CONFIDENTIAL Memorandum

TO: M08059 GENERATION UTILIZATION AND OPTIMIZATION STAKEHOLDERS

FROM: BOB FAGAN, RACHEL WILSON, DAVID WHITE – SYNAPSE ENERGY ECONOMICS

DATE: OCTOBER 16, 2017

RE: KEY INPUT ASSUMPTIONS AND MODELING PLAN FOR PLEXOS OPTIMIZATION ANALYSIS – DRAFT FOR COMMENT

This memo describes a modeling plan and the set of key input assumptions for use in the Generation Utilization and Optimization study. Synapse welcomes all stakeholder comments on the approach and the specific parameter values under consideration, especially those associated with the costs for future energy storage, wind and solar resources; and on the reasonableness of the alternative load scenarios, which incorporate different levels of incremental energy efficiency and demand response (combined, the "DSM" level of the scenario).

We note that the Generation Utilization and Optimization analysis is not intended to produce an integrated resource plan, although the approach contains IRP-like modeling. Primarily, we are attempting to gauge the overall longer-term costs of retention of NSPI's thermal fleet, and compare those costs to maintaining resource adequacy using different mixes of resources. Our aim is to provide a modeling analysis that shows the costs of retention versus the costs of alternative resource plans that use a different mix of resources to meet capacity needs.

The analysis proceeds in an electric sector world where wind, solar, and battery resource costs are declining, energy efficiency continues to be installed in Nova Scotia, and heat pumps begin to replace electric heating and some oil heat. Simultaneously, the average per-unit cost of energy from NS coal resources is increasing relative to historical trends, because of lower overall energy utilization (i.e., capacity factor) of the fleet and aging and operational-related costs. Sustaining capital costs are uncertain. One key question is whether the coal resources continue to remain an economically viable means to meet capacity needs when they produce less energy. The analysis also occurs during a time when electric and gas infrastructure that supports Nova Scotia is changing: the addition of the Maritime Link next year leads to the availability of energy and capacity from the Link in 2020; and ongoing uncertainty about the cost/price and availability of gas from both the Maritimes and Northeast pipeline and Eastern Canadian production sources renders the cost of gas capacity alternatives uncertain. The modeling also proceeds with year-over-year decreases in allowed carbon emissions, throughout the entire period (2018-2042).

Modeling Plan

The table below lists the initial set of scenarios that we will run using the PLEXOS LT (long-term) module. It includes 30 scenarios with varying combinations of core input assumptions, and it includes "bookend" runs that seek to illustrate system costs under two different prescriptive thermal retirement scenarios; these bookends are included for comparison purposes. Potential additional runs under sensitivity cases will be accommodated if/as time allows; and it is possible that resource constraints may not allow us to execute all of these scenarios.

We first define a reference plan using mostly NSPI assumptions, although as we describe below some input assumptions will vary from NSPI's initial estimates. We then define an additional 29 scenarios to gauge how the PLEXOS capacity expansion plan changes under different core input combinations. Each of these 30 model runs will produce an "optimal" capacity expansion plan from the PLEXOS LT module.

Subsequent to the LT module runs, we will employ the ST module in full production cost mode and conduct model runs for a subset of the scenarios –the lower cost scenarios - to more finely assess production costs and test resource adequacy in a more temporally granular environment. We will plan to run in this mode for five different years of the study period (2020, 2025, 2030, 2035, 2040), and interpolate between these years to create a stream of production costs for the full 25-year period.

Table 1. Initial Scenarios to Test in PLEXOS LT Module

			Key Input Parameters Specification				
Scenario #	**Notation**	**Scenario Name**	**Load**	**Sust Capital**	**Wind CapCredit**	**NB Trans**	**HardCode RetirePath**
1	NSPI Reference	Ref	Ref	Ref	Ref	No	No
2	Change Case	Med DSM	Med DSM	Ref	Ref	No	No
3	Change Case	High DSM	High DSM	Ref	Ref	No	No
4	Change Case	Ref/HighSusCap	Ref	High	Ref	No	No
5	Change Case	Med DSM/HighSusCap	Med DSM	High	Ref	No	No
6	Change Case	High DSM/HighSusCap	High DSM	High	Ref	No	No
7	Change Case	Ref/HighWindCapCredit	Ref	Ref	High	No	No
8	Change Case	Med DSM/HighWindCapCredit	Med DSM	Ref	High	No	No
9	Change Case	High DSM/HighWindCapCredit	High DSM	Ref	High	No	No
10	Change Case	Ref/HighSusCap/HighWindCapCredit	Ref	High	High	No	No
11	Change Case	Med DSM/HighSusCap/HighWindCapCredit	Med DSM	High	High	No	No
12	Change Case	High DSM/HighSusCap/HighWindCapCredit	High DSM	High	High	No	No
13	Change Case	Ref/NB Trans	Ref	Ref	Ref	Yes	No
14	Change Case	Med DSM/NB Trans	Med DSM	Ref	Ref	Yes	No
15	Change Case	High DSM/NB Trans	High DSM	Ref	Ref	Yes	No
16	Change Case	Ref/NB Trans/HighWindCapCredit	Ref	Ref	High	Yes	No
17	Change Case	Med DSM/NB Trans/HighWindCapCredit	Med DSM	Ref	High	Yes	No
18	Change Case	High DSM/NB Trans/HighWindCapCredit	High DSM	Ref	High	Yes	No
19	Change Case	Ref/HighSusCap/NB Trans	Ref	High	Ref	Yes	No
20	Change Case	Med DSM/HighSusCap/NB Trans	Med DSM	High	Ref	Yes	No
21	Change Case	High DSM/HighSusCap/NB Trans	High DSM	High	Ref	Yes	No
22	Change Case	Ref/NB Trans/HighWindCapCredit/HighSustCap	Ref	High	High	Yes	No
23	Change Case	Med DSM/NB Trans/HighWindCapCredit/HighSustCap	Med DSM	High	High	Yes	No
24	Change Case	High DSM/NB Trans/HighWindCapCredit/HighSustCap	High DSM	High	High	Yes	No
Bookends - with Retirement							
25	Change Case	Ref/RetirePath1	Ref	Ref	Ref	Yes	Yes
26	Change Case	Med DSM/RetirePath1	Med DSM	Ref	Ref	Yes	Yes
27	Change Case	High DSM/RetirePath1	High DSM	Ref	Ref	Yes	Yes
28	Change Case	Ref/RetirePath2	Ref	Ref	Ref	Yes	Yes
29	Change Case	Med DSM/RetirePath2	Med DSM	Ref	Ref	Yes	Yes
30	Change Case	High DSM/RetirePath2	High DSM	Ref	Ref	Yes	Yes

Table 2. Primary Modeling Parameters for Scenarios and Possible Sensitivity Cases

Core Scenario Variables	Reference Values	Alternative Values for Scenarios	Possible Sensitivity Cases
Load Forecast - Bounding Cases	1-2017 NSPI Fcst, 2-Med DSM, 3-High DSM	Three different peak/energy scenarios	Higher load case to reflect increased electrification and EVs beyond what is already in reference plan
Sustaining Capital Costs	NSPI 2017 10-Yr System Plan – Extrapolated to years after 2027	NSPI 2017 Plus 50%	+25%, +100%
Wind Capacity Contribution	2017 NSPI 0% ERIS, 17% NRIS	20% All Wind	25% All Wind (GE Study)
NB Transmission	NSPI 2017 $400 Million + New Eng. Capac. Market Costs	Either With or Without NB incremental transmission	Smaller intertie connection, different NS costs
Retire Path 1 Bookend	Synapse: 5 Coal + TC1 by 2026	Only for Scen. 25-27	High Wind Cap Credit, NB Transmission
Retire Path 2 Bookend	Synapse: All Coal + TC1 by 2030	Only for Scen. 28-30	High Wind Cap Credit, NB Transmission

Description/Explanation of Load Forecast Scenarios and Modeling Parameters

The modeling plan includes scenarios with three different "net" load levels. Peak shaving and increased energy efficiency resources in Nova Scotia are critical resources that cannot be as well-represented in PLEXOS as the supply-side alternatives. To minimize the complexity of using PLEXOS and to capture the demand-side potential, we are proceeding with a scenario approach that focuses first on the level of NSPI system load (annual energy and firm peak) that needs to be met by the supply and import resources.

The load forecast table (Table 3 below) outlines the three scenarios used – NSPI reference load, mid DSM, and high DSM. The choice of mid DSM and high DSM is predicated on feasible increments to both energy efficiency implementation in Nova Scotia, and measures to reduce system firm peak, such as direct load control, demand response in addition to currently-available interruptible load, time-of-use rate structures, and enabling technologies that could be used with any AMI installations that may occur over time.

The "med DSM" scenario incorporates solely incremental energy efficiency, tied to increases that target savings at a 2.0%/year (retail sales) level. This level is less than the achieved EE levels seen in the highest tier of US utilities implementing EE. The "high DSM" scenario incorporates this same 2.0%/year EE level, plus an additional peak shaving from a portfolio of demand response measures that could be implemented through conventional and more innovative approaches, such as but not limited to AMI. The table also shows the incremental DSM contributions for peak load reduction (from EE) for the reference, medium and high DSM cases. The 2014 IRP parameters for base case DSM increments, and the base case annual energy, are shown for comparison.

The costs of these load scenarios will be accounted for outside of PLEXOS and will be based on a to-be-determined utility cost per MWh saved (energy) and utility cost per kW of firm peak reduction. We have not estimated these costs at this point in the project, but will do so, with stakeholder feedback, over the course of the modeling. The PLEXOS modeling can proceed without having a firm estimate for these costs; the envelope of quantity reductions is the key input assumption.

As noted, the mid DSM scenario includes ramping up the current energy efficiency programs to achieve a 2.0%/year savings (energy); this includes peak savings that are roughly double the adjusted net peak savings seen in the reference case.

The "high DSM" case incorporates the same level of increased energy efficiency and associated peak reduction as the medium DSM case, but in addition assumes specific increases in peak shaving (demand response). The profile of increased peak savings from demand response is estimated to lead to achieved reductions equal to 5% of net peak load within 10 years, to allow for installation of enabling technologies, and time for customer adaption of such technologies.

We welcome input especially on the trajectory of peak load and energy load reductions that can be achieved through energy efficiency and demand response programs.

These two DSM cases are meant to demonstrate comparative capacity expansion paths under two increasingly more aggressive demand-side approaches to meeting Nova Scotia's load requirements.

Sustaining capital costs use NSPI's current estimates, with extrapolations through to 2042 based on the same pattern of expenditures seen in NSPI's 10 year System Outlook report. To assess the sensitivity of the analysis to higher costs, we define alternative scenarios that assume these costs will be 50% higher. Sensitivities around these values can be considered to test how critical a factor these costs are to overall economics of retention of the thermal units.

Wind capacity contribution effects will be tested by using NSPI's current values for the reference case (which use 0% capacity contribution for ERIS resources, and 17% for NRIS resources), and using 20% of the installed capacity of all wind as a capacity contribution for alternative scenarios. These values could also be tested as a sensitivity; for example, the recent 2016 GE Pan-Canadian wind reports suggests higher values could be considered.

Scenarios assuming a second 345 kV tie to New Brunswick will be run with different combinations of the other core scenario inputs.

Lastly, to provide an envelope around, or bookend to, the analysis, we will determine capacity expansion paths and alternative costs for aggressive retirement scenarios for the coal fleet and the Tufts Cove 1 plant, as seen in the table below.

	Calendar Year Beginning	
Unit	**Retire Path 1**	**Retire Path 2**
Lingan 2	2020	2020
Lingan 1	2021	2021
Tufts Cove 1	2022	2022
Lingan 3	2023	2023
Lingan 4	2024	2024
Trenton 5	2025	2025
Trenton 6		2026
Point Tupper		2028
Point Aconi		2030

The other key variables incorporated into the PLEXOS modeling system are alternative resource costs, fuel and O&M costs, and import costs. Table 4 (following, below) summarizes the input assumptions, presents options for possible sensitivities, and includes comments.

Table 3. Load Forecast Scenarios

	All Cases		Reference Case MW			Medium DSM Case MW			High DSM Case MW			Compare	Annual GWh Energy		Compare
Year	Firm Peak No DSM	Inter-ruptible Loads	Annual Increm. Peak DSM	Peak DSM Cum Total	Firm Peak With DSM	Peak DSM Cum Total	Annual Increm. Peak DSM	Firm Peak with DSM	Add'l Demand Response Peak	Peak DSM+DR Cum Total	Firm Peak with DSM+DR	2014 IRP - Base Case Annual Increm. DSM Peak Save	Reference	Medium and High DSM (Same)	2014 IRP - Base Case Annual Energy
2018	2,014	156		21	1,993	38		1,976	0	38	1,976	26	10,987	10,955	11,022
2019	2,043	156	12	33	2,010	63	25	1,980	10	73	1,970	25	10,952	10,864	11,024
2020	2,077	155	15	48	2,029	91	28	1,986	20	111	1,966	23	10,976	10,805	9,966
2021	2,099	155	13	61	2,038	121	30	1,978	30	151	1,948	22	10,947	10,690	9,922
2022	2,128	155	14	75	2,053	150	29	1,978	40	189	1,939	23	10,958	10,615	9,922
2023	2,161	154	13	88	2,073	179	30	1,982	50	229	1,932	22	10,983	10,554	9,931
2024	2,181	154	13	101	2,080	209	30	1,972	59	268	1,913	23	11,010	10,497	9,961
2025	2,199	154	14	115	2,084	237	29	1,962	69	306	1,893	20	10,980	10,388	9,933
2026	2,212	153	14	129	2,083	266	28	1,946	78	344	1,868	23	10,958	10,293	9,929
2027	2,230	153	15	144	2,086	293	27	1,937	87	380	1,850	29	10,967	10,240	9,889
2028	2,255	153	15	159	2,096	322	30	1,933	97	419	1,836	28	10,965	10,164	9,884
2029	2,280	153	15	174	2,107	352	30	1,928	96	448	1,832	32	10,963	10,088	9,802
2030	2,306	153	15	189	2,117	382	30	1,924	96	478	1,827	33	10,960	10,012	9,744
2031	2,331	153	15	204	2,127	412	30	1,919	96	508	1,823	33	10,958	9,937	9,690
2032	2,357	153	16	220	2,138	443	31	1,914	96	539	1,819	32	10,956	9,863	9,640
2033	2,383	153	16	235	2,148	474	31	1,910	95	569	1,814	31	10,954	9,789	9,595
2034	2,410	153	16	251	2,159	505	31	1,905	95	600	1,810	30	10,951	9,716	9,555
2035	2,437	153	16	268	2,169	536	31	1,901	95	631	1,806	29	10,949	9,644	9,523
2036	2,464	153	16	284	2,180	568	32	1,896	95	662	1,802	27	10,947	9,572	9,497
2037	2,491	153	17	301	2,190	599	32	1,892	95	694	1,797	24	10,945	9,500	9,484
2038	2,519	153	17	318	2,201	632	32	1,887	94	726	1,793	26	10,943	9,429	9,469
2039	2,547	153	17	335	2,212	664	32	1,883	94	758	1,789	24	10,940	9,359	9,463
2040	2,575	153	17	352	2,223	697	33	1,878	94	791	1,785		10,938	9,289	
2041	2,604	153	18	370	2,234	730	33	1,874	94	824	1,780		10,936	9,219	
2042	2,633	153	18	388	2,245	763	34	1,870	93	857	1,776		10,934	9,150	
CAGR '18-'27	**1.1%**				**0.5%**			**-0.2%**			**-0.7%**		**0.0%**	**-0.7%**	
CAGR '18-'42	**1.1%**				**0.5%**			**-0.2%**			**-0.4%**		**0.0%**	**-0.7%**	

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Table 4. Other Variable Values, Performance, Escalation, Comments, and Sensitivity Options

Other Variables	Source – Costs	2017 Value ($CA)	Perform -ance	Real Cost Escalation Rate	Comments	Possible Sensitivity Cases
Battery Costs – average LCOS, peaker replacement (4-hour duration)	Lazard 2.0	$541/kWh	92% RT eff.	-9%/year	Ave. value peaker replacement $433/kWh $US. Ave. escalation rate for power/energy sources.	Low: Lazard 2.0 low end, or lower duration (2 hrs. vs. 4 hrs.)
Gas Price Delv'd. M&N	NSPI 2017	[redacted]		Long-term flat.		Low: EIA AEO 2017 Low Gas
Wind Costs – installed	NSPI 2017	$2,000/kW	40% CF, Utility Scale	-2.0%/year	LBL, Lazard similar costs. Estimated cost trend. Estimated performance best available sites. Recent cost declines > than 2%/yr.	Lower/higher installed costs, performance
NB Transmission	NSPI 2017	$400 million			345 kV back to Coleson Cove.	
Imports via NB: NE Market Capacity Costs + Transmission	Synapse: Recent FCM + NSPI for NB Transm. Costs	FCM=$6.61/kW -month		0%/year	NE FCM 2020 clearing price $5.30/kW-mo. $US	Lower transmission costs – partial build or different cost allocation
Imports via ML: NE Market Capacity Costs	Synapse: Recent FCM	FCM=$6.61/kW -month		0%/year	NE FCM 2020 clearing price $5.30/kW-mo. $US	Negotiated pricing - NFL
Solar PV Costs	LBL 2016 Utility Scale Solar Report, Lazard 10.0	$2.75/watt (AC) median	18.3% CF (AC)	-2.5%/year	$US 2.2/watt (AC) Lazard, LBL similar values. 0.15/watt adder single axis tracking	Higher/lower costs
Coal Prices	NSPI 2017	Varies by unit. See Figure 2.				
Oil Prices	NSPI 2017	[redacted]			Heavy Fuel Oil	
Carbon / CO2 emissions	NSPI 2017	See NSPI 2017 10-Yr. System Outlook p. 34			Declining cap per regulations through 2030, and continuing @ ~2.5%/yr thereafter.	2030-2042 Steeper Cap Decline (5%/year)
SO2, NOx, Hg	NSPI 2017	See NSPI 2017 10-Yr. System Outlook p. 35-36.			Declining cap per regs. thru 2030. NOx constant after. SO2, Hg step declines - 2035.	
Gas-Fired CT, CC Costs	NSPI 2017	See Table 5.		0%/year	250 MW CC, 100 MW CT, 93 MW RICE	
Fixed and Variable O&M Costs	NSPI 2017	Varies		0%/year	Sustaining capital costs pick up related cost increases	
Wreck Cove Pumped Stor.	NSPI 2017	[redacted]		0%/year	Based on Confidential Landsvirkjun Power/Verkís Report, Dec. 2012. Table 1, page 16, escalated to 2017.	

Figure 1. Average Annual Natural Gas Prices – Nominal and Real. Winter and Summer Nominal Natural Gas Prices.

Redacted

Real price estimated using 2% inflation. Source: NSPI Plexos inputs.

Figure 2. Coal Prices

Redacted

Source: NSPI Plexos inputs.

Figure 3. Heavy Oil Prices

Redacted

Source: NSPI Plexos inputs.

Table 5. New Fossil Fuel Generation Costs

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2017 $/kW) Low	Base	High	Fixed O&M ($/kw-yr)	Variable O&M ($/MWh)	Lead Time (years)
Combustion Turbine	100	8,700	$1,180	$1,315	$1,500	$12.00	$6.00	2-4
Combustion Turbine	49	9,600	$1,180	$1,315	$1,500	$12.00	$6.00	2-4
Conventional CC (1 x 1)	253	7,200	$1,425	$1,580	$2,000	$16.00	$3.50	3-5

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2017 $/kW) Low	Base	High	Fixed O&M ($/kw-yr)	Variable O&M ($/MWh)	Lead Time (years)
Phased-in Conversion CC (Add HRSG)	150	8,000	$1,620	$1,800	$2,075	$16.00	$3.75	4-7
Conventional CC (1 x 1)	145	7,200	$1,460	$1,620	$1,860	$16.00	$3.50	3-5
Reciprocating Engine (10 x 9.3 MW)	93	8,520	$1,400	$1,560	$1,800	$12.00	$10.50	2-3

Source: NSPI

Time Frame

- 25 Years (2018-2042) for capacity expansion runs.

- At least five individual years for ST production cost (8760 hour) runs (2020, 2025, 2030, 2035, and 2040).

Specific Capacity Resource Options to be Considered in Capacity Expansion/Retirement Analysis

The following resource options will be made available to PLEXOS in capacity expansion optimization mode. Cost parameters are listed in Table 4.

1. Existing thermal fleet (less Lingan 2, retired in 2020): Lingan 1, 3 and 4, Pt. Tupper, Trenton 5 and 6, Point Aconi, Tufts Cove 1, 2 and 3, and Tufts Cove 4, 5 and 6. Sustaining capital costs will be incorporated into the O&M cost representation in PLEXOS to allow for these costs to be directly considered in the optimization.

2. Onshore wind 100 MW increments. Annual capacity factor = 40%.

3. Solar PV – Utility Scale w/ single-axis tracking – 5 MW increments. Annual capacity factor = 18.3% (AC).

4. Bulk System Li-ion Battery Storage 20 MW increment, 2-hour duration costing.

5. Bulk System Li-ion Battery Storage 20 MW increment, 4-hour duration costing.

6. Pumped Storage – Wreck Cove expansion scenario, 6-hour duration costing.

7. Combined cycle unit (gas/oil) 250 MW.

8. Combustion turbine unit (gas/oil) 100 MW.

9. Reciprocating Engine (gas/oil) 93 MW (9.3 MW x 10 units).

10. Import capacity 10 MW increments – via Newfoundland – beyond NS Block commitment – up to 150 MW.

11. Import capacity 10 MW increments – via New Brunswick if new transmission – up to 300 MW.

Baseline Resource Mix

All scenarios will assume the following resources remain:

- CTs (Burnside 1-4, Vict
  oria Junction, Tusket) – 231 MW total (includes Burnside 4).

- All current hydro/tidal (377.1 MW) plus 30 MW increment at Mersey. Assume 10 MW increment at Wreck Cove (Source: NSPI).

- All current NSPI renewables (wind, biomass) remain in place at existing MW levels.

- All current IPP facilities remain in place at existing MW levels (wind, small hydro, biomass, tidal, including FIT).
- ML Block, Supplemental, quantities commencing in 2020.
- ML Surplus energy (NSPI pricing - MA hub pricing).
- NB import/export paths, existing capability (NSPI pricing based on MA hub).

Other Constraints

Plexos modeling constraints will include the following:

- Allow up to 600 MW of additional wind in NS only with NB transmission option, no earlier than 2022 for new transmission.
- Allow up to 100 MW of additional wind in NS after Maritime Link in place, to test wind addition economics in the absence of new NB transmission.
- 20% planning reserve margin over firm peak.
- Various transmission path flow constraints.
- Various unit commitment constraints (e.g., minimum number of thermal units online).
- Operating reserve/ancillary service constraints – e.g., ramping, spinning, regulation.

Sustaining Capital Costs

Sustaining capital costs for the reference case will be as reflected in NSPI's 2017 10 Year System Outlook. The alternative case scenario will assume sustaining capital costs are 50% higher than those costs. Synapse will extrapolate these annual costs for all remaining years of the study period beyond the values available from NSPI in the 2017 outlook report.

Key Sources

1. NSPI, 2017 10-Year System Outlook, 2017 Load Forecast, responses to discovery questions (M08059).
2. Lazard's Levelized Cost of Energy Analysis, Version 10.0, December 2016. https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf
3. Lazard's Levelized Cost of Storage Analysis, Version 2.0, December 2016. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf
4. EIA AEO 2017 Natural Gas Price Projections for Electric Power Sector, New England Region, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-1&cases=ref2017&start=2015&end=2050&f=A&linechart=~ref2017-d120816a.38-3-AEO2017.1-0&map=ref2017-d120816a.4-3-AEO2017.1-0&ctype=linechart&sourcekey=0

5. LBL Wind Technologies Report 2016. https://energy.gov/sites/prod/files/2017/08/f35/2016_Wind_Technologies_Market_Report_0.pdf
6. Lawrence Berkeley Laboratories, Utility Scale Solar 2016. https://emp.lbl.gov/sites/default/files/utility-scale-solar-2016-report.pdf
7. NREL PV Watts for estimate of annual capacity factor from single-axis tracking solar PV. Shearwater, NS location. http://pvwatts.nrel.gov/
8. Pan Canadian Wind Integration Study, Revision 3 (October 2016). http://canwea.ca/wp-content/uploads/2016/07/pcwis-fullreport.pdf

Appendix 5.6 Additions – as Used in Plexos Modeling

NSPI Updated Gas Price Forecast (11/3/2017)

Redacted

NSPI Updated Coal Price Forecast (11/3/2017)

Redacted