Nova Scotia Utility and Review Board

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

2019 Ten Year System Outlook

NS Power

July 2, 2019

NON-CONFIDENTIAL

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1.0 INTRODUCTION

In accordance with the 3.4.2.1[1] Market Rule requirements this report provides NS Power's 10-Year System Outlook on behalf of the NS Power System Operator (NSPSO) for 2019.

The 2019 10-Year System Outlook report contains the following information:

- A summary of the NS Power load forecast and update on the Demand Side Management (DSM) forecast in Section 2.
- A summary of generation expansion anticipated for facilities owned by NS Power and others in Sections 3 through 5, including an updated Unit Utilization and Investment Strategy in Section 3.3.
- A summary of environmental and emissions regulatory requirements, as well as forecast compliance in Section 6. This section also includes projections of the level of renewable energy available.
- A Resource Adequacy Assessment in Section 7.
- A discussion of transmission planning considerations in Section 8.
- Identification of transmission related capital projects currently in the Transmission Development Plan in Section 9.

[1] 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).

Since the 2018 10-Year System Outlook - IRP Action Plan Update, and following the completion of the Generation Utilization and Optimization process, the UARB directed NS Power in its letter dated October 5, 2018[2] to undertake an IRP process to be completed by mid-2020 and outlined several pre-IRP analyses. To date, NS Power has held two sessions with interested parties and is on track to complete its pre-IRP deliverables for July 31, 2019.

[2] M08059, UARB Decision Letter, Generation Utilization and Optimization, October 5, 2018.

2.0 LOAD FORECAST

The NS Power load forecast provides an outlook on the energy and peak demand requirements of in-province customers. The load forecast forms the basis for fuel 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 UARB in the 2019 Load Forecast Report on April 30, 2019 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 a Net System Requirement (NSR).

Figure 1 on the following page shows historical and forecast net system requirements (NSR) which includes in-province energy sales plus system losses. Anticipated growth is expected to be driven by increased electric heating in the residential sector as well as industrial growth. These will be offset by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside of structured DSM programs, as well as increased behind-the-meter small scale solar installations. The net result of these inputs is an annual decline of 0.4 percent in energy compared to a peak forecast that remains flat.

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

Year	NSR (GWh)	Growth (%)
2009	12,073	-3.7%
2010	12,158	0.7%
2011	11,907	-2.1%
2012	10,475	-12.0%
2013	11,194	6.9%
2014	11,037	-1.4%
2015	11,098	0.5%
2016	10,809	-2.6%
2017	10,873	0.6%
2018	11,250	3.5%
2019*	11,331	0.7%
2020*	11,300	-0.3%
2021*	11,303	0.0%
2022*	11,278	-0.2%
2023*	11,240	-0.3%
2024*	11,220	-0.2%
2025*	11,135	-0.8%
2026*	11,069	-0.6%
2027*	11,005	-0.6%
2028*	10,958	-0.4%
2029*	10,844	-1.0%

***Forecast value**

NS Power also forecasts the peak hourly demand for future years. The total 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 total 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. After accounting for the effects of DSM savings, system peak is expected to remain 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)	Firm Contribution to Peak (MW)	System Peak (MW)	Growth (%)
2009	268	1,824	2,092	-4.5%
2010	295	1,820	2,114	1.0%
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*	155	2,066	2,221	7.2%
2020*	163	2,070	2,234	0.6%
2021*	170	2,073	2,243	0.4%
2022*	170	2,078	2,248	0.2%
2023*	170	2,080	2,249	0.1%
2024*	170	2,086	2,255	0.3%
2025*	169	2,086	2,255	0.0%
2026*	169	2,081	2,250	-0.2%
2027*	169	2,076	2,245	-0.2%
2028*	168	2,070	2,239	-0.3%
2029*	168	2,060	2,228	-0.5%

***Forecast value**

3.0 GENERATION RESOURCES

3.1 Existing Generation Resources

Nova Scotia's generation portfolio is composed of a mix of fuel and technology types that include coal, petroleum coke, light and heavy oil, natural gas, biomass, wind, tidal and hydro. 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 Standard (RES) discussed in Section 6.1, 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 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 being displaced by renewable resources when they are producing energy. This is discussed further in Section 3.3.

Figure 3 lists NS Power's and IPPs' verified and forecast firm generating capability for generating stations/systems along with their fuel types. It has been updated to include changes and additions to the IPPs and renewables effective up to the filing date of this report.

1 **Figure 3: 2019 Firm Generating Capability for NS Power and IPPs**

Facility	Fuel Type	Winter Net Capacity (MW)
Avon	Hydro	6.8
Black River	Hydro	22.5
Lequille System	Hydro	24.2
Bear River System	Hydro	37.4
Tusket	Hydro	2.4
Mersey System	Hydro	42.5
St. Margaret's Bay	Hydro	10.8
Sheet Harbour	Hydro	10.8
Dickie Brook	Hydro	3.8
Wreck Cove	Hydro	212.0
Annapolis Tidal[3]	Hydro	3.5
Fall River	Hydro	0.5
Total Hydro		**377.1**
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

[3] The firm capacity of the Annapolis Tidal unit is based on average performance level at peak time. Nameplate capacity (achieved at low tide) is 19.5 MW.

Facility	Fuel Type	Winter Net Capacity (MW)
Tusket[4]	Light Fuel Oil	0
Victoria Junction	Light Fuel Oil	66
Total Combustion Turbine		**198**
Pre-2001 Renewables	Independent Power Producers (IPPs)	25.8
Post-2001 Renewables (firm)[5]	IPPs	63.4
NS Power wind (firm)[5]	Wind	13.7
Community-Feed-in-Tariff (firm)[5]	IPPs	30.7
0		
Total IPPs & Renewables		**133.6**
Total Capacity		**2400**

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 *NPCC Regional Reliability Reference Directory #9, Generator Real Power Verification.*[6] Since 2016, there has been a staged transition from Directory #9 to the requirements of NERC Standard *MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability*. NPCC Directory #9 will be retired fully in October, 2019 and NERC

[4] On January 7, 2019 the UARB declined approval of the Tusket CT Generator Replacement Capital Item. Therefore, the asset has been removed from NS Power's listing of Firm Generating Capability. On June 17, 2019 NS Power resubmitted a request for approval of the Tusket CT Generator Replacement Capital Item. Should the Board approve NS Power's resubmitted application, the asset will be returned to service and NS Power will include the firm capacity provided by the Tusket CT. For the purposes of this Report the Company has not forecasted the return of the firm capacity provided by the Tusket CT.

[5] Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) wind projects are assumed to have a firm capacity contribution of 17% as detailed in Section 7.3.1.

[6] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

MOD-025-2 will provide the ongoing criteria for generator verification and data reporting.

The Net Operating Capacity of the thermal units and large hydro units covered by the NPCC and NERC criteria require an adjustment to Lingan 2. The Net Operating Capacity of Lingan 2 has been reduced from 153 MW to 148 MW due to a internal steam path restriction. Since the unit is scheduled to be retired in 2020 and the substantial investment requirement (turbine overhaul) NS Power does not plan to regain this capacity at this time. All other units are unchanged. NS Power will continue to refresh unit maximum capacities in the 10-Year System Outlook each year as operational conditions change.

3.2 Changes in Capacity

Figure 4 provides the firm Supply and DSM capacity changes in accordance with the assumption set developed for the 2020-2022 Base Cost of Fuel forecast and the 2019 Load Forecast.

Figure 4: Firm Capacity Changes & DSM

New Resources 2019-2028	Net MW
DSM firm peak reduction[7]	195
Total Demand Side MW Change Projected Over Planning Period	**195**
Community Feed-in Tariff (Firm capacity)	1

[7] DSM Firm Peak Reduction is calculated from the 2019 NS Power 10-Year Energy and Demand Forecast, M09191, Exhibit N-1, Table A-3 and A-4, April 30, 2019.

New Resources 2019-2028	Net MW
Biomass[8]	43
Maritime Link Import - Base Block	153
Assumed Unit Retirements/Lay-ups[9]	-148
Total Firm Supply MW Change Projected Over Planning Period	**49**

3.2.1 Tusket Combustion Turbine

On May 31, 2017, NS Power filed CI 51526 – Combustion Turbine (CT) Tusket Generator Replacement with the Nova Scotia Utility and Review Board (Board, UARB) for approval. On November 24, 2017, the Board issued a decision stating that the Board did not have sufficient justification to approve the application at this time. On July 17, 2018, NS Power refiled CI 51526 with the Board for approval with the additional generator condition assessment and an analysis of alternative options to its replacement.

NS Power subsequently advised the Board on August 31, 2018 that the Tusket CT generator experienced a failure and required replacement and that the Company would be proceeding with the work at shareholder risk. On January 7, 2019, the Board issued its Decision and again declined to approve NS Power's application to replace the Tusket CT generator.

On June 17, 2019, NS Power submitted a request to the Board to reconsider its Decision in light of additional information and analysis provided in its letter to address the Board's concerns regarding the requirement for the Tusket CT for system security, operating reserve requirements, and cost-benefit alternatives analysis.

[8] The transmission upgrades being completed for the Maritime Link will allow 45 MW of the PH Biomass unit to be counted as firm; however, tests for operating capacity completed have resulted in 43 MW of available firm capacity able to be credited. The work is expected to be completed in 2019.
[9] Retirement of Lingan 2 unit once Maritime Link Base Block provides firm capacity service.

Given that the Board has not yet approved this submission, for the purposes of this Report the Company has not forecast the return of the firm capacity provided by the Tusket CT.

3.2.2 Mersey Hydro

NS Power continues to assess options to address current concerns on the Mersey Hydro System. Degradation of the powerhouse and water control structures after nearly a century of service for some hydro assets has necessitated the need for 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 hydroelectric production. The Company is preparing a Mersey Redevelopment Project Application for filing with the UARB.

3.3 Unit Utilization & Investment Strategy

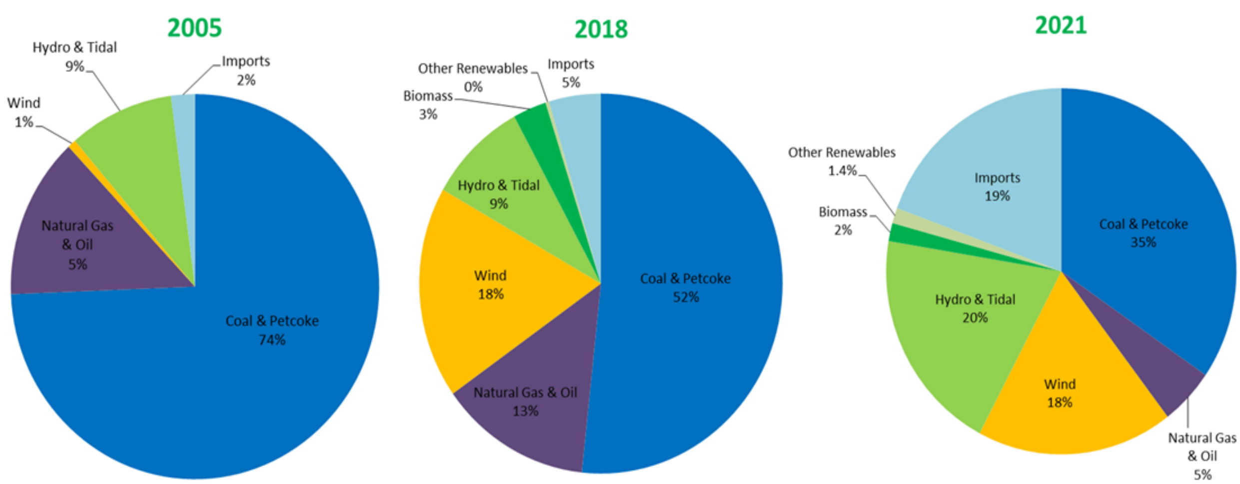
The following sub-sections provide an updated Unit Utilization and Investment Strategy (UUIS). The Company forecasts 10 years of utilization and investment projections in this report. These projections are based on NS Power's currently available assumptions; forecasts will continuously change as assumptions are adjusted based on regulatory or policy changes, operational experience and market information. There are many operational realities, such as the prices of fuel and power or changes in policy, that could trigger a significant shift in the utilization forecast to provide the most economic system dispatch for customers.

This UUIS is a product of generation planning and engineering integrating the latest in Asset Management methodology and Generation Planning techniques in the service of a complex generation operation. It provides an outlook for how NS Power will operate and invest in generation assets recognizing the trend towards lower utilization along with demands for flexible operation arising from renewables integration, and will continue to be updated annually in the 10-Year System Outlook Report.

3.3.1 Evolution of the Energy Mix In Nova Scotia

NS Power's energy production mix has undergone significant changes over the last decade. Since the implementation of the Renewable Electricity Standard (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 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 (e.g. coal, gas) as shown in Sections 3.1 and 3.2, while the energy output of conventional units is being displaced by renewable resources. Figure 5 below illustrates this change with the actual energy mix from 2005 and 2018 and the forecast energy mix for 2021.

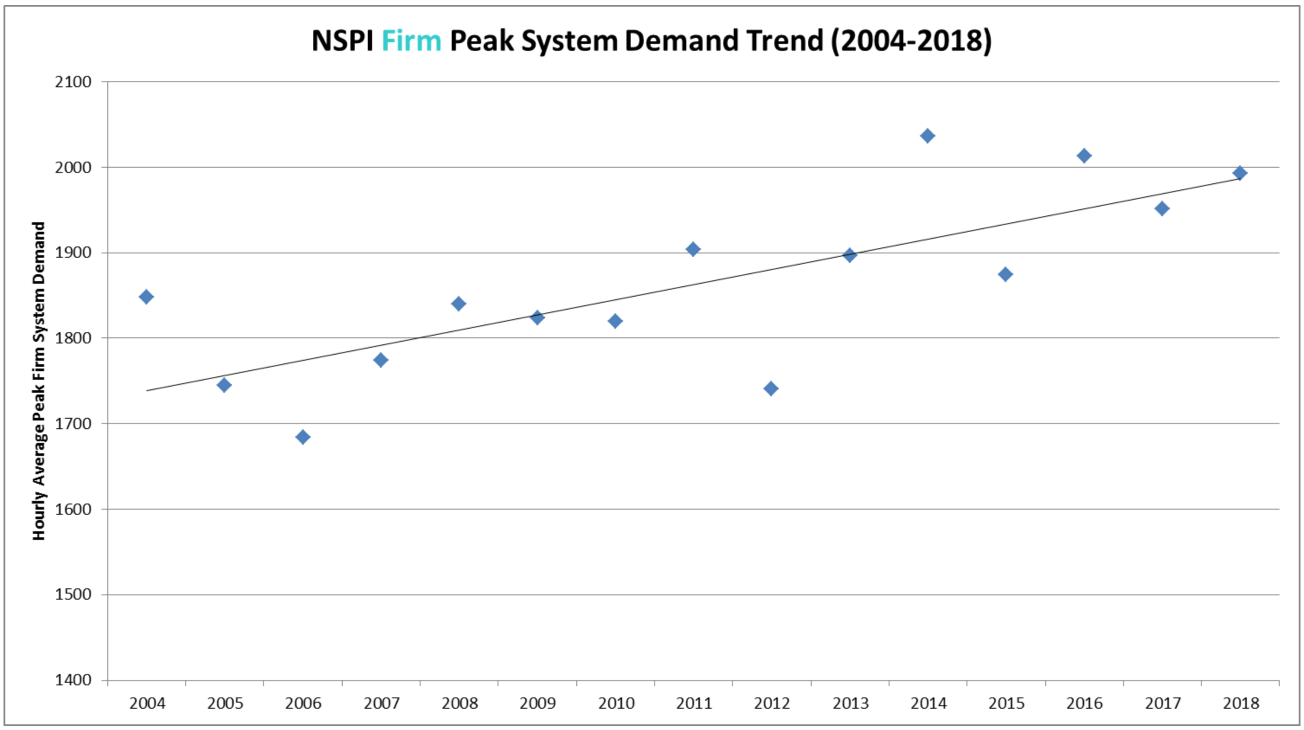
Figure 5[10]: 2005, 2018 Actual, 2021 Forecast Energy Mix



[10] Consistent with the provisions of the Renewable Electricity Regulations, in 2021 the category of Imports includes ML Surplus energy while the category of Hydro includes ML NS Base Block and Supplemental Energy from the Muskrat Falls hydro project.

As illustrated in Figure 6 below, NS Power's firm peak demand has been increasing at a trend of approximately one percent per year. While energy is increasingly being produced by new renewable sources, the capacity required to serve system demand will continue to be served by dispatchable conventional resources together with firm imports. The steam units also provide other critical services to the system such as load-following.

Figure 6: Peak System Demand Trend



3.3.2 Projections of Unit Utilization

NS Power prepares a 10-year forecast of projected unit utilization parameters annually in in this report using the Plexos modeling tool and the current assumptions regarding fuel and market prices, load forecast, system constraints, and generating parameters; these assumptions change year-over-year and the Company adjusts its utilization strategy accordingly. As the Plexos model optimizes dispatch against this set of input assumptions, the forecast utilization of the generating units can be expected to vary as inputs such as fuel pricing shift.

Figure 7 below provides the current forecast unit utilization of NS Power's steam fleet. As noted above, assumptions and policy changes could alter the near-term of this utilization forecast, particularly if carbon emission limits after 2022 change due to extension of the NS Cap and Trade program. As policy outcomes become clear the forecast model will be updated and the updated results will be provided in future 10-Year System Outlook reports.

Figure 7: NS Power Steam Fleet Unit Utilization Forecast

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Lingan 1	Capacity Factor (%)	64	41	44	34	32	16	20	25	17	18
	Unit Cycles (Ranges)	< 10	10 - 25	10 - 25	25 - 50	25 - 50	10 - 25	< 10	< 10	10 - 25	10 - 25
	Service Hours	8011	6186	7134	4831	4829	2307	2526	2986	2290	2329
Lingan 2	Capacity Factor (%)	20	0	0	0	0	0	0	0	0	0
	Unit Cycles (Ranges)	< 10	< 10	0	0	0	0	0	0	0	0
	Service Hours	1918	0	0	0	0	0	0	0	0	0
Lingan 3	Capacity Factor (%)	62	45	40	49	47	46	42	44	44	46
	Unit Cycles (Ranges)	< 10	25 - 50	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	7524	6581	6316	7104	6823	7147	6662	6651	6913	7287
Lingan 4	Capacity Factor (%)	62	44	41	43	43	36	36	39	36	35
	Unit Cycles (Ranges)	< 10	25 - 50	25 - 50	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	7574	6738	6681	5813	6051	5161	4851	5013	4927	4599
Point Aconi	Capacity Factor (%)	70	67	60	64	59	65	74	66	64	68
	Unit Cycles (Ranges)	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10
	Service Hours	7929	7905	7138	6673	6264	6922	7531	6739	6644	7027
Point Tupper	Capacity Factor (%)	81	54	53	45	47	38	39	28	39	32
	Unit Cycles (Ranges)	< 10	< 10	< 10	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	8562	7999	7935	6134	6551	4438	4055	3035	4183	3321
Trenton 5	Capacity Factor (%)	15	12	6	11	9	7	4	3	4	4
	Unit Cycles (Ranges)	10 - 25	10 - 25	< 10	10 - 25	10 - 25	10 - 25	< 10	< 10	< 10	< 10
	Service Hours	1942	1527	837	1718	1493	1107	721	486	562	634
Trenton 6	Capacity Factor (%)	26	19	23	36	38	30	34	36	34	32
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	10 - 25	< 10	< 10	< 10	< 10
	Service Hours	3011	2613	2949	4564	4793	3169	3239	3364	3294	3124
Tufts Cove 1	Capacity Factor (%)	0	2	0	8	7	6	5	5	5	2
	Unit Cycles (Ranges)	< 10	< 10	< 10	10 - 25	10 - 25	10 - 25	10 - 25	< 10	10 - 25	< 10
	Service Hours	58	221	27	1073	916	675	608	507	532	278
Tufts Cove 2	Capacity Factor (%)	1	1	2	6	10	11	11	11	11	10
	Unit Cycles (Ranges)	< 10	< 10	< 10	25 - 50	25 - 50	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	104	101	285	932	1723	1622	1572	1483	1585	1487
Tufts Cove 3	Capacity Factor (%)	7	6	11	25	21	31	23	28	28	28
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	25 - 50	25 - 50	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	1496	1210	2203	4182	3401	4602	3476	4218	4249	4304
Tufts Cove 4	Capacity Factor (%)	46	47	61	60	60	64	66	67	64	64
	Unit Cycles (Ranges)	0	> 100	50 - 100	> 100	50 - 100	> 100	> 100	> 100	> 100	> 100
	Service Hours	4510	4958	6395	6363	6255	6291	6361	6475	6179	6133
Tufts Cove 5	Capacity Factor (%)	45	44	64	57	62	61	65	65	65	63
	Unit Cycles (Ranges)	> 100	> 100	50 - 100	> 100	> 100	> 100	> 100	> 100	> 100	> 100
	Service Hours	4410	4674	6723	5942	6482	6031	6318	6300	6271	6133
Tufts Cove 6	Capacity Factor (%)	24	24	33	34	34	37	38	37	36	36
	Unit Cycles (Ranges)	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	> 100	0	50 - 100	50 - 100	50 - 100
	Service Hours	4177	4306	5817	5476	5556	5321	5468	5510	5223	5224

3.3.3 Projections of Unit Sustaining Investment

Unit utilization and reliability objectives have long been the drivers for generator 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 necessary to also consider the effects of unit starts, operating hours, flexible operating modes (e.g. ramping and two-shifting) and the latest understanding of asset health along with the forecast unit capacity factors.

NS Power has created the concept of utilization factor (UF) for the purpose of communicating the operation strategy for a particular generator. The essence of this approach is to better express the demands placed upon NS Power's generating units given the 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. Refer to Figure 8 below.

Figure 8: 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 actually be exacerbated by reducing load operation (e.g. valves, some pumps, throttling devices).

- Unit cycles (downward and upward ramping of generating units) can stress many components (e.g. turbines, motors, breakers, and fatigue in high energy piping systems) and accelerate 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 shut down during low load overnight and restart 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 and Figure 11 below provide 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 re-assessed 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 cost effectively maintain unit reliability while minimizing undepreciated capital. Mitigating risks by using less intensive investment strategies is a tactic executed throughout the thermal fleet. Major outage intervals are extended where possible to reduce large investments in the thermal fleet.

Major changes in the asset management plan from the 2019 10-Year System Outlook include:

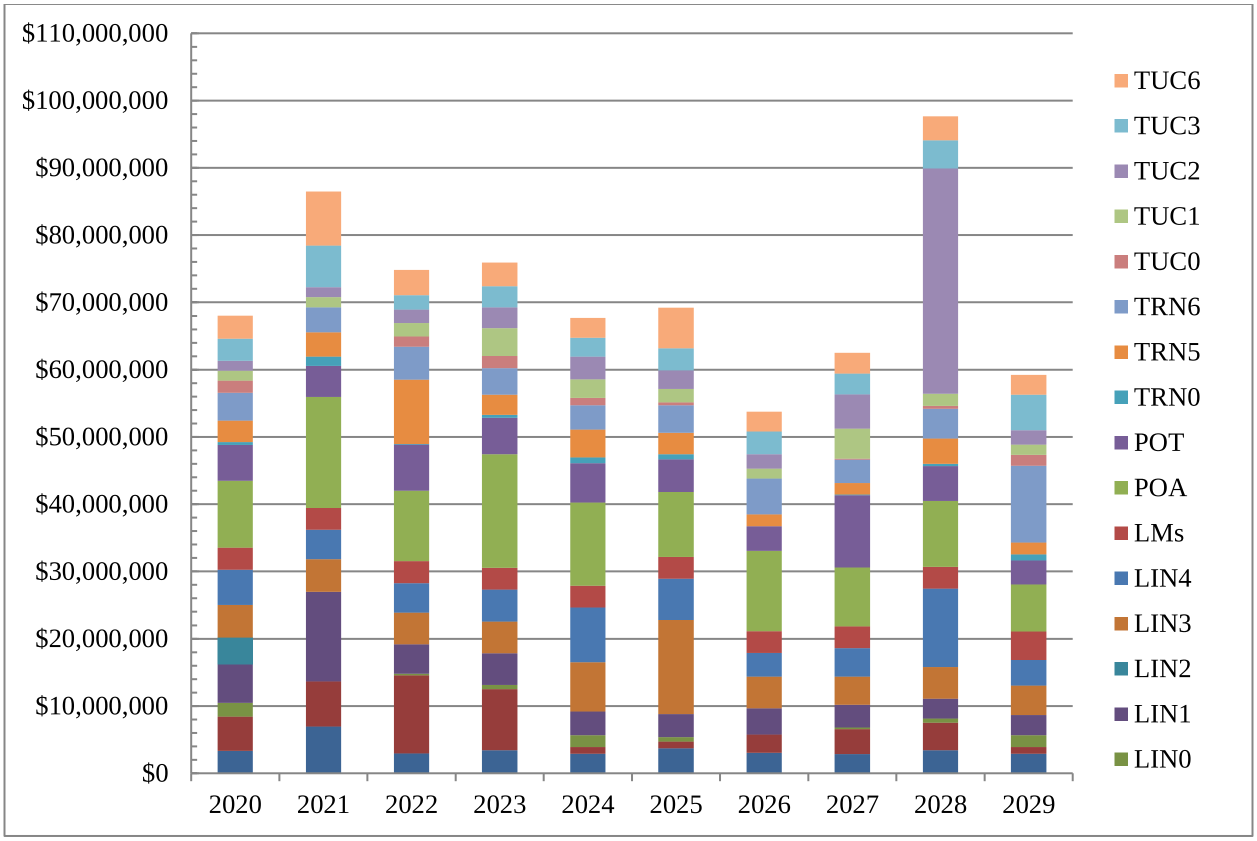
- Increased cycling (output ramping or two-shifting) of the thermal fleet can sustain the unit utilization factors even as the capacity factors decline. For example, a unit that is heavily cycled can require more sustaining investment than a base loaded machine. Figure 9 shows the projected unit utilization factors.

- Lower Utilization forecasts for Trenton Unit #5 have dropped the sustaining capital by approximately 29 percent over the period.
- Higher Utilization of Lingan Unit #1 has driven the Turbine major turbine refurbishment interval into 2021.

Figure 9: Forecast Unit Utilization Factors

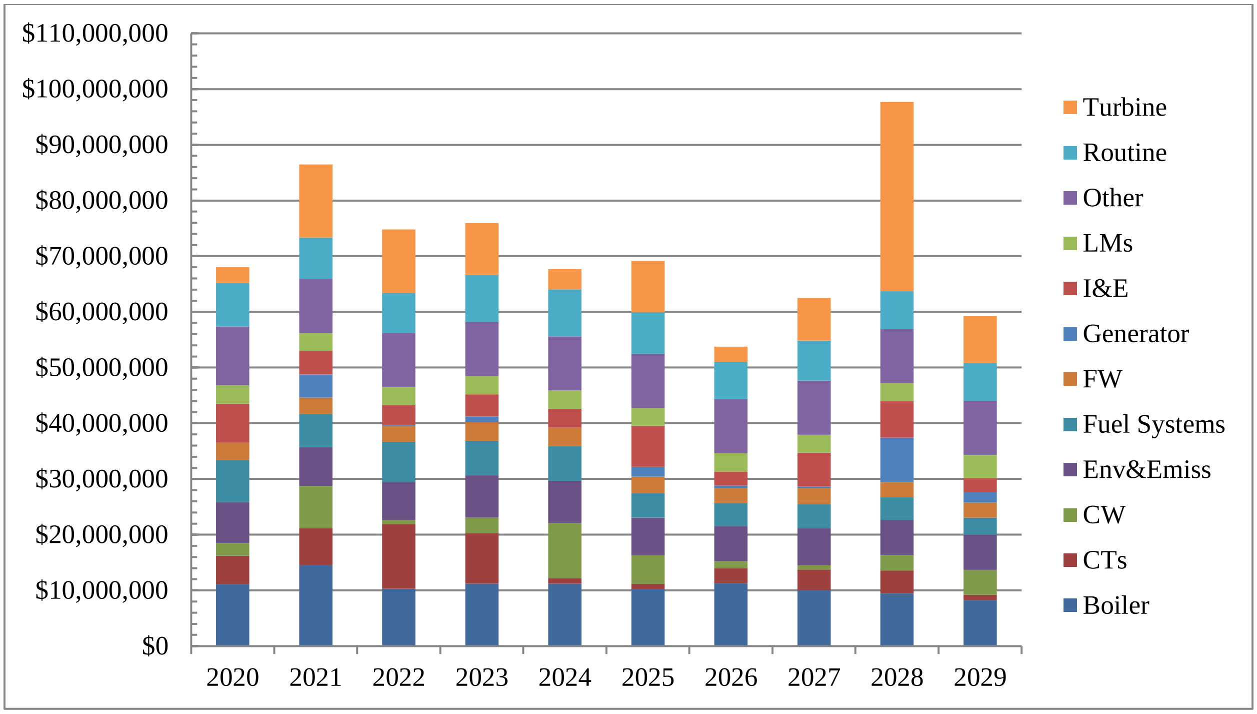
Unit	UF(2020-2024)	UF(2025-2029)
LIN-1	High	Med
LIN-2	Med/Low	Off
LIN-3	High	High
LIN-4	High	High
PHB-1	High	High
POA-1	High	High
POT-2	High	Medium
TRE-5	Low	Low
TRE-6	Medium	Medium
TUC-1	Low	Ultra Low
TUC-2	Low	Low
TUC-3	Medium	Medium
TUC-4	High	High
TUC-5	High	High
TUC-6	High	High

Figure 10: Forecast Annual Investment (in 2019$) by Unit



Note: Figure does not include escalation as it is used for asset planning.

Figure 11: Forecast Annual Investment (in 2019$) by Asset Class



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

NS Power notes the large sustaining capital investment projection for the year 2028 for Tufts Cove Unit #2. Consistent with Synapse Energy Economics Inc.'s (Synapse) recommendation #7 in its Generation Utilization and Optimization study,[11] to determine the capacity and unit commitment requirements to assess possible Tufts Cove unit economic retirement, as part of the upcoming IRP, NS Power plans to assess replacement options for this unit as an alternative to the sustaining capital investment.

[11] M08059, Synapse Final Report, Generation Utilization and Optimization, May 1, 2018, page 57.

3.3.4 Steam Fleet Retirement Outlook

As stated in NS Power's submission to the UARB dated June 7, 2018 in regard to Synapse's Generation Utilization and Optimization report (M08059) filed on May 1, 2018:[12]

> Synapse's results provide a direct answer to the Board's question posed through the approved objective in the Terms of Reference for this work; it is cost-effective for rate payers is the retention of the coal fleet through 2030, and possibly beyond. Synapse confirmed this interpretation of the results at the Technical Conference on March 28, 2018.
>
> NS Power understands this is not a final determination as to the long-term utilization of these generation units and recognizes that uncertainty remains with respect to a major resource planning factor, the carbon regime to be implemented in Nova Scotia over the next decade and beyond. A long-term view of the useful lives of these plants will not be firmly established until this regime is established and understood. The Company currently expects this will be resolved by the end of 2018, likely enabling the undertaking of an Integrated Resource Planning (IRP) exercise in 2019, subject to clarity surrounding federal and provincial carbon policy.

As set out in Section 6.3, the details of the amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations[13] and a related potential equivalency agreement are under discussion between the Province and the Government of Canada, and NS Power is providing input to that process as required. The potential outcomes of these discussions include a range of unit retention or retirement possibilities.

NS Power is developing an updated retirement schedule as part of the upcoming IRP and the forecast major investment intervals for the units, as well as the conclusions of the

[12] M08059 NS Power comments on Synapse Final Report, Generation Utilization and Optmization, June 7, 2018, 2018, page 4.
[13] Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, SOR/2012/167, made under the Canadian Environmental Protection Act, 1999, SOR/2012/167, s.7.3.

Equivalency Agreement negotiations for the Federal Coal-fired Generation of Electricity Regulations. In the interim, Lingan Unit 2 is planned for retirement upon the commencement of the delivery of the Nova Scotia Block of energy and related firm capacity from the Muskrat Falls, currently anticipated in 2020.

4.0 NEW SUPPLY SIDE FACILITIES

As of June 4, 2019 NS Power has six Active Transmission Connected Interconnection Requests (141.052 MW) and four Active Distribution Connected Interconnection Requests (14.3 MW) at various stages of interconnection study.

Proponents of the transmission projects have requested Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). Distribution projects do not receive an NRIS or ERIS designation. NRIS refers to a firm transmission interconnection request with the potential requirement for transmission reinforcement upon completion of the System Impact Study (SIS). ERIS refers to an interconnection request for firm service only to the point where transmission reinforcement would be required. Results of the interconnection studies will be incorporated into future transmission plans.

5.0 QUEUED SYSTEM IMPACT STUDIES

Figure 12 below provides the current combined Transmission and Distribution Advanced State Interconnection Queue.

Figure 12: Combined Transmission & Distribution Advanced Stage Interconnection Queue as of June 4th, 2019

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point	Type	Inservice date DD-MMM-YY	Status	Service Type
1-T	426	27-Jul-12	Richmond	45.0	45.0	47C	Biomass	1-Sep-18	GIA Executed	NRIS
2-T	516	5-Dec-14	Cumberland	5.0	5.0	37N	Tidal	31-May-20	GIA Executed	NRIS
3-T	517	15-Dec-14	Cumberland	4.0	4.0	37N	Tidal	1-Oct-19	GIA Executed	NRIS
4-T	540	28-Jul-16	Hants	14.1	14.1	17V	Wind	31-Oct-23	GIA Executed	NRIS
5-T	542	26-Sep-16	Cumberland	5.952	5.952	37N	Tidal	1-Jan-19	FAC Complete	NRIS
6-D	557	19-Apr-17	Halifax	5.6	5.6		CHP	1-Sep-18	SIS Complete	
7-D	548	31-Jan-17	Kings	6.0	6.0	36V-302	Tidal	31-Dec-19	SIS Complete	N/A

Active transmission and distribution requests not appearing in the Combined Transmission & Distribution Advanced Stage Interconnection Request Queue are considered to be at the initial queue stage, as they have not yet proceeded to the SIS stage of the Generator Interconnection Procedures (GIP). Figure 13 below indicates the location and size of the generating facilities currently in the Combined T/D Advanced Stage Interconnection Request Queue.

Figure 13: Generation Projects Currently in the Combined T/D Advanced Stage Interconnection Request Queue

Company/Location	Nameplace Capacity (MW)
IR #426 NRIS Verson of existing 64MW (IR 219, which was ERIS) Biomass	N/A
IR #516 Tidal in Cumberland County	5.0
IR #517 Tidal in Cumberland County	4.0
IR #540 Wind in Hants County	14.1
IR #542 Tidal in Cumberland County	5.952
IR #557 Generation Replacement Load Following	4.6
IR #548 Tidal in Kings County	6.0
Total	**39.7**

Port Hawkesbury Biomass, 63.8 MW gross / 45 MW net output, generating unit is presently an ERIS classified resource which will be converted to NRIS following the system upgrades associated with Transmission Service Request 400, which are expected to be complete in 2019.

5.1 OATT Transmission Service Queue

There is presently one request in the OATT Transmission Queue, as shown in Figure 14.

Figure 14: Requests in the OATT Transmission Queue

Number	Project	Date & Time of Service Request	Project Type	Project Location	Requested In Service Date	Project Size (MW)	Status
4	TSR 400	July 22, 2011	Point-to-Point	NS-NB	May 31, 2018	330	Waiting for completion of one final piece of construction work, expected later this year (2019)

6.0 ENVIRONMENTAL AND EMISSIONS REGULATORY REQUIREMENTS

6.1 Renewable Electricity Requirements

The Nova Scotia Renewable Electricity Standard (RES) includes a renewable energy requirement for NS Power of 25 percent of energy sales in 2015, and 40 percent in 2020.

In addition to these requirements, Nova Scotia has a Community Feed-in-Tariff (COMFIT) for projects which include community ownership that are connected to the distribution system and Net Metering legislation for renewable projects.[14] The current Net Metering program was initiated in July 2011, and implementation of the COMFIT program occurred in September 2011.

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.[15] NS Power continues to have contractual obligations associated with operation and maintenance of this biomass co-generation facility.

NS Power has complied with the renewable electricity requirement in all applicable years. From 2015 through to 2018 the Company served 26.6 percent, 28 percent, 29 percent and 30 percent of sales, respectively, using qualifying renewable energy sources. NS Power's production tracking and forecast for the current year indicate that renewable electricity compliance will also be achieved for the year 2019.

[14] Effective December 18, 2015, the *Electricity Act* reduced the maximum nameplate capacity for Net Metering from 1,000 kW to 100 kW. Net metering applications submitted on or after December 18, 2015 are subject to the new 100 kW limit. The legislation also closed the COMFIT to new applications.

[15] 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. 2018-133 (effective May 8, 2018), N.S. Reg. 83/2018s. 5 2A.

The total annual RES-eligible energy from the Maritime Link is forecast to amount to 1.1 TWh, which includes both the Base Block and Supplemental Block (for the first five years of operation) (together the Nova Scotia Block). RES compliant electricity that will be delivered on the Maritime Link in 2020 may vary depending on the start date of the flow of Muskrat Falls energy. The Company's RES forecast for 2020 assumes the flow of energy from Muskrat Falls begins June 1, 2020.

The RES Compliance Forecast in Figure 15 below illustrates the full amount of RES-eligible energy forecast to be available to the Company if the Nova Scotia Block energy flow begins on June 1, 2020 and the biomass unit is fully dispatched (290 GWh when Port Hawkesbury Paper (PHP) load is being supplied and 341 GWh when PHP load is not being supplied).

Figure 15: RES 2020 and 2021 Compliance Forecast

RES Compliance Forecast[16]	2020 With PHP	2020 No PHP	2021 With PHP	2021 No PHP
Energy Requirements (GWh)[17]				
NSR including DSM effects	11,300	10,168	11,303	10,171
Losses	769	746	765	742
Sales	10,531	9,422	10,538	9,429
RES (%) Requirement	40%	40%	40%	40%
RES Requirement (GWh)	**4,212**	**3,769**	**4,215**	**3,772**
Renewable Energy Sources (GWh)				
NSPI Wind	264	264	264	264
Post 2001 IPP's	756	756	757	757
PH Biomass	290	341	290	341
COMFIT Wind Energy	534	534	534	534
COMFIT Non-Wind Energy	44	44	44	44
Eligible Pre 2001 IPP's	92	92	92	92
Eligible NSPI Legacy Hydro	935	935	935	935
REA procurement (South Canoe/Sable)	357	357	357	357
Renewable Compliant Imports	940	625	1,134	1,134
Forecast Renewable Energy (GWh)	**4,212**	**3,948**	**4,407**	**4,458**
Forecast Surplus or Deficit (GWh)	**0**	**179**	**191**	**686**
Forecast RES Percentage of Sales	**40%**	**42%**	**42%**	**47%**

6.2 Environmental Regulatory Requirements

The Nova Scotia Greenhouse Gas Emissions Regulations[18] specify emission caps for 2010 – 2030, as outlined in Figure 16. The net result is a hard cap reduction from 10.0 to

[16] Port Hawkesbury Paper LP (PHP) is approved to operate under the Load Retention Tariff until the end of 2019. As such, the compliance forecast figures are shown both inclusive and exclusive of the PHP customer load.
[17] NSR and Losses are from the 2019 NS Power 10 Year Energy and Demand Forecast, M09191, Exhibit N-1, Table A-1, April 30, 2019.

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 will have decreased by 58 percent from 2005 levels.

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

Under the GHG Cap and Trade system Nova Scotia Power is allowed to purchase only five percent of GHG credits which will be put up for auction by the province. Nova Scotia Power is forecasting that the GHG credits available for the company to purchase will be around 0.1 Mt annually. Although bilateral GHG trades among participants are allowed, NS Power does not expect to be able to trade significant amounts of GHG credits with other participants. Due to limited GHG credit purchase opportunities, GHG credit purchase will not be the primary means of GHG compliance. The primary means of meeting the caps is a reduction in thermal generation from the existing coal-fired generating units, replaced by non-emitting energy.

Although the free GHG allowance under the GHG Cap and Trade system was specified for each year from 2019 to 2022, the allowances can be redistributed in a four-year compliance period between 2019 and 2022 in order to reduce the cost of compliance. Nova Scotia Power is forecasting GHG release over the GHG Cap and Trade free allowance allocation for the years 2019 and 2020, and GHG release under the free GHG allocation in the years 2021 and 2022, as the lowest cost of compliance.

[18] 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.

Figure 16: Multi-year Greenhouse Gas Emission Limits

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)

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

NS Power thermal facilities that meet the CO_2 emissions threshold for cap-and-trade (50,000 tonnes) are not required to pay fuel surcharges on fuel consumed for electricity generation. Fuel consumed for onsite activities via mobile equipment is subject to a fuel surcharge under the *Cap-and-Trade Regulations*.

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

The *Nova Scotia Air Quality Regulations*[19] specify emission caps for sulphur dioxide (SO_2), nitrogen oxides (NO_X), and mercury (Hg). These regulations were subsequently 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 NO_X.

NS Power was advised by the Minister of Environment that the province intends to propose amendments to the *Air Quality Regulations* respecting the SO_2 cap for a three-year period from 2020 to 2022. The revised emissions requirements are shown below in Figure 18. The regulations also provide local annual maximums[20], as well as limits on individual coal units for SO_2, as provided in Figure 19 and Figure 20 respectively. The mercury emission caps are outlined in Figure 21.

[19] 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. 2017-255 (October 12, 2017), N.S. Reg. 150/2017.
[20] [20] Annual maximum SO2 caps were not defined in the 2019 proposed amendments to the *Air Quality Regulations*; however, NSE has indicated new regulations will be adjusted accordingly.

Figure 18: Emissions Multi-Year Caps (SO2, NOx)

<table>
<tr><th>Multi-Year Caps Period</th><th>SO_2 (t)</th><th>NO_X (t)</th></tr>
<tr><td>2015 – 2019 (equal outcome)</td><td>304,500</td><td>96,140</td></tr>
<tr><td>2020</td><td>60,900</td><td rowspan="2">14,955</td></tr>
<tr><td>2021-2022</td><td>90,000</td></tr>
<tr><td>2023-2024</td><td>68,000 (with annual maximum caps)</td><td>56,000</td></tr>
<tr><td>2025</td><td>28,000</td><td>11,500</td></tr>
<tr><td>2026 – 2029</td><td>104,000</td><td>44,000</td></tr>
<tr><td>2030</td><td>20,000</td><td>8,800</td></tr>
</table>

Figure 19: Emissions Annual Maximums (SO_2, NO_X)[21]

Year	SO_2 Annual Maximum (t)	NO_X Annual Maximum (t)
2015 – 2019	72,500	21,365
2021 – 2024	36,250	14,955
2026 – 2029	28,000	11,500

Figure 20: Individual Unit Limits (SO_2)

Year	SO_2 Individual Unit Limit (t)
2015 – 2019	42,775
2020 – 2024	17,760
2025 – 2029	13,720
2030	9,800

[21] Annual maximums apply to the multi-year ranges from Figure 19 only. Please refer to Figure 20 for the caps on years that are not contained within the multi-year cap ranges.

Figure 21: Mercury Emissions Caps

Year	Hg Emission Cap (kg)
2010	110
2011	100
2013	85
2014	65
2020	35
2030	30

By 2030, emissions of sulphur dioxide from generating electricity will have been reduced by 80 percent from 2005 levels. Nitrogen oxides 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. 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.

The 2017 amendments to the *Nova Scotia Air Quality Regulations*[22] also provide an optional program until the end of 2025 through which NS Power can obtain credits to be used to make up deferred mercury emission requirements from earlier in the decade as well as for compliance from 2020 through to 2029. NS Power offers a mercury recovery program, such as recycling light bulbs or other mercury-containing consumer products, which reduces the amount of mercury going into the environment through landfills. NS Power, through its contracted service provider, Efficiency One, has collected mercury credits of 2.3 kg in 2015, 19.2 kg in 2016, and 44.8 kg in 2017. Efficiency One collected

[22] 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. 2017-255 (October 12, 2017), N.S. Reg. 150/2017

58.1 kg of credit in 2018; NS Power is awaiting confirmation and acceptance of the 2018 annual report by Nova Scotia Environment (NSE). A limited amount of credits approved by NSE (30 kg in 2020, 10 kg per year for subsequent years) can be used to compensate for the deferred mercury emissions by 2020 as well as for compliance from 2020 to 2029. NS Power continues to offer the program in 2019.

6.3 Upcoming Policy Changes

Until the recent federal coal phase-out policy changes announced in the fall of 2016,[23] NS Power's operation of and planning for its coal-fired generation units has been proceeding consistent with the provisions of the Agreement on Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (the Equivalency Agreement). The Equivalency Agreement was finalized in May 2014, and effective starting July 1, 2015 contemporaneous with the effective date for the current federal Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations. On March 30, 2019 the Renewal of this Equivalency Agreement was published in Canada Gazette I.

In November 2016, the Province of Nova Scotia announced that an agreement-in-principle had been reached with the Government of Canada to develop a new equivalency agreement that will enable the province to move directly from fossil fuels to clean energy sources but enable Nova Scotia's coal-fired plants to operate at some capacity beyond 2030. The need for this new agreement was driven by amendments proposed by the Federal Government to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations.[24] The amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations and the related equivalency agreement are under discussion between the Province and the Government of Canada, and NS Power is providing input to that process as required. In the Renewal

[23] https://www.canada.ca/en/environment-climate-change/news/2017/11/taking_action_tophase-outcoalpower.html
[24] Vol. 152, No. 7 Canada Gazette Part I Ottawa, Saturday, February 17, 2018.

of the existing Equivalency Agreement published March 30, a Quantitative Analysis for the period to 2040 was examined, which will likely form the basis for the second Equivalency Agreement.

7.0 RESOURCE ADEQUACY

7.1 Operating Reserve Criteria

Operating Reserves are generating resources which can be called upon by system operators on short notice to respond to the unplanned loss of generation or imports. 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 UARB. 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.[25]

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO),*[26] 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.

[25] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx
[26] New Brunswick's new 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 formula results in a reserve share of approximately 40 percent of the largest loss-of-source contingency in the Maritimes Area (limited to 10 percent of Maritimes Area coincident peak load). This yields a reserve share requirement for NS Power of approximately 40 percent of 550 MW, or 220 MW, capped at the largest on-line unit in Nova Scotia. When Point Aconi is online, NS Power maintains a ten-minute operating reserve of 168 MW (equivalent to Point Aconi net output), of which approximately 33 MW is held as spinning reserve on the system. Additional regulating reserve is maintained to manage the variability of customer load and generation. The reserve sharing requirement with Maritime Link as the largest source in Nova Scotia will depend on the amount of Maritime Link power used in Nova Scotia.

7.2 Planning Reserve Criteria

The Planning Reserve Margin (PRM) intends to maintain sufficient resources to 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 UARB. These criteria are outlined in *NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System*[27] and states that:

> 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

[27] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

The 2014 IRP Loss of Load Expectation (LOLE) study confirmed that the 20 percent planning reserve margin applied by NS Power is required to meet the NPCC reliability criteria. The PRM is a long-term planning assumption that is typically updated as part of an IRP process; each year in the 10-Year System Outlook Report the Company verifies that the established PRM remains in compliance with the NPCC reliability criteria. NS Power is in the process of initiating an updated LOLE study to establish the planning reserve margin for the next cycle of long-term planning.

The planning reserve margin 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 such as load-following (ramping capability) and emissions compliance. The optimal capacity requirement is determined through a long-term planning exercise such as an IRP, as discussed in Section 7.4.

7.3 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 its letter dated October 5, 2018[28] the UARB directed NS Power to complete a number of pre-IRP analyses by July 31, 2019. One of these pre-IRP deliverables is a Capacity Study which will calculate the ELCC of wind and other renewable energy generators, both for the existing wind resources as well as potential new resources. As part of the Capacity study NS Power is also evaluating the ability for storage to provide system capacity; most importantly, what duration of energy storage technologies will be required for Nova Scotia at varying levels of storage penetration.

Once this study is completed in the upcoming IRP, NS Power will use the updated values in the system capacity forecast in future 10-Year System Outlook Reports. NS Power has used the 17 percent capacity value of wind historically applied in Nova Scotia for the purposes of this year's Report. Please also refer to Section 7.3.1 regarding the inclusion of Energy Resource Interconnection Service wind resources.

For future long-term planning exercises, the marginal capacity value of any incremental wind generation decreases due to saturation effects and the increase of variable generation affecting the ability to serve load during peak demand. The results of the Capacity Study will provide the appropriate capacity values to be used in modeling new wind resources considered in long term resource planning exercises.

Some municipal load is served from one independent wind farm supply. This generation is not included in NS Power's sourced wind generation but contributes to operational considerations of the total amount of wind generation.

7.3.1 Energy Resource Interconnection Service Connected Resources

In the 2018 10-Year System Outlook Report, NS Power provided a study to determine the potential capacity contribution of ERIS facilities based on current system configuration and conditions. The study concluded that existing ERIS facilities can

[28] M08059, UARB Decision Letter, Generation Utilization and Optimization, October 5, 2018.

operate as though they are NRIS facilities and therefore can contribute to system capacity for the purposes of resource planning at this time without the requirement for additional system upgrades. The transmission system upgrades undertaken to enable the transmission of Maritime Link energy across Nova Scotia contributed to the change to ERIS facility capacity treatment.

Consistent with this, and for the purposes of reflecting this potential additional capacity in this report, NS Power has applied a capacity value of 17 percent to existing wind resources at this time, both ERIS and NRIS, in this report.

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

7.4 Load and Resources Review

The ten-year Load and Resources Outlook in Figure 22 and Figure 23 below are based on the capacity changes and DSM forecast from Figure 4 above, and provides details regarding NS Power's required minimum forecast planning reserve margin equal to 20 percent of the firm peak load.

The current forecast indicates a capacity deficit. In the upcoming IRP, NS Power is evaluating the required Planning Reserve Margin to comply with NPCC criteria as discussed in Section 7.2. The IRP will also provide guidance on the optimal resource mix to address any capacity deficit if required following the update of the reserve margin percentage. As illustrated in Figure 24, the deficit likely only affects one week in the coming years, and would not be expected to affect the Company's ability to serve its firm peak load in the near term. The Company expects to be able to manage through this upcoming winter period, and can also find near-term solutions for access to firm capacity if required. NS Power will continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve and will adjust decisions accordingly.

As stated in Section 3.2.1 for the purposes of this Report the Company has not forecast the return of the firm capacity provided by the Tusket CT. The additional contribution of Tusket CT's 33 MW would help aliviate the current capacity deficit forecast.

Figure 22 is intended to provide a medium-term outlook of the capacity resources available to the Company compared to expected customer demand, given the most recent assumptions to date. As noted in Section 8.2, the planning reserve margin provides a basis for the minimum required firm generation NS Power must maintain to comply with NPCC reliability criteria; it does not necessarily represent the optimal or maximum required capacity to serve other system requirements such as wind-following (ramping capability) and emissions compliance. In its final report submitted to the UARB in the Generation Utilization and Optimization proceeding,[29] Synapse stated:

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

[29] 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

> allow capture of all these moving parts when optimizing retirement and build decisions.[30]

As stated by Synapse, other considerations may dictate the most economic generating capacity for the system; therefore, any surplus capacity in an outlook does not necessarily suggest that any full or partial unit retirement would be possible or optimal, as these units may provide other additional value. The optimal capacity requirement, including addressing a capacity shortfall and the appropriateness of any unit retirements, is determined through a long-term planning exercise such as an IRP.

[30] Ibid at section 3.1,

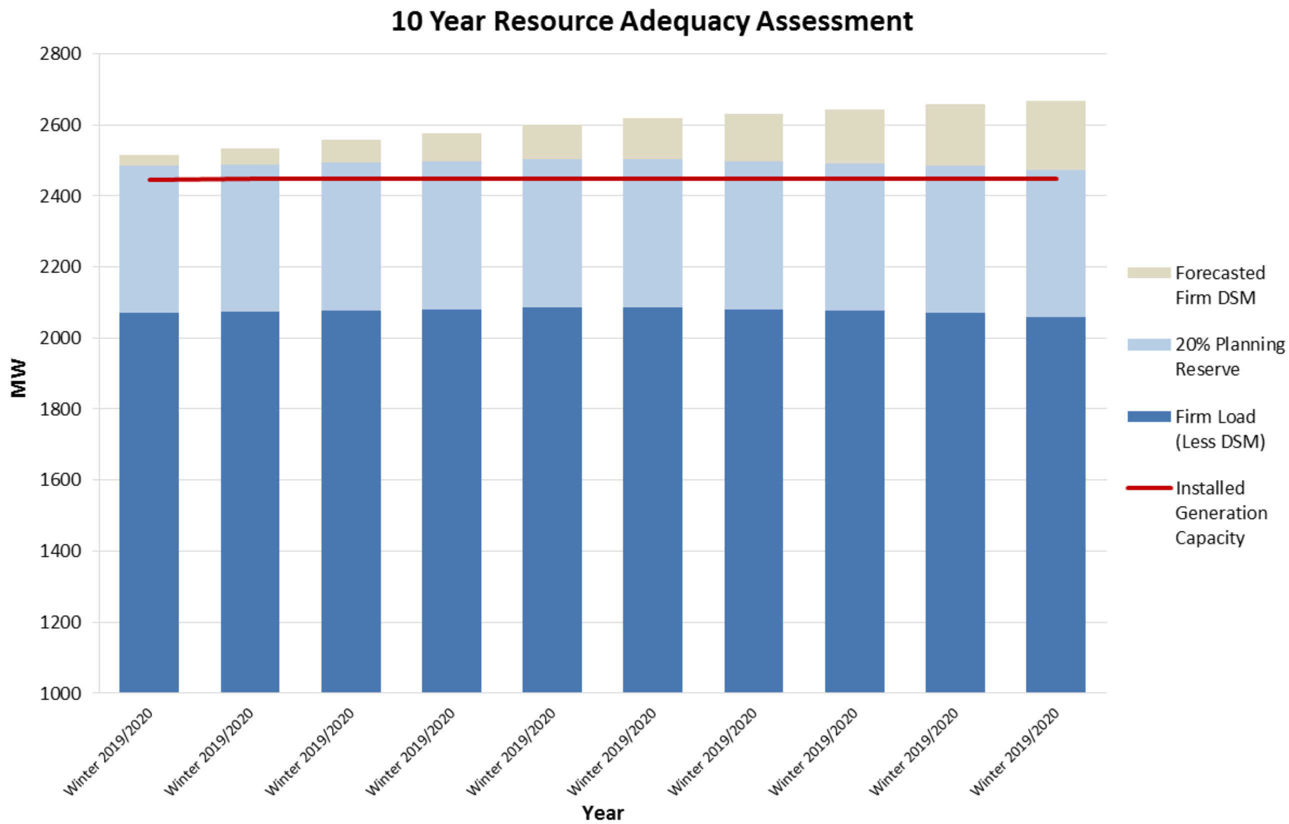
Figure 22: NS Power 10 Year Load and Resources Outlook

	Load and Resources Outlook for NSPI - Winter 2019/2020 to 2028/2029 (All values in MW except as noted)										
		2019/2020	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**	**2027/2028**	**2028/2029**
A	Firm Peak Load Forecast	2,100	2,119	2,141	2,160	2,183	2,201	2,214	2,229	2,244	2,255
B	DSM Firm[31]	29	46	63	80	97	115	133	152	173	195
C	Firm Peak Less DSM (A - B)	2,070	2,073	2,078	2,080	2,086	2,086	2,081	2,076	2,070	2,060
D	Required Reserve (C x 20%)	414	415	416	416	417	417	416	415	414	412
E	Required Capacity (C + D)	2,484	2,487	2,493	2,495	2,503	2,503	2,498	2,492	2,485	2,472
F	Existing Resources	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400
	Firm Resource Additions:										
G	Thermal Additions[32]		-148								
H	Biomass[33]	43									
I	Community Feed-in-Tariff[34]	1.0									
J	Maritime Link Import		153								
K	Total Annual Firm Additions (G + H + I + J)	44	5	0	0	0	0	0	0	0	0
L	Total Cumulative Firm Additions (K + L of the previous year)	44	49	49	49	49	49	49	49	49	49
M	Total Firm Capacity (F + L)	2444	2449	2449	2449	2449	2449	2449	2449	2449	2449
	+ Surplus / - Deficit (M - E)	-41	-39	-44	-47	-54	-55	-49	-43	-36	-23
	Reserve Margin % [(M - C)/C]	18%	18%	18%	18%	17%	17%	18%	18%	18%	19%

[31] Cumulative estimated Firm Peak reduction based on DSM forecast
[32] Includes assumed Lingan 2 retirement once Maritime Link Base Block provides firm capacity service.
[33] 43 MW from the PH Biomass plant which will be able to provide firm service following completion of the transmission upgrades required for the Maritime Link.
[34] The Community Feed-in-Tariff represents distribution-connected renewable energy projects, totalling 156.6 MW installed by beginning of 2020 (150.5 wind, 6.1 MW non-wind).

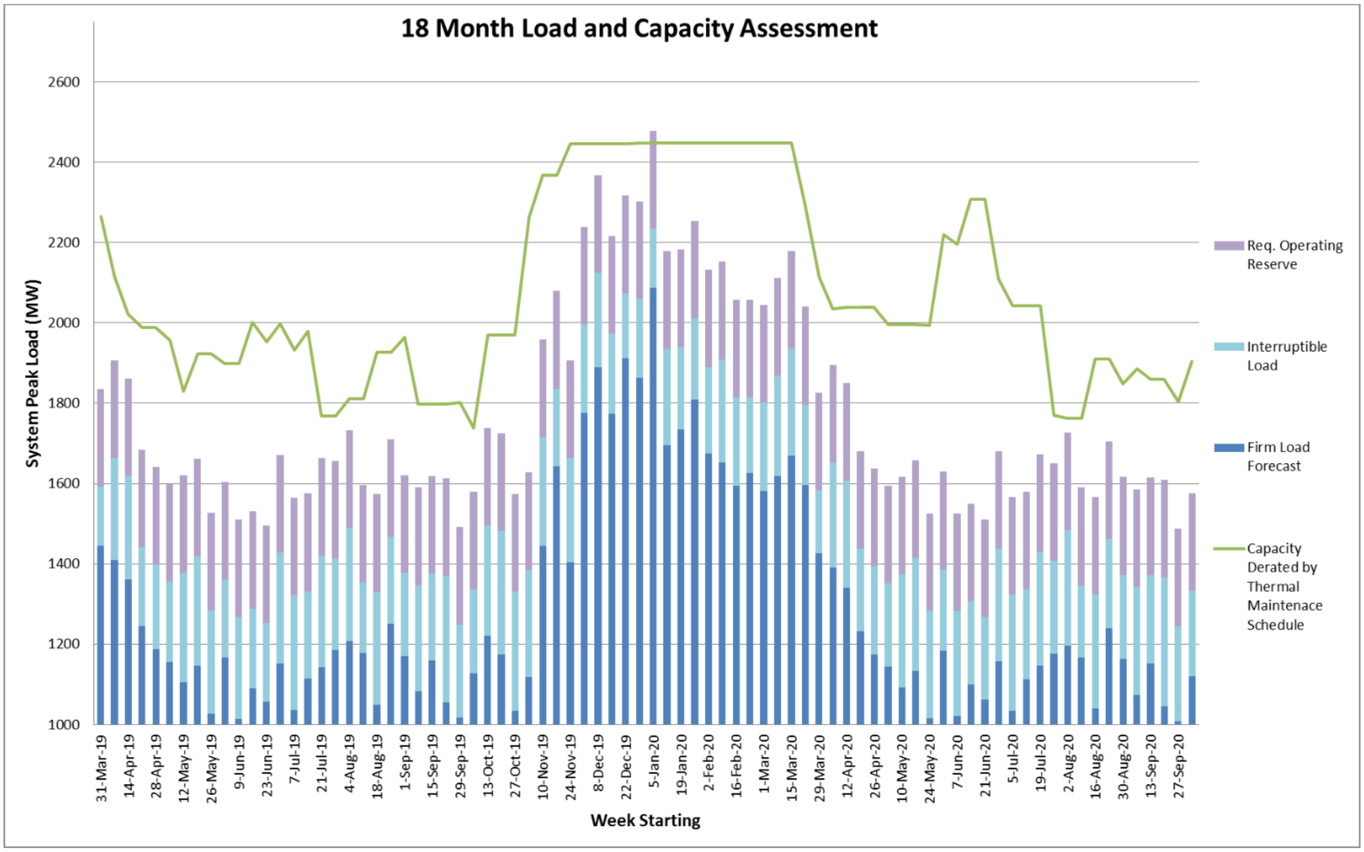
Figure 23 is a graphical representation of the assessment completed in Figure 22 above. It provides a breakdown of the forecast system demand and planning reserve margin and how this will be served by the system capacity.

Figure 23: Firm Capacity and Peak Demand Analysis



NS Power performs an assessment of operational resource adequacy covering an 18-month period twice a year (in April and October proceeding the summer and winter peak capacity periods) in compliance with NERC standards and in association with NPCC working groups. These reports of system capacity and adequacy are posted on the NSPSO's OASIS site in the Forecast and Assessments Section. Figure 24 shows a graphical representation of NS Power's 18 month assessment with the updated 2019 Load forecast.

Figure 24: 18 Month Load and Capacity Assessment

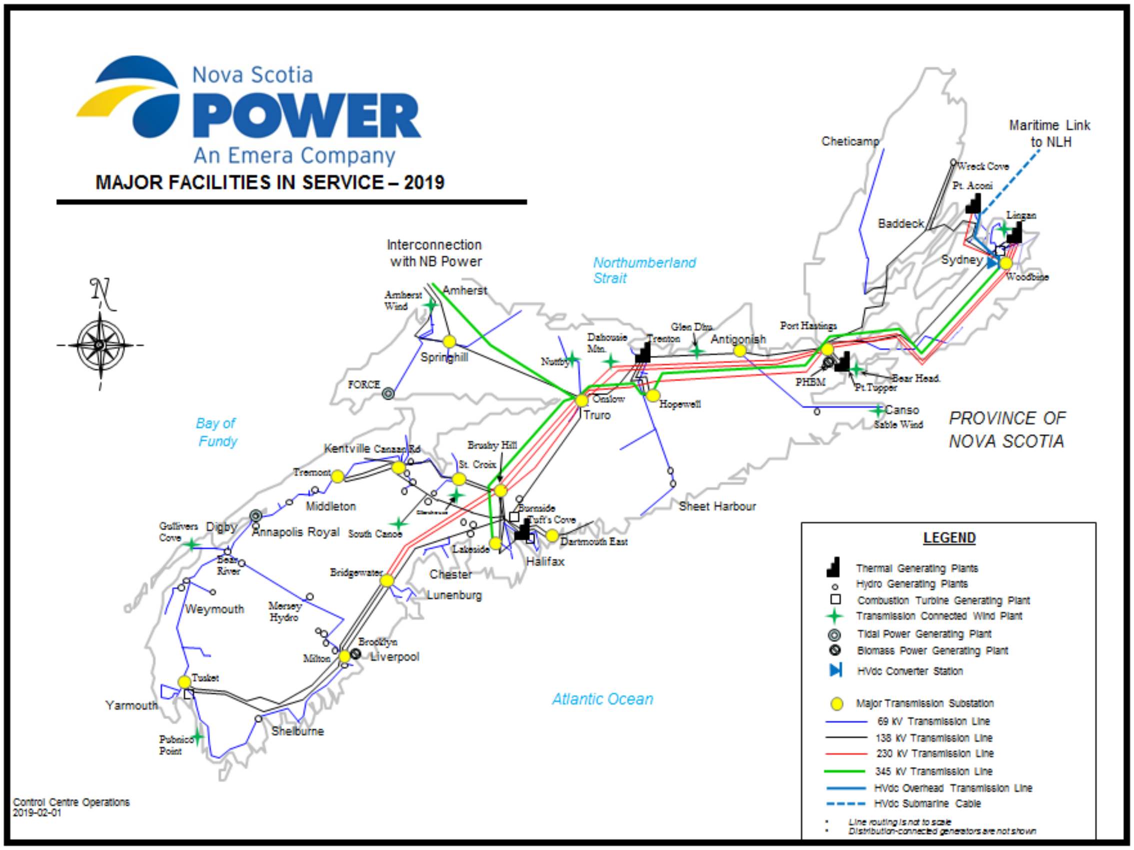


8.0 TRANSMISSION PLANNING

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 25.

Figure 25: NS Power Major Facilities in Service 2019



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

The 230 kV transmission system is approximately 1271 km in length and is comprised of 47 km of steel/laminated structures and 1224 km of wood pole lines.

The 138 kV transmission system is approximately 1871 km in length and is comprised of 303 km of steel structures and 1568 km of wood pole lines.

The 69 kV transmission system is approximately 1560 km in length and is comprised of 12 km of steel/concrete structures and 1548 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 up to 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 500MW, +/-200kV DC Maritime Link tie that was placed into service on January 15, 2018 in preparation for the receipt of capacity and energy from the Muskrat Falls Hydro project and the Labrador Island Link DC tie between Labrador and Newfoundland. The Maritime Link is owned and operated by NSP Maritime Link Inc., a wholly owned subsidiary of Emera Newfoundland & Labrador.

8.2 Transmission Design Criteria

NS Power, consistent with good utility practice, 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.

8.2.1 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).

8.2.2 Bulk Electric System (BES)

On July 1, 2014, the NERC Bulk Electricity System (BES) definition took effect in the United States. The 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 of 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 Order of the Board dated April 6, 2017.

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

8.2.3 Special Protection Systems (SPS)

NS Power also makes use of Special Protection Systems (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.

8.2.4 NPCC A-10 Standard Update

The NPCC Task Force on Coordination of Planning (TFCP) is in the process of revising Document A-10 and its application, in consultation with the Task Force on Coordination of Operation (TFCO), Task Force on System Protection (TFSP), and Task Force on System Studies (TFSS). Currently, Document A-10 provides a methodology to identify Bulk Power System (BPS) elements in the interconnected NPCC Region. At present, all NPCC criteria apply to BPS facilities; however, there are questions as to whether this application produces the appropriate level of reliability in NPCC.

The objectives of the review were as follows:

(1) Consider existing and alternative methodologies to:
- Identify critical facilities for the applicability of NPCC Directories;
- Simplify the existing methodology to make it less labor-intensive;
- Improve consistency across Areas in application and outcomes of the methodology.

(2) Consider conforming changes to NPCC documents to implement any necessary improvements as a result of the review.

NS Power has representation on the A-10 Working group that performed the review for TFCP. Throughout 2018, Webex meetings were typically held twice per week with in-person meetings including representatives from all NPCC areas occurring two days of every month. In 2018, the working group completed testing of the three methodologies submitted to TFCP in the interim report entitled CP-11, A-10 Review Phase 1 Final Report dated Nov 17, 2017:

1. Proposal #1: Revised A-10 Methodology

Maintain the framework of the existing A-10 performance-based test, improve the clarity and consistency of the testing procedure as well as direct the applicability of Directory #1 to where it is technically justified.

2. Proposal #2: Performance Based Methodology

Combine both bright-line filtering and performance-based analysis to develop a list of critical facilities that should be designed and operated according to NPCC's more stringent criteria. This methodology has two performance-based tests – one for Directory #1 and one for Directory #4 which clearly identify which elements are required to be classified as BPS due to their impact on system performance.

3. Proposal #3: Connectivity Based Methodology

Combine both bright-line determination and connectivity analysis to develop a list of facilities to be designed and operated according to NPCC's more stringent criteria. The objective of this methodology is to pursue a non-performance based method to identify critical facilities to which NPCC Directory #1 and Directory #4 may be applied.

The final report summarizing the Phase 2 findings and recommendations of the A-10 Working group entitled *Classification of Bulk Power System Elements, Document A-10 review Phase 2 – Final Report*, was submitted to TFCP on November 30, 2018.

In accordance with Task 1 of the Phase 2 Action Plan, Methodology 1 (Revised A-10) was recommended as the preferred methodology for classification of BPS buses. An improved element-by-element classification test was recommended by the Working Group that included a combination of automatic and study based exclusions of elements from Directory #1 applicability. Applicability of Directory 4, Bulk Power System Protection Criteria, will continue to be applied to all elements connected to BPS buses.

Following endorsement from both TFCP and RCC in December of 2018, the Working Group was directed to revise NPCC Document A-10 to reflect the aforementioned recommendations and to submit the revised A-10 for formal Member comment within NPCC's Open Process in 2019.

Changes to the existing A-10 methodology are not expected to have a material financial impact on NS Power as the revised methodology is not expected to greatly increase the number of BPS elements on NS Power's transmission system.

8.3 Transmission Life Extension

NS Power has in place a comprehensive maintenance program on 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 (for example, conductor, 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 (Bulk Power System) line on a three year cycle. Where a Lidar survey is requested for a non-BPS line, the survey will replace 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.

The aforementioned 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 the rating of each line is appropriate.

8.4 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 on the basis of a preliminary assessment of need. The projects will be subjected to further technical studies, internal approval at NS Power, and approval by the UARB. 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 UARB.

In 2008, the Maine and Atlantic Technical Planning Committee (MATPC) was established to review intra-area plans for regional resource integration and transmission reliability. The MATPC forms the core resource for coordinating input to studies conducted by each member organization and presenting study results, such as evaluation of transmission congestion levels in regards to the total transfer capabilities on the utility interfaces. This information is used as part of assessments of potential upgrades or expansions of the interties. The MATPC has transmission planning representation from NS Power, Maritime Electric Company Ltd., Emera Newfoundland and Labrador, Northern Maine Independent System Administrator (which includes Emera Maine Northern Operating Region and Eastern Maine Electric Cooperative), Newfoundland and Labrador Hydro, and New Brunswick Power (NB Power). NS Power and NB Power jointly conduct annual Area Transmission Reviews for NPCC.

8.5 New Large load Customer Interconnection Requests

With the legalization of Cannabis in NS, NS Power has seen a large number of new load requests for commercial grow operations. Loads at each these facilities are expected to range between 2MW and 10MW depending on the size of the facility. Many of these facilities are expected to drive feeder and substation upgrades in excess of $250,000 that are not already captured in the Annual Capital Expense Plan.

8.6 Wind Integration Stability Study - PSC

In its October 5, 2018 letter regarding Integrated Resource Planning and Generation utilization ond Optimization (M08059), the Nova Scotia Utility and Review Board (NS-UARB) issued a directive for NS Power conduct a study to accomplish the following:

> "Establish requirements to allow increased levels of wind on the NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of

technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support".

NS Power has engaged Power Systems Consultants (PSC) to carry out a wind integration stability study to determine the system requirements needed to allow increased levels of wind generation in Nova Scotia beyond the current level of approximately 600MW. Final results from the study are expected in mid 2019 as part of the pre-IRP deliverables and this work will be considered through the upcoming IRP.

9.0 TRANSMISSION DEVELOPMENT 2019 TO 2029

9.1 Impact of Proposed Load Facilities

As noted in Section 8.5 of this report, there are a number of system upgrades that may be required to serve new cannabis facilities that are being proposed across Nova Scotia. There are currently seven developers for cannabis facilities that have initiated Load Impact Studies with NS power for new facilties with expected loads in excess of 1 MW. In the event that these projects proceed, they will immediately precipitate the following system upgrades not identied in previous ACE plans or 10 Year System Outlook reports:

1. Construct new 25/33/42 MVA, 138kV-25kV substation in Stellarton Area in 2019/2020
2. Replace Willow Lane 15/20/25//28MVA, 69kV-25kV transformer 15N-T3 in 2019/2020
3. Install a new 15/20MVA, 69kV-25kV transformer in Middleton supplied via L-5044 in 2020
4. Install a new 15/20/25MVA, 138kV-25kV transformer at 74N-Springhill in 2020
5. Install a second 25/33/42MVA , 138kV-25kV transformer at 1N-Onslow in 2020/2021

9.2 Transmission Development Plans

Transmission development plans are summarized below. As highlighted earlier, these projects are subject to change. For 2019, the majority of the projects listed are included in the 2019 Annual Capital Expenditure Plan. Further transmission investment may be identified through the IRP process.

2019

- 2C Port Hastings 138kV substation will be uprated to meet NPCC BPS standards (moved from 2018).

- New 12MVA Mount Hope 69kV-25kV substation in Dartmouth (moved from 2018)
- 5P 25MVA Mobile Substation Replacement
- 6S Terrace Street 69 kV substation will be retired once the existing 4 kV distribution load is converted to 12 kV.
- Replacement of 15/20/25MVA Penhorn 69-12.5kV Transformer 48H-T1
- 101W-Port Mersey Expansion to include a new 138kV-25kV, 15/20/25MVA transformer and two feeders (C0011261)
- 78W-Martins Brook substation relocation and transformer replacement (C0010956)
- 5V-Lumsden Dam geneator transformer replacement (C0011039)
- Capacitor Bank Breaker replacement at 103H-Lakeside (3 breakers). These are high duty cycle units critical to the operation of the transmission system.
- 2019 Transmission Right of Way Widening 69kV to reduce the occurrence of edge and off right of way tree contacts (Year 4 of 8)
- L-5014, L-5017, L-5026, L-5027, L-5039, L-5053, L-5505, L-5511, L-5541, L-5548, L-5564, L-6549, L-7002, L-7004, L-7005 & L-8001 structure replacements and upgrades
- Replacement of 9W-B53 support structure
- Replacement of 73W-T1 transformer at Auburndale with a new 138/69-25 kV transformer rated at 15/20/25 MVA.
- Upgrades/replacements to tap changers, insulator replacements, etc.

2020

- Replacement of 7.5/10//11.2 MVA Halliburton 69-25kV Transformer 56N-T1 with new 15/20/25MVA unit due to load growth and voltage conversions from 4kV to 25kV. CI:52328
- Transmission Right of Way Widening 69kV to reduce the occurrence of edge and off right of way tree contacts (Year 5 of 8)

- Replace existing 12.5/14MVA Milton transformer with 15/20/25MVA unit supplied at either 69kV or 138kV.
- Replace existing 5/5.6MVA Central Argyle 7.5/10/12.5MVA unit.
- Replace existing 4.5/10/12.5//14MVA Barrington Passage transformer with 15/20/25MVA unit and add additional feeder circuit.
- Replace existing 3/4//4.48MVA Lower East Pubnico transformer with 7.5/10/12.5MVA unit.

2021

- 2021 Transmission Right of Way Widening 69kV to reduce the occurrence of edge and off right of way tree contacts (Year 6 of 8).

2022

- 2022 Transmission Right of Way Widening 69kV to reduce the occurrence of edge and off right of way tree contacts (Year 7 of 8)
- Install New 138kV Supply to 50V-Klondike and replace existing 69-25kV transformer with new 15/20/25 MVA unit.

2023

- 2023 Transmission Right of Way Widening 69kV to reduce the occurrence of edge and off right of way tree contacts (Year 8 of 8).

2026

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

2028

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

9.3 Bulk Electricity System

The following compliance gaps were identified concerning the implementation of the BES definition in Nova Scotia Power:

1. The 85S Wreck Cove substation is not classified as BES but the generator transformers and the generators are classified as BES. A sequence of events recorder exists at the 85S Wreck Cove substation to record breaker positions, protection operations and teleprotection status. The monitoring of the generators and generator transformers that reside in the plant are the responsibility of generation services as protective relaying and other monitoring equipment also resides there.

Update: An assessment has concluded that there is no reliability standards requirement to have disturbance monitoring equipment for the Wreck Cove generators; however, upcoming protection system upgrades will supply sequence-of-events and fault recording capabilities for the two units.

2. The 14H – Burnside and 83S – Victoria Junction generators have been classified as BES elements. An assessment is required by generation services for sequence of events and fault recorder capabilities.

Update: An assessment has concluded that the generators at Victoria Junction and Burnside do not require sequence-of-events and fault recording capabilities. They are not connected to BES buses and the Transmission Owner has not been identified them as BES buses requiring sequence-of-events and fault recording capabilities.

3. At 1N Onslow and 103H Lakeside there are deficiencies in the monitoring capabilities for the shunt devices and modifications are required to bring these substations into compliance.

Update: The reference to 1N Onslow identified in the 2018 10 Year System Outlook Report is incorrect. The correct site is 79N Hopewell.

An assessment of the reliability standards requirements has concluded that sequence-of-events and fault recording capabilities are only required on three BES buses, a requirement which is already met by NS Power. No additional sequence-of-events and fault recording capabilities are required at 79N Hopewell and 103H Lakeside as a result of the implementation of the BES definition in NS Power.

9.4 Western Valley Transmission System – Phase II Study

A study was initiated in late 2017 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)

The scope of the study is to assess four options for dealing with the clearance, age, and capacity issues on Lines L-5531 (13V-Gulch to 15V-Sissiboo), L-5532 (13V-Gulch to

3W-Big Falls), L-5535 (15V-Sissiboo to 9W-Tusket), and L-5541 (3W-Big Falls to 50W-Milton):

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 69kV)

Status: Work on the Western Valley Transmission System – Phase II Study was deferred in 2018 and the study is now expected to be completed in 2019.

10.0 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 in Canada and Nova Scotia continues to drive a transformation of the NS Power electric power system. Within the 10-year window considered in this Report, NS Power will experience further reductions in hard caps for CO_2, SO_2, NO_X and mercury, and will be required to serve 40 percent of sales with renewable electricity from qualifying sources.

The Company is currently forecasting a slight deficit in firm generation capacity. The Company expects to be able to manage through this upcoming winter period, and can also find near-term solutions for access to firm capacity if required. NS Power will continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve and will adjust decisions accordingly.

Starting in 2019 and continuing into 2020, NS Power will be participating in an Integrated Resource Planning exercise as directed by the UARB with input from a variety of stakeholders across the province. The Company is on track to complete its pre-IRP deliverables by July 31, 2019.

As descried in Section 7.3 above, the Capacity Study will calculate the ELCC of wind and other renewable energy resources. In addition, a Supply Options Study will provide estimates of the initial and sustaining costs and performance of new bulk grid supply options. Transmission requirements and system design considerations to accommodate increased levels of renewable energy on NS Power’s grid is being evaluated through a Renewables Stability Study and Demand Response (DR) assumptions are being developed to study specific DR programs.

The outcome of this IRP process will impact and inform all future Ten-year System Outlook Reports and related long term planning processes. The Company expects the IRP will provide also address any capacity deficit if required following the update of the planning reserve margin percentage.

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