
Nova Scotia Utility and Review Board

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

2021 10-Year System Outlook

NS Power

June 30, 2021

NON-CONFIDENTIAL

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1 **1.0 INTRODUCTION**

2
3 In accordance with the 3.4.2.1¹ Market Rule requirements, this Report provides the 10-Year
4 System Outlook on behalf of the Nova Scotia Power System Operator (NSPSO) for 2021.

5
6 The 2021 10-Year System Outlook Report contains the following information:

- 7
- 8 • A summary of the Nova Scotia Power Incorporated (NS Power, Company) load forecast
9 and update on the Demand Side Management (DSM) forecast in Section 2.
 - 10 • A summary of generation expansion anticipated for facilities owned by NS Power and
11 others in Sections 3-5. NS Power’s generation planning for existing facilities, including
12 retirements as well as investments in upgrades, refurbishment or life extension and new
13 generating facilities committed in accordance with previously approved NSPSO system
14 plans.
 - 15 • A summary of environmental and emissions regulatory requirements, as well as forecast
16 compliance in Section 6. This Section also includes projections of the level of renewable
17 energy available and discusses anticipated policy changes.
 - 18 • A Resource Adequacy Assessment in Section 7.
 - 19 • A discussion of transmission planning considerations in Section 8.
 - 20 • Identification of transmission-related capital projects currently in the Transmission
21 Development Plan in Section 9.
 - 22 • A discussion of NS Power’s ongoing COVID-19 pandemic response in Section 10.
- 23

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).”

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1 As discussed in Section 7.4, the Company's 2020 Integrated Resource Plan (2020 IRP) evaluated
2 a robust set of future planning scenarios, with modeling assumptions that were created
3 incorporating significant stakeholder input. The 2020 IRP documented capacity
4 expansion/retirement modeling optimization results and associated insights over a 25-year
5 planning horizon (2021-2045). The reference plan from the 2020 IRP (Scenario 2.0C) forms the
6 planning basis for the 2021 10-Year System Outlook. For energy forecasting purposes, updated
7 PLEXOS modeling for the initial three years 2022-2024 was completed and the reference plan from
8 the 2020 IRP (Scenario 2.0C) provides the data for the period 2025-2031. Recently announced
9 federal and provincial policy statements discussed in Section 6.3 have the potential to impact the
10 future of the Company's thermal generation fleet if such statements become legislative and/or
11 regulatory requirements. NS Power continues to monitor and evaluate such developments and to
12 the extent they become law, NS Power will incorporate them into its planning studies and reflect
13 them in future 10 Year-System Outlook Reports.

14
15 As discussed in Section 10, NS Power continues to monitor the ongoing COVID-19 pandemic and
16 remains focused on the health and safety of employees, consultants, contractors, and their
17 families. A response team is monitoring the situation, coordinating with authorities, and keeping
18 employees informed via regular business updates. The economic effects of the COVID-19
19 pandemic and their impact on short and medium-term system planning continue to be evaluated.

20

1 **2.0 LOAD FORECAST**

2
3 The NS Power load forecast provides an outlook on the energy and peak demand requirements of
4 customers in the province. The load forecast forms the basis for fuel supply planning, investment
5 planning, and overall operating activities of NS Power. The figures presented in this Report are
6 the same as those filed with the NSUARB in the 2021 Load Forecast Report on April 30, 2021 and
7 were developed using NS Power’s statistically adjusted end-use (SAE) model to forecast the
8 residential and commercial rate classes. The residential and commercial SAE models are combined
9 with an econometric-based industrial forecast and customer-specific forecasts for NS Power’s
10 large customers to develop an energy forecast for the province, also referred to as the Net System
11 Requirement (NSR).

12
13 **Figure 1** shows historical and forecast NSR which includes in-province energy sales plus system
14 losses. NSR is expected to grow slowly until 2024, driven by increased residential customer count,
15 electric heating in the residential sector, and industrial growth. Over the long term, this expected
16 growth will be offset by anticipated Demand Side Management (DSM) initiatives and natural
17 energy efficiency improvements outside structured DSM programs, as well as increased behind-
18 the-meter small scale solar installations, resulting in a reduction in overall load between 2025 and
19 2031. The net result of these inputs is an annual average decline of 0.1 percent in NSR compared
20 to a peak demand forecast that remains flat.

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

3

| Year | NSR (GWh) | Growth (%) |
|-------------|----------------------|-----------------------|
| 2011 | 11,907 | -2.1 |
| 2012 | 10,475 | -12.0 |
| 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* | 11,039 | 3.0 |
| 2022* | 11,005 | -0.3 |
| 2023* | 11,043 | 0.3 |
| 2024* | 11,119 | 0.7 |
| 2025* | 11,083 | -0.3 |
| 2026* | 11,047 | -0.3 |
| 2027* | 10,997 | -0.5 |
| 2028* | 10,974 | -0.2 |
| 2029* | 10,913 | -0.5 |
| 2030* | 10,876 | -0.3 |
| 2031* | 10,875 | 0.0 |

4 *Forecast value

5
6 NS Power also forecasts the peak hourly demand for future years. The total system peak
7 is defined as the highest single hourly average demand experienced in a year. It includes
8 both firm and interruptible loads. Due to the weather-sensitive load component in Nova
9 Scotia, the total system peak occurs in the period from December through February.

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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 Reduction (DR) activities, adjusted for Effective Load Carrying Capacity (ELCC) as outlined in the 2020 IRP and including critical peak pricing and direct control components, are included in the firm peak. After accounting for the effects of DSM savings, system peak is expected to remain essentially flat on average 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) | System Peak (MW) | Growth (%) |
|-------|---|---|--------------------------------|------------------|------------|
| 2011 | 265 | - | 1,903 | 2,168 | 2.5 |
| 2012 | 141 | - | 1,740 | 1,882 | -13.2 |
| 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* | 155 | - | 2,073 | 2,228 | 8.6 |
| 2022* | 158 | -4 | 2,062 | 2,225 | -0.1 |
| 2023* | 162 | -12 | 2,065 | 2,240 | 0.7 |
| 2024* | 162 | -24 | 2,060 | 2,247 | 0.3 |
| 2025* | 169 | -36 | 2,053 | 2,257 | 0.5 |
| 2026* | 170 | -39 | 2,049 | 2,258 | 0.0 |
| 2027* | 169 | -39 | 2,046 | 2,254 | -0.2 |
| 2028* | 169 | -39 | 2,044 | 2,251 | -0.1 |
| 2029* | 169 | -38 | 2,044 | 2,251 | 0.0 |
| 2030* | 168 | -38 | 2,047 | 2,253 | 0.1 |
| 2031* | 168 | -37 | 2,057 | 2,262 | 0.4 |

*Forecast value

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

6

1 **3.0 GENERATION RESOURCES**

2
3 **3.1 Existing Generation Resources**

4
5 NS Power’s generation portfolio is composed of a mix of fuel and technology types that
6 include coal, petroleum coke, light and heavy oil, natural gas, biomass, wind and hydro.
7 In addition, NS Power purchases energy from Independent Power Producers (IPPs) located
8 in the province and imports power across the NS Power/NB Power intertie and the
9 Maritime Link. Since the implementation of the *Renewable Electricity Standards* (RES)
10 discussed in Section 6.1, an increased percentage of total energy is produced by variable
11 renewable resources such as wind. However, due to their intermittent nature, these variable
12 resources provide less firm capacity than conventional generation resources. Therefore,
13 the majority of the system requirement for firm capacity is met with NS Power’s
14 conventional units (e.g. coal, gas) while their energy output is displaced by renewable
15 resources when they are producing energy. This is discussed further in Section 3.3 below.

16
17 **Figure 3** lists NS Power’s and the IPPs’ verified and forecast firm generating capability for
18 generating stations/systems along with their fuel types up to the filing date of this Report.
19 The changes and additions over the 10-year period to this total capacity are shown in
20 **Figure 19** in Section 7.4.

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Figure 3: 2021 Firm Generating Capability for NS Power and IPPs

| Plant/System | Fuel Type | Winter Net Capacity ² (MW) |
|---------------------------------|---|--|
| 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 | 40.4 |
| St. Margaret's Bay | Hydro | 10.3 |
| Sheet Harbour | Hydro | 10.2 |
| Dickie Brook | Hydro | 3.6 |
| Wreck Cove | Hydro | 201.4 |
| Annapolis Tidal ³ | Hydro | 0.0 |
| Fall River | Hydro | 0.5 |
| Total Hydro | | 354.9 |
| 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 | Coal/Pet Coke/Heavy Fuel Oil | 607 |
| Point Aconi | Coal/Pet Coke & Limestone Sorbent (CFB) | 168 |
| Total Steam | | 1547 |
| Tufts Cove Units 4, 5 & 6 | Natural Gas | 144 |
| Total Combined Cycle | | 144 |
| Burnside | Light Fuel Oil | 132 |
| Tusket | Light Fuel Oil | 33 |
| Victoria Junction ⁴ | Light Fuel Oil | 66 |
| Total Combustion Turbine | | 231 |

² Wind and Hydro are Effective Load Carrying Capability (ELCC) values. Please refer to Section 7.3 for further information.

³ Annapolis is assumed to be out of service. Please refer to Section 3.2.3.

⁴ Please refer to Section 3.2.2.

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| Plant/System | Fuel Type | Winter Net Capacity ² (MW) |
|--|------------------------------------|--|
| Pre-2001 Renewables | Independent Power Producers (IPPs) | 25.8 |
| Post-2001 Renewables (firm) ⁵ | IPPs | 66.4 |
| NS Power wind (firm) ⁵ | Wind | 14.5 |
| Community Feed-in Tariff (firm) ⁵ | IPPs | 33.2 |
| Total IPPs & Renewables | | 139.9 |
| Total Capacity | | 2416.9 |

Figure 4: Firm Generating Capability for Wholesale Market Participants

| Wholesale Market Participant | Fuel Type | Winter Net Capacity ⁶ (MW) |
|-----------------------------------|----------------------------------|--|
| Backup Top-Up (BUTU) ⁷ | Wind [Ellershouse ⁸] | 4.2 |
| Backup Top-Up (BUTU) | Import Contract ⁹ | 0 |
| Total | | 4.2 |

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*

⁵ 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 7.3.1.

⁶ Assuming 18 percent ELCC for wind and 0 percent for non-firm Imports to align with current NS Power planning practices. This matter is pending before the UARB.

⁷ Wholesale Market Backup/Top-up Service (BUTU) Tariff participants currently include the Municipal load for Berwick, Mahone Bay, Antigonish and Riverport.

⁸ Ellershouse wind farm owned by Alternative Resource Energy Authority (AREA).

⁹ Import contract is currently delivered via the Nova Scotia/New Brunswick Intertie.

1 *Power Capability and Synchronous Condenser Reactive Power Capability*¹⁰ which
2 was approved by Federal Energy Regulatory Commission (FERC) on March 20,
3 2014.

4
5 The Net Operating Capacity of the thermal units and large hydro units covered by
6 the NERC criteria do not require adjustments at this point. NS Power will continue
7 to refresh unit maximum capacities in the 10-Year System Outlook each year as
8 operational conditions change.

9 10 **3.1.2 Mersey Hydro**

11
12 NS Power continues to assess options to address current concerns on the Mersey
13 Hydro System. Degradation of the powerhouses and water control structures after
14 nearly a century of service has necessitated the need for significant redevelopment
15 work. The Mersey Hydro System is an important part of NS Power's hydro assets
16 and is responsible for approximately 25 percent of annual domestic hydroelectric
17 production. The Company is preparing a capital application for the redevelopment
18 of the first phase of Mersey Hydro System, which is anticipated to include the
19 replacement of the Big Falls Powerhouse, the Big Falls Control Structure and the
20 redevelopment of the Big Falls Substation.

21
22 The 2020 IRP completed an analysis on the redeveloping the Mersey system:¹¹

23
24 The Mersey Hydro system was analyzed during the Resource
25 Screening phase of the IRP (described in Section 4.2.2) and
26 economically retained, based on the assumptions developed from
27 Nova Scotia Power's Hydro Asset Study (HAS). This resulted in the
28 Mersey system being modeled as retained in all IRP key scenarios
29 and sensitivities. However, due to the significant costs associated
30 with redeveloping the Mersey system (as described in the HAS),

¹⁰ <https://www.nerc.com/pa/Stand/Pages/Project2007-09-Generator-Verification.aspx>

¹¹ M08929, NS Power Integrated Resource Planning (IRP) Report, November 30, 2020, page 101.

1 IRP participants expressed a desire to examine the Mersey system
2 specifically via a PLEXOS sensitivity.

3 //

4 The results of this sensitivity indicate that redevelopment of the
5 Mersey system is economic relative to decommissioning when
6 comparing the 25-year NPVRR with end effects. The sensitivity is
7 shown to be equivalent to the base case in terms of relative rate
8 impact, while the decommissioning sensitivity was indicated a
9 lower cost under the shorter NPVRR metrics (25-year without end
10 effects and 10-year NPVRR). Nova Scotia Power notes that these
11 are very close results in all cases, particularly for a long-lived hydro
12 asset like the Mersey system; accordingly, additional economic
13 analysis will be provided in any capital applications for Mersey
14 system refurbishment.
15

16 **3.1.3 Wreck Cove Hydro**

17
18 Wreck Cove Hydro is an important asset for NS Power, providing critical and
19 renewable generation for peak demand periods. With the ability to quickly provide
20 212 MW of peak capacity from two operating units and average annual generation
21 of 300 GWh, Wreck Cove is NS Power's largest hydroelectric system. In 2020, NS
22 Power submitted a capital application to the NSUARB to perform Life Extension
23 & Modernization (LEM) work for the Wreck Cove Generating Station.¹² The Nova
24 Scotia Utility and Review Board (NSUARB, Board) approved the proposed
25 generator, turbine and spherical valve portion of work.¹³ Specifically, as part of
26 the LEM Project, the two unit turbines will be replaced with newly designed turbine
27 runners which will have increased efficiency and a wider operating range over the
28 existing ones. While the change in turbine runners will not change the peak capacity
29 of 212 MW, it will provide a forecast increase of 5 percent to the annual generation
30 from Wreck Cove. The completion of this project will bring the average annual
31 generation at Wreck Cove to 315 GWh per year.

¹² M09596, NS Power Wreck Cove Life Extension and Modernization – Unit Rehabilitation and Replacement, CI 13838, February 28, 2020.

¹³ M09596, NS Power Wreck Cove Life Extension and Modernization, NSUARB Order, February 2, 2021.

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1 **3.2 Changes in Capacity**

2
3
4
5
6
7

Figure 5 provides the firm Supply and DSM capacity changes in accordance with the assumption set developed for the 2020 IRP and the 2021 Load Forecast.

Figure 5: Firm Capacity Changes & DSM

| New Resources 2022-2031 | Net MW |
|---|------------|
| DSM Peak reduction | 290 |
| Demand Response (Firm contribution) ¹⁴ programs | 37 |
| Total Demand Side MW Change Projected Over Planning Period | 327 |
| | |
| Biomass | 43 |
| Assumed Unit Retirements/Lay-ups ¹⁵ | -148 |
| Maritime Link Import - Base Block | 153 |
| Tidal (Firm capacity) | 6 |
| IRP Reference Plan Additions: | |
| Firm imports over existing infrastructure | 165 |
| Battery | 10 |
| Natural Gas Units | 259 |
| New Wind Build (Firm capacity) | 40 |
| IRP Reference Plan Retirements: | |
| Trenton 5 | -150 |
| Tufts Cove 1 & 2 | -171 |
| Pt Aconi | -168 |
| Total Firm Supply MW Change Projected Over Planning Period | 40 |

8

¹⁴ Represents the firm contribution of demand response programs in 2031 assuming an ELCC of 48 percent. Refer to Section 2.0, Figure 2 for the annual DR totals from 2022 to 2031.

¹⁵ Retirement of Lingan 2 after the Martime Link Base Block provides firm capacity service.

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3.2.1 2020 IRP

The 2020 IRP evaluated resource plans that integrate more renewable energy and reflect a provincial decarbonization strategy over the next 25 years.¹⁶ The 2020 IRP serves as a directional roadmap to guide future decision making; it is not prescriptive in nature. The 2020 IRP Reference Plan (2.0C) outlines changes to the resource mix that are representative of many common elements in the resource plans evaluated. However, the specific type, quantity and timing of future resource additions and retirements remains uncertain as several key actions arising from the 2020 IRP continue and further clarity and legislative direction is obtained in response to recent government policy announcements.

Figure 6: Additions and Retirements as per the 2020 IRP Reference Plan (2.0C)

| 2020 IRP Reference Plan (2.0C)¹⁷ | | |
|--|---|-----------------------------|
| | Additions | Retirements |
| 2022 | Firm import opportunities on existing transmission infrastructure (165 MW) | |
| 2023 | Reciprocating Engine (9.3 MW) | Trenton 5 (- 150 MW) |
| | Battery ¹⁸ (10 MW) | |
| 2024 | | |
| 2025 | | |
| 2026 | Combustion turbines (150 MW) | Tufts Cove 1 & 2 (- 171 MW) |
| 2027 | | |
| 2028 | | |
| 2029 | | |
| 2030 | New Wind additions (Installed capacity 400 MW - Firm 40 MW based on marginal ELCC of 10%) ¹⁹ | Pt Aconi (- 168 MW) |
| | Combustion turbine (100 MW) | |
| 2031 | | |

¹⁶ M08929, NS Power Integrated Resource Planning (IRP) Report , November 30, 2020

¹⁷ Lingan 2 is assumed to be retired prior to 2022 in IRP Scenario 2.0C.

¹⁸ Delayed from 2021 to 2023 due to lead times.

¹⁹ See Section 7.3 for more on ELCC of new wind; verification of wind integration strategies via additional system studies will be completed as part of the IRP Action Plan.

1 **3.2.2 Victoria Junction Combustion Turbine**

2
3 On March 23, 2020 the NSUARB issued its decision²⁰ to decline approval of the
4 Company's capital application for the work related to the refurbishment of the
5 Victoria Junction Unit 2 Combustion Turbine (VJ2). VJ2 is a 33 MW combustion
6 turbine that provides black start capability, 10-minute reserve, Volt-Ampere
7 Reactive support and additional firm capacity to the NS Power electrical system.
8 In its decision, the NSUARB stated:

9
10 NS Power may re-apply following the completion of the review of
11 existing CT (oil) resources during the 2020 IRP proceeding or after
12 a comprehensive alternate analysis of all the Company's oil CTs has
13 been completed.

14
15 The 2020 IRP included analysis which confirmed that existing combustion turbine
16 resources provide economic benefit to customers and are economically sustained
17 through the planning horizon with the modeled levels of sustaining capital
18 investment.

19
20 On May 25, 2021, NS Power resubmitted a capital application to the NSUARB²¹
21 for the refurbishment of VJ2. For the purposes of this study, the Company has
22 forecast the inclusion of the firm capacity provided by VJ2 in NS Power's resource
23 mix.

²⁰ M09560, NSUARB letter to NS Power re Approval of 2020 Capital Work Order (P-520), March 23, 2020.

²¹ M10129, NS Power Application for Approval of VJ2 Engine Refurbishment (P-128.20), May 25, 2021.

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Figure 9 below provides the current forecast unit utilization of NS Power’s steam fleet.

Figure 9: NS Power Steam Fleet Unit Utilization Forecast

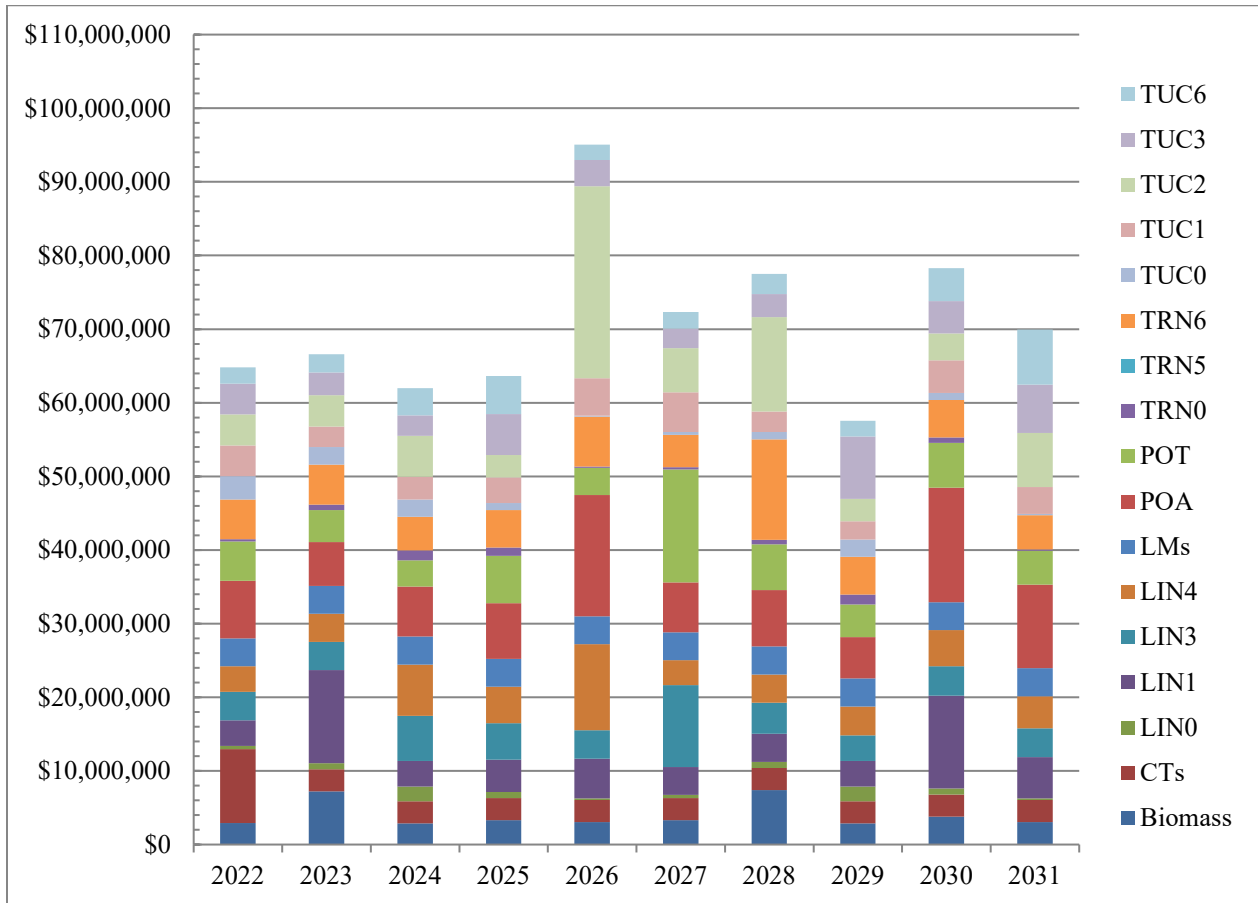
| | | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|--------------|----------------------|----------|----------|----------|---------|----------|---------|----------|---------|----------|----------|
| Lingan 1 | Capacity Factor (%) | 42 | 59 | 48 | 25 | 25 | 27 | 25 | 33 | 20 | 20 |
| | Unit Cycles (Ranges) | < 10 | < 10 | < 10 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 25 - 50 | 10 - 25 | 10 - 25 |
| | Service Hours | 5555 | 8271 | 6468 | 3369 | 3359 | 3760 | 3359 | 4777 | 2564 | 2546 |
| Lingan 2 | Capacity Factor (%) | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Unit Cycles (Ranges) | < 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Service Hours | 305 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Lingan 3 | Capacity Factor (%) | 30 | 24 | 27 | 42 | 27 | 27 | 28 | 23 | 24 | 22 |
| | Unit Cycles (Ranges) | 10 - 25 | 10 - 25 | 10 - 25 | 25 - 50 | 50 - 100 | 25 - 50 | 50 - 100 | 25 - 50 | 25 - 50 | 25 - 50 |
| | Service Hours | 3665 | 2680 | 3493 | 6195 | 3820 | 3898 | 4131 | 3113 | 2979 | 2661 |
| Lingan 4 | Capacity Factor (%) | 43 | 38 | 40 | 27 | 27 | 24 | 25 | 24 | 19 | 22 |
| | Unit Cycles (Ranges) | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 25 - 50 | 25 - 50 | 25 - 50 | 10 - 25 |
| | Service Hours | 5796 | 4680 | 5049 | 3474 | 3356 | 3119 | 3279 | 3323 | 2452 | 2702 |
| Point Aconi | Capacity Factor (%) | 23 | 26 | 25 | 30 | 64 | 66 | 64 | 59 | 0 | 0 |
| | Unit Cycles (Ranges) | < 10 | < 10 | < 10 | < 10 | < 10 | < 10 | < 10 | < 10 | 0 | 0 |
| | Service Hours | 2860 | 2955 | 2891 | 3076 | 6821 | 7196 | 6868 | 6345 | 0 | 0 |
| Point Tupper | Capacity Factor (%) | 34 | 31 | 37 | 67 | 62 | 61 | 61 | 62 | 50 | 51 |
| | Unit Cycles (Ranges) | 10 - 25 | < 10 | 10 - 25 | < 10 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 25 - 50 | 25 - 50 |
| | Service Hours | 4464 | 3770 | 4647 | 7524 | 7033 | 7215 | 7060 | 7317 | 5510 | 5706 |
| Trenton 5 | Capacity Factor (%) | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Unit Cycles (Ranges) | < 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Service Hours | 100 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Trenton 6 | Capacity Factor (%) | 43 | 45 | 46 | 60 | 60 | 58 | 58 | 57 | 37 | 35 |
| | Unit Cycles (Ranges) | < 10 | < 10 | < 10 | < 10 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 | 10 - 25 |
| | Service Hours | 5739 | 6078 | 5862 | 6781 | 6788 | 6625 | 6705 | 6458 | 3720 | 3633 |
| Tufts Cove 1 | Capacity Factor (%) | 19 | 15 | 13 | 7 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Unit Cycles (Ranges) | 10 - 25 | < 10 | < 10 | 10 - 25 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Service Hours | 2526 | 1870 | 1613 | 892 | 0 | 0 | 0 | 0 | 0 | 0 |
| Tufts Cove 2 | Capacity Factor (%) | 10 | 9 | 11 | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Unit Cycles (Ranges) | 25 - 50 | 25 - 50 | 25 - 50 | 10 - 25 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Service Hours | 1781 | 1413 | 1781 | 1599 | 0 | 0 | 0 | 0 | 0 | 0 |
| Tufts Cove 3 | Capacity Factor (%) | 19 | 21 | 28 | 22 | 26 | 22 | 22 | 21 | 19 | 16 |
| | Unit Cycles (Ranges) | 25 - 50 | 25 - 50 | 25 - 50 | 10 - 25 | 50 - 100 | 25 - 50 | 25 - 50 | 25 - 50 | 25 - 50 | 25 - 50 |
| | Service Hours | 3415 | 3217 | 4435 | 4194 | 4643 | 3955 | 4009 | 3880 | 2804 | 2493 |
| Tufts Cove 4 | Capacity Factor (%) | 69 | 73 | 67 | 66 | 68 | 68 | 66 | 69 | 67 | 68 |
| | Unit Cycles (Ranges) | 50 - 100 | 50 - 100 | 50 - 100 | > 100 | > 100 | > 100 | > 100 | > 100 | > 100 | > 100 |
| | Service Hours | 6872 | 7220 | 6657 | 6377 | 6464 | 6518 | 6403 | 6819 | 6356 | 6429 |
| Tufts Cove 5 | Capacity Factor (%) | 66 | 72 | 73 | 69 | 64 | 65 | 65 | 65 | 67 | 67 |
| | Unit Cycles (Ranges) | 50 - 100 | 50 - 100 | 50 - 100 | > 100 | > 100 | > 100 | > 100 | > 100 | > 100 | > 100 |
| | Service Hours | 6622 | 7126 | 7316 | 6730 | 6114 | 6205 | 6281 | 6412 | 6357 | 6317 |
| Tufts Cove 6 | Capacity Factor (%) | 39 | 42 | 38 | 41 | 44 | 44 | 44 | 43 | 45 | 45 |
| | Unit Cycles (Ranges) | 25 - 50 | 10 - 25 | 10 - 25 | 10 - 25 | 25 - 50 | 25 - 50 | 10 - 25 | 25 - 50 | 50 - 100 | 50 - 100 |
| | Service Hours | 7623 | 7753 | 6928 | 7595 | 7359 | 7209 | 7496 | 7265 | 7140 | 7048 |

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1 Major outage intervals are extended where possible to reduce large investments in
2 the thermal fleet.

3
4 The total sustaining capital forecasts in **Figure 12** are generally under the 2020 IRP
5 sustaining capital assumptions since the utilization factors are updated with model
6 output data versus being conservatively modeled at a high utilization factor in the
7 2020 IRP process.
8

9 **Figure 12: Forecast Annual Investment (in 2021\$) by Unit**



11
12 Note: Figure does not include escalation as it is used for asset planning. Forecast investments are subject to change
13 arising from asset health and actual utilization. Changes in currency value can also have significant effect on actual
14 cost.

1 **6.2 Environmental Regulatory Requirements**

2
3 The Nova Scotia *Greenhouse Gas Emissions Regulations*³² specify emission caps for 2010-
4 2030, as outlined in **Figure 16**. The net result is a hard cap reduction from 10.0 to 4.5
5 million tonnes over that 20-year period, which represents a 55 percent reduction in CO₂
6 release over 20 years. Carbon emissions in Nova Scotia from the production of electricity
7 in 2030 are forecast to have decreased by 58 percent from 2005 levels.

8
9 **Figure 16: Multi-year Greenhouse Gas Emission Limits**

10

| Year | GHG Cumulative Million tonnes |
|-------------|--------------------------------------|
| 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) |

11
12 The *Sustainable Development Goals Act*³³ states Nova Scotia’s goals to achieve province-
13 wide greenhouse gas emission reductions of at least 10 percent below levels emitted in
14 1990 by 2020, at least 33 percent below the levels that were emitted in 2005 by 2030, and

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.

³³ *An Act to Achieve Environmental Goals and Sustainable Prosperity*, S.N.S. 2019, c. 26, not proclaimed in force.

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1 a “net zero” by 2050 by balancing greenhouse gas emissions with greenhouse gas removals
2 and other offsetting measures.

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

6
7 Under the GHG cap-and-trade system NS Power is allowed to purchase no more than 5
8 percent of GHG credits which may be offered for auction by the province. Nova Scotia
9 Power is forecasting that the GHG credits available for the company to purchase will be
10 approximately 0.05 Mt annually. Although bilateral GHG trades among participants are
11 permitted, there have been no bilateral trades reported to date and any liquidity in this
12 market is likely to be slow to develop. Due to limited GHG credit purchase opportunities,
13 the primary means of meeting the caps is a reduction in thermal generation from the
14 existing coal-fired generating units, replaced by low-emitting energy.

15
16 Although the free GHG allowance under the GHG cap-and-trade system was specified for
17 each year from 2019 to 2022 as noted in **Figure 17**, the allowances can be redistributed in
18 a four-year compliance period between 2019 and 2022 in order to reduce the cost of
19 compliance. NS Power is on track to meet the requirements of the program, where
20 compliance is forecast to be achieved through reduced emissions and credit purchases.

21
22 **Figure 17: Greenhouse Gas Free Allowances 2019-2022**

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

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1 NS Power thermal facilities that meet the CO₂ emissions threshold for cap-and-trade
2 (50,000 tonnes) are not required to pay fuel surcharges on fuel consumed for electricity
3 generation. Fuel consumed for on-site activities via mobile equipment is subject to a fuel
4 surcharge under the *Cap-and-Trade Regulations*.

5
6 As the Port Hawkesbury Biomass facility and the combustion turbine sites do not meet the
7 emissions threshold, fuel consumed on those sites will be subject to fuel surcharges under
8 the *Cap and Trade Regulations*.

9
10 The Nova Scotia *Air Quality Regulations*³⁴ specify emission caps for sulphur dioxide
11 (SO₂), nitrogen oxides (NO_x), and mercury (Hg). These regulations were amended to
12 extend from 2020 to 2030, effective January 1, 2015. The amended regulations replaced
13 annual limits with multi-year caps for the emissions targets for SO₂ and NO_x.

14
15 The Province introduced amendments to the *Air Quality Regulations* respecting the SO₂
16 cap for a three-year period from 2020 to 2022, effective January 21, 2020. The regulations
17 also provide local annual maximums, as well as limits on individual coal units for SO₂.
18 The revised emissions requirements are shown below in **Figure 18**.

³⁴ *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.

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Figure 18: Emissions (SO₂, NO_x, Hg)

| Multi-Year Caps Period | SO₂ (t) | SO₂ (t) Annual Max | NO_x (t) | NO_x (t) Annual Max | Hg (kg) |
|-------------------------------|---------------------------|--|---------------------------|--|----------------|
| 2020 | 60,900 | | | | 35 |
| 2021-2022 | 90,000 | | 14,955 | 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, SO₂ emissions from generating electricity will have been reduced by 80 percent from 2005 levels. NO_x emissions will have decreased by 73 percent and mercury emissions will have decreased 71 percent from 2005 levels.

SO₂ reductions are being addressed mainly by reduced thermal generation and changes to fuel blends. NO_x reductions are being addressed through reductions in thermal generation and the previous installation of Low NO_x Combustion Firing Systems. Mercury reductions are being accomplished through reduced thermal generation, changed fuel blends and the use of Powder Activated Carbon systems. NS Power offered a mercury recovery program, such as recycling light bulbs or other mercury-containing consumer products, which reduced the amount of mercury going into the environment through landfills. The amount of mercury diverted in 2019 resulted in the total amount of credits exceeding the credit target for the program; therefore, NS Power no longer funded the program as of January 31, 2020. Credits approved by Nova Scotia Environment and Climate Change (ECC) may be used to compensate from the deferred emissions by 2020, and a limited amount 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.

1 **6.3 Anticipated Policy Changes**

2
3 Until the federal coal phase-out policy changes announced in the fall of 2016,³⁵ NS Power’s
4 operation of and planning for its coal-fired generation units proceeded consistent with the
5 provisions of the Agreement on Equivalency of Federal and Nova Scotia Regulations for
6 the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (the
7 Equivalency Agreement). The Equivalency Agreement was finalized in May 2014 and
8 commenced in July 2015, contemporaneous with the effective date for the current federal
9 *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity*
10 *Regulations*.

11
12 In November 2016, the Province of Nova Scotia announced that an agreement-in-principle
13 had been reached with the Government of Canada to develop a new equivalency agreement
14 driven by amendments proposed by the Federal Government to the *Reduction of Carbon*
15 *Dioxide Emissions from Coal-fired Generation of Electricity Regulations*.³⁶ On March 30,
16 2019 the Renewal of this Equivalency Agreement was published in Canada Gazette I. This
17 Equivalency is valid until 2024, with notional direction to 2029.

18
19 The Federal Government recently announced its intention to cease all coal-fired electricity
20 generation by 2030. The Government of Nova Scotia has indicated a similar intention
21 with respect to the Province of Nova Scotia. In February 2021 the Government of Nova
22 Scotia announced its intention to implement a Renewable Energy Standard of 80 percent
23 by 2030. In addition, the Federal Government has also indicated its intention to increase
24 the cost of GHG emissions by increasing the Federal carbon price by \$15/tonne beginning
25 in 2023 and reaching a level of \$170/tonne by 2030.

³⁵ https://www.canada.ca/en/environment-climate-change/news/2017/11/taking_action_tophase-outcoalpower.html

³⁶ Vol. 152, No. 7 Canada Gazette Part I Ottawa, Saturday, February 17, 2018.

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1 In response to these recent governmental policy statements and to better prepare for the
2 potential that these policy statements become law, NS Power is developing a
3 comprehensive plan to transform its generation fleet, eliminating coal-fired generation by
4 2030 and reducing GHG emissions to 1-2 Mt/year by 2030. NS Power continues to engage
5 with both levels of government to explore opportunities to accelerate the Company's
6 carbon reduction strategy in a way that is affordable for customers and that supports NS
7 Power's customers and the communities where they live and work.

8
9 As the government's announced policy changes become legislative and regulatory
10 requirements, NS Power will reflect these changes in future planning studies.

1 **7.0 RESOURCE ADEQUACY**

2
3 **7.1 Operating Reserve Criteria**

4
5 Operating Reserves are resources which can be called upon by system operators on short
6 notice to respond to the unplanned loss of generation or imports. These assets are essential
7 to the reliability of the power system.

8
9 As a member of the Maritimes Area of NPCC, NS Power meets the operating reserve
10 requirements as outlined in *NPCC Regional Reliability Reference Directory #5, Reserve*.
11 These Criteria are reviewed and adjusted periodically by NPCC and subject to approval by
12 the NSUARB. The Criteria require that:

13
14 Each Balancing Authority shall have ten-minute reserve available that is at
15 least equal to its first contingency loss...and,

16
17 Each Balancing Authority shall have thirty-minute reserve available that is
18 at least equal to one half its second contingency loss.³⁷

19
20 In the *Interconnection Agreement between Nova Scotia Power Incorporated and New*
21 *Brunswick System Operator (NBSO)*³⁸ NS Power and New Brunswick Power (NB Power)
22 have agreed to share the reserve requirement for the Maritimes Area on the following basis:

23
24 The Ten-Minute Reserve Responsibility, for contingencies within the
25 Maritimes Area, will be shared between the two Parties based on a 12CP
26 [coincident peak] Load-Ratio Share... Notwithstanding the Load-Ratio
27 Share the maximum that either Party will be responsible for is 100 percent
28 of its greatest, on-line, net single contingency, and, NSPI shall be
29 responsible for 50 MW of Thirty-Minute Reserve.

37 <https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories>

38 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").

1 The Ten-Minute Reserve Responsibility formula results in a reserve share of approximately
2 40 percent of the largest loss-of-source contingency in the Maritimes Area (limited to 10
3 percent of Maritimes Area coincident peak load). This yields a reserve share requirement
4 for NS Power of approximately 40 percent of 550 MW, or 220 MW, capped at the largest
5 on-line unit in Nova Scotia. When Point Aconi is online, NS Power maintains a ten-minute
6 operating reserve of 168 MW (equivalent to Point Aconi net output), of which
7 approximately 33 MW is held as spinning reserve on the system. Additional regulating
8 reserve is maintained to manage the variability of customer load and generation. The
9 reserve sharing requirement with Maritime Link as the largest source in Nova Scotia will
10 depend on the amount of Maritime Link power used in Nova Scotia.

11

12 **7.2 Planning Reserve Criteria**

13
14 The Planning Reserve Margin (PRM) is intended to maintain sufficient resources to
15 reliably serve firm customers. Unit forced outages, higher than forecast demand, and lower
16 than forecast wind generation are all conditions that could individually or collectively
17 contribute to a shortfall of dispatchable capacity resources to meet customer demand.

18
19 NS Power is required to comply with the NPCC reliability criteria that have been approved
20 by the NSUARB. These criteria are outlined in *NPCC Regional Reliability Reference*
21 *Directory #1 – Design and Operation of the Bulk Power System*³⁹ which states:

22
23 Each Planning Coordinator or Resource Planner shall probabilistically
24 evaluate resource adequacy of its Planning Coordinator Area portion of the
25 bulk power system to demonstrate that the loss of load expectation (LOLE)
26 of disconnecting firm load due to resource deficiencies is, on average, no
27 more than 0.1 days per year. [This evaluation shall] make due allowances
28 for demand uncertainty, scheduled outages and deratings, forced outages
29 and deratings, assistance over interconnections with neighboring Planning
30 Coordinator Areas, transmission transfer capabilities, and capacity and/or
31 load relief from available operating procedures.

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

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1 The PRM is a long-term planning assumption that is typically updated as part of an IRP
2 process. In advance of the 2020 IRP, NS Power engaged Energy+Environmental
3 Economics Consulting, LLC (E3) to undertake a PRM and capacity value study. The study
4 found that in order to meet a 0.1 days/year loss of load expectation (LOLE) target and
5 comply with the NPCC reliability requirements, NS Power should maintain a PRM
6 between 17.8 percent and 21 percent.⁴⁰ The range in target PRM is due to a higher and
7 lower estimate of operating reserve requirements for the NS Power system. NS Power
8 studied the appropriate calculation of its PRM as part of the 2020 IRP.⁴¹ The 2020 IRP
9 confirmed that this PRM target was appropriate for long term planning, as noted in the
10 report:

11
12 There are two alternative PRM accounting methods commonly used in the
13 industry, based on using a unit's unforced capacity (UCAP) or installed
14 capacity (ICAP) values. While either method will result in the same
15 reliability standard and the same total quantity of effective capacity, the
16 methods differ in how they measure qualifying capacity. ICAP accounting
17 credits traditional dispatchable resources (e.g., coal, natural gas) at their
18 nameplate capacity, without considering forced outage de-rates, and credits
19 energy-limited resources, including solar, wind, hydro, and battery storage,
20 at their effective load carrying capacity (discussed in further detail below).
21 As an alternative, utilities and capacity markets are beginning to transition
22 to an unforced capacity (UCAP) rather than installed capacity (ICAP)
23 approach to determine the PRM for purposes specifically associated with
24 capacity expansion modeling. This UCAP value adjusts the peak
25 contribution of thermal resources to account for their forced outage or
26 deratings, instead accounting for these resources based on their UCAP or
27 unforced capacity value. This approach puts existing and candidate thermal
28 and renewable resources on an "equal footing" by accounting for the
29 resources' contributions to peak in a consistent way. For the 2020 IRP, Nova
30 Scotia Power used its existing 20 percent ICAP PRM, which the E3 planning
31 and reserve margin study verified was within the range of PRMs consistent
32 with the reliability criterion, and converted this to an equivalent 9 percent
33 UCAP PRM. This UCAP translated value was adopted for the capacity
34 expansion modeling only, based on feedback and discussion with IRP

⁴⁰ M08929, Energy + Environmental Economics, Planning Reserve Margin and Capacity Value Study for Nova Scotia Power Inc. July 2019 found as Attachment 17 to NS Power's [Pre-IRP Deliverables Report](https://irp.nspower.ca/documents/pre-irp-deliverables/) located at <https://irp.nspower.ca/documents/pre-irp-deliverables/>.

⁴¹M08929, Nova Scotia Power, IRP Final Report, November 27, 2020, page 40.

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1 participants, to ensure that renewable resources (primarily wind) would face
2 an equivalent crediting formula to new and existing thermal alternatives.
3 This choice does not change the reliability criterion or use of ICAP PRM
4 calculations in other reporting and analysis. The PRM target will remain
5 appropriate for as long as the given load characteristics and reserve
6 requirements remain consistent. As Nova Scotia Power begins to serve new
7 electrification load, or as significant changes start to occur to the overall
8 generation mix, the appropriate PRM may require re-evaluation and
9 adjustment.

10
11 The PRM provides a basis for the minimum required firm generation NS Power must plan
12 to maintain to comply with NPCC reliability criteria; it does not represent the optimal or
13 maximum required capacity to serve other system requirements such as load following
14 (ramping capability) and emissions compliance. The optimal capacity requirement is
15 determined through a long-term planning exercise such as the 2020 IRP, as discussed in
16 Section 7.4 below.

1 **7.3 Capacity Contribution of Renewable Resources in Nova Scotia**

2
3 Due to their variability, renewable energy resources, such as wind and solar, are not always
4 available to contribute during peak demand hours. The Effective Load Carrying Capability
5 (ELCC), or “capacity value” of a resource represents the statistical likelihood that it will
6 be available to serve the firm peak demand, and as a result, what percentage of its capacity
7 can be counted on as firm for system planning. Loss of Load Expectation (LOLE) studies
8 are the industry standard used to calculate the ELCC or capacity value of these renewable
9 resources.

10
11 By letter dated October 5, 2018⁴² the NSUARB directed NS Power to complete a number
12 of pre-IRP analyses by July 31, 2019. One of the pre-IRP deliverables directed by the
13 NSUARB was a Capacity Study to calculate the ELCC of wind and other renewable energy
14 generators, both for the existing wind resources as well as potential new resources. The
15 study was undertaken by E3⁴³ on behalf of NS Power and the results determined the
16 average ELCC of the wind currently installed on the NS Power system to be 19 percent.
17 The declining marginal ELCC value of adding new wind to the NS Power system was
18 determined to be 11 to 9 percent. In the 2020 IRP, the Company used 10 percent for the
19 ELCC value of new wind. The ELCC value of Hydro was determined to be 95 percent. For
20 the purposes of this Report, NS Power has used the 18 percent capacity value of existing
21 wind to account for the wind farm serving wholesale market participants under the BUTU
22 Tariff, 10 percent capacity value of new wind, and 95 percent for hydro.

23
24 Please refer to Section 7.3.1 regarding the inclusion of ERIS wind resources.

⁴² M08059, UARB Decision Letter, Generation Utilization and Optimization, October 5, 2018.

⁴³ M08929, Integrated Resource Planning and Generation Utilization and Optimization (P-884)
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/>

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

5
6 **7.3.1 Energy Resource Interconnection Service Connected Resources**

7
8 In the 2018, 10-Year System Outlook Report, NS Power provided a study to
9 determine the potential capacity contribution of ERIS facilities based on current
10 system configuration and conditions. The study concluded that existing ERIS
11 facilities can operate as though they are NRIS facilities and therefore can contribute
12 to system capacity for the purposes of resource planning at this time without the
13 requirement for additional system upgrades. The transmission system upgrades
14 undertaken to enable the transmission of Maritime Link energy across Nova Scotia
15 contributed to the change to ERIS facility capacity treatment.

16
17 Consistent with this, and for the purposes of reflecting this potential additional
18 capacity in this Report, NS Power has applied a capacity value of 18 percent to
19 existing wind resources, both ERIS and NRIS, in this Report. Please refer to Section
20 7.3 for further information on the capacity study used to determine the 18 percent.

21
22 This represents a new area for resource planning and remains subject to change.
23 Until these matters are better understood it remains premature to make longer-term
24 resource planning decisions based on this capacity addition. The Company will
25 continue to monitor this resource planning input and will refine the capacity
26 estimates as required. Changes, if necessary, will be incorporated within future 10-
27 Year System Outlook Reports.

1 **7.4 Load and Resources Review**

2
3 The 10-year load and resources outlook in **Figure 19** is based on the capacity changes and
4 DSM forecast from **Figure 5**, and provides details regarding NS Power’s required
5 minimum forecast PRM equal to 20 percent of the firm peak load.

6
7 The current forecast indicates a capacity deficit from 2022 until 2024. Solutions for
8 capacity shortfalls will be evaluated including access to firm capacity if required. NS
9 Power will continue to monitor potential deficits or apparent surpluses as forecasts
10 continue to evolve and will adjust decisions accordingly.

11
12 **Figure 19** is intended to provide a medium-term outlook of the capacity resources available
13 to the Company compared to expected customer demand, given the most recent
14 assumptions to date. As noted in Section 7.2, the PRM provides a basis for the minimum
15 required firm generation NS Power must maintain to comply with NPCC reliability criteria;
16 it does not necessarily represent the optimal or maximum required capacity to serve other
17 system requirements such as wind-following (ramping capability) and emissions
18 compliance. In its Final Report submitted to the NSUARB in the Generation Utilization
19 and Optimization proceeding,⁴⁴ Synapse stated:

20
21 The PRMs provide one high-level measure of the amount of generation
22 capacity relative to the NPCC 20 percent planning reserve margin
23 requirement. PRM is defined as the amount of firm capacity available over
24 the planning peak load. Notably, the NPCC constraint is not the only
25 constraint that dictates how much capacity might be required on the system.
26 Plexos’ ability to model hourly dispatch requirements means that any
27 ramping requirements must be met with adequate capacity. Also, the
28 presence of annual emissions constraints combined with the multi-fossil-
29 fuel environment in which the thermal fleet operates (coal, oil, gas) leads to
30 capacity requirements that could exceed thresholds needed to meet either
31 NPCC reserve or ramping requirements. The integrated aspect of the model

⁴⁴ Synapse Energy Economic Inc., Nova Scotia Power Inc. Thermal Generation Utilization and Optimization Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059, filed on May 1, 2018.

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1 (long-term planning and short-term dispatch) is intended to allow capture
2 of all these moving parts when optimizing retirement and build decisions.⁴⁵
3

4 As noted by Synapse, other considerations may dictate the most economic generating
5 capacity for the system; therefore, any surplus capacity in an outlook does not necessarily
6 suggest that any full or partial unit retirement would be possible or optimal, as these units
7 may provide other additional value. The optimal capacity requirements, including
8 addressing a capacity shortfall and the appropriateness of any unit retirements, have been
9 evaluated in the 2020 IRP and will be analyzed further as NS Power updates its long term
10 planning analyses.

11
12 The reference plan from the 2020 IRP (Scenario 2.0C) forms the planning basis for the
13 2021 10-Year System Outlook.

⁴⁵ *Ibid* at Section 3.1.

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1 **Figure 19: NS Power 10-Year Load and Resources Outlook**

| Load and Resources Outlook for NSPI - Winter 2021/2022 to 2030/2031 (All values in MW except as noted) | | | | | | | | | | | |
|---|---|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|
| | | 2021/ 2022 | 2022/ 2023 | 2023/ 2024 | 2024/ 2025 | 2025/ 2026 | 2026/ 2027 | 2027/ 2028 | 2028/ 2029 | 2029/ 2030 | 2030/ 2031 |
| A | Firm Peak including effects of DSM & DR ⁴⁶ | 2,062 | 2,065 | 2,060 | 2,053 | 2,049 | 2,046 | 2,044 | 2,044 | 2,047 | 2,057 |
| B | Required Reserve (Ax20%) | 412 | 413 | 412 | 411 | 410 | 409 | 409 | 409 | 409 | 411 |
| C | Required Capacity (A+B) | 2,475 | 2,478 | 2,472 | 2,463 | 2,459 | 2,455 | 2,453 | 2,453 | 2,457 | 2,468 |
| D | Existing Resources (NS Power and IPPs) ⁴⁷ | 2,417 | 2,417 | 2,417 | 2,417 | 2,417 | 2,417 | 2,417 | 2,417 | 2,417 | 2,417 |
| E | Existing Resources (Wholesale Market Resources) ⁴⁸ | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| F | Total Existing Resources | 2,421 | 2,421 | 2,421 | 2,421 | 2,421 | 2,421 | 2,421 | 2,421 | 2,421 | 2,421 |
| | Firm Resource Additions: | | | | | | | | | | |
| G | Thermal Additions ⁴⁹ | 43 | | | | | | | | | |
| H | Thermal Retirements ⁵⁰ | -148 | | | | | | | | | |
| I | | | | | | | | | | | |
| J | Tidal ⁵¹ | 2 | 1 | 1 | 1 | | | 2 | | | |
| K | Hydro ⁵² | | -108 | | 101 | | | | | | |
| L | Maritime Link Import | 153 | | | | | | | | | |
| M | IRP Additions ⁵³ | 165 | 19 | | | 150 | | | | 140 | |
| N | IRP Retirements ⁵³ | | -150 | | | -171 | | | | -168 | |
| O | Total Annual Firm Additions (G+H+I+J+K+L+M+N) | 215 | -237 | 1 | 102 | -21 | 0 | 2 | 0 | -28 | 0 |
| P | Total Cumulative Firm Additions (O+P of the previous year) | 215 | -23 | -21 | 80 | 59 | 59 | 61 | 61 | 33 | 33 |
| Q | Total Firm Capacity (F+P) | 2,636 | 2,399 | 2,400 | 2,501 | 2,480 | 2,480 | 2,482 | 2,482 | 2,454 | 2,454 |
| | + Surplus/- Deficit (Q - C) | 161 | -80 | -73 | 38 | 22 | 25 | 29 | 29 | -3 | -14 |
| | Reserve Margin % [(Q - A)/A] | 28% | 16% | 16% | 22% | 21% | 21% | 21% | 21% | 20% | 19% |

2

⁴⁶ Firm peaks as per 2021 Load Forecast including the effects of both DSM and DR programs as shown in Section 2.0, Figure 2.

⁴⁷ Existing Resources NS Power-owned and IPPs as shown in Section 3.1, Figure 3

⁴⁸ Existing Resources Wholesale Market Resources - resources managed by participants in the wholesale market as shown in Section 3.1, Figure 4.

⁴⁹ PH Biomass assumed to transfer to NRIS service in Q4 2021.

⁵⁰ Lingan 2 retirement/lay-up (- 148 MW) upon commencement of Maritime Link Base Block import (+ 153 MW)

⁵¹ Tidal projects (firm capacity) forecast to be phased-in over the 10 years..

⁵² Assumes ELCC 95% for hydro sites. Mersey is derated by 6.8 MW during anticipated rebuild work, refer to Section 3.1.2. Wreck Cove life extension modifications assumes one WC unit will be unavailable from June 2022 to July 2024, refer to Section 3.1.3. Solutions for any capacity shortfalls will be evaluated including access to firm capacity if required.

⁵³ Additions and Retirements as per the 2020 IRP Reference Plan (2.0C) shown in Section 3.2.1, Figure 6.

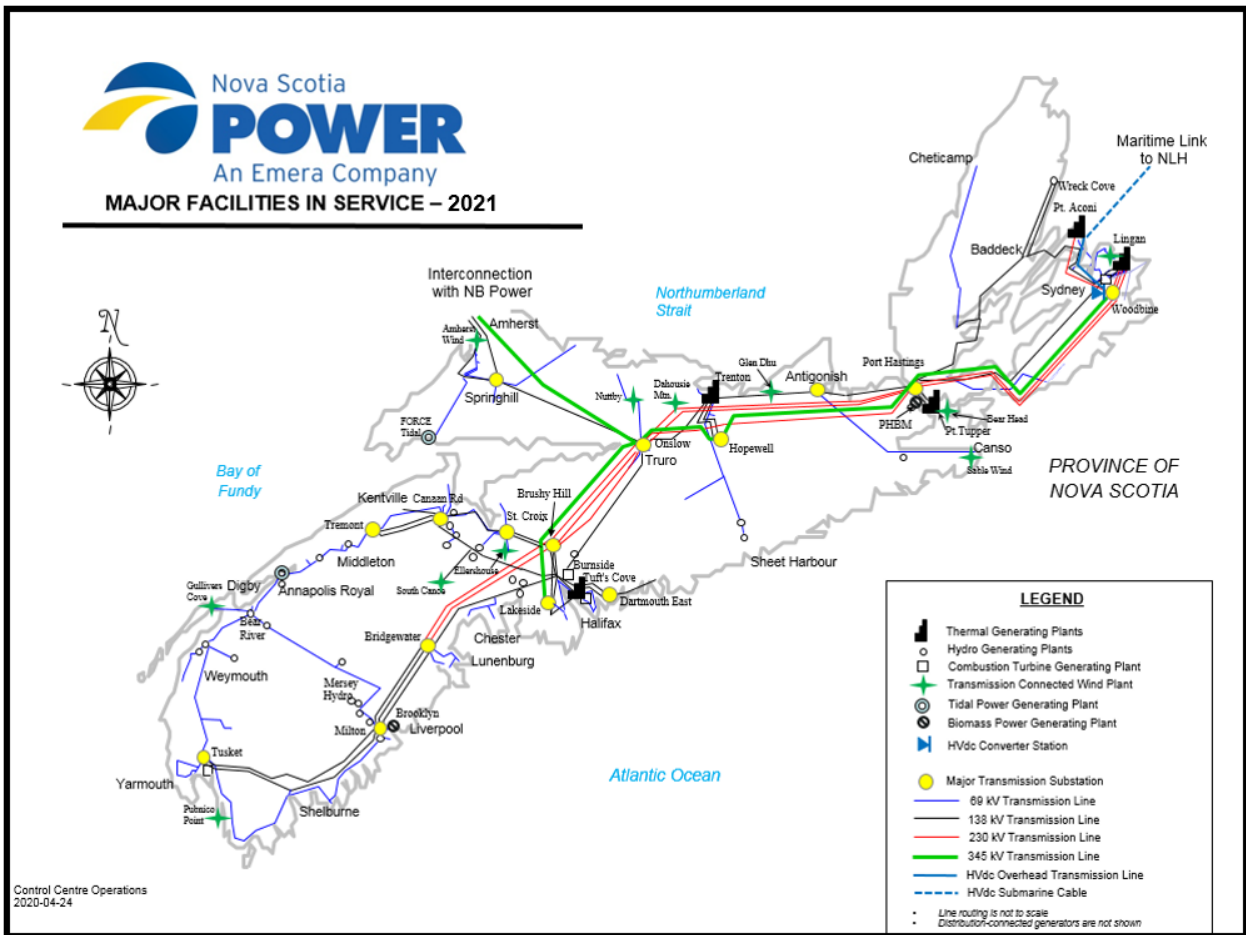
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8.0 TRANSMISSION PLANNING

8.1 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 2021



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.

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

3
4 The 138 kV transmission system is approximately 1,871 km in length and comprises 303
5 km of steel structures and 1,568 km of wood pole lines.

6
7 The 69 kV transmission system is approximately 1,560 km in length and comprises 12
8 km of steel/concrete structures and 1,548 km of wood pole lines.

9
10 Nova Scotia is interconnected with the New Brunswick electric system through one 345
11 kV and two 138 kV lines providing up to 505 MW of transfer capability to New Brunswick
12 and between 0 and 300 MW of transfer capability from New Brunswick, depending on
13 system conditions. As the New Brunswick system is interconnected with the province of
14 Quebec and the state of Maine, Nova Scotia is integrated into the NPCC bulk power system.

15
16 Nova Scotia is also interconnected with Newfoundland via a 500 MW, +/-200 kV DC
17 Maritime Link tie that was placed into service on January 15, 2018 in preparation for the
18 receipt of capacity and energy from the Muskrat Falls Hydro project and the Labrador
19 Island Link DC tie between Labrador and Newfoundland. The Maritime Link is owned and
20 operated by NSP Maritime Link Inc., a wholly owned subsidiary of Emera Newfoundland
21 & Labrador.

22
23 **8.2 Transmission Design Criteria**

24
25 Consistent with good utility practice, NS Power utilizes a set of deterministic criteria for
26 its interconnected transmission system that combines protection performance
27 specifications with system dynamics and steady state performance requirements.

1 The approach used has involved the subdivision of the transmission system into various
2 classifications, each of which is governed by the NS Power System Design Criteria. The
3 criteria require the overall adequacy and security of the interconnected power system to be
4 maintained following a fault on and disconnection of any single system component.

5
6 **8.2.1 Bulk Power System (BPS)**

7
8 The NS Power bulk transmission system is planned, designed and operated in
9 accordance with North American Electric Reliability Corporation (NERC)
10 Standards and NPCC criteria. NS Power is a member of the NPCC, therefore, those
11 portions of NS Power’s bulk transmission network where single contingencies can
12 potentially adversely affect the interconnected NPCC system are designed and
13 operated in accordance with the NPCC Regional Reliability Directory 1: Design
14 and Operation of the Bulk Power System, and are defined as Bulk Power System
15 (BPS).

16
17 **8.2.2 Bulk Electric System (BES)**

18
19 The NERC Bulk Electric System BES definition encompasses any transmission
20 system element at or above 100 kV with prescriptive inclusions and exclusions that
21 further define BES. System Elements that are identified as BES elements are
22 required to comply with all relevant NERC reliability standards.

23
24 NS Power has adopted the NERC definition of the BES and an NS Exception
25 Procedure for elements of the NS transmission system that are operated at 100 kV
26 or higher for which contingency testing has demonstrated no significant adverse
27 impacts outside the local area. The NS Exception Procedure is used in conjunction
28 with the NERC BES definition to determine the accepted NS BES elements and is
29 equivalent to Appendix 5C of the NERC Rules of Procedure.

1 The BES Definition and NS Exception Procedure were approved by NSUARB
2 Order dated April 6, 2017.⁵⁴

3
4 Under the BES definition and NS Exception Procedure approved by the NSUARB,
5 elements classified as NS BES elements are required to adhere to all relevant NERC
6 standards that have been approved by the NSUARB for use in Nova Scotia.

8 **8.2.3 Special Protection Systems (SPS)**

9
10 Special Protection Systems (SPS) are also referred to as Remedial Action Schemes
11 (RAS) in NERC documentation. Both terms are valid.

12
13 NS Power also makes use of SPS in conjunction with the Supervisory Control and
14 Data Acquisition (SCADA) system to enhance the utilization of transmission assets.
15 These systems act to maintain system stability and remove equipment overloads,
16 post- contingency, by rejecting generation and/or shedding load. The NS Power
17 system has several transmission corridors that are regularly operated at limits
18 without incident due to these SPS.

19 20 **8.2.4 NPCC Directory 1 Review**

21
22 A Working Group under the NPCC Task Forces on Coordination of Planning
23 (TFCP) and Coordination of Operation (TFCO) has been created to conduct a
24 review of the NPCC Directory 1 Document: Design and Operation of the Bulk
25 Power System.

⁵⁴ M06930, Nova Scotia Power Application for Approval of the NERC Bulk Electric System (BES) definition, the NS Power BES Exception Procedure, the BES Exception Request Form and NS Power's specific requests for exceptions from the BES, NSUARB Order, April 6, 2017.

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1 Membership was solicited from the NPCC Task Forces on Coordination of Planning, and
2 Coordination of Operation and other interested representatives of NPCC Member
3 Companies.

4
5 At present, Directory 1⁵⁵ provides a “design-based approach” to design and operate the
6 bulk power system to a level of reliability that will not result in the loss or unintentional
7 separation of a major portion of the system from any of the contingencies referenced. The
8 objectives of the review are stated as follows:

9
10 In accordance with the NPCC Directory Review and Revision Manual
11 perform the periodic review of NPCC Directory #1 Design and Operation
12 of the Bulk Power System. Considering the differing performance
13 requirements and objectives of the NPCC criteria and NERC reliability
14 standards, this review will:

15 1. Review landscape of Directory #1 related NERC reliability standards
16 with focus on upcoming or proposed standard changes; e.g. "Establish and
17 Communicate SOL Projects."

18 2. Review of Directory #1 related NERC standards and:

19 a. Assess incremental value of Directory #1 over NERC standards

20 b. Determine if revision(s) to NERC standards may support North
21 American BES reliability and notify the Regional Standards
22 Committee.

23 3. Review Directory#1 operating criteria to ensure consistency with NERC
24 IROL and SOL requirements & terminology.

25 4. Identify any required changes based on increased penetration of
26 distributed energy resources (“DER”) or unnecessary obstacles to the
27 reliable deployment of DER.

28 5. Perform a cost effectiveness review on the planning and operating criteria
29 in Directory#1 to identify potential alternatives that achieve the same
30 reliability outcome.

31 6. Consider any NERC continent-wide efforts (e.g. SPIDERWG) to verify
32 that proposed Directory #1 revisions align with those efforts.

⁵⁵ <https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories>

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1 7. Consider and propose alternatives to the terms “significant adverse
2 impact”, “local area”, and “small or radial portions of the system” in
3 performance requirements for the contingencies of Table 1 and Table 3 that
4 better align with NERC terminology and concepts.

5 8. Update Directory #1 to reflect the term Remedial Action Scheme
6 (“RAS”), rather than Special Protection System (“SPS”).

7 9. Review Directory #1, R12 and consider clarification of when the
8 application of a RAS is not an acceptable solution to meet system
9 performance requirements.

10 10. Resolve Directory 1 and Directory 7 references to “applicable criteria.”
11 Directory 1 could describe what is meant by “applicable criteria”, as noted
12 in multiple spots in the revised Directory 7, or Directory 7 could replace
13 “applicable criteria” with a more general reference to facilitating
14 achievement of the intended performance outcome.

15 11. Consider whether specific guidance on loop flow assumptions need to
16 be considered when establishing base cases and the associated transfers.

17 12. Review guidelines in Directory #1 Appendix B for consistency with
18 Area Transmission Review presentation formats.

19 13. Consider mechanisms to enhance communication between Operations
20 and Planning.

21 14. Consider the impact of increasing amounts of Variable Energy
22 Resources (“VER”), e.g. wind and solar generation. Determine if there are
23 obstacles or more effective and reliable approaches to VER deployment.

24 15. Ensure NPCC is not inhibiting the State and Provincial decarbonization
25 goals while meeting reliability and resilience objectives.

26 16. Review relevance of Directory #1 appendices content.

27
28 NS Power has representation from both Operations and Planning on the Directory 1
29 Working Group that is performing the review. At this time, the Directory 1 Working Group
30 anticipates the review will take approximately two years to complete.
31

1 **8.3 Transmission Life Extension**

2
3 NS Power has in place a comprehensive maintenance program on the transmission system
4 focused on maintaining reliability and extending the useful life of transmission assets. The
5 program is centered on detailed transmission asset inspections and associated prioritization
6 of asset replacement (i.e. conductor line, poles, cross-arms, guywires, and hardware
7 replacement).

8
9 Transmission line inspections consist of the following actions:

- 10
11 • Visual inspection of every line once per year via helicopter, or via ground patrol in
12 locations not practical for helicopter patrols.
13 • Foot patrol of each non-BPS line on a three-year cycle. Where a Lidar survey is
14 requested for a non-BPS line, the survey will replace the foot patrol in that year.
15 • For BPS lines, Lidar surveys every two years out of three, with a foot patrol
16 scheduled for the third year.

17
18 These inspections identify asset deficiencies or damage and confirm the height above
19 ground level of the conductor span while recording ambient temperature. This enables the
20 NSPSO to confirm that the rating of each line is appropriate.

21
22 **8.4 Transmission Project Approval**

23
24 The transmission plan presented in this document provides a summary of the planned
25 reinforcement of the NS Power transmission system. The proposed investments are
26 required to maintain system reliability and security and comply with System Design
27 Criteria and other standards. NS Power has sought to upgrade existing transmission lines
28 and utilize existing plant capacity, system configurations, and existing rights-of-way and
29 substation sites where economic.

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

7
8 **8.5 New Large load Customer Interconnection Requests**

9
10 NS Power received a number of new large load requests in 2020 with respect to proposed
11 commercial, mining, aquaculture and government projects ranging in size from 1-15 MVA.
12 As a result, approximately 45 Preliminary Assessments were performed, leading to the
13 completion of eight formal Load Impact Studies on both the transmission and distribution
14 systems. Five Load Impact studies are also either in progress or yet to be initiated. In two
15 instances, Preliminary Assessments determined that a Load Impact Study was not required.
16 Not all these assessments translate into near-term load, as some projects have multi-year
17 construction or are not completed.

18
19 There have been five applications to serve new or upgraded hospital facilities. These
20 facilities are now requiring two distribution feeder supplies, each fed from a different
21 substation. Both supplies must be capable of feeding the entire hospital load. Under normal
22 conditions, each feeder circuit carries approximately 50 percent of the load. Upon loss of
23 one source, the load supplied by that circuit automatically transfers to the second circuit.
24 Where an existing distribution feeder circuit supply exists, NS Power has assumed
25 responsibility for system upgrades for the primary supply to the facility. However, the
26 facilities are responsible for the full cost of the second supply and all system upgrades
27 required to provide that supply.

1 **9.0 TRANSMISSION DEVELOPMENT 2020 TO 2030**

2
3 Investments in transmission infrastructure can be affected by energy policy and the changing
4 sources of energy and capacity. Proposed transmission development plans and projects are subject
5 to reconsideration and alignment with current policy goals. Items described below are current as
6 of the date of this report.

7
8 **9.1 Impact of Proposed Load Facilities**

9
10 As noted in Section 8.5 of this Report, there are a number of system upgrades required to
11 serve load facilities greater than 1 MW that were proposed in 2019 and 2020. These
12 projects have precipitated the need for the following system upgrades:

- 13
- 14 1. Construction of new 15/20/25 MVA, 138 kV-26 kV substation at 101W-Bowater.
15 This substation is currently under construction with an expected completion date in
16 2022.
 - 17 2. Advancement of upgrades to 69 kV line L-5021 supplying the 50V-Klondike
18 Substation. The temperature rating of L-5021 was upgraded to 70°C in 2020.
 - 19 3. Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in
20 2020/21. The design of this substation is currently in progress.
 - 21 4. Replacement of the 15N-Willow Lane 15/20/25//28 MVA, 69 kV-25 kV
22 transformer 15N-T3 in 2020/21. A replacement transformer was ordered in 2020
23 and is scheduled to be installed in 2021.
 - 24 5. Replacement of the Trenton 15/20/25 MVA, 69 kV-25 kV transformer 50N-T63 in
25 2020/21. A replacement transformer was ordered in 2020 and is scheduled to be
26 installed in 2021.

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- 1 6. Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow
2 in 2022. Area load continues to be monitored to determine the appropriate timing
3 of this installation.
- 4 7. Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Suzie Lake
5 Crescent in 2023. Property acquisition for this site is currently underway.
- 6 8. Installation of a new 10MVA, 69-25 kV portable dead-front transformer on line L-
7 5510 required to provide a 25 kV supply to a new mine site in 2022/23.
- 8 9. Refurbishment of the 6S-Terrace Street Substation following retirement of 4kV
9 source with a new 7.5/10/12.5 MVA, 69-12.5 kV transformer complete with two
10 new 12.5 kV feeder circuits in 2022/23 to accommodate reliability in the Sydney
11 area and to provide a second source to the Cape Breton Regional Hospital (CBRH)
12 facility. A capital contribution will be required of the CBRH for this work.

13

14 **9.2 129H-Kearney Lake Relocation**

15

16 In the 2020 10-Year System Outlook Report, NS Power reported the lease for the 129H
17 Kearney Lake Road substation property had been extended on February 27, 2018 and was
18 set to expire on December 31, 2022. NS Power had been advised that the property owner
19 intended to develop the site and that further lease extensions. As such, NS Power planned
20 to relocate the 129H-Substation from its present site to two land parcels located across the
21 street which were purchased for this purpose in 1986 and 1988.

22

23 Detailed inspection of these two land parcels revealed that site development costs would
24 higher than expected in order to grade the property and provide a suitable access route into
25 the site for a mobile transformer unit. Subsequent negotiations with the owners of the
26 existing site resulted the Company acquiring an option to swap the existing Kearney Lake
27 Substation site (plus sufficient property to enable an expansion for a second transformer
28 and new approach structure) with the NS Power-owned land parcels across the street. The
29 owners of the Kearney Lake site are also prepared to extend the existing lease if required

1 in order to complete this option. This option also involves surrendering a small portion of
2 the existing L-6038 right-of-way resulting in re-alignment of the 129H transmission
3 approaches so that L-6038 will be in the same corridor as the existing L-5004.

4
5 As a result of this new option, NS Power has suspended plans to build a new 129H Kearney
6 Lake substation, and instead is developing a scope of work to remain at the existing site.

8 **9.3 Transmission Development Plans**

9
10 Transmission development plans are summarized below. As noted above, these projects
11 are subject to change. The majority of the projects listed are included in the 2021 Annual
12 Capital Expenditure Plan. In addition, some of the timelines associated with the projects
13 listed in 2021 continue to be impacted by the ongoing COVID-19 global pandemic.

14 15 **2021**

- 16 • Complete 12 MVA Mount Hope 69 kV-25 kV substation in Dartmouth (carry-over
17 from 2020).
- 18 • 5P 25 MVA Mobile Substation Replacement (carry-over from 2020).
- 19 • 101W-Port Mersey Expansion to include a new 138 kV-25 kV, 15/20/25 MVA
20 transformer and two feeders (C0011261, carry-over from 2020).
- 21 • Deteriorated Transmission Structure replacements and upgrades (L-6539, L-6516,
22 L-6020, L-5054)
- 23 • Replacement of 9W-B53 support structure (carry-over from 2020).
- 24 • Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in
25 2021/22.
- 26 • Replacement of the 15N-Willow Lane 15/20/25//28 MVA, 69 kV-25 kV
27 transformer 15N-T3 in 2021.

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- 1 • Replacement of the Trenton 15/20/25 MVA, 69 kV-25 kV transformer 50N-T63 in
2 2021.
- 3 • Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and
4 off right-of-way tree contacts (Year 6 of 8).
- 5 • Procure the existing 129H-Kearney Lake Substation site from existing property
6 owner in exchange for NS Power property on the other side of Kearney Lake Road
7 in 2021.

8

9 **2022**

- 10 • Installation of a second 25/33/42 MVA , 138 kV-25 kV transformer at 1N-Onslow.
- 11 • Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and
12 off right-of-way tree contacts (Year 7 of 8).
- 13 • Install New 138 kV Supply to 50V-Klondike and replace existing 69-25 kV
14 transformer with new 15/20/25 MVA unit.

15

16 **2023**

- 17 • Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Suzie Lake.
- 18 • Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and
19 off right-of-way tree contacts (Year 8 of 8).

20

21 **2026**

- 22 • Replace transformers 62N-T1 and 62N-T2 at end of expected life with a single
23 138/69 kV-25 kV, 15/20/25 MVA transformer.
- 24 • Add a second 25/33/42 MVA, 138 kV-25 kV transformer at new Stellarton
25 substation.

26

27

1 **2028**

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

4

5 **9.4 Western Valley Transmission System – Phase II Study**

6

7 A study was initiated in late 2017 to determine the system upgrades needed to address
8 transmission line capacity, clearance, and age issues in the Western Valley over a 15-year
9 transmission planning horizon. In particular, the following 69 kV lines were targeted:

- 10
- 11 • L-5531 (13V-Gulch to 15V-Sissiboo)
 - 12 • L-5532 (13V-Gulch to 3W-Big Falls)
 - 13 • L-5535 (15V-Sissiboo to 9W-Tusket)
 - 14 • L-5541 (3W-Big Falls to 50W-Milton)

15

16 The scope of the study is to assess the following five options:

- 17
- 18 Option 1 - Restore L-5531, L-5532, L-5535, and L-5541 to 50°C Temperature Rating
 - 19 Option 2 - Upgrade L-5531, L-5532, L-5535, and L-5541 to 80°C Temperature Rating
 - 20 Option 3 - Rebuild L-5531, L-5532, L-5535, and L-5541 with 336 ACSR Linnet and
21 100°C Temperature rating
 - 22 Option 4 - Rebuild L-5531, L-5532, L-5535, and L-5541 with 556 ACSR Dove and
23 100°C Temperature rating (Operate at 69kV)
 - 24 Option 5 - Bypass L-5025, L-5026, L-5531, and L-5535 with a new 138 kV line from
25 51V-Tremont to new substations at 13V-Gulch and 9W-Tusket

26

27 Status: Work on the Western Valley Transmission System – Phase II Study is anticipated
28 to be completed by early Q3 2021.

1 **10.0 PANDEMIC RESPONSE**

2
3 As a result of the response to the COVID-19 global pandemic, Nova Scotia Power has experienced
4 slight shifts in the timing and ramping of peak load. The impacts on load continue, with an increase
5 in residential load and a decrease in commercial load compared to prior years as a result of the
6 pandemic. Weather remains the main driver of load profiles. The effects of the COVID-19
7 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated as the
8 situation unfolds.

9
10 NS Power has created and enacted system operator contingency plans to ensure health and safety
11 of personnel and continued reliable operation of the power grid. The Company is evaluating
12 contingency plans for T&D and Generation planned work, planned maintenance, and forced
13 outages to proceed conservatively while mitigating short-term and longer term reliability risks.
14 Contingency plans have continued to be evaluated over the course of the pandemic.

15
16 NS Power continues to monitor the ongoing spread of COVID-19 and remains focused on the
17 health and safety of employees, consultants, contractors, and their families. A response team is
18 monitoring the situation, coordinating with authorities, and keeping employees informed via
19 regular business updates.

1 **11.0 CONCLUSION**

2
3 Customers count on NS Power for energy to power every moment of every day, and for solutions
4 to power a sustainable tomorrow. Environmental legislation and policy initiatives in Canada and
5 Nova Scotia have driven and will continue to drive transformation of the NS Power electric power
6 system.

7
8 As discussed in Section 10.0 above, NS Power continues to monitor the ongoing spread of COVID-
9 19 and the impacts of the pandemic.

10
11 The Company is currently forecasting a capacity deficit from 2022 until 2024. Solutions for any
12 capacity shortfalls will be evaluated, including access to firm capacity if required. NS Power will
13 continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve and will
14 adjust decisions accordingly.

15
16 The key inputs for Transmission Planning in the 10-year window of this report include the impact
17 of proposed new load facilities outlined in Section 9.1, transmission of energy to be delivered over
18 the Maritime Link, and continued compliance with Reliability Standards.

19
20 The 2020 IRP evaluated a robust set of future planning scenarios, with modeling assumptions that
21 were created with comprehensive stakeholder input. Section 7.2 provides the detailed analysis of
22 the PRM assumption that was evaluated in the 2020 IRP. As discussed in Section 7.3 the 2020 IRP
23 evaluation has provided an updated ELCC for existing and new wind. The reference plan from the
24 2020 IRP (Scenario 2.0C) forms the planning basis for the 2021 10-Year System Outlook and is
25 the reference for the current Steam Fleet Retirement schedule as shown in Section 3.2.1, the current
26 Unit Utilization and Investment Strategy as discussed in Section 3.3 and the foundation for the
27 Load and Resources Review found in Section 7.4. For energy forecasting purposes, updated
28 PLEXOS modeling for the initial three years 2022-2024 was completed and the reference plan
29 from the 2020 IRP (Scenario 2.0C) provides the data for the period of 2025-2031.

30

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1 Given the recent announcements by the Federal Government of its intention to cease all coal-fired
2 electricity generation by 2030 and to increase the cost of GHG emissions by increasing the carbon
3 price, as well as the announcement by the Government of Nova Scotia to implement a renewable
4 energy standard of 80 percent it is anticipated that NS Power will experience significant changes
5 over the 10-year period considered in this report.

6
7 As these changes are better understood through legislative and regulation changes, these changes
8 will be used inform future 10-Year System Outlook Reports and related long-term planning
9 processes.