similarly rated unit (deteriorated tap changer issues).
- Replace existing 3/4/4.48 MVA Lower East Pubnico transformer with 7.5/10/12.5 MVA unit.

2026

- Replace transformers 62N-T1 and 62N-T2 at end of expected life with a single 138/69 kV-25 kV, 15/20/25 MVA transformer.

- Add a second 25/33/42 MVA, 138 kV-25 kV transformer at new 98N substation in Stellarton.
- Replace 83V-Wolfville Ridge transformer 83V-T51 with a 138/69kV-25 kV, 15/20/25 MVA transformer.
- Replace 93V-Saulnierville transformer 93V-T51 with a 138/69 kV-25 kV, 15/20/25 MVA transformer.
- Add a second 25/33/42 MVA, 138 kV-25 kV transformer at the 4C substation (Lochaber Road) in Antigonish.
- Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow.

2027

- Installation of a new 138/69 kV-25 kV, 15/20/25 MVA substation in Lower Truro tapped to Line L-5028.

2028 – 2033

- There are currently no completed planning studies with transmission recommendations beyond 2028, but NS Power anticipates that more projects will be identified as coal-fired generation is phased out and electrification advances.

NS Power has several transmission and distribution planning studies in progress that are evaluating the following items for inclusion in future ACE Plans. The outcome of the studies referenced below may result in additional capital work, which will be reflected in future iterations of the 10-Year System Outlook report:

- Installation of new 138 kV Supply to 50V-Klondike and replace existing 69-25 kV transformer with new 15/20/25 MVA unit.
- Replace existing 7.5/10/12.5/14 MVA 22W - Barrington Passage transformer with 15/20/25 MVA unit and add additional feeder circuit.

- Installation of a fourth feeder at 126H-Porter's Lake Substation.
- Installation of a fourth feeder and replacement of the substation transformer at 127H-Aerotech Park Substation.

8.4 Reliability Tie

NS Power is currently developing a second 345kV intertie, the Reliability Tie, between Onslow, Nova Scotia and Salisbury, New Brunswick. The development of the Reliability Tie is in alignment with the findings of the 2020 IRP and the 2023 Evergreen IRP update enabling increased integration of variable renewable generation. NS Power provides updates on the Reliability Tie in its IRP Action Plan Updates[49]. Progressing the Reliability Tie also facilitates future expanded Regional Interconnections to electricity systems beyond Nova Scotia, including the proposed Atlantic Loop. IRP results indicate that the Reliability Tie is an important contributor to the system independent of the Atlantic Loop project. The earliest potential in-service date for the Reliability Tie is currently estimated to be 2027.

8.5 Western Valley Transmission System – Phase II Study

The Western Valley transmission study was initiated to determine the system upgrades needed to address transmission line capacity, clearance, and age issues in the Western Valley over a 15-year transmission planning horizon. In particular, the following 69 kV lines were targeted:

- L-5531 (13V-Gulch to 15V-Sissiboo)
- L-5532 (13V-Gulch to 3W-Big Falls)
- L-5535 (15V-Sissiboo to 9W-Tusket)
- L-5541 (3W-Big Falls to 50W-Milton)

[49] Slides 11 – 12 of the NS Power February 2023 IRP Action Plan Update provides NS Power's most recent update on the Reliability Tie and can be accessed here: PowerPoint Presentation (nspower.ca)

The scope of the study included the assessment of the following four options:

Option #1 - Restore L-5531, L-5532, L-5535, and L-5541 to 50ºC Temperature Rating
Option #2 - Upgrade L-5531, L-5532, L-5535, and L-5541 to 80ºC Temperature Rating
Option #3 - Rebuild L-5531, L-5532, L-5535, and L-5541 with 336 ACSR Linnet and 100ºC Temperature rating
Option #4 - Rebuild L-5531, L-5532, L-5535, and L-5541 with 556 ACSR Dove and 100ºC Temperature rating (Operate at 69 kV)

A fifth and sixth option were subsequently added in 2021 and 2022 respectively to assess bypassing the existing 69 kV infrastructure with either a single 138 kV circuit, or 138 kV double circuit construction.

Option #5 - Bypass L-5025, L-5026, L-5531, and L-5535 with a new 138 kV line from 51V-Tremont to new substations at 13V-Gulch and 9W-Tusket
Option #6 - Bypass L-5025, L-5026, L-5531, and L-5535 with new double circuit 138 kV line from 51V-Tremont to new substations at 13V-Gulch and 9W-Tusket.

The scope of the study was subsequently expanded in 2022 to also include the impacts of electrification on the Western Valley and Western regions. However, study work was paused due to an influx of Feasibility Studies related to the Rate Base Procurement (RBP) process for the procurement of 1100 GWh (~350MW) of renewable generation within the province. After this and the identification of the RBP final procurement list, NS Power received an influx of System Impact Study requests. Work on the Western study will continue to be on hold pending completion of these studies. The scope of this study will be reviewed based on the outcomes of the studied projects as well as the updated 2023 Load Forecast.

9.0 CONCLUSION

Customers count on NS Power for energy to power every moment of every day, and for solutions to power a sustainable tomorrow. Environmental legislation and policy initiatives in Canada and Nova Scotia continue to drive transformation of the NS Power electric power system. The Evergreen IRP update (**Section 3.2.1**) is NS Power's commitment to continuously refining the IRP Action Plan and Roadmap items to reflect changes in the planning environment. Scenario CE1-E1-R2 from the Evergreen IRP modeling work forms the planning basis for the 2023 10-Year System Outlook as it closely reflects the current understanding of the system planning environment at the time of this filing (**Section 5.0**). This updated analysis will be used to inform future 10-Year System Outlook Reports and related long-term planning processes.