Request IR-1:

In Section 3 beginning on page 14, NSPI discusses affordability. That discussion does not appear to include any reference to customer bills. If NSPI is of the view that customer bills are not a component of affordability, please explain why not. If NSPI is of the view that customer bills are a component of affordability, please explain why Section 3 does not address it.

Response IR-1:

Customer bills are a component of affordability. While significant participants in the DSM programs will see bill savings from DSM, non-participants will see bill increases in the program period.

For additional discussion on the merits of rate and bill impact analyses compared to partial revenue requirement, as relates to affordability, please refer to Synapse IR-21.

Request IR-2:

At page 15, Lines 18-25, NSPI discusses the $37 million it is committing over ten years, in partnership with Clean Nova Scotia, to assist 6600 low income homeowners, and in its conclusions on page 50, NSPI notes that this initiative, in combination with other DSM spending of approximately $22 million per year, would produce appropriate energy savings of 100 Gwh per year. In light of the role the partnership with Clean Nova Scotia may have in the provision of the 100 Gwh, please provide a copy of any contract between NSPI and Clean Nova Scotia with respect to this initiative. If a contract is currently not in place, please describe the status of negotiations and the expected date for contract completion.

Response IR-2:

Please refer to Confidential Attachment 1.

Multeese IR-2 Attachment 1 has been removed due to confidentiality.

Request IR-3:

At page 15, Lines 18-25, NSPI discusses the $37 million it is committing over ten years, in partnership with Clean Nova Scotia, to assist 6600 low income homeowners. With respect to this initiative, please provide a detailed description of NSPI's role in:

(a) Program design, delivery, evaluation and verification.

(b) Expenditure management, including a description of the parameters in place to facilitate that management (e.g. any mechanisms in place to control annual spending, any flexibility for annual over spending to be borrowed from future years or under spending to carry forward to future years, any performance penalties or incentives, etc.)

Response IR-3:

(a-b) Please refer to Multeese IR-2 Confidential Attachment 1.

Request IR-4:

At page 15, Lines 18-25 NSPI discusses the $37 million it is committing over ten years to assist 6600 low income homeowners. Please provide for each of 2016, 2017 and 2018,

(a) the number of customers to be provided with DSM service

(b) the amounts proposed to be spent

(c) the annual and cumulative energy savings expected

(d) the annual and cumulative demand savings expected

(e) the expected change in NSPI's revenue requirement, complete with its derivation and assumptions

(f) the expected effect on rates, complete with its derivation and assumptions

(g) the expected bill reduction for participating customers, complete with its derivation and assumptions

Response IR-4:

(a-d) Clean Foundation's low income program is in its first year of operation. In each year of 2015-2018, 660 customers are expected to be served. Please refer to Multeese IR-2 Confidential Attachment 1.

(e-f) The assistance of $37 million to low income customers is a donation. This expenditure will not be reflected in revenue requirement. The Company expects the overall impact on

revenue requirement to be minimal. Energy savings from the program are expected to produce a fuel savings partially off-set by a lost contribution to fixed costs.

(g) The anticipated energy savings per customer are expected to be approximately [redacted]. [redacted].

[redacted].

[redacted].

Request IR-5:

With respect to Figure 3.1 on page 17, has NSPI investigated how factors such as government policy, generation mix and costs, environmental restrictions or renewable energy requirements influence the variances that are shown across Canada? If so, please provide that analysis. If not, why not?

Response IR-5:

The Company's conclusion did not require that it perform this analysis. Figure 3.1 was prepared based on publicly available information and was intended to provide context to the overall cost of the DSM expenditure proposed by E1 relative to other DSM portfolios in Canada. It shows that DSM spending in Nova Scotia on a per capita and per customer is among the highest in Canada.

Request IR-6:

With respect to Figure 3.4 on page 23 showing a breakeven point of seven years, please provide the assumptions and analysis which support it.

Response IR-6:

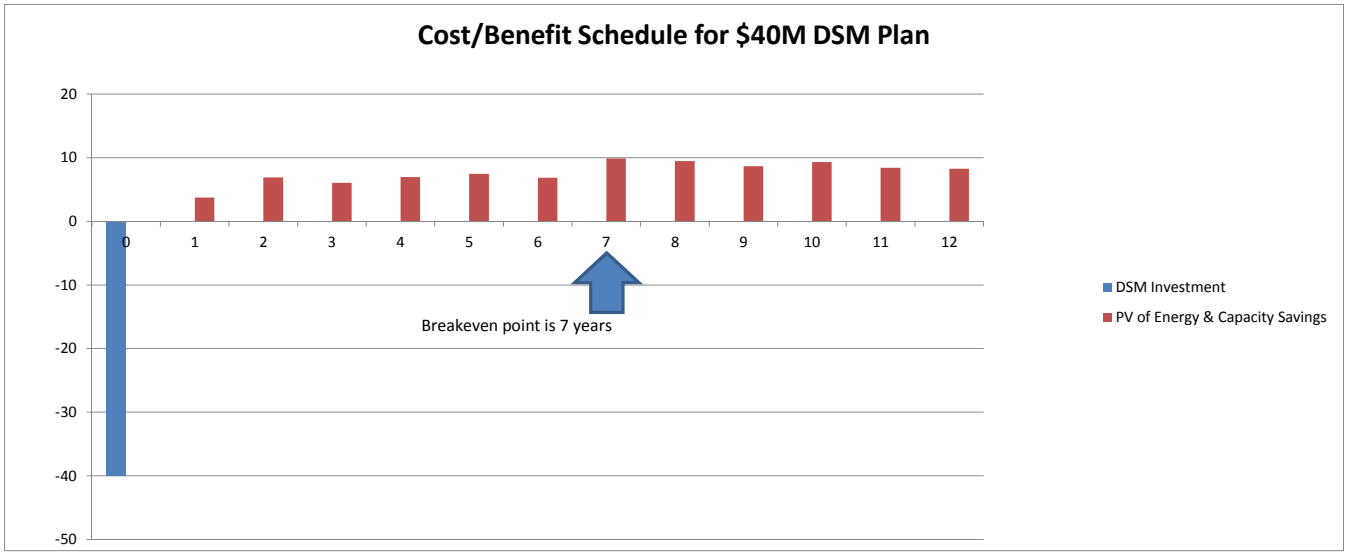
NS Power discovered a discrepancy in Figure 3.4 of its Evidence. A revised Figure 3.4 and supporting documents are attached as Attachment 1.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Illustrative Model of One-time DSM investment

DSM Investment	-40	$M
Savings	135	Gwh
After tax WACC discount rate	6.8%	

Year		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
DSM Investment made at end of 2015		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Energy-related Savings (Avoided energy costs)	$nominal/MWh	$ 63.63	$ 59.67	$ 58.38	$ 54.92	$ 57.14	$ 59.62	$ 62.11	$ 83.76	$ 84.51	$ 85.78	$ 86.76	$ 88.76	$ 92.66
PV of energy-related savings	$2015/MWh	$ -	$ 55.86	$ 51.17	$ 45.07	$ 43.90	$ 42.89	$ 41.83	$ 52.82	$ 49.89	$ 47.41	$ 44.89	$ 43.00	$ 42.03
PV of Energy-related Savings	2015 $M	$ -	3.8	6.9	6.1	5.9	5.8	5.6	7.1	6.7	6.4	6.1	5.8	5.7
Energy & Capacity Savings (all-in avoided costs)	$nominal/MWh	$ 63.63	$ 59.67	$ 58.38	$ 54.92	$ 67.13	$ 76.69	$ 75.69	$ 116.32	$ 119.18	$ 116.14	$ 133.48	$ 129.08	$ 135.03
PV of Energy & Capacity Savings	$2015/MWh		$ 55.86	$ 51.17	$ 45.07	$ 51.58	$ 55.17	$ 50.98	$ 73.34	$ 70.36	$ 64.19	$ 69.07	$ 62.54	$ 61.25
PV of Energy & Capacity Savings	2015 $M	$ -	3.8	6.9	6.1	7.0	7.4	6.9	9.9	9.5	8.7	9.3	8.4	8.3
Economic Balance (Energy-related)	2015 $M	-$ 36.2	-$ 29.3	-$ 23.2	-$ 17.3	-$ 11.5	-$ 5.9	**$ 1.3**	$ 8.0	$ 14.4	$ 20.5	$ 26.3	$ 31.9	
Economic Balance (Energy & capacity-related)	2015 $M	-$ 36.2	-$ 29.3	-$ 23.2	-$ 16.3	-$ 8.8	-$ 1.9	**$ 8.0**	$ 17.5	$ 26.1	$ 35.4	$ 43.9	$ 52.2	



Request IR-7:

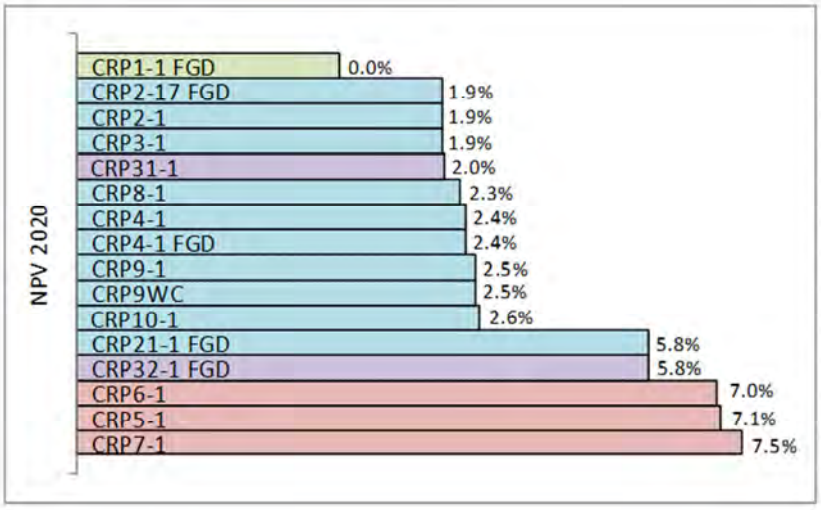
Does the net present value of revenue requirements of any of the Candidate Resource Plans presented in Figure 3.6 on page 31 include customer costs of DSM? If so, please provide a version of Figure 3.6 that excludes all customer costs of DSM from all CRP's.

Response IR-7:

Yes, the Candidate Resource Plans presented in Figure 3.6 include participant costs of DSM.

Below is a version of Figure 3.6 which excludes customer costs of DSM.

Ranking of Candidate Resource Plans Excluding Customer Costs of DSM



Request IR-8:

With respect to footnote 42 on page 31, please provide annual estimates for the period 2015 - 2020 of the percentage of NSPI's total revenue requirement that is excluded from the partial revenue requirements included in Figure 3.7?

Response IR-8:

Estimate of Percentage of Total Revenue Requirement Excluded from Partial Revenue Requirement shown in Figure 3.7:

Year	Percentage (%)
2015	50
2016	45
2017	45
2018	35
2019	35
2020	35

Request IR-9:

With respect to Figures 3.7 and 3.8 on pages 32 and 33,

(a) Please confirm that the case designated "Low DSM (w FGD)" has annual demand and energy savings corresponding to the Navigant Low DSM case and that the annual DSM expenditures are half the expenditures of the Navigant Low DSM case (as suggested by Lines 12-13 on page 31).

(b) If (a) is not confirmed, please provide annual DSM expenditures and demand and energy savings included in the "Low DSM (w FGD)" case, and explain how they were developed.

(c) Please identify whether adjustments similar to those made to develop the "Low DSM (w FGD)" case DSM were also made to the other scenarios presented. If no similar adjustments were made to the other scenarios, please explain why not, and how, in the absence of such adjustments, the comparisons presented are valid.

(d) Please confirm that except for the level of DSM, all input assumptions to the simulations that produced the results shown are common to all plans. If this is not the case, please identify all assumptions that vary across the plans and identify the assumption used for each plan.

Response IR-9:

(a-b) Confirmed.

(c) With these program adjustments to the Low case, NS Power was demonstrating the merits of accelerating the delivery of the most cost effective DSM initiatives to customers. NS Power was not intending to modify the costing and programming of all

levels of DSM in the Navigant Study. Comparisons show the advantages of assessing DSM programing against both the level required by the system and the cost of delivery.

(d) Yes, the model input assumptions are common across all resource plans except for the level of DSM.

Request IR-10:

With respect to Figure 4.1 on page 35 and footnote 44:

(a) **Please confirm that the plan designated "Low DSM" (which has a Planning Period NPV = $10,774) includes the annual energy and demand savings identified in the Low DSM scenario of the Navigant report, but the annual cost are assumed to be half of the cost of the Navigant Low DSM scenario cost.**

(b) **If (a) is confirmed, please provide support for such a variance from the Navigant report.**

(c) **If (a) is confirmed, please identify any similar assumptions made with respect to the cost of DSM in other Navigant scenarios.**

(d) **If (a) is not confirmed, please clarify footnote 44.**

(e) **Please confirm that the plan designated "Low DSM" is the same plan that is labelled "Low DSM (w FGD) in Figures 3.7 and 3.8. If this is not confirmed, please identify the differences between these plans.**

(f) **If the plan designated "Low DSM" was not modelled in the IRP, please provide details of the plan (as provided for each IRP CRP in Appendix L of the Final IRP report dated October 15, 2014).**

(g) **Please provide the annual revenue requirements for each of the plans shown in Figure 4.1, as well as the derivation of the NPV's shown for each plan.**

Response IR-10:

(a) Confirmed.

(b) The Company analyzed the franchise holder's 2016-2018 ELRAM and determined that DSM energy and capacity savings costs could be significantly reduced such that the "Low" DSM levels from the Navigant study may be achievable at the "half low" cost modelled in the IRP (its consultant produced a similar analysis). The Company then updated the "low" DSM scenario NPV and partial revenue requirement to reflect the analysis.

(c) The Company has not made similar assumptions for other Navigant scenarios as the "low" scenario at the cost demonstrated in the NS Power analysis provided the best balance of long-term cost effectiveness and affordability. The Company had requested alternate DSM plans that would have allowed it to provide further analysis from the franchise holder but was not given those plans.

(d) Please refer to part (a).

(e) The Plan designated Low DSM in Figure 4.1 is the same as the plans labelled Low DSM (w FGD) in Figure 3.7 and 3.8.

(f) Please refer to Attachment 1.

(g) Please refer to the table below. There is a correction to two of the NPVs shown in Figure 4.1. The corrected values are shown in the table below for NPV 2020 and NPV 2030 for the Half-Low DSM Plan. The Study NPVs are taken directly from Strategist and are not calculated. NS Power will file an errata with the Board with a revised Figure 4.1 showing the two corrected.

Annual Revenue Requirements for each of the Resource Plans shown in Figure 4.1

	No DSM Plan ($K)	CRP01-01-FGD-R01 Half-Low DSM ($K)	Low DSM ($K)	CRP2-17 FGD Base DSM ($K)	CRP Mid DSM/FGD (Synapse Model) ($K)
2015	629,462	650,868	648,296	672,897	677,679
2016	645,129	662,920	657,606	680,599	684,399
2017	679,201	693,333	685,503	706,393	710,258
2018	780,589	791,400	781,290	804,984	812,269
2019	812,559	819,928	801,532	827,443	838,025
2020	775,642	772,738	752,602	780,492	794,512
2021	797,205	793,696	770,720	790,016	800,243
2022	853,230	808,806	782,247	795,438	803,631
2023	886,301	877,915	802,777	810,210	815,551
2024	907,267	895,013	817,458	820,411	824,702
2025	965,077	925,959	842,035	843,928	848,436
2026	987,079	964,898	859,328	858,349	861,065
2027	1,012,143	971,546	862,334	859,087	860,180
2028	1,056,839	1,010,285	895,237	886,476	884,343
2029	1,086,197	1,033,928	910,869	896,002	889,053
2030	1,145,344	1,071,397	942,054	920,508	900,244
2031	1,188,258	1,113,494	965,188	937,268	906,727
2032	1,238,026	1,130,970	973,130	931,497	893,602
2033	1,270,164	1,155,501	987,614	939,559	897,885
2034	1,341,623	1,177,162	1,002,271	946,863	901,051
2035	1,439,042	1,252,221	1,049,692	961,930	893,889
2036	1,495,851	1,297,237	1,072,300	981,272	911,833
2037	1,547,495	1,317,351	1,083,605	986,839	907,846
2038	1,635,416	1,368,172	1,103,691	1,000,629	917,033
2039	1,677,389	1,403,760	1,139,799	1,043,225	925,265
NPV 2020 $M	$3,679	$3,742	$3,690	$3,815	$3,851
NPV 2025 $M	$6,341	$6,340	$6,121	$6,275	$6,331
NPV 2030 $M	$8,674	$8,572	$8,097	$8,230	$8,277
Planning PV $M	$12,302	$11,762	$10,774	$10,731	$10,623
Study PV $M	$20,833	$18,946	$16,722	$16,244	$15,626

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MAY 2015

2014 IRP Draft Analysis Results*
LOW DSM

* These are indicative results from a high level planning perspective. Can only be used to provide guidance and direction. This is not a prescriptive solution.

Low DSM Input Assumptions

Low DSM Case:

- Base Load Forecast
- Low DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

Low DSM Preliminary Results

	Low DSM at Half-Low Costs
2015	
2016	
2017	ML Oct 2017
	Lin 2 retire
2018	
2019	Mersey Redevelopment
2020	
2021	
2022	
2023	
2024	
2025	TUC 1 Retire
	FGD (Lin 3/4 300 MW)
2026	
2027	
2028	
2029	
2030	
2031	
2032	TUC 2 Retire
	CT 50MW
2033	
2034	
2035	Tre 5 Retire
	2 x CT 50MW
	CT 34MW
2036	
2037	
2038	
2039	2 x CT 50 MW
	PHBM 51.7MW firm *
	Lin 1 Retire
Planning PV $M	10,774
Study PV $M	16,722

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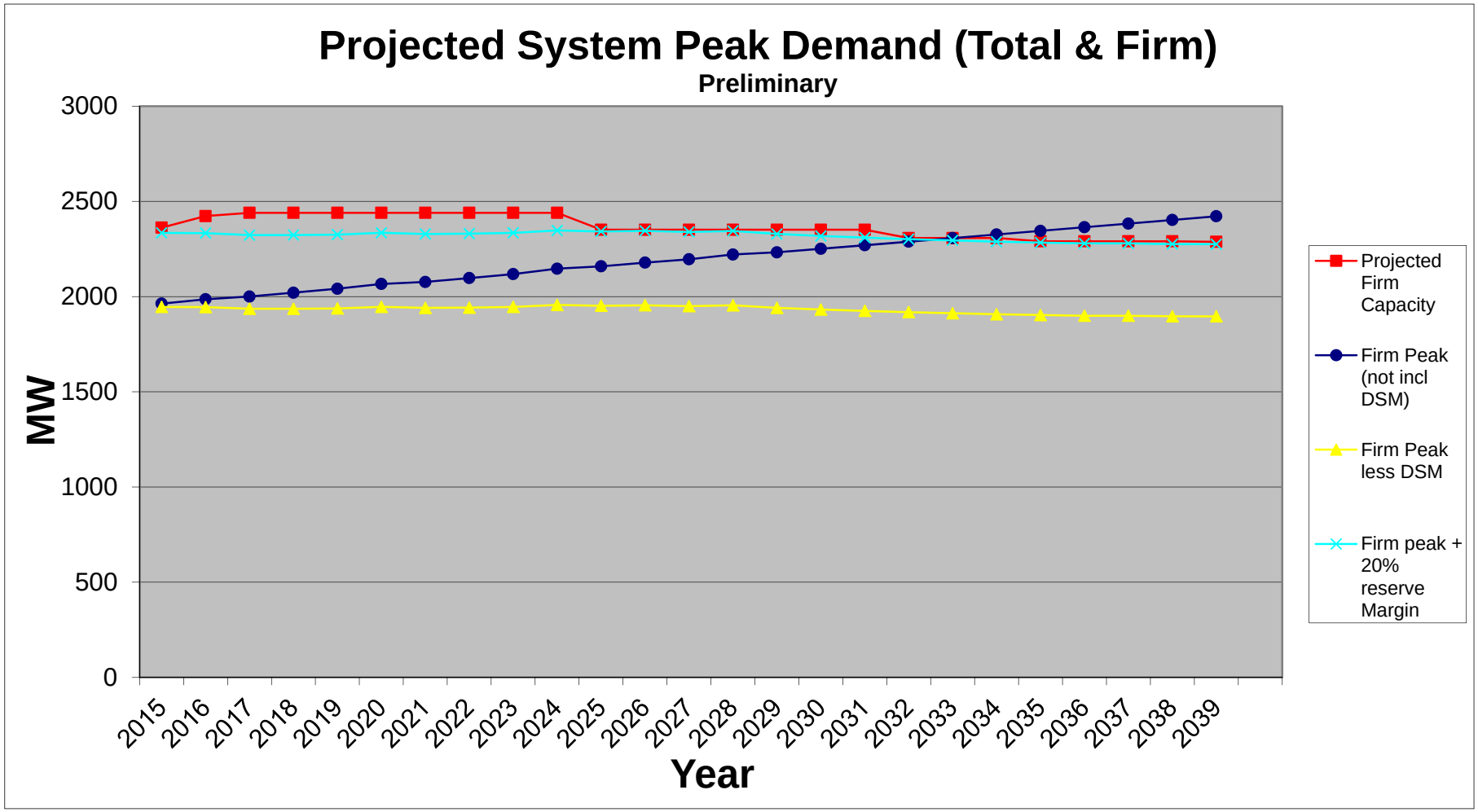
Low DSM Preliminary Results

Low DSM Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	18	41	65	84	104	120	136	155	172	191	207	319	442	465	484	506	526
Firm Peak Less DSM	1,946	1,945	1,936	1,936	1,938	1,946	1,941	1,942	1,946	1,956	1,952	1,932	1,903	1,899	1,899	1,896	1,896
RM Required	389	389	387	387	388	389	388	388	389	391	390	386	381	380	380	379	379
Required MWs	2,335	2,334	2,323	2,323	2,325	2,335	2,329	2,331	2,335	2,347	2,342	2,318	2,284	2,279	2,279	2,276	2,275
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	51.7
Additional Wind																	
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit											-8		132.8				98.8
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-89.0	0.0	-17.2	0.0	0.0	0.0	-2.5
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	98.7	98.7	9.7	9.7	-51.1	-51.1	-51.1	-51.1	-53.6
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2440	2440	2351	2351	2290	2290	2290	2290	2288
Surplus (Deficit) MWs above RM	27	89	117	117	115	105	111	110	105	93	9	33	7	11	11	15	13
Reserve Margin %	21.4%	24.6%	26.0%	26.0%	25.9%	25.4%	25.7%	25.6%	25.4%	24.8%	20.5%	21.7%	20.4%	20.6%	20.6%	20.8%	20.7%

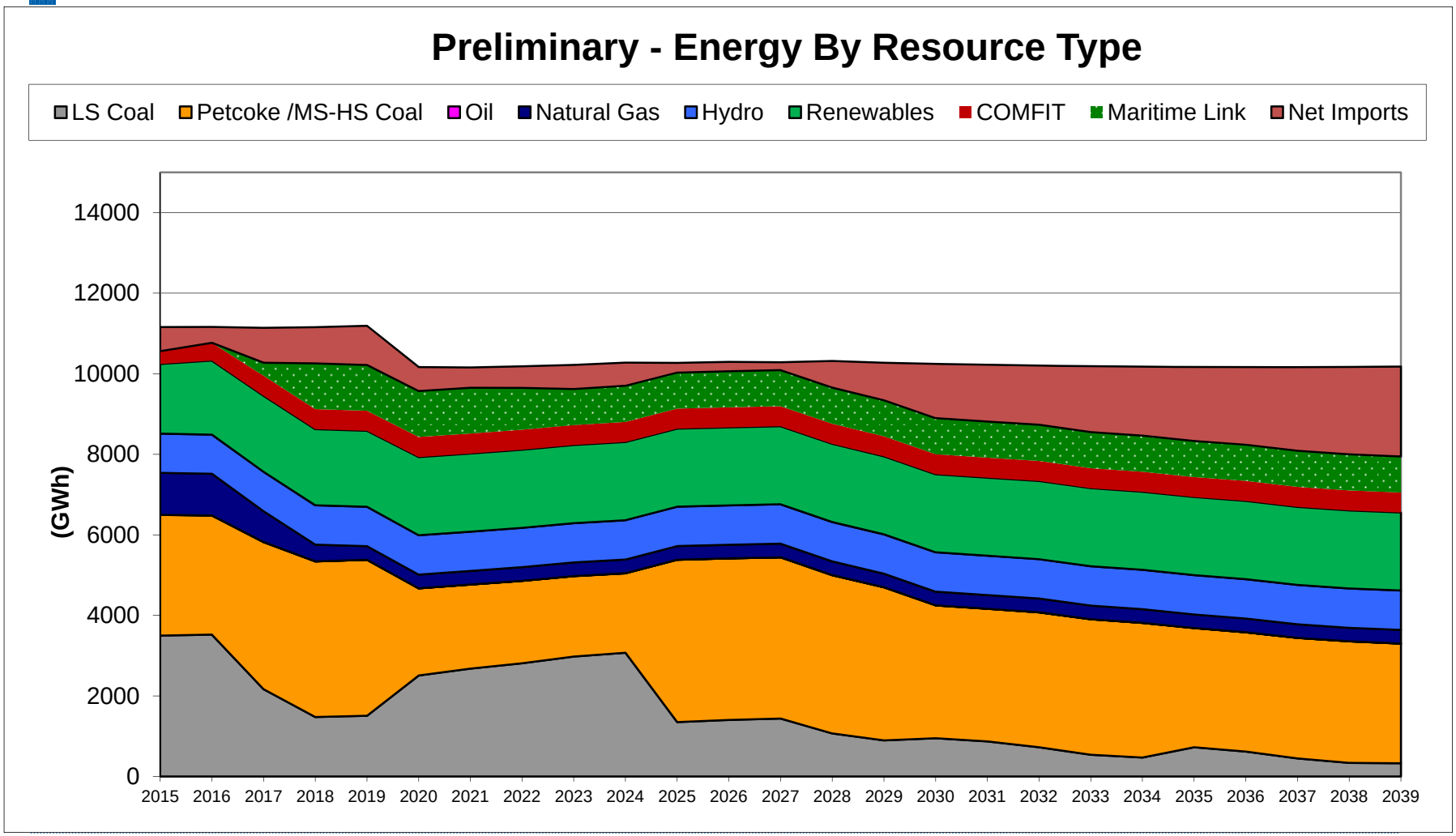
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Low DSM Preliminary Demand and DSM



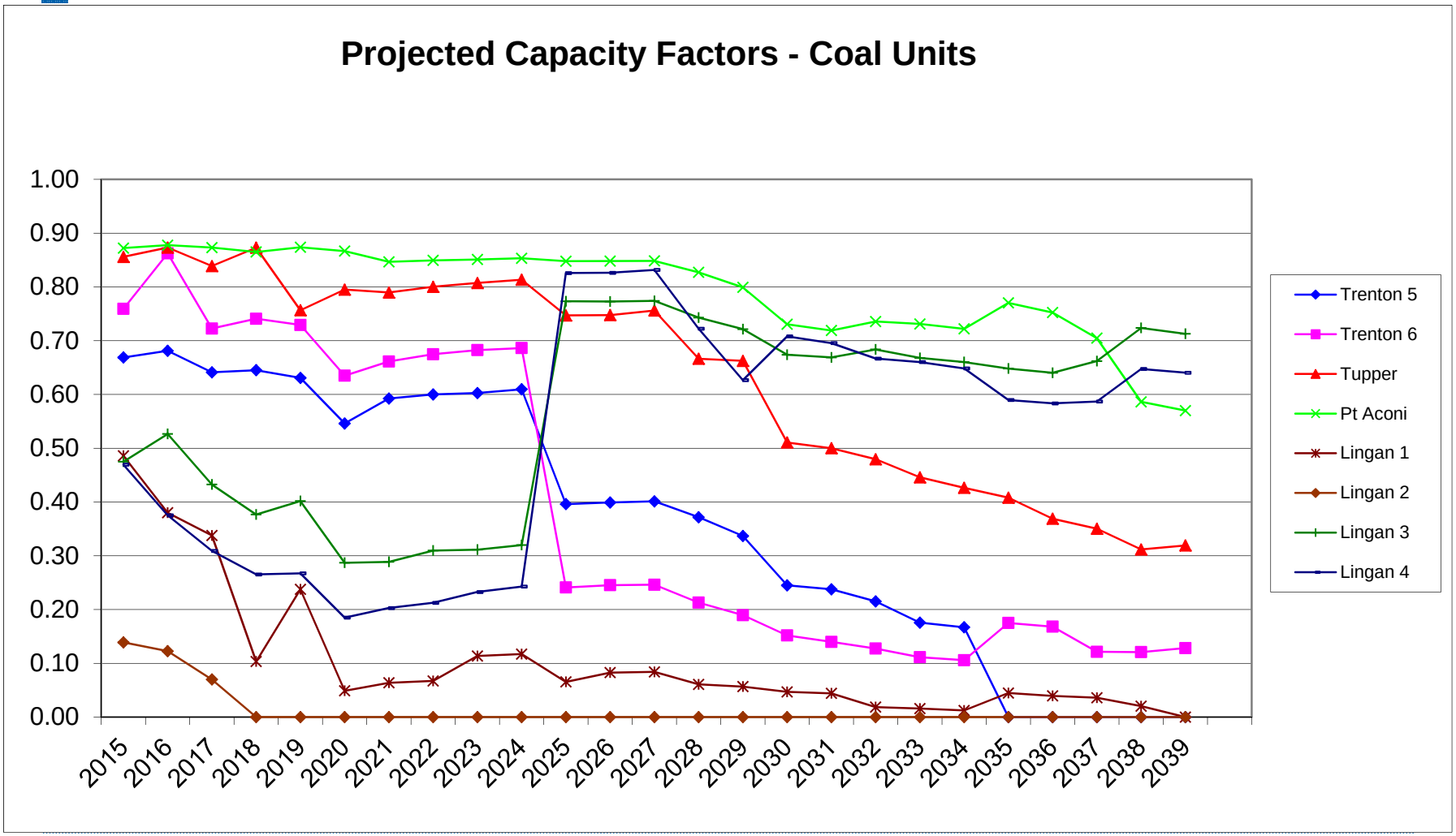
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Low DSM Preliminary Energy by Resource Type



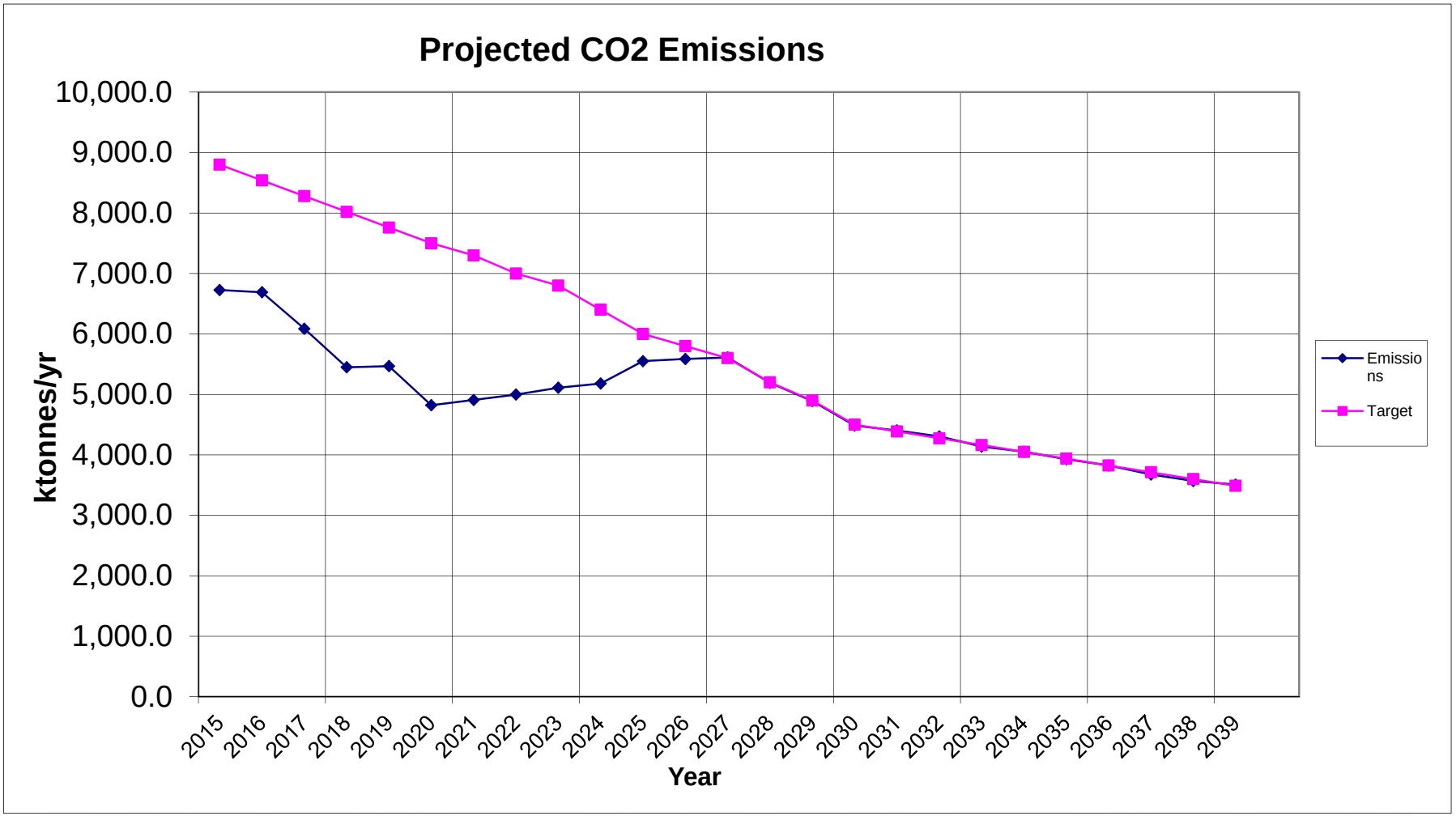
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Low DSM Preliminary Coal Capacity Factors



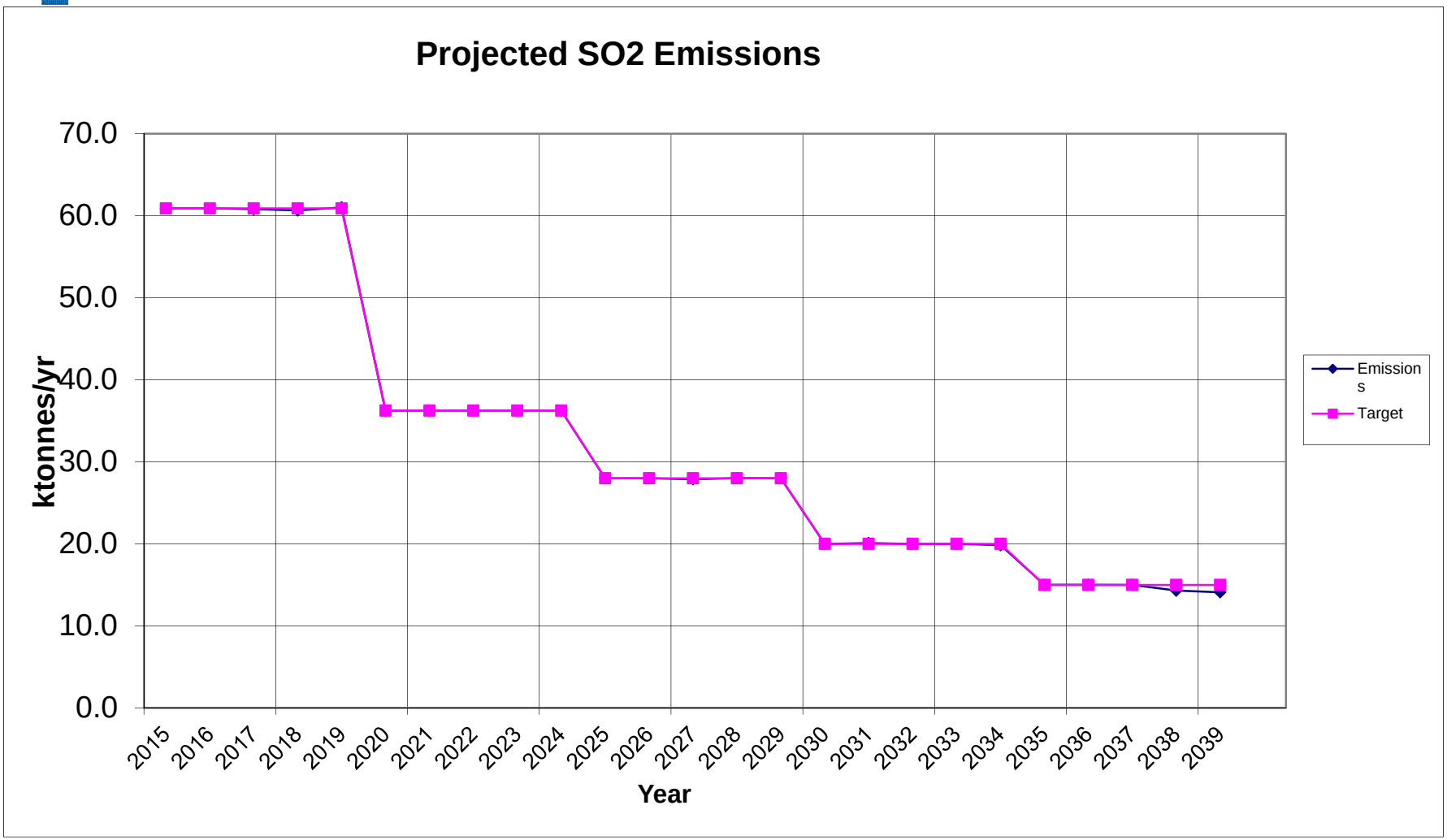
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Low DSM Preliminary CO_2 Emissions



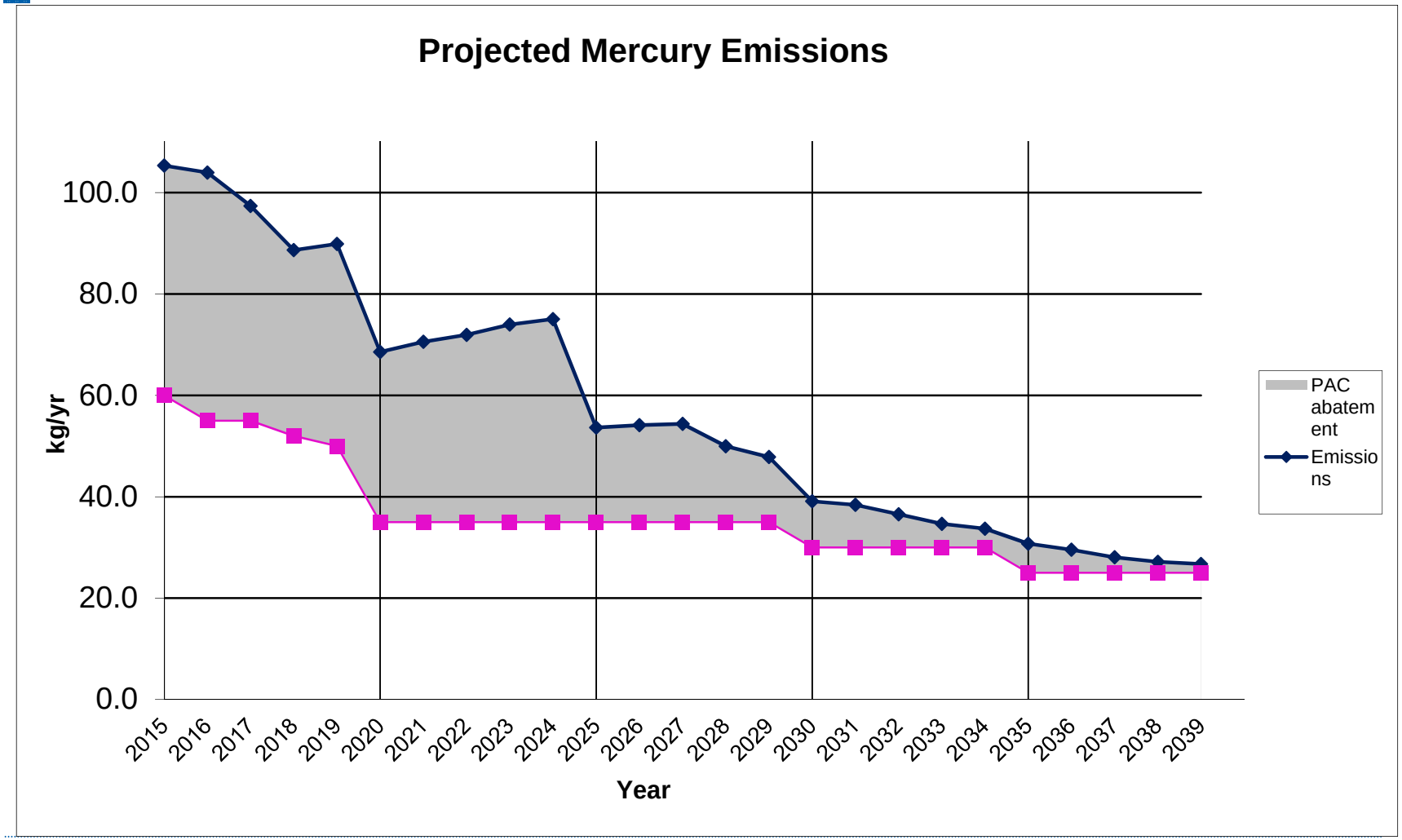
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Low DSM Preliminary SO_2 Emissions



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Low DSM Preliminary Hg Emissions



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Request IR-11:

With respect to the No DSM Plan in Figure 4.1

(a) Please provide the annual forecast of total system energy requirement and system peak load assumed in this plan.

(b) Please confirm that "No DSM" has no new DSM spending beyond 2015, but does include the effects of efficiency improvements due to factors such as changes in codes and standards.

(c) If (b) is not confirmed, please describe what "No DSM" means.

Response IR-11:

(a) Please refer to the table below.

Year	Total System Energy Requirement (GWh)	Total System Peak Load (MW)
2015	11,242	2,095
2016	11,351	2,112
2017	11,430	2,127
2018	11,532	2,147
2019	11,651	2,168
2020	10,704	2,127
2021	10,768	2,137
2022	10,884	2,158
2023	11,002	2,178
2024	11,146	2,207

Year	Total System Energy Requirement (GWh)	Total System Peak Load (MW)
2025	11,220	2,219
2026	11,330	2,239
2027	11,428	2,256
2028	11,558	2,281
2029	11,629	2,293
2030	11,730	2,311
2031	11,832	2,330
2032	11,936	2,349
2033	12,040	2,368
2034	12,146	2,386
2035	12,252	2,405
2036	12,360	2,424
2037	12,469	2,444
2038	12,579	2,463
2039	12,690	2,482

(b) Confirmed. The "No DSM" forecast is based on the load forecast provided in the 2014 IRP Assumptions and as such does not include any new DSM spending beyond and including 2015. Energy efficiency improvements due to factors such as changes in codes and standards are incorporated into the end-use intensity forecasts used in developing the residential and commercial forecasts.

(c) "No DSM" refers to the absence of DSM savings achieved by a DSM administrator (ENSC/E1). It includes non-administrator DSM to the extent reflected in the IRP load forecast.

Request IR-12:

NSPI's alternate plan presented in Section 5.0, beginning on page 37, and in Attachment B, splits the DSM expenditures (excluding Enabling Strategies) over the three years approximately 25% Residential and 75% Commercial. This compares to the E1 proposal which has approximately 45% Residential and 55% Commercial. Does NSPI have any concerns with respect to the equity of the alternate plan? If not, why not?

Response IR-12:

Please refer to CA IR-1 and E1 IR-11.

Request IR-13:

Beginning page 40, Line 30, NSPI states: "In order for NS Power to forecast its load requirements and effectively manage the provision of capacity and energy, the Company requires annual DSM performance, measurement and reporting." Further, at page 41, Lines 7-9, NSPI provides its view that E1 should have "annual deliverables".

(a) Please confirm that NSPI's position would set annual energy and demand savings targets and annual payments, and that each year would be independent of the other years covered by the three year agreement.

(b) If (a) is not confirmed, please clarify NSPI's position.

(c) Given E1's proposed annual measurement and performance, how is NSPI's position with respect to annual measurement and reporting different from E1's?

(d) To provide context for the discussion of this issue, please provide the annual budgeted and actuals for each of the following for each of the years 2010 -2014:

(i) Annual system energy requirements

(ii) Annual peak demand

(iii) Annual hydro production

(iv) Annual energy from wind

Response IR-13:

(a) Confirmed. However, as noted in NSUARB IR-8, the general supervision of the Board over the utility per the provisions of the *Public Utilities Act* remains, and the Board's authority to direct a change in the agreement if it determines this to be in the public interest, is undiminished. Please also refer to E1 IR-36(b).

(b) Not applicable.

(c) Please refer to Peach IR-20(c). As stated by Mr. Pickles at pages 40-41, Appendix A of NS Power's Evidence, using the three year cumulative performance measurements as proposed by E1 would not permit evaluation of E1's satisfaction of the performance requirement until after the first quarter of 2019, which would be too late to improve performance. Annual performance targets with annual payments are also important in ensuring funds are not moved by between program years without proper consideration and approval.

(d) The information requested in the IR is provided in the following tables.

(i) Annual system energy requirements

The below table was submitted in Liberty's 2014 FAM audit report. 2014 has been added to the table for the purpose of this IR.

Forecast versus actual Net System Requirement (GWh)

	2010	2011	2012	2013	2014
FAM Load Forecast NSR (less PHP and Bowater)	10,007.8	10,050.9	10,098.4	9,861.9	9,831.2
Actual NSR (less PHP and Bowater)	9,900.1	10,031.2	9,947.4	10,113.9	9,957.8
NSR Variance to Forecast	-1.1%	-0.2%	-1.5%	2.6%	1.3%
Weather Normalized NSR (less PHP and Bowater)	10,052.3	10,126.3	10,096.8	10,113.5	9,963.8
Weather Normalized NSR Variance to Forecast (less PHP and Bowater)	0.4%	0.7%	0.0%	2.6%	1.3%

(ii) Annual peak demand

Forecast versus actual System Peak (MW)

	2010	2011	2012	2013	2014
FAM Peak Forecast (less PHP and Bowater)	1,929.5	2,001.1	2,004.6	1,997.3	1,981.6
Actual Peak (less PHP and Bowater)	1,880.8	1,961.9	1,781.7	1,995.5	2,104.9
Peak Variance to Forecast	-2.5%	-2.0%	-11.1%	-0.1%	6.2%
Weather Normalized Peak (less PHP and Bowater)	1,914.3	2,009.5	1,935.4	2,032.9	2,031.8
Weather Normalized Peak Variance to Forecast (less PHP and Bowater)	-0.8%	0.4%	-3.5%	1.8%	2.5%

(iii) Annual hydro production

Annual Hydro Production (MWh)

FAM Quarterly Report	2010	2011	2012	2013	2014
Budgeted	967,594	970,260	975,376	985,353	985,354
Actual	991,469	1,088,460	827,857	973,339	1,099,171

(iv) Annual energy from wind

Annual Energy From Wind (MWh)

	FAM Quarterly Report	2010	2011	2012	2013	2014
NSPI	Budgeted	2,666	250,580	250,580	253,796	253,796
WIND	Actual	25,268	247,452	256,307	261,034	258,159
IPP*	Budgeted	603,129	709,747	794,295	866,493	932,262
	Actual	525,624	743,257	838,284	845,118	848,711

*IPP Includes wind, Sackville Landfill, PRE-2001 - Black River Hydro, PRE-2001 - Brooklyn Power, PRE-2001 - Morgan falls Company and PRE-2001 - Taylor Lumber Company.

Request IR-14:

At page 41, Line 13, NSPI states: "Although E1 may require some degree of flexibility in the implementation of its plan, decision-making authority for items as significant as shifting budgets between programs and those identified by E1 in its Evidence should be subject to approval of the Board with input from NS Power."

At page 17, Line 4 of his evidence, Mr. Pickles states: "To the extent that EfficiencyOne intends to use subcontractors to deliver portions of its services, I recommend that EfficiencyOne be required to submit the results of its competitive procurement process to NSP and the UARB for review."

At page 25, Line 12 of his evidence, Mr. Pickles states: "I recommend that EfficiencyOne be directed to engage with NSP to consider a broad range of program types and program expenditures…"

Given the above statements, please discuss how NSPI proposes to separate itself from any responsibility for the outcomes of its contract with E1 while at the same time maintaining a significant degree of influence over E1's design and delivery of DSM.

Response IR-14:

The above statements address the issue of the need for E1 to gather input from NS Power, allow NS Power to review the results of procurements and engage with NS Power in the provision of information. NS Power is not seeking to control the design or the delivery of the Plan but does want the opportunity to comment and be in a position to provide the Company's views to the UARB as it conducts its reviews.

Rather than attempting control over design and delivery, NS Power is simply trying to ensure that the Supply Agreement provides an adequate description of the scope of services to be

provided as well as the means of ascertaining that such deliverables are both cost-effective and affordable for NS Power's customers. Commenting on the inappropriateness of the flexibility which E1 is proposing to afford itself under the Supply Agreement, in NS Power's Evidence at Appendix A, page 36, David Pickles notes that the discretionary control sought by E1 could "significantly affect the outcome, equity, rate impacts and cost of the Plan…"

Such activities are consultative and consistent with NS Power's current procurement practices with third-party suppliers. They are not intended to grant NS Power a "significant degree of influence over E1's design and delivery of DSM".

Request IR-15:

As noted in IR-14, at page 17, Line 4 of his evidence, Mr. Pickles states: "To the extent that EfficiencyOne intends to use subcontractors to deliver portions of its services, I recommend that EfficiencyOne be required to submit the results of its competitive procurement process to NSP and the UARB for review."

(a) Please elaborate on why Mr. Pickles believes such a review is necessary and what it is intended to achieve.

(b) Please explain what would constitute an appropriate level of review by NSP.

(c) Please explain what would constitute an appropriate level of review by the UARB.

(d) Under what conditions, if any, would a review by NSP alone be sufficient?

(e) Does Mr. Pickles propose that the UARB and NSP review any submission from EfficiencyOne simultaneously or consecutively?

(f) In the event of an NSP review endorsing the EfficiencyOne submission, would a UARB review still be necessary?

Response IR-15:

(a) This review is necessary to ensure that the contracted services are appropriate and that they are competitively priced, reasonable and prudent. This is especially important since E1 has proposed to collect $121 million without providing meaningful description of how those costs are to be spent and the services to be provided. Further, Mr. Pickles believes that this information will be helpful to NS Power in administering the contract with E1. Mr. Pickles also believes it would be helpful to the Board in fulfilling its legislative

requirements under Section 79(M) (1) of the *Public Utilities Act* which states "In making an order approving an agreement pursuant to Section 79L, the Board shall establish such performance requirements for the franchise holder as the Board considers appropriate." Mr. Pickles also believes it will assist the Board by ensuring it has the information it requires to fulfill its obligation under Section 79L(8) in determining that the agreement between NS Power and the franchise holder is in the best interests of NS Power's customers.

(b) An appropriate level of review by NS Power would provide either: i) demonstration by E1 that the proposed costs are reasonable through detailed description and justification of the services and costs, or ii) an opportunity for:

(i) Review of the request for proposals
(ii) Review of the list of recipients for the request for proposals
(iii) Review of scoring sheets and other evaluation materials
(iv) Review of pricing details and contract terms

(c) The Board has general supervision over the franchise holder under Section 79G(1) of the *Public Utilities Act*. An appropriate level of review would be that which the UARB finds necessary to meet its statutory obligations, including those identified in part (a) above. It is anticipated that this level of review would include either the description and demonstration of the reasonableness of the costs, or the results of the competitive procurement process, as described in the response to part (b) above.

(d) NS Power anticipates that UARB review will always be necessary. NS Power would not propose that NS Power's review would in any way limit or restrict the general supervisory authority of the UARB over the franchise holder under the *Public Utilities Act*.

(e) Mr. Pickles does not make a proposal with respect to simultaneous or consecutive review. NS Power would only seek the opportunity to provide input to the UARB as a stakeholder in the process.

(f) The Board has general supervision over the franchise holder and as such NS Power is of the view that UARB review will always be necessary. Section 79L of the *Public Utilities Act* is clear that no agreement between NS Power and the franchise holder is valid until it has been approved by the UARB. Section 79L(8) provides that an agreement will not be approved by UARB unless it is satisfied that the agreement is in the best interests of NS Power's customers and satisfies the requirements of the *Public Utilities Act*.

Request IR-16:

At page 42, Line 9, NSPI references Attachment C which contains draft forms of Schedules A and B of the Supply Agreement. Please describe, with examples, how NS Power proposes that the information contained in Attachment C be applied.

Response IR-16:

Schedule A of the Supply Agreement between E1 and NS Power outlines the scope of services E1 is to supply NS Power over the 2016-18 contract period. Section 79J(c) of the *Public Utilities Act* provides that the Agreement must "describe the electricity efficiency and conservation activities that the franchise holder will provide to Nova Scotia Power Incorporated."

Schedule A will be used as a reference over the contract period.

NS Power will use the information provided for load forecasting, production cost modelling and rate planning purposes. In combination with E1's 8760 model the information provided will support understanding and modelling of DSM impacts on hourly demand.

The Compensation Schedule defines the monthly financial amounts to be provided by NS Power to E1 and addresses how surpluses are to be dealt with.

Request IR-17:

Section 7, beginning page 44 addresses E1's rate and bill impact analysis. Foundational to this analysis are avoided costs.

(a) Please describe the methodology used by NSPI to calculate the avoided costs it provided to E1.

(b) Please provide the annual avoided capacity and energy costs for the DSM plan proposed by E1 (essentially the IRP Base Plan), the IRP mid-level DSM plan, and the NSPI alternate DSM plan as presented in Section 5 of its evidence.

Response IR-17:

(a) As directed by the Board on November 5, 2014, the difference in revenue requirement (DRR) method was used to calculate the avoided costs for E1. The avoided cost calculations are based on resource plans developed using the 2014 IRP assumptions. Using this method, the annual partial revenue requirements of a plan that does not include DSM (the "No DSM" plan) is compared with the annual partial revenue requirements of a plan which includes one of the DSM profiles from the Navigant Potential study used in the 2014 IRP. The partial revenue requirements are those costs which have been included in the Strategist modeling. They include only the generation-related costs such as fuel and purchased power, thermal and hydro unit O&M and capital costs for new resources added in the plan. Other costs are common across the cases and are netted out in the DRR calculation.

The differences in partial revenue requirements are allocated to energy and capacity each year to determine the annual avoided energy and capacity costs on a $/MWh and $/kW basis, respectively. The O&M costs and fuel and purchased power costs have been allocated to avoided energy. The capital cost for new resources have been allocated

based on their contribution to capacity versus energy. For example, if a combustion turbine is added in the resource plan to maintain planning reserve margin and runs at a low capacity factor, its capital costs would all be allocated to capacity. However, any variable operating costs associated with running the combustion turbine would still be allocated to energy.

(b) Please refer to CA IR-20(i) for the annual avoided capacity and energy costs for each DSM case. The NS Power Alternative DSM scenario is represented by the Low DSM Case avoided costs.

Request IR-18:

At page 44, Lines 24-28, NSPI recommends that E1's Rate and Bill Impact analysis be disregarded by the Board and stakeholders because it is incomplete.

(a) Has NSPI applied any alternative approach to analyse the rate and bill impacts of any of the DSM scenarios in this proceeding?

(b) If the answer to a) is affirmative, please provide the results of such analysis, complete with methodology description, assumptions and calculations.

(c) As noted by E1 in Appendix D, Attachment 2, page 4, the avoided cost of energy is not included in the rate and bill impact analysis as energy costs represent variable costs which do not impact rates. E1 notes that this may be an oversimplification. Does NSPI agree that this is a simplification and that customer bills would likely be affected by fuel savings?

(d) Given that the FAM adjustment is calculated with reference to a Base Cost of Fuel expressed in cents per Kwh, would fuel savings at an avoided cost higher than the FAM base cost create a FAM credit; for example, if the base cost of fuel is $50/Mwh and a kwh is saved at an avoided fuel cost of $60/Mwh, does a credit of $10 accrue to the FAM? If not, please explain why not?

(e) What is the current base cost of fuel (in $/Mwh) that is included in FAM?

(f) Does the potential creation of a FAM credit due to the difference in avoided energy costs and the FAM base cost mitigate to any degree the effects on rates of recovering fixed costs over lower sales which occur because of DSM? If not, why not?

(g) What is NSPI's estimate of the percentage of total 2016 revenue requirement that is fixed, and the percentage of the fixed costs that will be recovered through energy charges in 2016?

Response IR-18:

(a-b) As provided in NS Power's Evidence at page 34, the Company has relied on its IRP analysis to assess the DSM levels needed to meet the requirements of the power system and balance cost effectiveness and affordability. The Company has done this because the Rate and Bill Impact analysis is incomplete. Both analyses provide similar results – under increased DSM spending, customer rates and bills will increase in the near-term. Please refer to Synapse IR-21.

(c) Yes. Customer bills are affected by a variety of factors, one of which is fuel.

(d) Yes, in the context of the example provided. However, please refer to part (f), below.

(e) The 2015 base cost of fuel is $49.68/MWh. Please refer to Synapse IR-16 Attachment 1.

(f) A reduction in system load does not automatically result in FAM credit because there are times when lower cost fuels can now be on the margin depending upon the generation operating in that hour (e.g. must-run generation sources which may have a higher cost). In such circumstances an avoided unit fuel cost can be lower than the average fuel cost in rates, resulting in a debit rather than a credit to the FAM. In this situation all non-participants in DSM will see increases in the fuel portions of their bills.

Since the unrecovered fixed costs are considerably higher than the potential fuel cost credit under the FAM, the FAM has small mitigating effect on rates.

(g) NS Power has not done revenue requirement analysis for 2016. The most recent analysis was performed for the 2014 test year in the 2013 GRA proceeding. The breakdown of the total revenue requirement associated with electric sales, before accounting for the Load Retention Rate, is as follows

	Amount ($K)	**Unit Cost ($/MWh)**	**Relative Share**
Fixed Cost	$829,119,139	$84.50	65%
Fuel costs	$448,026,861	$45.66	35%
Total	$1,277,146,000	$130.16	100%
Load (MWh)	9,811,994		

Request IR-19:

Further to the discussion of E1's proposed reserve fund in Section 9.0 of NSPI's evidence, please identify any of the four external risk factors listed by E1 at the top of page 54 of its evidence which is considered by NSPI in the determination of an appropriate return on equity.

Response IR-19:

An appropriate return on equity gives NS Power an opportunity to:

(a) earn a return on investment commensurate with that of comparable risk enterprises;
(b) maintain its financial integrity; and
(c) attract capital on reasonable terms.

The business risks that NS Power is subject to and must manage are disclosed in its annual financial reports and include but are not limited to:

- Regulatory and Political Risk
- Changes in Environmental Legislation
- Weather Risk
- Foreign Exchange Risk
- Commodity Price Risk
- Commercial Relationships Risk
- Interest Rate Risk
- Labour Risk
- Credit Risk
- Capital Market and Liquidity Risk
- Cyber Security Risk