Request IR-1:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

NSPI has proposed a DSM spending of approximately $22 per year for the years 2016-2018. How was an annual DSM budget of $22 million determined to be appropriate for the period 2016-18?

Response IR-1:

It is the objective of NS Power to align the DSM program with energy and capacity requirements of the 2014 IRP and achieve this in a cost effective and affordable manner as set out in the *Public Utilities Act.* NS Power's analysis to date indicates this can be achieved with an annual DSM expenditure of approximately $22 million. NS Power notes that this level of DSM spending is consistent with per customer DSM expenditures of other Canadian jurisdictions.

NS Power used the ELRAM to produce four alternative DSM scenarios, a summary of which can be found below, and in NS Power's Evidence at Appendix A, Page 24, Table 6, as revised (please refer to EAC IR-7).

Revised Table 6. Summary of Alternate DSM Scenarios

Scenario Name	Assumption Changes	Three Year Impacts			
		GWH	MW	$M	TRC
E1	None	405.9	62.5	$ 121.5	2.0
A	Eliminate TRC's < 1.0	387.0	59.8	$ 110.0	2.2
B	Eliminate TRC's < 1.0 Allow implemention costs to vary +/- 20% Allow incentive costs to vary from the E1 minimum Participation is estimated as a function of program cost, with goal ~ Scen. A	381.7	60.5	$ 107.9	2.2
C	NS Power Alternate Proposal	279.0	33.0	$ 67.5	3.2
D	Eliminate TRC's < 1.0 Allow implemention costs to vary +/- 20% Allow incentive costs to vary from the E1 minimum Participation is estimated as a function of program cost, with goal ~ 300GWh	300.8	46.3	$ 65.2	2.3

Please note, the Company has not put forward a DSM plan for the Board's approval. Rather, NS Power has requested the Board consider our Evidence and direct E1 to design a plan that would provide DSM spending of approximately $22 million and achieve energy savings of 100 GWh/year and associated demand savings over the 2016-18 contract period.

Request IR-2:

Reference: 2016-2018 DSM Plan NS Power Evidence Section 3.2

What level of unit costs does NSPI determine is not affordable for ratepayers and why?

Response IR-2:

Please refer to CA IR-38.

Request IR-3:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

Does NSPI see any negative consequences for the longer term in focusing solely on low unit costs as a determinant of where DSM investment should occur?

Response IR-3:

Please refer to SBA IR-5.

Request IR-4:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

How do the lifetime energy and demand savings and costs of NSPI DSM plan and E1's plan compare with the projected marginal fuel cost of generating electricity in Nova Scotia?

Response IR-4:

Please refer to E1 IR-11 and CA IR-1. The alternate DSM scenario which NS Power discusses in its Evidence and included as Appendix B is not intended to be a detailed alternative for approval. However, for the 2016-18 contract period, NS Power's Evidence shows that such a plan would align with the energy and demand savings provided through the "Low" DSM from E1's DSM potential Study at a cost of between $20 and $25 million.

The lifetime DSM costs for the E1 DSM Plan (2016-2018) and the Low DSM case are given below. The analysis assumes the average life of the DSM measures is 12.96 years (rounded to 13 years). The lifetime costs are compared to NS Power's projected range of marginal costs.

Comparison of Lifetime DSM Costs and Marginal Costs

Low DSM Plan 2016-2018 Energy Savings Lifetime Costs ($/MWh)	E1 2016-2018 DSM Lifetime Costs ($/MWh)	Projected Marginal Cost 2016-2030 ($/MWh)
25.61	33.23	50-70

The table indicates that the lifetime cost of three years of the Low DSM case is less than that of the E1 DSM Plan; both cases are less than the projected marginal cost.

Request IR-5:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

Please provide residential increases in rates and Fuel Adjustment Mechanism charges in both absolute and percentage terms since 2011?

Response IR-5:

Year	Revenue increase due to GRA ($)	% increase due to GRA	Revenue increase due to FAM (all components combined including: BCF, AA, BA) ($)	% increase to FAM (all components combined including: BCF, AA, BA)	Composite revenue increase ($)	Composite % increase
2011	-	0.0%	19,686,300	3.6%	19,686,300	3.6%
2012	36,619,083	6.1%	17,811,624	3.0%	54,430,707	9.1%
2013	35,652,760	5.8%	(17,308,957)	-2.8%	18,343,804	3.0%
2014	31,254,707	5.0%	(12,361,491)	-2.0%	18,893,216	3.0%
2015	-	0.0%	31,015,699	4.4%	31,015,699	4.4%

Request IR-6:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

Has NSPI an estimate of the net present value of energy savings under its plan?

Response IR-6:

Please refer to CA IR-1 and E1 IR-11. For a plan that aligns with the energy and demand savings provided through the "Low" DSM scenario from ENS's DSM Potential Study at a cost equal to that of the "Half-Low" DSM scenario, the NPV savings over the twenty-five year planning period would be approximately $1.5 billion.

Request IR-7:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

2016-2018 DSM NS Power Evidence Appendix B Page 1 of 2 shows that most of DSM spending under NSPI's plan would occur in the BNI sector.

(a) What is the balance of spending between residential and BNI under NSPI's proposals?

(b) Was this balance taken into account when submitted a plan.

Response IR-7:

(a-b) Please refer to CA-IR-1 and E1 IR-11.

Request IR-8:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

2016-2018 DSM NS Power Evidence Appendix B Page 1 of 2 shows that residential lighting as proposed by E1 would have a TRC of 3.8. Why was this program not selected for inclusion in NSPI's plan?

Response IR-8:

Please refer to revised Table 6 in EAC IR-7 Attachment 2. This table demonstrates that there are lower cost alternatives than the plan put forward by E1 in its Application. The indicative Measures selected in certain of these scenarios combine to produce a higher total TRC than E1's plan, even though some of the individual Measures may have lower TRCs than certain Measures in E1's plan.

Request IR-9:

Reference: 2016-2018 DSM Plan NS Power Evidence Section 3.1, Line 19 and 20

(a) Please provide additional detail on NSPI's commitment to spending on low income homeowners and renters, including forecast spending and energy and demand savings for 2015-2018.

(b) Please describe NSPI's on plans to evaluate energy and demand savings from this spending and plans to report this to stakeholders.

(c) Will any evaluation be comparable to that currently conducted on E1's results?

(d) If not, why not?

Response IR-9:

(a-d) Please refer to CA IR-1, E1 IR-11, AEC IR-4, AEC IR-5 and Multeese IR-2 Confidential Attachment 1 "*The Contribution Agreement Between Nova Scotia Power Incorporated and The Clean Nova Scotia Foundation*".

Request IR-10:

Reference: 2016-2018 DSM Plan NS Power Evidence

What would be the effect on rates of the NSPI plan versus the plans proposed by E1 for the period 2016-18?

Response IR-10:

Please refer to CA IR-38. There is no funding currently in rates for DSM programming. DSM spending in the 2016-2018 contract period puts upward pressure on customer rates. Notionally, however, an increase in spending of $13 million is approximately equal to 1 percent in customer rates.

Request IR-11:

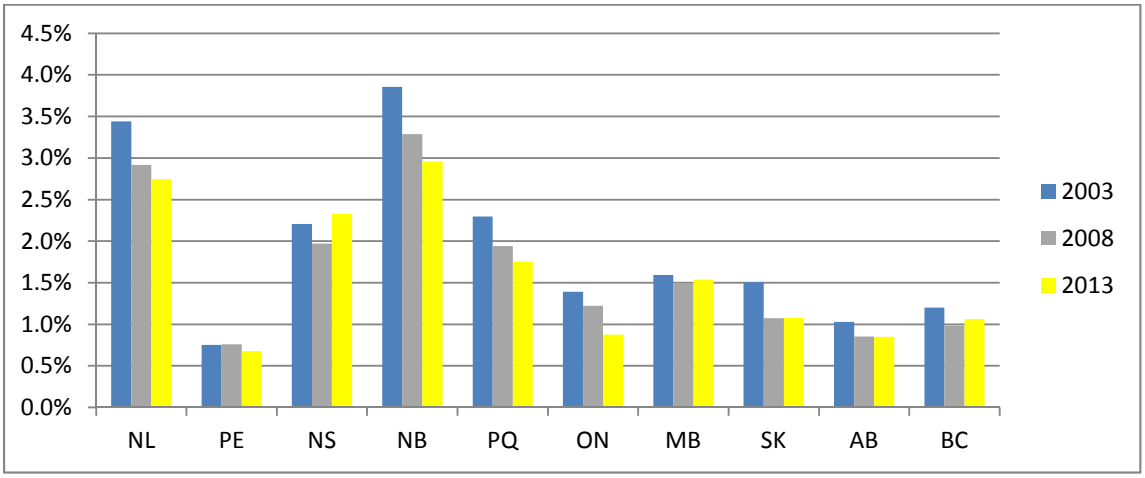
Reference: 2016-2018 DSM Plan NS Power Evidence Appendix A, Attachment B

(a) Did NSPI carry out any other comparisons of Canadian jurisdictions with respect to electricity pricing and/or expenditures and specifically did it compare the cost of electricity at the margin, avoided cost, or percentage generated from domestic energy resources? Please provide results if available.

(b) If not, why was such analysis not conducted?

Response IR-11:

(a) Yes. NS Power compared the average monthly residential household bill as a percentage of gross income per household.



Marginal electricity costs, avoided costs and domestic generation were not explored. Please refer to Multeese IR-5.

(b) Not applicable.

Request IR-12:

Reference: 2016-2018 DSM Plan NS Power Evidence

Please provide annual spending by the largest categories of expenditures by NSPI since 2011 and the absolute and percentage increase in them since them time? Include fuel, salaries, capital expenditures, operation and maintenance, and third party contracts.

Response IR-12:

Major Expenditures ($M)*

	2011	2012	2013	2014	$ Increase (2014 v 2011)	% Increase (2014 v 2011)
Salaries	113.2	109.1	112.9	114.8	1.6	1%
Contracts & Consulting	58.9	60.5	53.2	61.1	2.3	4%
Pension**	41.1	51.5	58.3	49.6	8.5	21%
Fuel	547.6	494.9	556.9	507.6	(40.0)	-7%
Interest	104.0	113.0	119.4	116.1	12.1	12%
Provincial Grants & Taxes	38.7	37.8	37.7	38.3	(0.4)	-1%
Capital	315.2	284.4	207.5	272.8	(42.4)	-13%

*Total Operation Maintenance & General (inclusive of salaries, pension and third party contracts) is as follows:

	2011	2012	2013	2014	$ Increase (2014 v 2011)	% Increase (2014 v 2011)
Operating Maintenance and General	$ 262.6	$ 252.6	$ 264.6	$ 264.4	$1.8	0.7%

** Pension includes current service costs plus accrued benefits related to future obligations.

Request IR-13:

Reference: 2016-2018 DSM Plan NS Power Evidence

(a) Would NSPI explain in more detail why it recommends that the Total Resource Cost test be retained post 2018 and what value the test has for ratepayers?

(b) Please elaborate on the value of the RIM test?

(c) Please explain why reporting should be at the measure rather than the program level?

Response IR-13:

(a-c) Please refer to Peach IR-24.

Request IR-14:

Reference: 2016-2018 DSM Plan NS Power Evidence Appendix B

Please provide the fuel costs as percentage of expenditures for Canadian jurisdictions.

Response IR-14:

NS Power does not have this information.

Request IR-15:

Regarding the statement on slide 11 of the NSPI presentation "Review of DSM Scenarios, Avoided Costs and Associated Planning Analysis," February 2015 that "Avoided Costs for Transmission and Distribution" provides a "limited benefit."

(a) Please define the term "limited" and quantify the potential benefit that is excluded.

(b) Does NS Power agree that avoiding or deferring T&D investments would improve the affordability of a DSM portfolio?

(c) Please provide each value of avoided T&D used by NS Power for screening DSM at any time since January 2010.

Response IR-15:

(a) The term "limited" is used in this case to mean restricted or reduced.

The benefit of T&D avoided costs is restricted (or limited) by what has been a largely broad based roll out of efficiency programs in Nova Scotia. Program delivery has been directed at broad customer uptake, more so than power system requirements.

In the ongoing maintenance and management of the electrical distribution system the T&D benefits of efficiency programs would be limited by the following factors:

- Transformers that are replaced because of load rating, and have remaining useful operating life, are regularly repurposed on the power system.

- Transformers replaced for reliability purposes (unit condition or age) may be replaced with a unit of a higher rating (incremental increase).

- Primary distribution feeders rebuilt for reliability purposes may be reconductored with electrical conductor of a higher rating which could be in response to feeder loading or could reflect current construction standards.

(b) Focused DSM programming could avoid, defer, or reduce some T&D investments; however, a high degree of coordination between utility planners and efficiency program designers would be necessary to achieve a material result. In addition, there would need to be a willingness to focus DSM investment in discrete geographic areas to match the power system topology rather than the current broad-based offerings across the province.

(c) Please refer to CA IR-16.

Request IR-16:

Reference: Feb 2015 Presentation, page 8:

Regarding the statement that "While total avoided transmission and distribution costs are not included, it is recognized that these components do contribute in some part to the avoided costs:"

(a) Please provide NSPIs' current estimates of avoided T&D costs.

(b) Please provide the Company's most recent avoided T&D cost study, including all workpapers and electronic spreadsheets (with formulas intact).

(c) Please provide the source of NSPI's current estimates of avoided T&D costs, including studies, workpapers, and Excel spreadsheets (with formulas intact), if different from the response to (b).

Response IR-16:

(a-c) Please refer to NSUARB IR-6. The Company has not prepared a formal study on T&D avoided costs.

Request IR-17:

For each ACE filing from 2010 through 2015:

(a) Please provide a list of the T&D projects identified in the filing that were justified by experienced or expected demand growth,

(i) For each such project, provide the anticipated cost of the project.

(b) Please provide a list of the T&D projects that were canceled or delayed following the ACE filing, due to insufficient load growth.

Response IR-17:

(a) Load growth T&D-based projects, not including routines, have been extracted from the 2010 through 2015 ACE Plans and are listed below, including the anticipated costs for each project:

CI#	Project Title	2010 ACE Plan Budget ($)	Total Budget ($)	Ranking Category
Transmission Capital Items Included in 2010 ACE Plan				
33504	Upgrade 69 kV Circuit to Pleasant Street L5536	$1,449,970	$1,449,970	Overloaded Equipment
25391	25kV Bus Keltic Drive Substation	$487,804	$487,804	Overloaded Equipment
Distribution Capital Items Included in 2010 ACE Plan				
34602	25 kV Feeder Extension Bissett Road	$1,036,178	$1,036,178	Overloaded Equipment
25575	Reliability Keltic Drive New Feeder	$708,813	$708,813	Overloaded Equipment

CI#	Project Title	2011 ACE Plan Budget ($)	Total Budget ($)	Ranking Category
Transmission Capital Items Included in 2011 ACE Plan				
40322	New Prospect Road Substation (Note: resubmitted in 2012 ACE)	$3,068,581	$3,068,581	Overloaded Equipment
Distribution Capital Items Included in 2011 ACE Plan				
25575	Reliability Keltic Drive New Feeder	$1,205,023	$1,205,023	Overloaded Equipment
40204	70W-322 Starr Street Rebuild	$546,821	$546,821	Overloaded Equipment
40338	16W-301 Hebron Reconductor	$350,000	$350,000	Overloaded Equipment

1

CI#	Project Title	2012 ACE Plan Budget ($)	Total Budget ($)	Ranking Category
Transmission Capital Items Included in 2012 ACE Plan				
40322	New Prospect Road Substation	$3,153,291	$3,184,409	Load Growth
40321	Install Canaan Road to Prospect Road Transmission Line	$2,104,620	$2,182,578	Load Growth
40323	Canaan Road Line Terminal	$967,187	$1,004,202	Load Growth
41520	Harbour East Substation - Eastern Passage	$394,305	$3,490,007	Load Growth
41519	Harbour East 138 kV Transmission Line (Note: resubmitted in 2015 ACE)	$211,410	$7,859,669	Load Growth
41592	88W New Recloser and Relocate 88W-322	$111,171	$111,171	Overloaded Equipment
41522	138kV Line Terminal at Dartmouth East Substation	$40,743	$788,149	Load Growth
Distribution Capital Items Included in 2012 ACE Plan				
41540	99V Highbury Rd New Feeders	$1,093,229	$1,093,229	Load Growth
41359	79V-402 Feeder Load Reduction	$797,378	$797,378	Overloaded Equipment
41341	1H-Water Street New Feeder	$280,657	$280,657	Overloaded Equipment
41354	519N-201 Partial Feeder Voltage Conversion to 25KV	$164,814	$164,814	Overloaded Equipment
41363	88W New Feeder	$269,616	$269,616	Overloaded Equipment

2

CI#	Project Title	2013 ACE Plan Budget ($)	Total Budget ($)	Ranking Category
Transmission Capital Items Included in 2013 ACE Plan				
43267	13V Gulch Hydro Replace 13V-GT1 and 13V-VR1	$954,407	$954,407	Overloaded Equipment
43323	Tuft's Cove Line Swap	$266,923	$266,923	Overloaded Equipment
43428	Remove 6S 4kV Switchgear Breakers	$1,196,753	$1,918,857	Load Growth

Distribution Capital Items Included in 2013 ACE Plan				
43286	6S Terrace Street Conversion Phase 1	$743,269	$743,269	Load Growth
43548	533S Mason Street Conversion	$449,764	$449,764	Load Growth

CI#	Project Title	2014 ACE Budget ($)	Total Budget ($)	Ranking Category
Transmission Capital Items Included in 2014 ACE Plan				
45306	George Street Substation Addition (Note: resubmitted in 2015 ACE)	$362,477	$3,771,492	Load Growth
Distribution Capital Items Included in 2014 ACE Plan				
45027	535N - Powell Road Partial Conversion Phase 1	$357,418	$357,418	Overloaded Equipment
44759	16N-301 - Stewiacke - Load Transfer	$258,816	$258,816	Load Growth
44833	99V-312 - Highbury New Feeder	$256,828	$256,828	Load Growth
45026	639N - Mount Thom Overload	$181,132	$181,132	Overloaded Equipment

CI#	Project Title	2015 ACE Plan Budget ($)	Total Budget ($)	Ranking Category
Transmission Capital Items Included in 2015 ACE Plan				
41519	Harbour East 138 kV Transmission Line	$497,838	$8,793,272	Load Growth
45306	George Street Substation Addition	$2,431,743	$4,300,627	Load Growth
46587	Metro Voltage Support Add Capacitor	$1,499,915	$2,522,277	Load Balancing
Distribution Capital Items Included in 2015 ACE Plan				
45031	3N Oxford Conversion Phase 1	$716,167	$716,167	Overloaded Equipment
46457	79V-401 Cameron Lake Voltage Conversion	$282,166	$637,939	Load Growth
46398	20H Spryfield Voltage Conversion	$329,169	$444,970	Load Growth
46251	36V-303 Saxon Double Circuit	$425,838	$425,838	Overloaded Equipment
43218	88W-323HA Tusket Islands Phase 3	$286,911	$286,911	Load Growth
46593	70V Bridgetown Voltage Conversion	$237,679	$237,679	Overloaded Equipment
46581	500N-301 Caribou Island Overload	$168,922	$168,922	Load Growth

(b) NS Power does not have a complete record of projects that were cancelled or delayed due to insufficient load growth. From a project development perspective, planning studies may identify the need for projects based on predicted load growth, but the projects are not typically submitted for approval until the load actually begins to materialize.

Projects that are known to have been cancelled or delayed due to insufficient load growth include one transmission project and one distribution project. George Street (CI45306) substation was deferred due to delayed realization of load and 16N-301 - Stewiacke - Load Transfer (CI44759) was cancelled due to lower than expected load growth and the opportunity to serve the load from a different feeder configuration. It is noted that the Harbour East substation (CI41520) project has also been deferred; however, the deferral was due to industrial load loss, not insufficient load growth.

Request IR-18:

Regarding the 2015 Annual Capital Expenditure Plan filing:

(a) Please explain the difference between the New Customer projects (D061 and D062) and the New Customer Upgrades (D004).

(b) Please explain whether the New Customer projects (D061 and D062) would be less expensive if the loads of the new customers were lower.

(i) Please provide any available estimates of the reduction in cost for the New Customer projects for a reduction in the new-customer loads (e.g., 10% or 20% from standard practice).

(c) Please explain whether the D004 New Customer Upgrades are improvements to existing facilities required by the load of the new customers.

(i) If so, please provide any analysis that NS Power has conducted to estimate the effect of lower loads by existing and new customers on the amount of New Customer Upgrades.

(d) Please explain how NS Power determined that the New Customer Upgrades should be estimated to be 52% of the D061 and D062 budgets, net of capital contributions.

(i) Please provide the corresponding percentages used in the 2010–2014 ACE filings.

Response IR-18:

(a) The D061 New Customers – Residential and D062 New Customers – Commercial routines provide for new service connections as requested by customers.

The D004 New Customer Upgrades routine provides for the upgrading and replacement work required due to new load on the distribution system. Work covered under this item includes:

(i) Conductor replacement required to serve additional load. This may be ampacity driven or be required to maintain acceptable voltage levels.

(ii) Pole replacement to allow space for a transformer installation required by a new customer, or to allow space for additional conductors on a pole.

(iii) Transformer replacement to provide sufficient capacity to serve new load.

(b) The cost of a standard new service would not change, but overall new customer projects would cost less if the load was smaller, assuming the number of higher amperage services requested would be reduced. Larger services require larger or dedicated transformers and potentially heavier triplex.

(i) NS Power has not estimated the reduction in cost for the New Customer projects for a reduction in the new-customer loads.

(c) Projects completed under the D004 New Customer Upgrades routine are based on the cumulative effect of the load of new customers, so increased load will drive an upgrade to existing facilities.

(i) NS Power has not conducted analysis to estimate the effect of lower loads by existing and new customers on the amount of New Customer Upgrades.

(d) The New Customer routine category is budgeted based on a historical average; it is not a forward projection calculation. The 52 percent is the calculated percentage outcome once the historical budgeting estimates are completed for D061 and D062. The calculation of 52 percent for the 2015 D004 Budget is the total budget divided by the total combined budget of D061 New Customer Residential and D062 Commercial routines.

(i) The corresponding percentages used in the 2010-2014 ACE Plan filings are as follows:

Year	Budget Percentage
2010	32%
2011	32%
2012	34%
2013	43%
2014	53%

Request IR-19:

For each ACE Plan, 2010–2015, please provide:

(a) The projected, budgeted and (where available) actual expenditures for New Customer projects and New Customer Upgrades.

(b) Estimated demand of the new customers causing the New Customers Upgrades.

Response IR-19:

(a) The projected, budgeted and (where available) actual expenditures for New Customer projects and New Customer Upgrades for ACE Plan 2010-2015 are included in the table below.

New Customer Projects		D061 New Customers - Residential ($)	D062 New Customers - Commercial ($)	D004 New Customer Upgrades ($)	Total New Customer ($)
2010	Actual	11,736,732	3,974,611	4,675,924	20,387,267
	ACE Budget	11,386,814	5,050,104	5,205,561	21,642,479
2011	Actual	10,425,434	6,118,883	5,637,919	22,182,236
	ACE Budget	12,701,508	5,429,324	5,858,803	23,989,635
2012	Actual	10,067,395	6,372,715	7,712,194	24,152,304
	ACE Budget	11,401,508	5,724,324	5,858,803	22,984,635
2013	Actual	7,883,372	5,742,000	6,985,119	20,610,491
	ACE Budget	11,005,924	5,805,247	7,187,286	23,998,457
2014	Actual	8,355,597	4,890,886	7,636,214	20,882,697
	ACE Budget	8,442,778	5,563,386	7,385,274	21,391,438
2015	Actual YTD	2,135,464	2,429,992	2,373,189	6,938,645
	ACE Budget	8,437,808	5,562,112	7,382,233	21,382,153

(b) NS Power does not calculate or predict the estimated demand of the new customers causing the New Customers Upgrades. Special projects are often justified based on distribution planning studies identifying load growth, but new customer routines are budgeted based on historical averages.

Request IR-20:

Regarding the NSPI presentation "Review of DSM Scenarios, Avoided Costs and Associated Planning Analysis," February 2015, slide 5.

(a) Please provide an annual comparison of load and capacity for each of the five plans:

(i) No DSM Plan

(ii) Half-Low DSM

(iii) Low DSM

(iv) Base DSM

(v) Synapse Mid-DSM

(b) For each of the five plans, please provide

(i) the annual DSM energy savings at the generation level and

(ii) the resulting forecast of energy requirements.

(c) Please identify which of the five DSM plans in this slide is most representative of the energy and capacity savings proposed in this proceeding by:

(i) Efficiency One.

(ii) NS Power.

(d) **For each of the five plans, please provide the annual capacity factor for each coal- or gas-fired plant.**

(e) **For each of the five plans, please provide the annual projected variable cost of each steam plant (coal, gas and Port Hawkesbury biomass) in $/MWh.**

(f) **For each of the five plans, please provide a comparison of the annual supply and requirement for renewable energy.**

(i) **Assuming that the Province were to relax the requirement that the Port Hawkesbury biomass plant be operated as a baseload unit, please provide the savings of reduced operation of that unit under each plan.**

(g) **Please provide any analysis that NS Power has conducted to test whether the Lingan 3 and 4 FGDs reduce costs in the Base DSM and Synapse cases.**

(h) **The October 15, 2014 Final IRP Report, p. 60, shows the study period cost of the Base DSM case with the scrubber (CRP2-17 FGD) to be nearly $100 million higher than the Base DSM case without the scrubber (CRP2-1). Please explain why the scrubber is included in the expansion plan for the Base DSM and Synapse Mid-DSM cases.**

(i) **Please provide the equivalent of Slide 7 for each of the DSM cases.**

(j) **Please provide all workpapers supporting Slides 7 and 8.**

(k) **Please provide the equivalent of Slide 8 for the Base DSM and Synapse Mid-DSM cases, without the scrubber.**

Response IR-20:

(a) Please refer to Synapse IR-1(d).

(b) Please refer to Attachment 1, also filed electronically.

(c) (i) The Efficiency One plan is similar to the first 3 years of the Base DSM scenario at costs similar to the Low DSM scenario

(ii) NS Power's alternative scenario is similar to the Low DSM scenario at costs similar to the Half Low DSM scenario.

(d) Please refer to Attachment 2, also filed electronically.

(e) Please refer to Attachment 3, also filed electronically.

(f) Please refer to Attachment 4, also filed electronically.

(i) This analysis has not been conducted.

(g) This analysis was conducted as part of the 2014 IRP.[1] Please refer to the table below.

CRP	**CRP2-17 FGD**	**CRP2-1**	**CRP Mid DSM/FGD (Synapse Model)**	**CRP Mid DSM (No FGD)**
FGD	FGD	No FGD	FGD	No FGD
DSM Level	Base	Base	Mid (Synapse)	Mid (Synapse)
Planning Period NPV ($M)[2]	10,731	10,760	10,623	10,641

[1] October 20, 2014: Synapse's Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integration resource plan, page 4.

(h) The planning period cost of the plan that includes an FGD is lower in both the Base DSM and Synapse Mid-DSM cases than the cost without an FGD (please refer to part (g) above). NS Power has evaluated the plans based on the net present value over the planning period, not study period, as directed by the Board in its letter dated November 5, 2014:

> The Board also anticipates that, in accordance with the Terms of Reference, selection of the Preferred Resource Plan will be based on the lowest cost NPV over the 25-year planning horizon.

(i) Please refer to Attachments 5 to 8, also filed electronically.

(j) Please refer to Confidential Attachments 9 to 12, also filed electronically.

(k) Please refer to Attachment 13, also filed electronically.

[2] NPV values include DSM Program Administrator costs and do not include DSM Participant costs or sustaining capital.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

(GWh)	No DSM		Half-Low DSM		Low DSM		Base DSM		Synapse Mid DSM	
	Energy Requirement	Cumulative DSM Savings	Energy Requirement	Cumulative DSM Savings	Energy Requirement	Cumulative DSM Savings	Energy Requirement	Cumulative DSM Savings	Energy Requirement	Cumulative DSM Savings
2015	11243	0	11199	44	11159	84	11128	114	11101	141
2016	11351	0	11253	98	11163	188	11099	252	11041	310
2017	11430	0	11279	150	11141	289	11039	391	10945	485
2018	11532	0	11339	194	11157	376	11023	510	10895	637
2019	11651	0	11415	236	11190	461	11024	627	10868	783
2020	10704	0	10429	275	10166	538	9966	739	9776	928
2021	10769	0	10457	312	10157	612	9922	847	9699	1070
2022	10884	0	10528	356	10184	700	9922	962	9668	1216
2023	11002	0	10604	398	10218	784	9932	1071	9645	1357
2024	11147	0	10705	441	10276	871	9961	1185	9641	1505
2025	11220	0	10738	482	10268	952	9933	1287	9586	1634
2026	11330	0	10807	524	10295	1035	9929	1401	9540	1790
2027	11428	0	10851	577	10286	1141	9889	1539	9457	1971
2028	11558	0	10932	626	10317	1241	9884	1674	9407	2151
2029	11629	0	10945	684	10272	1357	9802	1827	9281	2348
2030	11730	0	10981	749	10245	1486	9744	1986	9188	2542
2031	11833	0	11022	810	10224	1609	9690	2143	9101	2731
2032	11936	0	11064	872	10204	1732	9640	2296	9025	2911
2033	12040	0	11108	932	10188	1852	9595	2445	8955	3085
2034	12146	0	11154	992	10174	1972	9555	2590	8895	3251
2035	12252	0	11203	1049	10166	2087	9523	2729	8846	3407
2036	12360	0	11255	1105	10161	2199	9497	2863	8806	3554
2037	12469	0	11312	1157	10168	2301	9484	2985	8781	3688
2038	12579	0	11369	1211	10170	2409	9469	3110	8755	3824
2039	12690	0	11430	1261	10181	2510	9463	3227	8739	3952

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

No DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	6%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 2	7%	9%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 3	18%	18%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%
	Pt Aconi	87%	88%	87%	87%	87%	87%	85%	85%	85%	85%	85%	85%	85%	83%	79%	76%	44%	68%	41%	38%	32%	29%	22%	23%	14%
	Lingan 1	49%	41%	37%	16%	27%	12%	20%	6%	15%	16%	10%	11%	10%	9%	9%	5%	5%	2%	3%	3%	10%	8%	6%	2%	0%
	Lingan 2	15%	14%	10%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Lingan 3	48%	55%	47%	38%	40%	36%	34%	29%	29%	31%	79%	78%	77%	72%	74%	75%	78%	75%	76%	72%	74%	74%	68%	69%	60%
	Lingan 4	48%	39%	34%	27%	27%	23%	21%	21%	22%	23%	82%	83%	74%	62%	63%	71%	77%	71%	75%	67%	69%	60%	61%	44%	47%
	Trenton 5	67%	69%	65%	63%	62%	57%	61%	63%	62%	62%	41%	43%	41%	34%	30%	22%	23%	19%	21%	21%	0%	0%	0%	0%	0%
	Trenton 6	76%	86%	74%	73%	72%	68%	68%	61%	65%	66%	31%	35%	32%	27%	23%	13%	14%	13%	13%	15%	16%	18%	19%	15%	23%
	Tupper	86%	88%	85%	84%	75%	81%	79%	81%	81%	82%	78%	78%	72%	69%	61%	46%	58%	42%	53%	54%	52%	43%	41%	44%	36%
	TUC 4/5/6	57%	57%	57%	35%	24%	26%	25%	26%	25%	25%	25%	24%	24%	25%	25%	26%	44%	26%	43%	58%	27%	46%	63%	40%	51%
New Units in Resource Plan	CC145	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	70%	75%
	CT34	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CC145	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	60%	67%	77%	62%	69%
	CT100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	1%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Half-Low DSM	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	6%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 2	7%	9%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 3	17%	17%	3%	1%	1%	1%	1%	1%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	Pt Aconi	87%	88%	87%	87%	87%	86%	85%	85%	85%	85%	85%	85%	85%	85%	83%	80%	77%	78%	74%	71%	63%	46%	45%	30%	25%
	Lingan 1	49%	40%	35%	14%	25%	7%	13%	14%	4%	5%	6%	5%	6%	5%	5%	3%	2%	2%	2%	2%	7%	7%	7%	4%	0%
	Lingan 2	14%	13%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Lingan 3	48%	54%	46%	37%	39%	34%	32%	34%	26%	28%	78%	79%	79%	76%	72%	73%	71%	70%	69%	70%	73%	75%	76%	73%	74%
	Lingan 4	47%	38%	33%	26%	27%	22%	23%	24%	22%	23%	82%	79%	81%	71%	63%	63%	64%	62%	63%	64%	67%	72%	61%	63%	64%
	Trenton 5	67%	68%	65%	64%	63%	55%	60%	61%	61%	62%	37%	37%	38%	37%	35%	23%	23%	22%	19%	20%	0%	0%	0%	0%	0%
	Trenton 6	76%	86%	73%	74%	72%	66%	67%	69%	58%	60%	20%	21%	22%	21%	18%	16%	15%	12%	12%	12%	18%	16%	18%	12%	14%
	Tupper	86%	88%	84%	86%	75%	80%	79%	80%	80%	81%	72%	72%	74%	66%	62%	48%	45%	43%	38%	39%	34%	35%	33%	41%	42%
	TUC 4/5/6	56%	57%	57%	35%	25%	26%	25%	25%	26%	26%	25%	25%	25%	25%	25%	26%	26%	26%	26%	26%	26%	26%	26%	26%	25%
New Units in Resource Plan	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CC145	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%	26%	38%	54%	62%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT34	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	CT34	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Low DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 2	7%	8%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 3	17%	17%	2%	1%	1%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	Pt Aconi	87%	88%	87%	87%	87%	87%	85%	85%	85%	85%	85%	85%	85%	83%	80%	73%	72%	74%	73%	72%	77%	75%	70%	59%	57%
	Lingan 1	49%	38%	34%	10%	24%	5%	6%	7%	11%	12%	7%	8%	8%	6%	6%	5%	4%	2%	2%	1%	4%	4%	4%	2%	0%
	Lingan 2	14%	12%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Lingan 3	47%	53%	43%	38%	40%	29%	29%	31%	31%	32%	77%	77%	77%	74%	72%	67%	67%	68%	67%	66%	65%	64%	66%	72%	71%
	Lingan 4	47%	38%	31%	27%	27%	18%	20%	21%	23%	24%	83%	83%	83%	72%	63%	71%	70%	67%	66%	65%	59%	58%	59%	65%	64%
	Trenton 5	67%	68%	64%	65%	63%	55%	59%	60%	60%	61%	40%	40%	40%	37%	34%	25%	24%	22%	18%	17%	0%	0%	0%	0%	0%
	Trenton 6	76%	86%	72%	74%	73%	63%	66%	67%	68%	69%	24%	25%	25%	21%	19%	15%	14%	13%	11%	11%	17%	17%	12%	12%	13%
	Tupper	86%	87%	84%	87%	76%	80%	79%	80%	81%	81%	75%	75%	76%	67%	66%	51%	50%	48%	45%	43%	41%	37%	35%	31%	32%
	TUC 4/5/6	56%	57%	57%	31%	25%	26%	26%	26%	25%	26%	25%	25%	25%	26%	25%	26%	26%	26%	26%	26%	26%	26%	26%	26%	24%
New Units in Resource Plan	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT34	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Base DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 2	7%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 3	17%	16%	2%	1%	1%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	Pt Aconi	87%	88%	87%	86%	88%	86%	84%	84%	84%	85%	84%	85%	85%	84%	83%	80%	80%	80%	76%	76%	76%	75%	72%	74%	75%
	Lingan 1	48%	37%	30%	9%	18%	3%	4%	4%	5%	5%	3%	3%	3%	2%	2%	2%	2%	1%	1%	1%	2%	2%	2%	2%	0%
	Lingan 2	14%	12%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Lingan 3	47%	51%	43%	36%	41%	24%	24%	24%	26%	26%	77%	77%	77%	77%	76%	69%	70%	67%	69%	70%	65%	64%	62%	60%	60%
	Lingan 4	47%	37%	31%	25%	26%	16%	18%	19%	22%	22%	82%	81%	81%	80%	73%	64%	60%	60%	59%	57%	59%	59%	57%	55%	51%
	Trenton 5	67%	68%	64%	64%	64%	54%	59%	60%	60%	61%	36%	35%	35%	35%	32%	26%	23%	21%	21%	18%	0%	0%	0%	0%	0%
	Trenton 6	76%	86%	72%	74%	75%	62%	59%	60%	61%	59%	18%	18%	17%	16%	15%	12%	11%	11%	10%	9%	17%	17%	16%	15%	11%
	Tupper	86%	87%	84%	88%	77%	78%	78%	79%	80%	81%	71%	71%	72%	70%	62%	57%	53%	51%	49%	43%	42%	39%	35%	34%	36%
	TUC 4/5/6	56%	57%	56%	31%	25%	26%	26%	26%	26%	26%	25%	25%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	25%
New Units in Resource Plan	CT100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CT50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Synapse Mid DSM	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	4%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 2	6%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	TUC 3	17%	15%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	Pt Aconi	87%	88%	87%	85%	87%	86%	84%	84%	85%	85%	84%	84%	85%	84%	85%	83%	82%	82%	79%	78%	81%	79%	78%	76%	75%
	Lingan 1	48%	36%	32%	8%	13%	2%	3%	2%	3%	3%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
	Lingan 2	14%	12%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Lingan 3	47%	50%	41%	35%	43%	20%	19%	19%	21%	21%	76%	76%	76%	74%	74%	75%	73%	72%	65%	62%	66%	62%	60%	58%	57%
	Lingan 4	46%	37%	29%	24%	27%	16%	16%	18%	20%	21%	79%	82%	78%	77%	62%	67%	70%	70%	54%	49%	55%	51%	54%	54%	50%
	Trenton 5	66%	67%	63%	64%	65%	53%	59%	59%	59%	60%	28%	26%	26%	26%	24%	17%	17%	16%	15%	14%	0%	0%	0%	0%	0%
	Trenton 6	76%	86%	69%	74%	76%	59%	53%	53%	54%	54%	13%	13%	13%	11%	10%	5%	5%	4%	4%	4%	12%	11%	12%	12%	8%
	Tupper	85%	87%	83%	87%	78%	78%	78%	78%	79%	80%	67%	67%	69%	68%	78%	46%	46%	45%	54%	53%	34%	34%	33%	33%	32%
	TUC 4/5/6	56%	57%	56%	31%	25%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
New Units in Resource Plan																										

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

No DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Units	TUC 1	$ 63.77	$ 75.89	$ 97.87	$ 118.69	$ 131.06	$ 134.78	$ 137.68	$ 139.82	$ 143.03	$ 145.47	$ -	$ -	$ -
	TUC 2	$ 67.47	$ 64.23	$ 93.00	$ 120.73	$ 126.63	$ 130.77	$ 133.06	$ 134.87	$ 137.94	$ 140.61	$ 144.95	$ 147.58	$ 151.15
	TUC 3	$ 83.55	$ 79.28	$ 91.22	$ 117.93	$ 119.55	$ 123.99	$ 127.89	$ 133.04	$ 135.96	$ 138.28	$ 139.58	$ 141.76	$ 145.38
	Pt Aconi	$ 41.81	$ 40.51	$ 41.44	$ 42.69	$ 43.32	$ 42.78	$ 43.89	$ 45.07	$ 46.28	$ 47.40	$ 48.48	$ 49.81	$ 51.09
	Lingan 1	$ 47.17	$ 47.37	$ 49.04	$ 52.19	$ 53.17	$ 55.34	$ 55.24	$ 57.07	$ 56.70	$ 58.12	$ 61.75	$ 63.27	$ 65.01
	Lingan 2	$ 47.47	$ 48.06	$ 49.43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 47.07	$ 47.07	$ 48.72	$ 50.23	$ 51.47	$ 51.50	$ 52.96	$ 54.81	$ 56.01	$ 57.18	$ 52.77	$ 54.02	$ 55.31
	Lingan 4	$ 46.85	$ 46.79	$ 48.71	$ 50.62	$ 52.00	$ 52.10	$ 53.60	$ 55.02	$ 56.06	$ 57.22	$ 52.89	$ 54.12	$ 55.58
	Trenton 5	$ 47.14	$ 47.34	$ 46.90	$ 48.80	$ 50.02	$ 54.36	$ 56.29	$ 56.33	$ 58.10	$ 60.80	$ 61.59	$ 59.78	$ 61.85
	Trenton 6	$ 36.50	$ 36.60	$ 48.33	$ 49.27	$ 50.48	$ 55.25	$ 56.86	$ 56.98	$ 59.90	$ 61.22	$ 57.28	$ 64.68	$ 63.48
	Tupper	$ 43.57	$ 43.72	$ 45.32	$ 44.94	$ 46.18	$ 48.89	$ 50.19	$ 51.54	$ 52.92	$ 54.19	$ 55.90	$ 57.39	$ 59.26
	TUC 4/5/6	$ 65.35	$ 64.95	$ 66.63	$ 82.84	$ 96.54	$ 95.50	$ 97.52	$ 100.07	$ 101.88	$ 104.15	$ 105.78	$ 108.08	$ 110.57
	PHBM	$ 86.73	$ 87.73	$ 88.73	$ 89.73	$ 90.73	$ 91.73	$ 92.73	$ 93.73	$ 94.73	$ 95.73	$ 96.73	$ 97.73	$ 98.73
New Units in Resource Plan	CC145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CC145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147.94
	CT100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 128.17	$ 130.55	$ 134.85
	CT50	$ -	$ -	$ -	$ -	$ -	$ 143.37	$ 145.99	$ 145.60	$ 147.41	$ 149.80	$ 141.02	$ 144.46	$ 146.17

No DSM		**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Existing Units	TUC 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 2	$ 155.05	$ 157.93	$ 152.53	$ 154.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 3	$ 149.25	$ 153.94	$ 158.95	$ 161.74	$ 165.70	$ 170.78	$ 175.21	$ 180.21	$ 184.50	$ 194.02	$ 189.94	$ 201.89
	Pt Aconi	$ 52.50	$ 53.83	$ 55.25	$ 56.71	$ 58.06	$ 59.58	$ 61.34	$ 62.74	$ 64.68	$ 66.75	$ 68.44	$ 70.95
	Lingan 1	$ 67.30	$ 68.49	$ 70.79	$ 72.27	$ 71.58	$ 72.70	$ 74.43	$ 77.70	$ 81.08	$ 81.91	$ 82.97	$ -
	Lingan 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 56.79	$ 58.30	$ 59.51	$ 60.67	$ 62.14	$ 63.55	$ 65.37	$ 67.01	$ 68.85	$ 70.90	$ 73.15	$ 75.43
	Lingan 4	$ 56.89	$ 58.23	$ 59.68	$ 60.90	$ 62.42	$ 63.80	$ 65.69	$ 67.49	$ 69.46	$ 71.43	$ 73.87	$ 76.27
	Trenton 5	$ 61.05	$ 62.50	$ 63.71	$ 65.13	$ 66.97	$ 68.24	$ 69.86	$ -	$ -	$ -	$ -	$ -
	Trenton 6	$ 62.95	$ 63.65	$ 65.15	$ 66.67	$ 68.15	$ 69.60	$ 71.31	$ 75.59	$ 74.76	$ 76.49	$ 78.36	$ 80.56
	Tupper	$ 61.01	$ 60.17	$ 63.40	$ 65.34	$ 63.16	$ 66.27	$ 67.95	$ 72.28	$ 72.86	$ 72.83	$ 72.35	$ 74.66
	TUC 4/5/6	$ 113.20	$ 115.74	$ 119.00	$ 113.88	$ 124.60	$ 120.70	$ 120.89	$ 134.53	$ 130.54	$ 133.08	$ 140.87	$ 142.27
	PHBM	$ 99.73	$ 100.73	$ 101.73	$ 102.73	$ 103.73	$ 104.73	$ 105.73	$ 106.73	$ 107.73	$ 108.73	$ 109.73	$ 110.73
New Units in Resource Plan	CC145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122.69	$ 127.74
	CT34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 189.07	$ 198.47	$ 202.56
	CC145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 110.33	$ 115.02	$ 120.51	$ 122.12	$ 127.42
	CT100	$ -	$ -	$ -	$ -	$ -	$ 154.70	$ 158.58	$ 164.88	$ 168.17	$ 172.94	$ 177.73	$ 182.71
	CT50	$ -	$ -	$ -	$ -	$ 172.26	$ 177.37	$ 181.62	$ 181.60	$ 187.10	$ 192.84	$ 200.01	$ 206.72
	CT50	$ -	$ -	$ -	$ -	$ 171.51	$ 177.15	$ 182.19	$ 178.52	$ 184.87	$ 191.06	$ 198.18	$ 207.77
	CT50	$ -	$ -	$ 161.36	$ 163.94	$ 168.45	$ 173.95	$ 181.38	$ 173.43	$ 181.29	$ 186.67	$ 195.13	$ 207.47
	CT50	$ 152.37	$ 158.35	$ 157.54	$ 160.48	$ 165.35	$ 169.41	$ 179.51	$ 169.14	$ 178.50	$ 181.37	$ 193.57	$ 206.15
	CT100	$ 132.89	$ 137.36	$ 143.14	$ 145.92	$ 149.98	$ 158.02	$ 160.74	$ 161.04	$ 169.74	$ 172.96	$ 182.25	$ 183.59
	CT50	$ 151.64	$ 161.16	$ 152.53	$ 156.58	$ 163.25	$ 164.68	$ 177.07	$ 166.34	$ 176.58	$ 177.19	$ 192.85	$ 203.67

Half-Low DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Units	TUC 1	$ 63.77	$ 76.18	$ 99.93	$ 116.00	$ 129.56	$ 130.98	$ 136.04	$ 138.50	$ 133.87	$ 140.95	$ -	$ -	$ -
	TUC 2	$ 67.54	$ 63.99	$ 95.35	$ 119.02	$ 127.73	$ 131.19	$ 134.39	$ 136.85	$ 137.33	$ 141.95	$ 144.51	$ 145.30	$ 149.39
	TUC 3	$ 83.85	$ 78.83	$ 94.70	$ 114.93	$ 121.70	$ 126.50	$ 129.50	$ 131.80	$ 136.31	$ 139.04	$ 140.63	$ 142.85	$ 146.24
	Pt Aconi	$ 41.81	$ 40.51	$ 41.44	$ 42.69	$ 43.31	$ 42.79	$ 43.89	$ 45.07	$ 46.26	$ 47.38	$ 48.50	$ 49.80	$ 51.08
	Lingan 1	$ 47.20	$ 47.46	$ 49.07	$ 51.85	$ 53.78	$ 54.83	$ 56.19	$ 57.68	$ 58.87	$ 60.21	$ 62.49	$ 63.94	$ 65.30
	Lingan 2	$ 47.75	$ 48.14	$ 49.40	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 47.02	$ 47.14	$ 48.72	$ 50.43	$ 51.55	$ 51.75	$ 53.22	$ 54.49	$ 56.19	$ 57.57	$ 52.83	$ 53.97	$ 55.28
	Lingan 4	$ 46.85	$ 46.84	$ 48.68	$ 50.58	$ 52.09	$ 52.08	$ 53.35	$ 54.70	$ 55.45	$ 57.11	$ 52.94	$ 54.25	$ 55.53
	Trenton 5	$ 47.05	$ 46.97	$ 46.92	$ 48.76	$ 50.01	$ 54.27	$ 56.35	$ 57.87	$ 57.58	$ 59.42	$ 56.42	$ 57.79	$ 59.94
	Trenton 6	$ 36.50	$ 36.60	$ 47.92	$ 49.23	$ 50.48	$ 54.30	$ 56.18	$ 58.42	$ 57.83	$ 59.82	$ 57.94	$ 59.21	$ 60.50
	Tupper	$ 43.58	$ 43.72	$ 45.34	$ 44.84	$ 46.17	$ 48.90	$ 50.17	$ 51.58	$ 52.97	$ 54.24	$ 55.82	$ 57.63	$ 58.97
	TUC 4/5/6	$ 65.35	$ 65.21	$ 66.45	$ 83.30	$ 96.48	$ 96.50	$ 98.29	$ 99.83	$ 102.62	$ 103.99	$ 106.12	$ 108.06	$ 110.34
	PHBM	$ 86.73	$ 90.20	$ 93.81	$ 97.56	$ 101.46	$ 105.52	$ 109.74	$ 114.13	$ 118.70	$ 123.44	$ 128.38	$ 133.52	$ 138.86
New Units in Resource Plan	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CC145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140.09	$ 144.46
	CT34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 141.14	$ 146.38

Half-Low DSM		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 2	$ 153.34	$ 157.37	$ 157.25	$ 155.43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 3	$ 149.86	$ 153.79	$ 155.69	$ 157.79	$ 161.00	$ 165.31	$ 169.61	$ 174.04	$ 180.35	$ 186.32	$ 189.62	$ 200.69
	Pt Aconi	$ 52.42	$ 53.69	$ 55.12	$ 56.64	$ 57.98	$ 59.54	$ 61.17	$ 62.88	$ 64.65	$ 66.60	$ 68.38	$ 70.52
	Lingan 1	$ 67.39	$ 69.21	$ 68.28	$ 70.07	$ 71.94	$ 73.79	$ 75.67	$ 79.94	$ 82.76	$ 84.41	$ 86.02	$ -
	Lingan 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 56.74	$ 58.11	$ 59.51	$ 60.84	$ 62.24	$ 63.78	$ 65.51	$ 67.16	$ 68.91	$ 70.81	$ 73.14	$ 75.24
	Lingan 4	$ 57.22	$ 58.46	$ 59.66	$ 60.95	$ 62.39	$ 63.90	$ 65.68	$ 67.44	$ 69.31	$ 71.45	$ 73.81	$ 75.89
	Trenton 5	$ 60.63	$ 62.34	$ 64.86	$ 65.57	$ 67.51	$ 69.23	$ 70.85	$ -	$ -	$ -	$ -	$ -
	Trenton 6	$ 62.06	$ 63.43	$ 65.22	$ 66.97	$ 68.87	$ 69.95	$ 71.65	$ 74.06	$ 75.92	$ 77.82	$ 79.38	$ 80.72
	Tupper	$ 59.82	$ 59.68	$ 64.29	$ 64.94	$ 64.74	$ 63.67	$ 65.26	$ 71.94	$ 72.14	$ 73.35	$ 73.66	$ 74.99
	TUC 4/5/6	$ 113.85	$ 115.74	$ 119.40	$ 122.55	$ 124.85	$ 127.30	$ 131.40	$ 135.60	$ 141.35	$ 144.35	$ 147.86	$ 151.84
	PHBM	$ 144.41	$ 150.19	$ 156.20	$ 162.44	$ 168.94	$ 175.70	$ 182.73	$ 190.04	$ 197.64	$ 205.54	$ 213.76	$ 222.32
New Units in Resource Plan	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 207.86
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 188.67	$ 208.31
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 177.19	$ 183.93	$ 185.53	$ 206.42
	CC145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108.17	$ 110.74	$ 114.16	$ 119.82	$ 125.39
	CT50	$ -	$ -	$ -	$ -	$ 157.39	$ 175.48	$ 179.89	$ 172.12	$ 176.10	$ 180.45	$ 183.65	$ 203.12
	CT50	$ -	$ -	$ -	$ 151.25	$ 151.11	$ 171.01	$ 176.36	$ 169.59	$ 175.79	$ 178.64	$ 183.11	$ 199.66
	CT34	$ 148.74	$ 151.98	$ 163.46	$ 163.88	$ 166.54	$ 181.48	$ 186.06	$ 185.39	$ 187.96	$ 198.12	$ 203.55	$ 205.10
	CT34	$ 151.15	$ 154.48	$ 165.71	$ 162.59	$ 165.32	$ 176.18	$ 180.40	$ 180.03	$ 182.31	$ 191.38	$ 194.60	$ 205.24

Low DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Units	TUC 1	$ 63.77	$ 75.82	$ 100.89	$ 116.88	$ 128.31	$ 127.28	$ 134.20	$ 135.88	$ 142.40	$ 143.49	$ -	$ -	$ -
	TUC 2	$ 67.60	$ 64.54	$ 95.78	$ 114.70	$ 128.42	$ 129.75	$ 133.60	$ 136.22	$ 140.08	$ 142.65	$ 144.43	$ 147.29	$ 151.05
	TUC 3	$ 84.07	$ 78.74	$ 95.18	$ 112.69	$ 121.24	$ 127.17	$ 130.00	$ 132.58	$ 135.69	$ 138.17	$ 139.80	$ 142.43	$ 145.95
	Pt Aconi	$ 41.81	$ 40.51	$ 41.45	$ 42.69	$ 43.31	$ 42.78	$ 43.89	$ 45.07	$ 46.26	$ 47.38	$ 48.50	$ 49.82	$ 51.10
	Lingan 1	$ 47.22	$ 47.56	$ 49.20	$ 52.48	$ 53.88	$ 54.59	$ 55.54	$ 57.00	$ 57.61	$ 59.14	$ 62.27	$ 64.37	$ 65.78
	Lingan 2	$ 47.77	$ 48.31	$ 49.61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 47.03	$ 47.19	$ 48.78	$ 50.36	$ 51.52	$ 51.92	$ 53.49	$ 54.82	$ 56.13	$ 57.43	$ 52.84	$ 54.06	$ 55.37
	Lingan 4	$ 46.86	$ 46.86	$ 48.62	$ 50.56	$ 52.04	$ 52.07	$ 53.37	$ 54.91	$ 56.01	$ 57.49	$ 52.91	$ 54.13	$ 55.45
	Trenton 5	$ 46.97	$ 46.63	$ 46.95	$ 48.71	$ 49.97	$ 53.45	$ 56.38	$ 57.16	$ 59.00	$ 60.76	$ 58.41	$ 57.92	$ 59.31
	Trenton 6	$ 36.50	$ 36.60	$ 47.36	$ 49.21	$ 50.44	$ 53.53	$ 54.61	$ 57.27	$ 59.55	$ 61.36	$ 57.81	$ 63.54	$ 65.83
	Tupper	$ 43.58	$ 43.73	$ 45.36	$ 44.78	$ 46.15	$ 48.93	$ 50.19	$ 51.58	$ 52.93	$ 54.22	$ 56.07	$ 57.59	$ 59.02
	TUC 4/5/6	$ 65.30	$ 65.20	$ 66.84	$ 86.92	$ 96.41	$ 96.38	$ 98.40	$ 100.09	$ 102.17	$ 104.32	$ 105.28	$ 107.44	$ 109.79
	PHBM	$ 86.73	$ 90.20	$ 93.81	$ 97.56	$ 101.46	$ 105.52	$ 109.74	$ 114.13	$ 118.70	$ 123.44	$ 128.38	$ 133.52	$ 138.86
New Units in Resource Plan	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Low DSM		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 2	$ 153.11	$ 157.12	$ 157.60	$ 160.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 3	$ 148.85	$ 152.97	$ 156.00	$ 159.34	$ 162.68	$ 166.57	$ 170.00	$ 175.58	$ 180.41	$ 186.77	$ 192.03	$ 200.59
	Pt Aconi	$ 52.49	$ 53.80	$ 55.42	$ 56.91	$ 58.20	$ 59.66	$ 61.26	$ 62.75	$ 64.60	$ 66.56	$ 68.75	$ 70.60
	Lingan 1	$ 67.68	$ 69.04	$ 71.56	$ 73.52	$ 72.56	$ 74.21	$ 76.49	$ 80.30	$ 83.33	$ 85.18	$ 84.32	$ -
	Lingan 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 56.89	$ 58.14	$ 60.19	$ 61.58	$ 62.80	$ 64.26	$ 66.10	$ 67.43	$ 69.35	$ 71.25	$ 73.29	$ 75.44
	Lingan 4	$ 57.06	$ 58.15	$ 60.03	$ 61.31	$ 62.67	$ 64.16	$ 65.95	$ 67.43	$ 69.42	$ 71.38	$ 73.77	$ 75.84
	Trenton 5	$ 60.98	$ 62.60	$ 64.36	$ 66.56	$ 67.40	$ 69.07	$ 71.09	$ -	$ -	$ -	$ -	$ -
	Trenton 6	$ 62.22	$ 63.77	$ 69.66	$ 67.51	$ 68.97	$ 70.47	$ 72.30	$ 75.18	$ 76.31	$ 78.22	$ 80.40	$ 82.82
	Tupper	$ 60.50	$ 60.42	$ 64.52	$ 66.32	$ 66.27	$ 65.41	$ 66.11	$ 72.96	$ 74.06	$ 72.85	$ 73.49	$ 75.42
	TUC 4/5/6	$ 112.86	$ 116.39	$ 119.38	$ 122.09	$ 124.61	$ 128.27	$ 131.59	$ 136.59	$ 139.96	$ 144.38	$ 149.79	$ 152.46
	PHBM	$ 144.41	$ 150.19	$ 156.20	$ 162.44	$ 168.94	$ 175.70	$ 182.73	$ 190.04	$ 197.64	$ 205.54	$ 213.76	$ 222.32
New Units in Resource Plan	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 207.02
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 207.69
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 183.37	$ 191.26	$ 189.05	$ 195.78	$ 205.95
	CT34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 182.58	$ 189.02	$ 190.29	$ 197.42	$ 210.74
	CT50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 178.51	$ 187.92	$ 182.66	$ 187.18	$ 200.92
	CT50	$ -	$ -	$ -	$ -	$ 164.10	$ 166.95	$ 168.79	$ 170.43	$ 182.69	$ 175.32	$ 174.77	$ 191.17

Base DSM		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Units	TUC 1	$ 63.76	$ 75.67	$ 103.55	$ 127.36	$ 126.58	$ 126.41	$ 130.15	$ 131.35	$ 134.78	$ 136.72	$ -	$ -	$ -
	TUC 2	$ 67.61	$ 64.38	$ 97.38	$ 124.44	$ 128.67	$ 128.71	$ 132.21	$ 134.24	$ 138.95	$ 141.04	$ 142.54	$ 144.71	$ 148.19
	TUC 3	$ 84.20	$ 78.55	$ 96.38	$ 116.79	$ 123.25	$ 127.42	$ 130.08	$ 132.63	$ 135.96	$ 138.60	$ 140.11	$ 142.56	$ 146.01
	Pt Aconi	$ 41.81	$ 40.51	$ 41.45	$ 42.71	$ 43.30	$ 42.80	$ 43.93	$ 45.11	$ 46.29	$ 47.38	$ 48.50	$ 49.82	$ 51.10
	Lingan 1	$ 47.24	$ 47.61	$ 49.22	$ 52.82	$ 53.78	$ 54.60	$ 56.04	$ 57.63	$ 58.86	$ 60.36	$ 61.22	$ 62.68	$ 64.20
	Lingan 2	$ 47.77	$ 48.42	$ 49.37	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 47.05	$ 47.25	$ 48.73	$ 50.44	$ 51.64	$ 52.15	$ 53.58	$ 54.97	$ 56.20	$ 57.63	$ 52.89	$ 54.06	$ 55.38
	Lingan 4	$ 46.87	$ 46.88	$ 48.65	$ 50.76	$ 52.03	$ 51.98	$ 53.28	$ 54.83	$ 55.63	$ 57.32	$ 52.95	$ 54.21	$ 55.52
	Trenton 5	$ 46.90	$ 46.30	$ 46.96	$ 48.73	$ 49.89	$ 52.81	$ 55.33	$ 57.35	$ 59.43	$ 59.25	$ 56.55	$ 58.05	$ 59.50
	Trenton 6	$ 36.50	$ 36.60	$ 47.38	$ 49.18	$ 50.32	$ 52.99	$ 53.50	$ 54.84	$ 56.49	$ 59.70	$ 57.97	$ 59.38	$ 60.78
	Tupper	$ 43.59	$ 43.74	$ 45.01	$ 44.77	$ 46.09	$ 48.98	$ 50.21	$ 51.63	$ 52.98	$ 54.24	$ 55.01	$ 56.53	$ 57.53
	TUC 4/5/6	$ 65.28	$ 65.44	$ 67.11	$ 86.97	$ 96.10	$ 96.52	$ 98.82	$ 100.76	$ 102.14	$ 104.42	$ 106.68	$ 108.64	$ 110.85
	PHBM	$ 86.73	$ 90.20	$ 93.81	$ 97.56	$ 101.46	$ 105.52	$ 109.74	$ 114.13	$ 118.70	$ 123.44	$ 128.38	$ 133.52	$ 138.86
New Units in Resource Plan	CT 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CT 50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Base DSM		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 2	$ 150.35	$ 154.71	$ 154.97	$ 158.60	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 3	$ 148.95	$ 153.68	$ 156.55	$ 160.24	$ 161.73	$ 165.47	$ 169.75	$ 178.02	$ 182.33	$ 187.28	$ 190.43	$ 196.38
	Pt Aconi	$ 52.44	$ 53.68	$ 55.12	$ 56.52	$ 57.93	$ 59.58	$ 61.10	$ 62.84	$ 64.68	$ 66.59	$ 68.61	$ 70.53
	Lingan 1	$ 65.93	$ 67.42	$ 69.09	$ 70.73	$ 72.63	$ 74.10	$ 76.02	$ 78.23	$ 80.65	$ 82.76	$ 84.72	$ -
	Lingan 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 56.79	$ 58.05	$ 59.56	$ 60.80	$ 62.30	$ 64.10	$ 65.76	$ 67.37	$ 69.24	$ 71.46	$ 73.86	$ 76.00
	Lingan 4	$ 56.95	$ 58.29	$ 59.60	$ 60.89	$ 62.34	$ 63.72	$ 65.46	$ 67.29	$ 69.15	$ 71.15	$ 73.63	$ 75.76
	Trenton 5	$ 61.02	$ 62.45	$ 66.43	$ 66.06	$ 67.78	$ 69.28	$ 71.00	$ -	$ -	$ -	$ -	$ -
	Trenton 6	$ 62.52	$ 63.92	$ 66.09	$ 67.30	$ 69.26	$ 70.60	$ 72.49	$ 74.41	$ 76.76	$ 78.96	$ 81.66	$ 84.18
	Tupper	$ 59.06	$ 57.96	$ 64.54	$ 65.88	$ 66.59	$ 66.97	$ 66.01	$ 73.38	$ 74.21	$ 74.89	$ 75.81	$ 76.15
	TUC 4/5/6	$ 113.64	$ 116.49	$ 119.56	$ 121.66	$ 124.56	$ 128.53	$ 132.62	$ 135.31	$ 140.27	$ 143.02	$ 147.30	$ 151.64
	PHBM	$ 144.41	$ 150.19	$ 156.20	$ 162.44	$ 168.94	$ 175.70	$ 182.73	$ 190.04	$ 197.64	$ 205.54	$ 213.76	$ 222.32
New Units in Resource Plan	CT 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175.73
	CT 50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 184.39	$ 185.76	$ 191.32	$ 187.05	$ 187.94

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	Synapse Mid DSM	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Existing Units	TUC 1	$ 64.86	$ 74.41	$ 114.96	$ 133.91	$ 132.25	$ 123.52	$ 121.72	$ 126.87	$ 129.73	$ 129.78	$ -	$ -	$ -
	TUC 2	$ 68.18	$ 65.42	$ 106.83	$ 136.65	$ 132.29	$ 127.42	$ 127.05	$ 131.84	$ 136.13	$ 136.96	$ 142.76	$ 141.77	$ 145.00
	TUC 3	$ 85.36	$ 80.52	$ 102.49	$ 129.15	$ 128.05	$ 127.67	$ 130.44	$ 133.29	$ 136.13	$ 138.75	$ 140.59	$ 142.62	$ 145.59
	Pt Aconi	$ 41.81	$ 40.51	$ 41.45	$ 42.72	$ 43.30	$ 42.80	$ 43.90	$ 45.09	$ 46.27	$ 47.39	$ 48.50	$ 49.83	$ 51.10
	Lingan 1	$ 47.24	$ 47.50	$ 49.31	$ 52.72	$ 53.92	$ 54.96	$ 56.38	$ 57.58	$ 58.88	$ 60.29	$ 61.23	$ 62.80	$ 64.41
	Lingan 2	$ 47.81	$ 48.34	$ 49.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 47.00	$ 47.23	$ 48.87	$ 50.56	$ 51.83	$ 52.70	$ 53.68	$ 55.13	$ 56.39	$ 57.79	$ 52.87	$ 54.14	$ 55.43
	Lingan 4	$ 46.85	$ 46.86	$ 48.65	$ 50.71	$ 51.76	$ 52.08	$ 53.21	$ 54.86	$ 55.71	$ 57.50	$ 52.99	$ 54.17	$ 55.65
	Trenton 5	$ 46.84	$ 46.17	$ 46.99	$ 48.72	$ 49.83	$ 53.52	$ 54.27	$ 55.77	$ 54.52	$ 59.56	$ 56.88	$ 58.26	$ 59.85
	Trenton 6	$ 36.50	$ 36.60	$ 47.34	$ 49.20	$ 50.26	$ 51.32	$ 52.37	$ 54.11	$ 58.92	$ 56.84	$ 58.26	$ 59.76	$ 61.33
	Tupper	$ 43.63	$ 43.75	$ 44.71	$ 44.79	$ 46.02	$ 49.00	$ 50.22	$ 51.65	$ 52.99	$ 54.28	$ 52.42	$ 53.78	$ 54.98
	TUC 4/5/6	$ 65.46	$ 65.38	$ 67.07	$ 87.81	$ 95.84	$ 95.90	$ 98.46	$ 101.12	$ 103.04	$ 104.86	$ 105.91	$ 108.07	$ 110.65
	PHBM	$ 86.73	$ 90.20	$ 93.81	$ 97.56	$ 101.46	$ 105.52	$ 109.74	$ 114.13	$ 118.70	$ 123.44	$ 128.38	$ 133.52	$ 138.86
New Units in Resource Plan														

Synapse Mid DSM		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Units	TUC 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 2	$ 145.56	$ 149.94	$ 145.62	$ 148.61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TUC 3	$ 148.79	$ 151.57	$ 153.61	$ 157.61	$ 158.20	$ 165.72	$ 166.32	$ 177.61	$ 182.01	$ 186.91	$ 191.49	$ 196.63
	Pt Aconi	$ 52.43	$ 53.62	$ 55.01	$ 56.42	$ 57.84	$ 59.36	$ 60.93	$ 62.59	$ 64.45	$ 66.36	$ 68.47	$ 70.47
	Lingan 1	$ 66.25	$ 67.57	$ 69.36	$ 70.94	$ 72.83	$ 74.46	$ 76.44	$ 78.22	$ 80.97	$ 82.86	$ 85.43	$ -
	Lingan 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lingan 3	$ 56.98	$ 58.11	$ 59.35	$ 60.68	$ 62.17	$ 63.70	$ 65.40	$ 67.19	$ 69.11	$ 71.12	$ 73.42	$ 75.56
	Lingan 4	$ 57.10	$ 59.11	$ 59.75	$ 61.00	$ 62.39	$ 64.03	$ 65.79	$ 67.48	$ 69.17	$ 71.08	$ 73.34	$ 75.79
	Trenton 5	$ 61.45	$ 62.95	$ 64.42	$ 65.93	$ 67.71	$ 69.16	$ 70.87	$ -	$ -	$ -	$ -	$ -
	Trenton 6	$ 62.97	$ 64.33	$ 64.44	$ 66.04	$ 67.64	$ 69.15	$ 70.95	$ 74.69	$ 77.09	$ 79.05	$ 81.47	$ 84.64
	Tupper	$ 56.39	$ 57.35	$ 59.47	$ 60.78	$ 62.34	$ 63.59	$ 65.18	$ 69.03	$ 69.76	$ 71.86	$ 74.00	$ 76.16
	TUC 4/5/6	$ 113.30	$ 115.71	$ 119.92	$ 122.87	$ 125.83	$ 128.68	$ 133.35	$ 137.09	$ 140.56	$ 145.03	$ 149.35	$ 152.52
	PHBM	$ 144.41	$ 150.19	$ 156.20	$ 162.44	$ 168.94	$ 175.70	$ 182.73	$ 190.04	$ 197.64	$ 205.54	$ 213.76	$ 222.32
New Units in Resource Plan													

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(GWh)	No DSM		Half-Low DSM		Low DSM		Base DSM		Synapse Mid DSM	
	Renewable Requirement	Renewable Supply	Renewable Requirement	Renewable Supply	Renewable Requirement	Renewable Supply	Renewable Requirement	Renewable Supply	Renewable Requirement	Renewable Supply
2015	2620	2700	2609	2700	2600	2700	2593	2700	2587	2700
2016	2641	2809	2618	2809	2597	2809	2583	2809	2569	2809
2017	2660	3188	2625	3188	2594	3188	2570	3188	2549	3188
2018	2685	4000	2640	4000	2599	4000	2568	4000	2539	4000
2019	2712	4020	2657	4020	2606	4000	2567	4000	2532	4000
2020	3964	4077	3863	4077	3766	4057	3692	4057	3623	4057
2021	3988	4069	3873	4069	3763	4049	3677	4049	3595	4049
2022	4031	4573	3900	3972	3774	3952	3677	3952	3584	3952
2023	4074	4450	3928	4450	3786	3809	3681	3809	3576	3809
2024	4128	4458	3965	4458	3807	3815	3692	3815	3575	3815
2025	4155	4450	3977	4450	3805	3809	3682	3809	3554	3809
2026	4195	4450	4003	4450	3815	3809	3681	3809	3538	3809
2027	4232	4450	4019	4450	3812	3809	3666	3809	3507	3809
2028	4280	4458	4049	4458	3823	3815	3664	3815	3489	3815
2029	4306	4450	4054	4450	3807	3809	3634	3809	3443	3809
2030	4343	4450	4068	4450	3797	3809	3613	3809	3409	3809
2031	4381	4450	4083	4450	3790	3809	3594	3809	3378	3809
2032	4419	4905	4098	4458	3782	3815	3575	3815	3350	3815
2033	4458	4896	4115	4450	3777	3809	3559	3809	3324	3809
2034	4497	4896	4132	4450	3772	3809	3545	3809	3302	3809
2035	4536	4896	4150	4450	3769	3809	3533	3809	3285	3809
2036	4576	4905	4169	4458	3768	3815	3524	3815	3270	3815
2037	4616	4896	4191	4450	3770	3809	3519	3809	3261	3809
2038	4656	4896	4211	4450	3771	3809	3514	3809	3252	3809
2039	4698	4896	4234	4450	3775	3809	3512	3809	3246	3809

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Avoided Energy and Capacity Costs
Mid DSM Case

	Difference in Cumulative Additions No DSM-Mid DSM	Avoided Capacity Costs k$	Avoided Capacity Costs $/kW	Total Cost Difference No DSM- Mid DSM k$	Avoided Energy Costs Total Cost less Capacity Costs k$	Difference in Load No DSM- Mid DSM GWh	Avoided Energy Costs $/MWh
2015	0.0	0	0	7,883	7,883	141	56
2016	0.0	0	0	18,229	18,229	310	59
2017	0.0	0	0	27,944	27,944	485	58
2018	0.0	0	0	34,420	34,420	637	54
2019	15.0	6,266	418	50,934	44,668	783	57
2020	64.4	12,607	196	67,830	55,223	928	59
2021	64.4	11,497	179	78,662	67,165	1070	63
2022	164.4	31,314	190	128,698	97,384	1216	80
2023	179.4	37,111	207	147,050	109,939	1357	81
2024	179.4	35,981	201	159,365	123,383	1505	82
2025	279.4	60,117	215	195,141	135,024	1634	83
2026	279.4	56,481	202	207,913	151,432	1790	85
2027	328.8	65,225	198	237,662	172,437	1971	87
2028	328.8	64,018	195	262,596	198,578	2151	92
2029	328.8	64,118	195	289,144	225,027	2348	96
2030	378.2	73,158	193	337,300	264,142	2541	104
2031	378.2	71,596	189	368,931	297,334	2731	109
2032	495.0	93,014	188	426,724	333,710	2910	115
2033	595.0	114,637	193	449,079	334,443	3085	108
2034	595.0	114,242	192	511,772	397,529	3250	122
2035	740.0	145,259	196	603,052	457,793	3406	134
2036	740.0	141,024	191	638,819	497,794	3553	140
2037	774.0	150,558	195	691,649	541,091	3687	147
2038	919.0	179,369	195	767,383	588,014	3823	154
2039	919.0	173,432	189	798,624	625,192	3951	158
NPV	2,993	586,297			2,038,179	20,065	

Levelized Capacity Cost 2015-2039 ($/kW) **$196**

Levelized Energy Cost 2015-2039 ($/MWh) **$102**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Avoided Energy and Capacity Costs
Base DSM

	Difference in Cumulative Additions No DSM-Base DSM	Avoided Capacity Costs k$	Avoided Capacity Costs $/kW	Total Cost Difference No DSM- Base DSM k$	Avoided Energy Costs Total Cost less Capacity Costs k$	Difference in Load No DSM- Base DSM GWh	Avoided Energy Costs $/MWh
2015	0.0	0	0	7,265	7,265	114	64
2016	0.0	0	0	15,030	15,030	252	60
2017	0.0	0	0	22,808	22,808	391	58
2018	0.0	0	0	28,005	28,005	510	55
2019	15.0	6,266	418	42,116	35,850	627	57
2020	64.4	12,607	196	56,650	44,043	739	60
2021	64.4	11,497	179	64,089	52,592	847	62
2022	164.4	31,314	190	111,892	80,578	962	84
2023	179.4	37,111	207	127,591	90,479	1071	85
2024	179.4	35,981	201	137,656	101,675	1185	86
2025	279.4	60,117	215	171,749	111,632	1287	87
2026	279.4	56,481	202	180,830	124,349	1401	89
2027	328.8	65,225	198	207,856	142,631	1539	93
2028	328.8	64,018	195	228,863	164,845	1674	98
2029	328.8	64,118	195	250,895	186,777	1827	102
2030	378.2	73,158	193	287,935	214,777	1986	108
2031	378.2	71,596	189	313,590	241,994	2143	113
2032	495.0	93,014	188	367,929	274,915	2296	120
2033	595.0	114,637	193	389,905	275,268	2445	113
2034	595.0	114,242	192	451,460	337,217	2590	130
2035	690.6	135,293	196	524,812	389,519	2729	143
2036	690.6	132,656	192	561,079	428,423	2863	150
2037	724.6	142,166	196	606,057	463,891	2985	155
2038	869.6	170,972	197	679,187	508,215	3110	163
2039	769.6	133,285	173	677,663	544,378	3227	169
NPV	2,909	568,272			1,703,050	15,926	

evelized Capacity Cost 2015-2039 ($/kW) **$195**

Levelized Energy Cost 2015-2039 ($/MWh) **$107**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Avoided Energy and Capacity Costs
Low DSM

	Difference in Cumulative Additions No DSM-Low DSM	Avoided Capacity Costs k$	Avoided Capacity Costs $/kW	Total Cost Difference No DSM- Low DSM k$	Avoided Energy Costs Total Cost less Capacity Costs k$	Difference in Load No DSM-Low DSM GWh	Avoided Energy Costs $/MWh
2015	0.0	0	0	5,355	5,355	84	64
2016	0.0	0	0	11,294	11,294	188	60
2017	0.0	0	0	16,916	16,916	289	59
2018	0.0	0	0	20,939	20,939	376	56
2019	15.0	6,266	418	32,199	25,933	461	56
2020	64.4	12,607	196	44,750	32,143	538	60
2021	64.4	11,497	179	49,040	37,543	612	61
2022	164.4	31,314	190	94,765	63,450	700	91
2023	179.4	37,111	207	107,721	70,610	784	90
2024	179.4	35,981	201	114,926	78,944	871	91
2025	279.4	60,117	215	148,915	88,798	952	93
2026	279.4	56,481	202	154,917	98,436	1035	95
2027	328.8	65,225	198	178,639	113,414	1141	99
2028	328.8	64,018	195	192,624	128,606	1241	104
2029	328.8	64,118	195	207,588	143,470	1357	106
2030	378.2	73,158	193	237,945	164,787	1486	111
2031	378.2	71,596	189	259,348	187,751	1609	117
2032	495.0	83,623	169	302,117	218,494	1732	126
2033	595.0	106,751	179	319,995	213,244	1852	115
2034	595.0	106,334	179	376,409	270,075	1972	137
2035	607.2	108,062	178	425,835	317,773	2087	152
2036	607.2	108,532	179	459,505	350,973	2199	160
2037	641.2	118,023	184	499,276	381,254	2301	166
2038	786.2	146,858	187	566,588	419,730	2409	174
2039	687.4	119,434	174	572,146	452,711	2510	180
NPV	2,804	531,133			1,349,165	11,925	

evelized Capacity Cost 2015-2039 ($/kW) **$189**

Levelized Energy Cost 2015-2039 ($/MWh) **$113**

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Avoided Energy and Capacity Costs
Half Low DSM Case

	Difference in Cumulative Additions No DSM-Half Low DSM	Avoided Capacity Costs k$	Avoided Capacity Costs $/kW	Total Cost Difference No DSM- Mid DSM k$	Avoided Energy Costs Total Cost less Capacity Costs k$	Difference in Load No DSM- Mid DSM GWh	Avoided Energy Costs $/MWh
2015	0.0	0	0	2,784	2,784	44	63
2016	0.0	0	0	5,980	5,980	98	61
2017	0.0	0	0	9,086	9,086	150	60
2018	0.0	0	0	10,829	10,829	194	56
2019	0.0	0	0	13,803	13,803	236	58
2020	49.4	7,405	150	24,614	17,209	275	63
2021	49.4	6,218	126	26,064	19,846	312	64
2022	149.4	25,971	174	68,206	42,235	356	119
2023	49.4	5,117	104	32,583	27,466	398	69
2024	49.4	6,166	125	37,371	31,205	441	71
2025	149.4	30,204	202	64,990	34,786	482	72
2026	81.4	10,651	131	49,346	38,695	524	74
2027	130.8	21,671	166	69,427	47,756	577	83
2028	130.8	20,223	155	77,576	57,353	626	92
2029	130.8	20,139	154	84,529	64,390	684	94
2030	180.2	29,048	161	108,603	79,555	749	106
2031	130.8	18,246	139	111,041	92,795	810	115
2032	198.2	31,761	160	144,278	112,517	872	129
2033	298.2	54,922	184	152,109	97,187	932	104
2034	298.2	54,595	183	201,519	146,924	992	148
2035	298.2	56,498	189	223,306	166,808	1049	159
2036	248.8	46,988	189	234,568	187,580	1105	170
2037	282.8	58,343	206	265,530	207,187	1157	179
2038	378.4	76,856	203	302,106	225,250	1211	186
2039	329.0	62,225	189	308,185	245,960	1261	195
NPV	1,274	220,117			672,455	6,035	

Levelized Capacity Cost 2015-2039 ($/kW) **$173**

Levelized Energy Cost 2015-2039 ($/MWh) **$111**

CA IR-20 Attachments 9-12 have been removed due to confidentiality.

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Avoided Cost of DSM - No FGD Cases (Future (Nominal) Dollars)

Year	2014 IRP - CRP Mid/No FGD (Synapse Model)		2014 IRP - Base DSM No FGD (CRP2 -1)	
	Annual Avoided Capacity Cost $/kW	Annual Avoided Energy Cost $/MWh	Annual Avoided Capacity Cost $/kW	Annual Avoided Energy Cost $/MWh
2015	$0	$56	$0	$64
2016	$0	$59	$0	$60
2017	$0	$58	$0	$58
2018	$0	$54	$0	$55
2019	$418	$57	$418	$57
2020	$196	$59	$196	$60
2021	$179	$63	$179	$62
2022	$190	$80	$190	$84
2023	$207	$81	$207	$85
2024	$201	$82	$201	$86
2025	$215	$91	$215	$95
2026	$202	$88	$202	$91
2027	$198	$90	$198	$93
2028	$195	$94	$195	$99
2029	$195	$98	$195	$103
2030	$193	$101	$193	$103
2031	$189	$106	$189	$108
2032	$188	$112	$188	$116
2033	$193	$107	$193	$110
2034	$192	$121	$192	$128
2035	$196	$128	$196	$134
2036	$191	$135	$192	$141
2037	$195	$141	$196	$148
2038	$195	$149	$197	$157
2039	$189	$155	$188	$163
Levelized 2015-2039	$196	$101	$196	$105

Request IR-21:

Please provide the rated capacity (in MW) NS Power assumed for:

(a) NRIS wind

(b) ERIS wind,

(c) Port Hawkesbury biomass.

Response IR-21:

(a-c) Please refer to the table below, based on the 2014 IRP assumptions:

Net Operating Capacity (MW)			
Year	**NRIS wind**	**ERIS wind**	**PH Biomass***
2015	265	164	45.4/51.7
2016	394	164	45.4/51.7
2017-2039	424	164	45.4/51.7

* Note: the net operating capacity of the biomass plant is based on whether or not the PHP mill is running; 45.4 MW when the PHP mill is on and 51.7 MW when off.

Request IR-22:

Please provide the capacity value (as a percentage of rated capacity) NS Power assumed for:

(a) NRIS wind,

(b) ERIS wind,

(c) Port Hawkesbury biomass.

Response IR-22:

(a-c) Please refer to the table below, based on the 2014 IRP Assumptions:

Capacity Value (%)			
Year	**NRIS wind**	**ERIS wind**	**PH Biomass***
2015	17	0	0
2016	17	0	0
2017-2038	17	0	0
2039*	17	0	100

* Note: The biomass plant is not counted as firm capacity until a second Lingan unit is retired in a particular resource plan. Accordingly, the year in which the biomass capacity value changes to 100% varies depending on the resource plan.

In cases where incremental wind was added (e.g. the No DSM Plan – 150 MW wind block in 2032) above the currently planned and committed wind as shown in CA IR-21, a capacity value of 12 percent was applied.

Request IR-23:

Please provide any progress that NS Power has made in estimating the capacity value of wind and ERIS resources since the Final 2014 IRP, and its schedule for improving these estimates.

Response IR-23:

As outlined in the 2014 IRP Action Plan,[1] NS Power is currently evaluating the coincidence of wind generation with peak load to better understand the capacity value of wind assets on the system by conducting multi-year studies using both Loss of Load Expectation (LOLE) methodology and Cumulative Frequency Analysis, and will continue these evaluations during 2015 and 2016. The Company is also evaluating the capacity contribution of Energy Resource Interconnection Service (ERIS) connected wind resources during 2015. NS Power will further report on the progress of these items in the 10 Year System Outlook Report.

[1] Please refer to 2014 Integrated Resource Plan, NS Power Final Report, October 15, 2014, pages 66 – 82.

Request IR-24:

Regarding the PPA assumed in the No-DSM and Half-DSM plans in the February 2015 presentation, slide 5.

(a) Please describe in detail the PPA assumed, including the assumed:

(i) fixed and variable charges,

(ii) losses from the seller to NS Power's transmission system,

(iii) dispatch flexibility, and

(iv) transmission requirements (noted on slide 6).

(b) Please provide the basis for the derivation of the PPA assumptions, including the assumed supplier, the source of the energy, and any actual transactions on which NS Power modeled the transaction.

Response IR-24:

(a) (i) The variable costs include the following components:

- Energy on and off peak procured at Mass Hub of NEISO at prices forecast by PIRA and also utilised in the 2014 IRP;
- NEISO Export Fee as quoted by NEISO;
- Renewable Energy Credit Cost based on an indication by a broker (ICAP) to reflect premiums paid for renewable energy; and

- NB Transmission Losses on and off peak at rates quoted by NBISO.

These components were summed on a monthly basis and modeled as the energy price on a $/MWh basis.

The fixed costs include the following components:

- Payments required to reserve capacity at rates forecast by PIRA; and

- Payments required to reserve transmission capacity through the NB Firm Transmission system as quoted by NBISO.

These components were summed on an annual basis and modeled as the annual fixed costs for the transaction.

(ii) No losses were assumed within NEISO; power was assumed to be delivered to the point of export. NB transmission losses were modelled at 3.30 percent.

(iii) The PPA was modeled as a fixed transaction, 600 GWh/year. It was assumed the energy could be counted as Renewable.

On-peak: 417 GWh/year (100 MW, 5 days/week, 16 hours/day)
Off-peak: 183 GWh/year (40 MW, evenings and weekends)

(iv) The PPA was assumed to have a firm capacity of 100 MW. The 2014 IRP Assumptions had a transmission option for a 100 MW firm import from New Brunswick at a cost of $45 million (please refer to page 33 of the 2014 IRP Assumptions). The transmission upgrades do not result in an increase in capacity

on the Nova Scotia-New Brunswick tie-line; they allow for 100 MW of the existing tie-line capacity to be counted as firm.

(b) The Potential PPA was constructed in a generic fashion as a long term firm and renewable power purchase from NEPOOL on the basis of general market conditions present in July 2014 (and reasonable estimates for their development in the future). NS Power calculated the cost of this potential PPA by considering market rates for reserving power generating capacity, premiums paid to renewable generators (Renewable Energy Credits, RECs), the cost of energy (Energy) in NEPOOL and transmission tariffs in effect at the time by NEISO and NB Power to transmit power to NS. NS Power did not consider any one specific counterparty or any actual transactions, nor did the Company make any assumptions about the source of energy underlying this potential PPA.

Request IR-25:

Please provide any information available to NS Power regarding:

(a) The market price for renewable energy delivered to New England, for each year 2016–2030.

(b) The transmission charges associated with exports of renewable energy from Nova Scotia to New England.

(c) The availability of firm and non-firm transmission to support sales of renewable energy to New England.

Response IR-25:

(a) Please refer to the IRP Appendix B page 62 at the following link: http://www.nspower.ca/site/media/Parent/20141015%202014%20IRP%20Final%20Report.pdf. The prices include a carbon cost that escalates from $15/tonne USD in 2020 to $37/tonne USD in 2030.

(b) Transmission charges for any exports of power from NS, through NB to New England (NEISO) would attract the charges in effect at the time of transmission as specified in the relevant NB Power tariffs which are publicly available at the following link: https://tso.nbpower.com/Public/en/op/transmission/tariff.aspx.

(c) The availability of transmission through New Brunswick to New England on a firm or interruptible basis is subject to evolving system and market conditions. NS Power has the same information on the availability of transmission to support sales of renewable energy to New England, in the short or long term, as other registered market participants. That information is provided by the System Operator for the Maritimes Region (NB

Power System Operator or NBSO) in accordance with the Open Access Transmission Tariff and is available at the following link:

https://tso.nbpower.com/Public/en/op/transmission/tariff.aspx.

Request IR-26:

Reference: Feb 2015 Presentation, page 7:

(a) Please provide the detailed calculations underlying the avoided capacity cost estimates (in total $ and $/kW), by year for the entire period 2019 through 2039.

(b) Please confirm that the avoided capacity costs in $/kW were calculated by dividing the total capacity costs in k$ by the cumulative additions in capacity.

(c) For each year of the forecast period, please provide the minimum required capacity addition.

(d) For each year of the forecast period, please provide avoided capacity costs per kW using the minimum required capacity addition as the divisor, rather than the planned capacity.

(e) If the avoided costs are stated in nominal terms, please explain why the costs do not rise with inflation.

Response IR-26:

(a) Please refer to CA IR-20(j).

(b) Confirmed.

(c-d) The table below shows the minimum required capacity in the No DSM plan based on maintaining a 20 percent planning reserve margin. The Mid DSM plan does not require any capacity additions over the planning period. The avoided capacity costs ($/kW) in the table below are now overstated since the avoided costs in dollars still reflect the

annual revenue requirements for the specific capacity additions in the No DSM Plan; the avoided capacity costs ($K) would have to be decreased due to the reduction in the assumed capacity additions. The 2014 IRP Assumptions for supply-side alternatives had discrete options for the model to choose from such as a 50 MW combustion turbine, 100MW combustion turbine or 145 MW combined cycle unit. The model did not have the granularity in the options to select the exact minimum capacity required in each year.

Avoided Capacity Costs for Mid DSM Case Assuming Minimum Required Capacity Additions

Year	No DSM Plan Minimum Capacity Additions to Maintain 20% Planning Reserve Margin (MW)	Mid DSM Avoided Capacity Cost ($K)	Mid DSM Avoided Capacity Costs ($/kW)
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	9	6,266	669
2020	39	12,607	319
2021	52	11,497	220
2022	77	31,314	408
2023	102	37,111	365
2024	136	35,981	265
2025	231	60,117	260
2026	255	56,481	222
2027	276	65,225	236
2028	306	64,018	209
2029	320	64,118	200
2030	342	73,158	214
2031	365	71,596	196
2032	480	93,014	194
2033	503	114,637	228
2034	525	114,242	217
2035	698	145,259	208
2036	721	141,024	196
2037	744	150,558	202
2038	767	179,369	234
2039	891	173,432	195

(e) The avoided capacity costs are based on the revenue requirements of the capital investments made in the No DSM plan. The revenue requirement profile for each investment is represented by a declining stream of values. In any given year the total avoided capacity cost is the sum of the revenue requirements in that year for each investment that has been added up to that point in the Plan. Thus the avoided capacity costs may rise in the year that a new investment is made and then decline until the next capital investment is made in the Plan.

Request IR-27:

Please provide the demand and energy loss factors applied to the avoided generation capacity and energy cost estimates.

(a) Please provide the basis of these demand and energy loss factors.

Response IR-27:

The avoided generation capacity and energy costs are based on the revenue requirement to meet energy and capacity requirements, including losses. As such, demand and energy losses are inherent to the calculation and specific loss factors are not required.

Request IR-28:

Reference: Feb 2015 Presentation, page 5:

(a) For the period 2019 through 2039, please provide the annual revenue requirements in each DSM case with and without Mersey Expansion Phase 1.

(b) For the period 2023 through 2039, please provide the annual revenue requirements in each DSM case with and without Mersey Expansion Phase 2.

(c) For the period 2025 through 2039, please provide the annual revenue requirements for the no DSM and the four DSM cases with and without the FGD investment.

Response IR-28:

(a-b) The two optimized resource plans could not be completed to meet the IR deadline. We offer the following commentary on these resource options.

This project provides incremental capacity (30 MW total Phase 1 and Phase 2) and a small amount of RES energy (40 GWh/year). In the 2014 IRP it was offered as an option to all Candidate Resource Plan optimizations. In some of the higher load scenarios it was picked in the least cost plans and in the lower load scenarios it was not. The option had a limited window when it could be picked to coincide with the Mersey re-development Phase 1 in 2019 and Phase 2 in 2023 so it could either be picked in those years or not. It did not have the option to be added later in the planning period.

(c) The tables below give the partial revenue requirements for the cases shown in Slide 5 of the February 2015 Avoided Cost presentation. A Without FGD resource plan was not developed for the No DSM case since the With FGD case was least cost in both the planning period and the study period.

Annual Partial Revenue Requirements - With FGD

	No DSM Plan ($K)	CRP01-01-FGD-R01 Half-Low DSM ($K)	Low DSM w Low DSM PA ($K)	CRP2-17 FGD Base DSM ($K)	CRP Mid DSM/FGD (Synapse Model) ($K)
2025	965,077	925,959	856,963	843,928	848,436
2026	987,079	964,898	874,162	858,349	861,065
2027	1,012,143	971,546	877,204	859,087	860,180
2028	1,056,839	1,010,285	910,315	886,476	884,343
2029	1,086,197	1,033,928	925,609	896,002	889,053
2030	1,145,344	1,071,397	956,898	920,508	900,244
2031	1,188,258	1,113,494	979,710	937,268	906,727
2032	1,238,026	1,130,970	987,008	931,497	893,602
2033	1,270,164	1,155,501	1,000,569	939,559	897,885
2034	1,341,623	1,177,162	1,014,113	946,863	901,051
2035	1,439,042	1,252,221	1,060,407	961,930	893,889
2036	1,495,851	1,297,237	1,081,946	981,272	911,833
2037	1,547,495	1,317,351	1,092,219	986,839	907,846
2038	1,635,416	1,368,172	1,111,328	1,000,629	917,033
2039	1,677,389	1,403,760	1,146,543	1,043,225	925,265

Annual Partial Revenue Requirements - Without FGD

	CRP01-01-FGD-R01 Half-Low DSM ($K)	Low DSM w Low DSM PA ($K)	CRP2-17 FGD Base DSM ($K)	CRP Mid DSM/FGD (Synapse Model) ($K)
2025	923,226	849,095	832,926	835,201
2026	953,822	874,449	855,055	855,474
2027	966,013	880,200	858,001	854,986
2028	1,004,917	911,774	886,001	879,854
2029	1,025,595	924,395	894,877	883,607
2030	1,079,558	968,344	931,199	907,596
2031	1,110,045	990,684	947,341	915,375
2032	1,135,486	996,499	939,363	901,328
2033	1,154,226	1,008,226	946,890	901,989
2034	1,177,025	1,019,984	953,056	905,814
2035	1,267,692	1,094,464	985,876	914,090

	CRP01-01-FGD-R01 Half-Low DSM ($K)	Low DSM w Low DSM PA ($K)	CRP2-17 FGD Base DSM ($K)	CRP Mid DSM/FGD (Synapse Model) ($K)
2036	1,308,235	1,114,850	1,006,039	929,446
2037	1,325,919	1,121,499	1,008,873	927,352
2038	1,365,082	1,138,623	1,020,183	935,036
2039	1,400,694	1,174,404	1,042,122	939,264

1

Request IR-29:

NS Power Evidence, April 10, 2015, p. 5

Regarding the statement that $22 million per year is "consistent with the average (per customer) DSM expenditures of other Canadian jurisdictions," please indicate whether these other jurisdictions were able to achieve a level of annual energy savings consistent with NSPI's planned reduction of 100 GWh for an expenditure of $22 million per year.

Response IR-29:

In order to derive the affordable and cost effective level of DSM savings and spend appropriate for customers, Nova Scotia Power analyzed DSM from 3 perspectives;

- System requirements
- Spending in other jurisdictions
- Alternative DSM possibilities

<u>System Requirements</u>

From a System Planning perspective, the Company used the 2014 IRP to determine what level of DSM the power system requires in the contract period and beyond, to ensure that system security and reliability are maintained, and environmental targets are met. The IRP analysis demonstrated that there were a number of robust plans that delivered comparable NPVs over the planning period, the main point of differentiation was the amount of DSM spending. As demonstrated in Figure 4.1 of the Company's Evidence, the low DSM profile has exactly the same capacity additions out to 2032 as the base DSM and the Synapse mid DSM. In other words, from a system planning perspective using the low DSM provides the same benefits as the higher DSM investment plans for the next 16 years at the lowest 2030 NPV. The Company therefore determined that the low DSM profile -approximately 100 GWh and associated demand

savings – provided the right amount of DSM for the system. Contracting additional DSM to avoid capacity additions beyond 2032 is costly and uncertain.

Spending in other jurisdictions

Once the Company determined the appropriate amount of DSM for system planning purposes, an analysis was conducted to benchmark DSM in other jurisdictions. This was done to establish some benchmarks against which Nova Scotia could be measured – recognizing that available, reasonably achievable and required DSM varies by jurisdiction based on system requirements and environmental targets. Nevertheless, the Company's Evidence demonstrates that on a per capita basis, Nova Scotians are spending more than the national average. Customers need the franchise holder to become more efficient in the interest of affordability.

Alternative DSM possibilities

The third facet of the Company's DSM analysis to determine what was the most affordable, cost effective DSM for Nova Scotia was the different types of DSM programs that the franchise holder could reasonably be expected to provide and at what cost. The Company analyzed the franchise holder's Application and its modelling tool to provide the UARB and stakeholders with 4 alternative possibilities to the E1 plan, since E1 would not provide those when asked. The revised Table 6 below, from the Evidence of David Pickles (please refer to EAC IR-7), shows that under the scenarios analyzed, savings for the contract period in line with the Low DSM case are in fact achievable for approximately $22 million.

Revised Table 6. Summary of Alternate DSM Scenarios

Scenario Name	Assumption Changes	Three Year Impacts			
		GWH	MW	$M	TRC
E1	None	405.9	62.5	$ 121.5	2.0
A	Eliminate TRC's < 1.0	387.0	59.8	$ 110.0	2.2
B	Eliminate TRC's < 1.0 Allow implemention costs to vary +/- 20% Allow incentive costs to vary from the E1 minimum Participation is estimated as a function of program cost, with goal ~ Scen. A	381.7	60.5	$ 107.9	2.2
C	NS Power Alternate Proposal	279.0	33.0	$ 67.5	3.2
D	Eliminate TRC's < 1.0 Allow implemention costs to vary +/- 20% Allow incentive costs to vary from the E1 minimum Participation is estimated as a function of program cost, with goal ~ 300GWh	300.8	46.3	$ 65.2	2.3

After demonstrating that approximately $22 million of DSM spending was the amount that was appropriate from a system planning perspective in accordance with the IRP, was aligned with spending in other jurisdictions and could be achievable by the franchise holder; the Company requested the UARB direct E1 to provide a more cost effective, affordable plan. The Company believes that this can be accomplished based on the evidence provided.

Request IR-30:

Please provide the numeric data underlying each figure in NS Power's Evidence.

Response IR-30:

Please refer to the following table:

Figures	Attachment
Figure 3.1: Recent and Projected DSM Spending by Canadian Province	Attachment 1, also filed electronically
Revised Figure 3.2: 2015 First Year Cost Comparison ($/kWh of Planned Savings)	Please refer to SBA IR-14 Attachment 1
Figure 3.3: Costs of Installed DSM ($/kWh)	Attachment 3, also filed electronically
Revised Figure 3.4: Cost/Benefit Schedule for $40M DSM Plan	Attachment 4, also filed electronically
Figure 3.5(a): U.S. Deployment and Cost for A-Type LED Lights 2008-2013	US Department of Energy
Figure 3.5(b): U.S. Deployment and Cost for Solar PV Modules 2008-2013	US Department of Energy
Figure 3.6: Ranking of CRPs	Attachment 5, also filed electronically
Figure 3.7: Annual Percent Difference in Partial Revenue Requirements Compared to No DSM Plan	Attachment 6, also filed electronically
Figure 3.8: Annual Percent Difference in Partial Revenue Requirements Compared to CRP 2	Attachment 7, also filed electronically
Revised Figure 4.1: NS Power System Requirements Based on 2014 IRP Assumptions	Attachment 8, also filed electronically

Figures 3.5(a) and (b) were referenced from the US Department of Energy's report entitled *Revolution Now: The Future Arrives for Four Clean Energy Technologies – 2014 Update.* The report can be accessed at the following link:

http://energy.gov/sites/prod/files/2014/10/f18/revolution_now_updated_charts_and_text_october_2014_1.pdf

In addition, please refer to the following IRs that contain the working papers and associated information for the appendices to NS Power's Evidence:

Appendix A – Direct Testimony of David Pickles: E1 IR-12 Confidential Attachments 1-4, SBA IR-21, and EAC IR-7.

Appendix A – Attachment B – Review of Nova Scotia's Energy Savings Portfolio: SBA IR-21 and SBA IR-14 Attachment 1.

Appendix B – NS Power Alternate DSM Plan: EAC IR-7.

Please note, there is no Attachment 2 to this IR.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Province	Program Administrator	Exhibit Order	Year	Actual DSM Spend ($Million)	Colum n1	Population (000's)	Colum n2	Number of Customers (000's)	Colum n3	Actual $DSM/capita	Actual $DSM/customer	2015* Planned DSM Spend ($Millions)	Colu mn4	Population in 2014 (000's)	Colum n5	Number of Customers in 2014 (000's)	Colum n6	Plan $DSM/capita	Plan $DSM/customer
Nova Scotia	Efficiency Nova Scotia	1.1	2014	39	1	943	9	501	17	41.05	77.21	39	25	943	33	501	41	41.37	77.81
British Columbia	BC Hydro	1.2	2014	120	2	4,631	10	1,915	18	25.97	62.82	148	26	4,631	34	1,915	42	31.96	77.29
Manitoba	Manitoba Hydro	1.4	2012	28	3	1,251	11	549	19	22.39	51.02	26.2	27	1,282	35	556	43	20.44	47.14
New Brunswick	Efficiency New Brunswick	1.7	2013	17	4	756	12	351	20	22.07	47.51	16.8	28	754	36	351	44	22.28	47.86
Ontario	Provincial	1.5	2013	267	5	13,551	13	4,800	21	19.67	55.52	306	29	13,551	37	4,800	45	22.57	63.72
Quebec	Hydro Quebec	1.6	2014	120	6	8,215	14	4,142	22	14.61	28.97	135	30	8,215	38	4,142	46	16.43	32.59
Saskatchewan	SaskPower	1.3	2013	15	7	1,106	15	501	23	13.92	30.74	10	31	1,125	39	501	47	8.89	19.96
Newfoundland	NL Power and NLLH	1.8	2012	4	8	527	16	280	24	7.59	14.29	5.7	32	527	40	280	48	10.90	20.51

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3	Manitoba Hydro 2011-2012 Annual Power Smart Review, http://www.hydro.mb.ca/projects/development_plan/bc_documents/pub_095b_attachment_2.pdf, Access February 4, 2015	a	
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19	Manitoba Hydro 62nd Annual Report, http://www.hydro.mb.ca/corporate/ar/2012/publish/files/assets/common/downloads/publication.pdf, Accessed January 23, 2015	26	
20	New Brunswick Power 2013 - 2014 Annual Report, http://www.nbpower.com/html/en/about/publications/annual/2014_Annual_Report_EN.pdf, Accessed January 28, 2015	87	
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30	Plan Gobal En Efficacity Energetique Budget 2015, http://publicsde.regie-energie.qc.ca/projets/282/DocPrj/R-3905-2014-B-0038-Demande-Piece-2014_08_01.pdf, Accessed January 30, 2015	7	
31	Final Independent Report for the Saskatchewan Rate Review Panel on SaskPower's 2014-2016 Rate Plan, Forkast Consulting, 2014, http://www.saskratereview.ca/images/docs/SaskPower2013/2014-spc-final-april-10-with-cover-and-executive-summary.pdf	66	
32	Newfoundland Five Year Energy Conservation Plan 2012 - 2016, http://www.pub.nl.ca/applications/NLH2013GRA/files/rfi/IN-NLH-009.pdf, Accessed January 27, 2015	21	Joint budget NLPower/Hydro
33	Statistics Canada, CANSIM, table 051-0001, http://www5.statcan.gc.ca/cansim/search-recherche?lang=eng&searchTypeByBalue=1&pattern=051-0001&p2=37	sheet 1	
34	Statistics Canada, http://www.bcstats.gov.bc.ca/StatisticsBySubject/Demography/PopulationEstimates.aspx, accessed January 28, 2015.		
35	Statistics Canada, http://www5.statcan.gc.ca/cansim/a01?lang=eng&p2=1, Accessed January 23, 2015		
36	Statistics Canada, http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/demo02a-eng.htm, Accessed January 28, 2015		
37	Statistics Canada, http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/demo02a-eng.htm		
38	Statistics Canada, http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/demo02a-eng.htm, Accessed January 28, 2015		
39	Statistics Canada, http://www5.statcan.gc.ca/cansim/a01?lang=eng&p2=1, Accessed January 23, 2015		
40	Statistics Canada, http://www.stats.gov.nl.ca/statistics/population/PDF/Annual_Pop_Prov.PDF, accessed February 4, 2015		
41	Statistics Canada, CANSIM, table 051-0001, http://www5.statcan.gc.ca/cansim/search-recherche?lang=eng&searchTypeByBalue=1&pattern=051-0001&p2=37	sheet 2	
42	BC Hydro Quick Facts June 2014, https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-quick-facts-june-2014.pdf, accessed January 28, 2015.	2	
43	Manitoba Hydro 63rd Annual Report, http://www.hydro.mb.ca/corporate/ar/2013/publish/63rd%20Annual%20Report/files/assets/common/downloads/publication.pdf, Accessed January 23, 2015	26	
44	New Brunswick Power 2013 - 2014 Annual Report, http://www.nbpower.com/html/en/about/publications/annual/2014_Annual_Report_EN.pdf, Accessed January 28, 2015	87	2013
45	Ontario's Electricity System, http://www.energy.gov.on.ca/en/files/2014/09/OntarioElectricitySystem-en.pdf	2	
46	Hydro Quebec 2013 Annual Report, http://www.hydroquebec.com/publications/en/annual_report/pdf/annual-report-2013.pdf, Accessed January 28, 2015	2	2013
47	SaskPower 2014, 2015, 2016 Rate Review, http://www.saskratereview.ca/images/docs/SaskPower2013/minimum-filing-requirements.pdf, Accessed January 23, 2015	8	2013
48	Newfoundland Five Year Energy Conservation Plan 2012 - 2016, http://www.nr.gov.nl.ca/nr/energy/electricity/		Combined customers for NLPower and Nalcor

NOTE: There is no CA IR-30 Attachment 2.

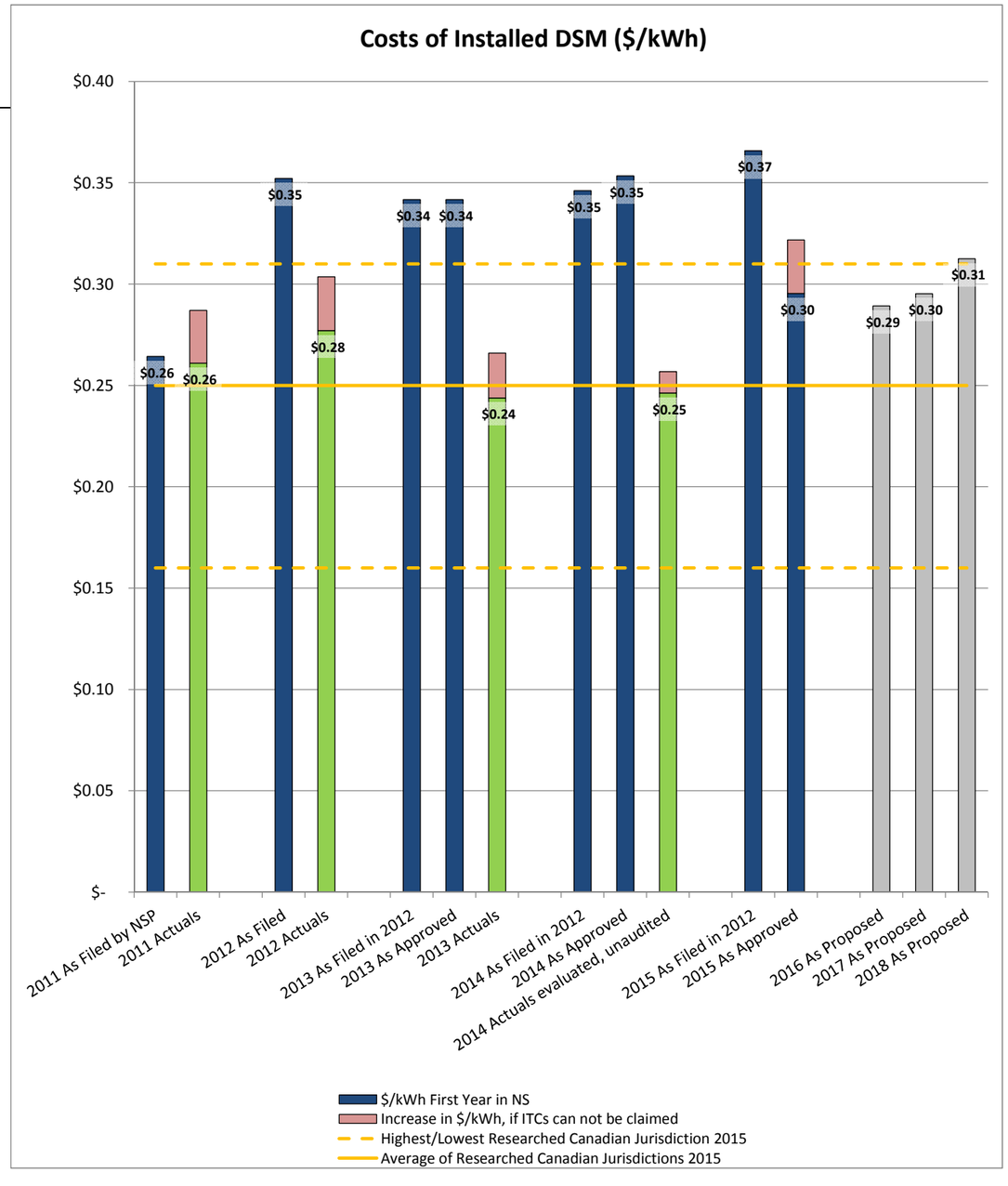
	$/kWh First Year in NS	$/KWh with Full HST	Increase in $/kWh, if ITCs can not be claimed	HST adjusted	Highest/Lowest Researched Canadian Jurisdiction 2015	Average of Researched Canadian Jurisdictions 2015	Lowest Canadian Jurisdiction 2015
	$ 0.3				$ 0.3	$ 0.3	$ 0.2
2011 As Filed by NSP	$ 0.26			$ 0.26	$ 0.3	$ 0.3	$ 0.2
2011 Actuals	$ 0.29	$ 0.29	$ 0.03	$ 0.26	$ 0.3	$ 0.3	$ 0.2
					$ 0.3	$ 0.3	$ 0.2
2012 As Filed	$ 0.35			$ 0.35	$ 0.3	$ 0.3	$ 0.2
2012 Actuals	$ 0.30	$ 0.30	$ 0.03	$ 0.28	$ 0.3	$ 0.3	$ 0.2
					$ 0.3	$ 0.3	$ 0.2
2013 As Filed in 2012	$ 0.34			$ 0.34	$ 0.3	$ 0.3	$ 0.2
2013 As Approved	$ 0.34			$ 0.34	$ 0.3	$ 0.3	$ 0.2
2013 Actuals	$ 0.27	$ 0.27	$ 0.02	$ 0.24	$ 0.3	$ 0.3	$ 0.2
					$ 0.3	$ 0.3	$ 0.2
2014 As Filed in 2012	$ 0.35			$ 0.35	$ 0.3	$ 0.3	$ 0.2
2014 As Approved	$ 0.35			$ 0.35	$ 0.3	$ 0.3	$ 0.2
2014 Actuals evaluated, unaudited	$ 0.26	$ 0.26	$ 0.01	$ 0.25	$ 0.3	$ 0.3	$ 0.2
					$ 0.3	$ 0.3	$ 0.2
2015 As Filed in 2012	$ 0.37			$ 0.37	$ 0.3	$ 0.3	$ 0.2
2015 As Approved	$ 0.30	$ 0.32	$ 0.03	$ 0.30	$ 0.3	$ 0.3	$ 0.2
					$ 0.3	$ 0.3	$ 0.2
2016 As Proposed	$ 0.29			$ 0.29	$ 0.3	$ 0.3	$ 0.2
2017 As Proposed	$ 0.30			$ 0.30	$ 0.3	$ 0.3	$ 0.2
2018 As Proposed	$ 0.31			$ 0.31	$ 0.3	$ 0.3	$ 0.2

Actuals are shown as per E1's 2016-2018 response to IR-35 and therefore do not reflect actual dollar amounts transferred from NS Power to ENS in the years shown.

Actuals for 2011, 2012, 2013, 2014 show $/kWh if ITCs can be claimed. Added as a red bar on top is the increase in $/kWh if ITC claim is not approved by CRA.

Unit costs for 2016, 2017 and 2018 assume E1 is ITC eligible

As per 2016-2018 DSM NS Power Evidence Appendix A, Attachment 1 Exhibit 2



REDACTED (CONFIDENTIAL INFORMATION REMOVED)

E1 Responses to NSPI Information Request (IR 35)

	Actual Program Spending including Full HST* ($M)	Actual Program Spending with HST Adjusted for ITCs ($M)	Annual Energy Savings (GWh)	Annual Demand Reductions (MW)	Full HST $/kWh	HST adjusted $/kWh
2010	$ 24.00	$ 23.00	82.45	15.9	$ 0.29	$ 0.28
2011	$ 40.70	$ 37.00	141.8	28.9	$ 0.29	$ 0.26
2012	$ 48.00	$ 43.80	158.1	32.9	$ 0.30	$ 0.28
2013	$ 43.40	$ 39.80	163.2	34.1	$ 0.27	$ 0.24
2014***	$ 39.00	$ 37.40	151.9	27.1	$ 0.26	$ 0.25
2015 (Approved)	$ 39.00	$ 35.80	121.2	21.2	$ 0.32	$ 0.30
2016 (Proposed by E1)****	$ 38.50	$ 38.50	133.1	20.4	$ 0.29	$ 0.29
2017 (Proposed by E1)****	$ 40.30	$ 40.30	136.5	21.0	$ 0.30	$ 0.30
2018 (Proposed by E1)****	$ 42.60	$ 42.60	136.3	21.0	$ 0.31	$ 0.31

2016-2018 Supply Agreement for EECA M06733 (E-ENS-R-15)
E1 Responses to NSPI Information Requests

NON-CONFIDENTIAL

	Actual Program Spending including Full HST* ($M)	Actual Program Spending with HST Adjusted for ITCs ($M)	Annual Energy Savings (GWh)	Annual Demand Savings (MW)
2010	24.0	23.0	82.5	15.9
2011	40.7	37.0	141.8	28.9
2012	48.0	43.8	158.1	33.8
2013	43.4	39.8	163.2	34.1
2014**	39.0	37.4	151.9	27.1
2015 (Approved)***	39.0	35.8	121.2	21.2
2016 (Proposed by E1)****	38.5	38.5	133.1	20.4
2017 (Proposed by E1)****	40.3	40.3	136.5	21.0
2018 (Proposed by E1)****	42.6	42.6	136.3	21.0

Notes:

* Per Balance Adjustment filings.

** 2014 energy savings and demand savings are evaluated; verification is pending. Spending is an estimate.

***Spending is an estimate.

**** Currency is expressed in 2016 dollars.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Cost per installed DSM ($/kWh)

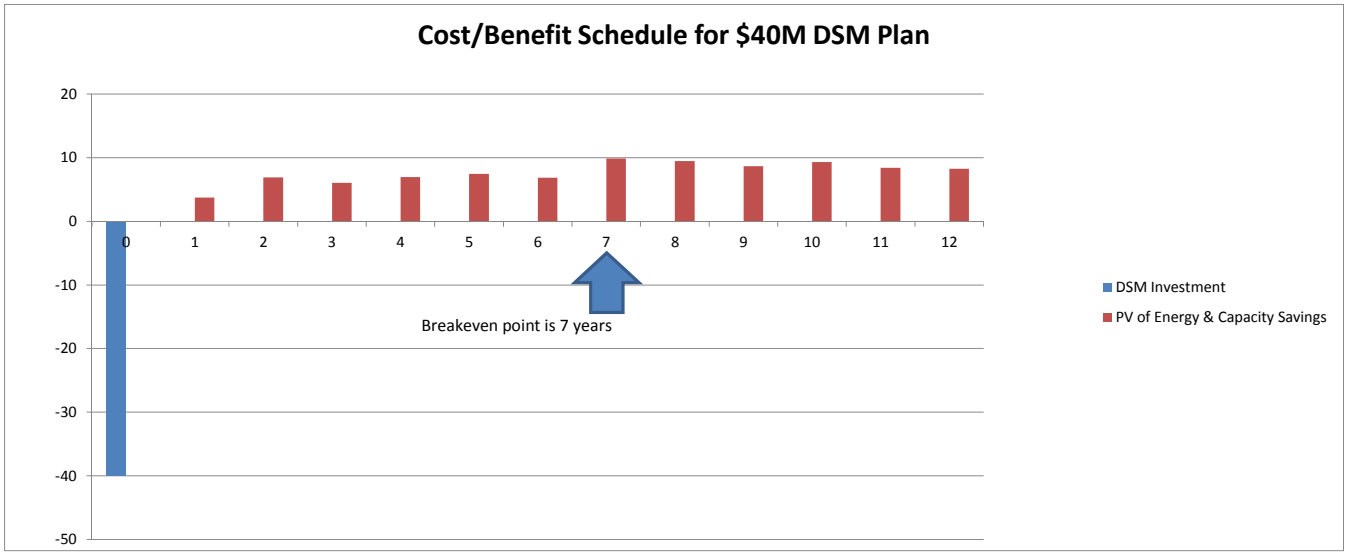
	$/kWh First Year	$M	GWh	Source for Spending	Source for Savings
2011 as Filed by NSP	$ 0.26	$ 41.90	158.5	NSP Evidence for 2011 DSM Plan, Page 10, Figure 3.2	NSP Evidence for 2011 DSM Plan, Page 10, Figure 3.3
2012 as Filed	$ 0.35	$ 43.70	124.1	ENS evidence 2012 DSM Plan & Q2 update report	ENS Evidence 2012 DSM Plan & Q2 update report
2013 As Filed in 2012	$ 0.34	$ 46.20	135.2	Revised DSM 2013-2015, ENS Evidence April 18, 2012, page 18 Figure 4.1	Revised DSM 2013-2015, ENS Evidence April 18, 2012, page 18 Figure 4.1
2013 As Approved	$ 0.34	$ 46.20	135.2	Q2 DSM update for 2013	Q2 DSM update for 2014
2014 As Filed in 2012	$ 0.35	$ 47.70	137.8	Revised DSM 2013-2015, ENS Evidence April 18, 2012, page 18 Figure 4.1	Revised DSM 2013-2015, ENS Evidence April 18, 2012, page 18 Figure 4.1
2014 As Approved	$ 0.35	$ 48.70	137.8	2016-2018 DSM Plan Evidence, ENS	2016-2018 DSM Plan Evidence, ENS
2015 As Filed in 2012	$ 0.37	$ 50.40	137.8	Revised DSM 2013-2015, ENS Evidence April 18, 2012, page 18 Figure 4.1	Revised DSM 2013-2015, ENS Evidence April 18, 2012, page 18 Figure 4.1
2016 As Proposed by E1	$ 0.29	$ 38.50	133.1	2016-2018 DSM Plan Evidence, Figure 3.1 page 21	2016-2018 DSM Plan Evidence, ENS
2017 As Proposed by E1	$ 0.30	$ 40.30	136.5	2016-2018 DSM Plan Evidence, ENS	2016-2018 DSM Plan Evidence, ENS
2018 As Proposed by E1	$ 0.31	$ 42.60	136.3	2016-2018 DSM Plan Evidence, ENS	2016-2018 DSM Plan Evidence, ENS

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

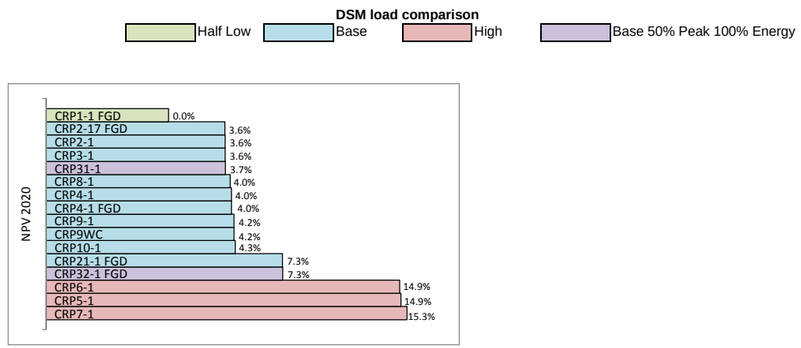


REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Derivation of Figure of Figure 3.6

	CRP1-1 FGD	CRP2-1	CRP2-17 FGD	CRP3-1	CRP4-1	CRP4-1 FGD	CRP5-1	CRP6-1	CRP7-1	CRP8-1	CRP9-1	CRP9WC	CRP10-1	CRP31-1	CRP21-1 (FGD WIND)	CRP32-1 (FGD PPA)
NPV 2020	$3,907	$4,049	$4,049	$4,049	$4,065	$4,065	$4,491	$4,489	$4,507	$4,062	$4,072	$4,072	$4,075	$4,050	$4,194	$4,195
NPV 2030	$9,025	$8,777	$8,780	$8,959	$8,836	$8,838	$9,547	$9,864	$9,790	$9,203	$9,182	$9,113	$9,063	$8,963	$9,764	$9,761
Planning Period	$12,449	$11,544	$11,530	$11,825	$11,737	$11,693	$12,125	$12,638	$12,512	$12,240	$12,200	$12,101	$12,000	$11,933	$13,070	$13,256
Study Period	$19,775	$17,103	$17,201	$17,419	$17,643	$17,469	$17,076	$17,829	$17,666	$18,095	$18,091	$17,968	$17,731	$17,831	$19,851	$20,585
NPV 2020	1	3	2	3	7	7	15	14	16	6	9	9	11	5	12	13
NPV 2030	7	1	2	5	3	4	12	16	15	11	10	9	8	6	14	13
Planning Period	12	2	1	5	4	3	9	14	13	11	10	8	7	6	15	16
**** Study Period**	14	2	3	4	6	5	1	9	7	13	12	11	8	10	15	16

	CRP7-1	CRP5-1	CRP6-1	CRP32-1 (FGD PPA)	CRP21-1 (FGD WIND)	CRP10-1	CRP9WC	CRP9-1	CRP4-1 FGD	CRP4-1	CRP8-1	CRP31-1	CRP3-1	CRP2-1	CRP2-17 FGD	CRP1-1 FGD
NPV 2020	$4,507	$4,491	$4,489	$4,195	$4,194	$4,075	$4,072	$4,072	$4,065	$4,065	$4,062	$4,050	$4,049	$4,049	$4,049	$3,907
% diff	15.3%	14.9%	14.9%	7.3%	7.3%	4.3%	4.2%	4.2%	4.0%	4.0%	4.0%	3.7%	3.6%	3.6%	3.6%	0.0%
NPV 2020	16	15	14	13	12	11	9	9	7	7	6	5	3	3	2	1

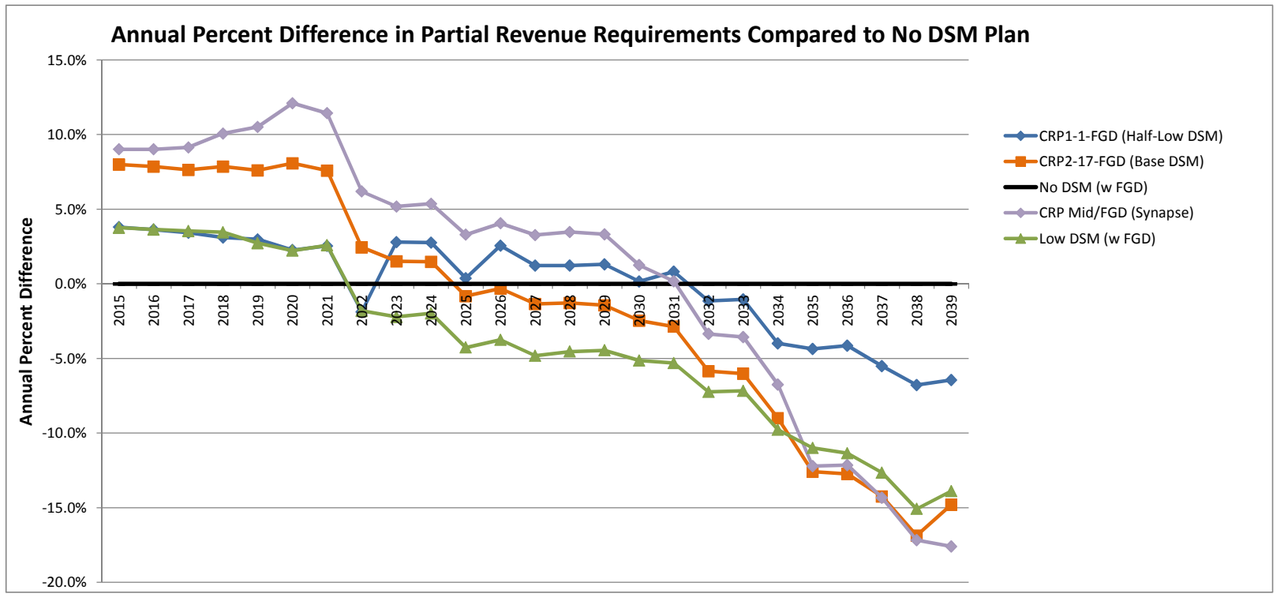


Derivation of Figure 3.7
Partial Revenue Requirements:
Fuel and Purchased Power, Thermal and Hydro O&M, Capital for new resources in the plan, DSM program administrator costs, sustaining capital (k$)

CRP	Half Low CRP1-1-FGD	Base CRP2-17-FGD	No DSM Plan	CRP Mid/FGD (Synapse)	Low DSM Plan
2015	651,665	673,694	630,259	678,476	649,093
2016	667,940	685,619	650,149	689,420	662,626
2017	701,354	714,414	687,222	718,278	693,524
2018	801,621	815,205	790,810	822,490	791,511
2019	832,639	840,154	825,270	850,736	814,243
2020	788,410	796,164	791,314	810,185	768,274
2021	812,420	808,740	815,929	818,967	789,444
2022	829,555	816,186	873,978	824,380	802,996
2023	900,858	833,153	909,244	838,494	825,720
2024	920,518	845,916	932,772	850,207	842,963
2025	953,922	871,891	993,040	876,399	869,998
2026	996,423	889,874	1,018,603	892,590	890,852
2027	1,004,948	892,489	1,045,545	893,582	895,736
2028	1,046,442	922,633	1,092,996	920,500	931,394
2029	1,071,620	933,694	1,123,889	926,744	948,561
2030	1,110,820	959,931	1,184,767	939,667	981,478
2031	1,152,344	976,118	1,227,107	945,577	1,004,037
2032	1,172,264	972,792	1,279,320	934,896	1,014,424
2033	1,202,175	986,233	1,316,838	944,558	1,034,288
2034	1,225,211	994,912	1,389,672	949,100	1,050,321
2035	1,301,881	1,011,590	1,488,701	943,549	1,099,351
2036	1,362,956	1,046,991	1,561,570	977,551	1,138,019
2037	1,382,527	1,052,016	1,612,672	973,023	1,148,781
2038	1,429,201	1,061,657	1,696,444	978,061	1,164,719
2039	1,465,236	1,104,702	1,738,865	986,742	1,201,276

Load (GWh)					
2015	11,199	11,128	11,242	11,102	11,158
2016	11,253	11,099	11,351	11,042	11,163
2017	11,279	11,039	11,430	10,946	11,141
2018	11,339	11,022	11,532	10,897	11,157
2019	11,415	11,024	11,651	10,869	11,190
2020	10,429	9,966	10,704	9,777	10,166
2021	10,457	9,922	10,768	9,700	10,157
2022	10,528	9,922	10,884	9,668	10,184
2023	10,604	9,931	11,002	9,646	10,218
2024	10,705	9,961	11,146	9,642	10,276
2025	10,738	9,933	11,220	9,586	10,268
2026	10,807	9,929	11,330	9,541	10,295
2027	10,851	9,889	11,428	9,457	10,287
2028	10,932	9,884	11,558	9,407	10,317
2029	10,945	9,802	11,629	9,281	10,272
2030	10,981	9,744	11,730	9,189	10,245
2031	11,022	9,690	11,832	9,102	10,224
2032	11,064	9,640	11,936	9,025	10,203
2033	11,108	9,595	12,040	8,955	10,188
2034	11,154	9,555	12,146	8,895	10,174
2035	11,203	9,523	12,252	8,846	10,166
2036	11,255	9,497	12,360	8,806	10,161
2037	11,312	9,484	12,469	8,781	10,168
2038	11,368	9,469	12,579	8,755	10,170
2039	11,430	9,463	12,690	8,739	10,181
	275,376	250,112	290,912	239,657	260,128

Figure 3.7



Derivation of Figure 3.7
Partial Revenue Requirements:
Fuel and Purchased Power, Thermal and Hydro O&M, Capital for new resources in the plan, DSM program administrator costs, sustaining capital (k$)

	Half Low	Base		CRP Mid/FGD	
cents/kWh	CRP1-1-FGD	CRP2-17-FGD	No DSM Plan	CRP Mid/FGD	Low DSM Plan
2015	5.82	6.05	5.61	6.11	5.82
2016	5.94	6.18	5.73	6.24	5.94
2017	6.22	6.47	6.01	6.56	6.22
2018	7.07	7.40	6.86	7.55	7.09
2019	7.29	7.62	7.08	7.83	7.28
2020	7.56	7.99	7.39	8.29	7.56
2021	7.77	8.15	7.58	8.44	7.77
2022	7.88	8.23	8.03	8.53	7.89
2023	8.50	8.39	8.26	8.69	8.08
2024	8.60	8.49	8.37	8.82	8.20
2025	8.88	8.78	8.85	9.14	8.47
2026	9.22	8.96	8.99	9.35	8.65
2027	9.26	9.03	9.15	9.45	8.71
2028	9.57	9.33	9.46	9.78	9.03
2029	9.79	9.53	9.66	9.99	9.23
2030	10.12	9.85	10.10	10.23	9.58
2031	10.45	10.07	10.37	10.39	9.82
2032	10.60	10.09	10.72	10.36	9.94
2033	10.82	10.28	10.94	10.55	10.15
2034	10.98	10.41	11.44	10.67	10.32
2035	11.62	10.62	12.15	10.67	10.81
2036	12.11	11.02	12.63	11.10	11.20
2037	12.22	11.09	12.93	11.08	11.30
2038	12.57	11.21	13.49	11.17	11.45
2039	12.82	11.67	13.70	11.29	11.80

Percent Change Compared to No DSM Plan

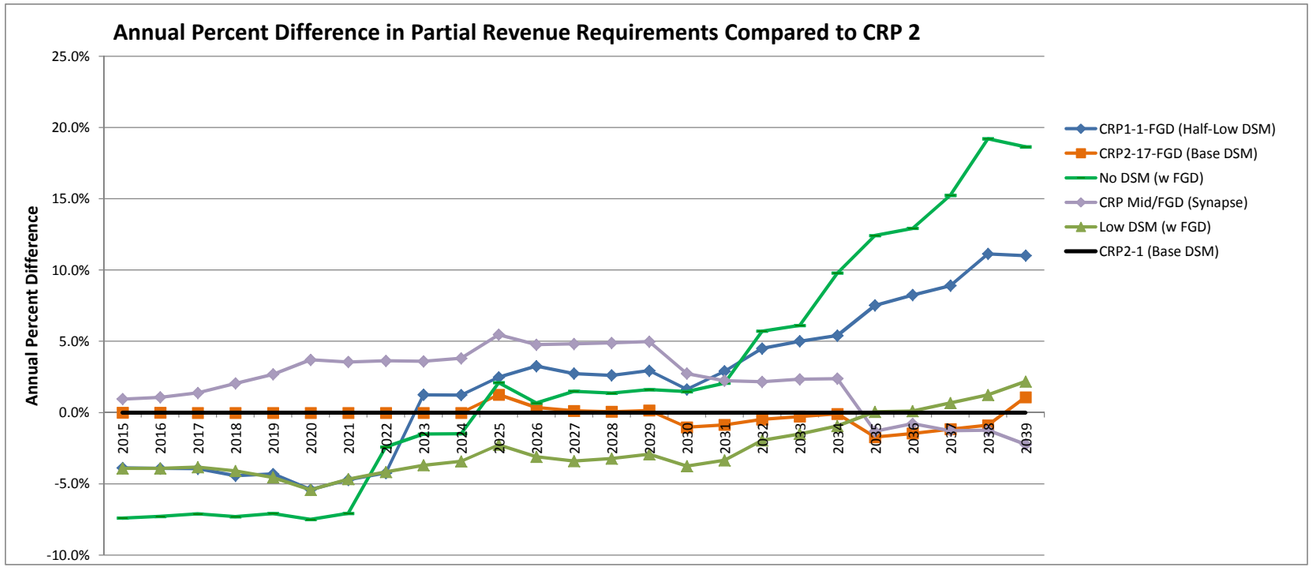
	CRP1-1-FGD (Half-Low DSM)	CRP2-17-FGD (Base DSM)	No DSM (w FGD)	CRP Mid/FGD	Low DSM (w FGD)
2015	3.8%	8.0%	0.0%	9.0%	3.8%
2016	3.6%	7.8%	0.0%	9.0%	3.6%
2017	3.4%	7.6%	0.0%	9.1%	3.5%
2018	3.1%	7.9%	0.0%	10.1%	3.5%
2019	3.0%	7.6%	0.0%	10.5%	2.7%
2020	2.3%	8.1%	0.0%	12.1%	2.2%
2021	2.5%	7.6%	0.0%	11.4%	2.6%
2022	-1.9%	2.4%	0.0%	6.2%	-1.8%
2023	2.8%	1.5%	0.0%	5.2%	-2.2%
2024	2.8%	1.5%	0.0%	5.4%	-2.0%
2025	0.4%	-0.8%	0.0%	3.3%	-4.3%
2026	2.6%	-0.3%	0.0%	4.1%	-3.7%
2027	1.2%	-1.4%	0.0%	3.3%	-4.8%
2028	1.2%	-1.3%	0.0%	3.5%	-4.5%
2029	1.3%	-1.4%	0.0%	3.3%	-4.5%
2030	0.2%	-2.5%	0.0%	1.2%	-5.1%
2031	0.8%	-2.9%	0.0%	0.2%	-5.3%
2032	-1.1%	-5.8%	0.0%	-3.4%	-7.2%
2033	-1.0%	-6.0%	0.0%	-3.6%	-7.2%
2034	-4.0%	-9.0%	0.0%	-6.7%	-9.8%
2035	-4.4%	-12.6%	0.0%	-12.2%	-11.0%
2036	-4.1%	-12.7%	0.0%	-12.1%	-11.4%
2037	-5.5%	-14.2%	0.0%	-14.3%	-12.6%
2038	-6.8%	-16.9%	0.0%	-17.2%	-15.1%
2039	-6.4%	-14.8%	0.0%	-17.6%	-13.9%

Derivation of Figure 3.8
Partial Revenue Requirements:
Fuel and Purchased Power, Thermal and Hydro O&M, Capital for new resources in the plan, DSM program administrator costs, sustaining capital (k$)

CRP	Half Low CRP1-1-FGD	Base CRP2-1	Base CRP2-17-FGD	No DSM Plan	CRP Mid/FGD (Synapse)	Low DSM
2015	651,665	673,700	673,694	630,259	678,476	649,093
2016	667,940	685,665	685,619	650,149	689,420	662,626
2017	701,354	714,536	714,414	687,222	718,278	693,524
2018	801,621	815,347	815,205	790,810	822,490	791,511
2019	832,639	840,323	840,154	825,270	850,736	814,243
2020	788,410	796,361	796,164	791,314	810,185	768,274
2021	812,420	808,959	808,740	815,929	818,967	789,444
2022	829,555	816,399	816,186	873,978	824,380	802,996
2023	900,858	833,364	833,153	909,244	838,494	825,720
2024	920,518	846,126	845,916	932,772	850,207	842,963
2025	953,922	861,077	871,891	993,040	876,399	869,998
2026	996,423	886,661	889,874	1,018,603	892,590	890,852
2027	1,004,948	891,397	892,489	1,045,545	893,582	895,736
2028	1,046,442	922,062	922,633	1,092,996	920,500	931,394
2029	1,071,620	932,320	933,694	1,123,889	926,744	948,561
2030	1,110,820	969,902	959,931	1,184,767	939,667	981,478
2031	1,152,344	984,585	976,118	1,227,107	945,577	1,004,037
2032	1,172,264	977,424	972,792	1,279,320	934,896	1,014,424
2033	1,202,175	988,958	986,233	1,316,838	944,558	1,034,288
2034	1,225,211	995,850	994,912	1,389,672	949,100	1,050,321
2035	1,301,881	1,029,317	1,011,590	1,488,701	943,549	1,099,351
2036	1,362,956	1,062,526	1,046,991	1,561,570	977,551	1,138,019
2037	1,382,527	1,064,410	1,052,016	1,612,672	973,023	1,148,781
2038	1,429,201	1,071,137	1,061,657	1,696,444	978,061	1,164,719
2039	1,465,236	1,092,858	1,104,702	1,738,865	986,742	1,201,276
	$12,085,768	$11,069,359	$11,055,345	$12,625,887	$10,947,180	$11,098,042

Load (GWh)						
2015	11,199	11,128	11,128	11,242	11,102	11,158
2016	11,253	11,099	11,099	11,351	11,042	11,163
2017	11,279	11,039	11,039	11,430	10,946	11,141
2018	11,339	11,022	11,022	11,532	10,897	11,157
2019	11,415	11,024	11,024	11,651	10,869	11,190
2020	10,429	9,966	9,966	10,704	9,777	10,166
2021	10,457	9,922	9,922	10,768	9,700	10,157
2022	10,528	9,922	9,922	10,884	9,668	10,184
2023	10,604	9,931	9,931	11,002	9,646	10,218
2024	10,705	9,961	9,961	11,146	9,642	10,276
2025	10,738	9,933	9,933	11,220	9,586	10,268
2026	10,807	9,929	9,929	11,330	9,541	10,295
2027	10,851	9,889	9,889	11,428	9,457	10,287
2028	10,932	9,884	9,884	11,558	9,407	10,317
2029	10,945	9,802	9,802	11,629	9,281	10,272
2030	10,981	9,744	9,744	11,730	9,189	10,245
2031	11,022	9,690	9,690	11,832	9,102	10,224
2032	11,064	9,640	9,640	11,936	9,025	10,203
2033	11,108	9,595	9,595	12,040	8,955	10,188
2034	11,154	9,555	9,555	12,146	8,895	10,174
2035	11,203	9,523	9,523	12,252	8,846	10,166
2036	11,255	9,497	9,497	12,360	8,806	10,161
2037	11,312	9,484	9,484	12,469	8,781	10,168
2038	11,368	9,469	9,469	12,579	8,755	10,170
2039	11,430	9,463	9,463	12,690	8,739	10,181

Figure 3.8



Derivation of Figure 3.8
Partial Revenue Requirements:
Fuel and Purchased Power, Thermal and Hydro O&M, Capital for new resources in the plan, DSM program administrator costs, sustaining capital (k$)

cents/kWh	Half Low CRP1-1-FGD	Base CRP2-1	Base CRP2-17-FGD	No DSM Plan	CRP Mid/FGD CRP Mid/FGD	Low DSM
2015	5.82	6.05	6.05	5.61	6.11	5.82
2016	5.94	6.18	6.18	5.73	6.24	5.94
2017	6.22	6.47	6.47	6.01	6.56	6.22
2018	7.07	7.40	7.40	6.86	7.55	7.09
2019	7.29	7.62	7.62	7.08	7.83	7.28
2020	7.56	7.99	7.99	7.39	8.29	7.56
2021	7.77	8.15	8.15	7.58	8.44	7.77
2022	7.88	8.23	8.23	8.03	8.53	7.89
2023	8.50	8.39	8.39	8.26	8.69	8.08
2024	8.60	8.49	8.49	8.37	8.82	8.20
2025	8.88	8.67	8.78	8.85	9.14	8.47
2026	9.22	8.93	8.96	8.99	9.35	8.65
2027	9.26	9.01	9.03	9.15	9.45	8.71
2028	9.57	9.33	9.33	9.46	9.78	9.03
2029	9.79	9.51	9.53	9.66	9.99	9.23
2030	10.12	9.95	9.85	10.10	10.23	9.58
2031	10.45	10.16	10.07	10.37	10.39	9.82
2032	10.60	10.14	10.09	10.72	10.36	9.94
2033	10.82	10.31	10.28	10.94	10.55	10.15
2034	10.98	10.42	10.41	11.44	10.67	10.32
2035	11.62	10.81	10.62	12.15	10.67	10.81
2036	12.11	11.19	11.02	12.63	11.10	11.20
2037	12.22	11.22	11.09	12.93	11.08	11.30
2038	12.57	11.31	11.21	13.49	11.17	11.45
2039	12.82	11.55	11.67	13.70	11.29	11.80

Percent Change Compared to CRP 2

	CRP1-1-FGD (Half-Low DSM)	CRP2-1 (Base DSM)	CRP2-17-FGD (Base DSM)	No DSM (w FGD	CRP Mid/FGD (	Low DSM (w FGD)
2015	-3.9%	0.0%	0.0%	-7.4%	0.9%	-3.9%
2016	-3.9%	0.0%	0.0%	-7.3%	1.1%	-3.9%
2017	-3.9%	0.0%	0.0%	-7.1%	1.4%	-3.8%
2018	-4.4%	0.0%	0.0%	-7.3%	2.0%	-4.1%
2019	-4.3%	0.0%	0.0%	-7.1%	2.7%	-4.5%
2020	-5.4%	0.0%	0.0%	-7.5%	3.7%	-5.4%
2021	-4.7%	0.0%	0.0%	-7.1%	3.6%	-4.7%
2022	-4.2%	0.0%	0.0%	-2.4%	3.6%	-4.2%
2023	1.2%	0.0%	0.0%	-1.5%	3.6%	-3.7%
2024	1.2%	0.0%	0.0%	-1.5%	3.8%	-3.4%
2025	2.5%	0.0%	1.3%	2.1%	5.5%	-2.3%
2026	3.3%	0.0%	0.4%	0.7%	4.8%	-3.1%
2027	2.7%	0.0%	0.1%	1.5%	4.8%	-3.4%
2028	2.6%	0.0%	0.1%	1.4%	4.9%	-3.2%
2029	2.9%	0.0%	0.1%	1.6%	5.0%	-2.9%
2030	1.6%	0.0%	-1.0%	1.5%	2.7%	-3.8%
2031	2.9%	0.0%	-0.9%	2.1%	2.2%	-3.3%
2032	4.5%	0.0%	-0.5%	5.7%	2.2%	-1.9%
2033	5.0%	0.0%	-0.3%	6.1%	2.3%	-1.5%
2034	5.4%	0.0%	-0.1%	9.8%	2.4%	-0.9%
2035	7.5%	0.0%	-1.7%	12.4%	-1.3%	0.1%
2036	8.2%	0.0%	-1.5%	12.9%	-0.8%	0.1%
2037	8.9%	0.0%	-1.2%	15.2%	-1.3%	0.7%
2038	11.1%	0.0%	-0.9%	19.2%	-1.2%	1.2%
2039	11.0%	0.0%	1.1%	18.6%	-2.2%	2.2%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

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

Request IR-31:

Regarding Figures 3.7 and 3.8 of NS Power's Evidence, please provide the Partial Revenue Requirements for each case in millions of dollars.

(a) If the partial revenue requirements underlying these figures are not stated in millions of dollars, please explain what they represent.

Response IR-31:

Please refer to CA IR-30 Attachments 6 and 7.

(a) Figures 3.7 and 3.8 are based on the partial revenue requirements divided by the load in each resource plan to give a partial rate.

Page 62 of the IRP defines partial revenue requirement as follows:

> Partial revenue requirements include the following:
>
> - fuel and purchased power
> - thermal and hydro unit O&M
> - capital costs for new resources added in the CRP
> - DSM program administrator costs
> - sustaining capital costs for existing and new generation added in the CRP
>
> Strategist revenue requirements do not include the following:
>
> - remaining O&M
> - regulatory adjustments/amortizations
> - depreciation, interest and tax impacts for existing assets
> - T&D sustaining capital cost[1]

[1] 2014 Integrated Resource Plan. NS Power Final Report. Filed October 14, 2014. page 62.

Request IR-32:

Regarding NS Power Evidence, page 44: Please provide the basis for the statement that "RBIM did not recognize the revenue increases required to offset the loss of fixed costs which results from the reduction in electric energy sales caused by DSM participant savings."

(a) Please explain how NS Power believes that "the revenue increases required to offset the loss of fixed costs" should be reflected in bill impact modeling.

(b) Please explain whether NS Power believes that "the revenue increases required to offset the loss of fixed costs" should be reflected in the computation of Partial Revenue Requirements, and if so, how.

Response IR-32:

A portion of NS Power's base rates recovers the annual amortized amount of previously approved fixed costs. The amount included in rates (on a cents/kWh basis) is adjusted when rates are reset through the General Rate Application process. Should the energy sales for a class decrease, for example through DSM initiatives, between GRAs when the rates remain unchanged, there is a shortfall in the revenue collected and intended to recover fixed costs. This adds to the costs which NS Power must manage in the absence of rate adjustment.

(a) Please refer to Synapse IR-21.

(b) No. Partial Revenue Requirements as used in the context of the IRP do not reflect fixed cost recoveries.

Request IR-33:

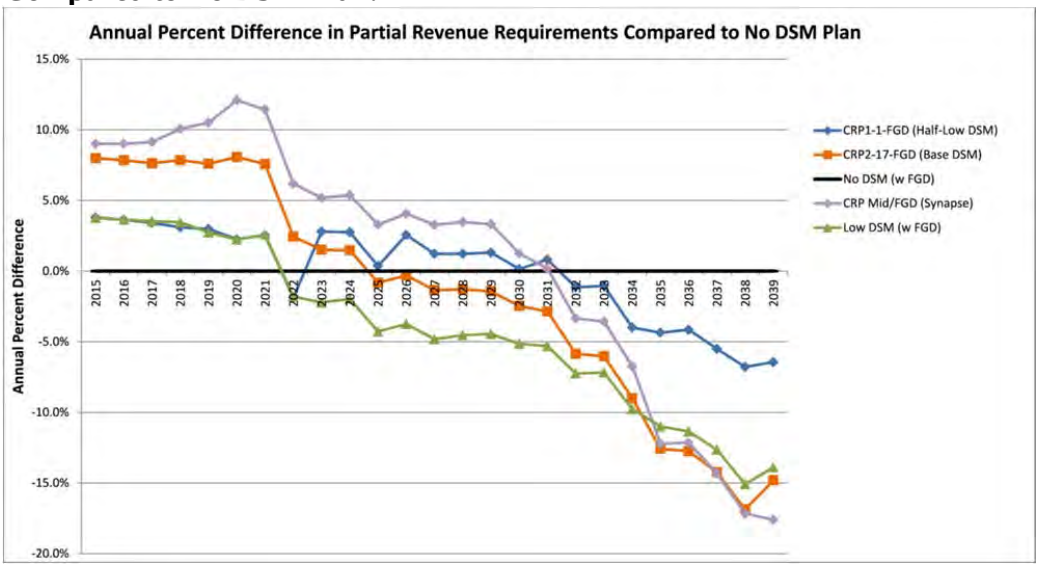
Please state whether NSPI believes that revenue requirements in millions of dollars for the period 2016-2035 (or any similarly long-term period) will be lower with its proposed DSM spending and savings in the period 2016-2018 than with E1's propose spending and savings. If so, please provide any analysis NSPI has conducted to support that conclusion.

Response IR-33:

The following analysis set out in NS Power's Evidence at page 31, lines 4 through 19, and page 32, lines 1 through 12, including Figure 3.7, demonstrates that from a revenue requirement performance basis, requiring E1 to produce a more affordable and cost effective DSM savings plan into the future would result in lower revenue requirements:

> NS Power's proposed DSM savings and spend profile for the Contract Period would provide the "Low" level of capacity and energy savings at the "Half-Low" price. This DSM profile would provide the best balance between affordability in the short term and overall cost effectiveness out beyond 2030 for the following reasons:
>
> (a) it aligns with near-term utility requirements for energy and capacity;
>
> (b) it recognizes greater confidence in near term forecasts; and
>
> (c) it is most economic at years 2025 and 2030, and the cross-over point (where it becomes less cost-effective than the higher DSM option) is not until 2034.
>
> The delay required for a DSM plan to become economic indicates that a more moderate level of DSM should be undertaken to mitigate near-term rate pressure for customers, while not sacrificing the future.

Figure 3.7: Annual Percent Difference in Partial Revenue Requirements Compared to No DSM Plan.[1]



NS Power has not created a revised long term projection as a result of E1's 2016-2018 plan for comparison.

[1] NS Power, DSM Evidence, April 10, 2015, page 31, line 12 to page 32, line 12.

Request IR-34:

What is the present expectation of NSPI as to what its revenue requirements will be over the next five years including 2015 (being the years 2015 through 2019)? Provide all evidence, studies or analysis relevant to NSPI's expectation.

Response IR-34:

Please refer to CA IR-33. The Company has analyzed its partial revenue requirements in the 2014 IRP and has provided that analysis in Section 3.3 of the Company's Evidence which demonstrates that from a revenue requirements perspective, a no DSM scenario is the lowest cost option out to 2020. However, a DSM profile aligned with the Low DSM savings from E1's potential study, at the Half-Low costs, provides the best balance of affordability and cost effectiveness out beyond 2030. The Company has proposed in its Evidence that E1 examine a number of different program and measure combinations in order to provide better DSM affordability over the 2016 to 2018 contract period. To date, E1 has not provided such details.

Request IR-35:

Identify the categories of NSPI costs which NSPI expects to increase over the period 2015 through 2019 and by how much NSPI expects each to increase. Provide all evidence, studies or analysis relevant to NSPI's expectation.

Response IR-35:

Please refer to CA IR-34. The Company has analyzed costs for the period in the context of the IRP framework and compared cost increases across a variety of different scenarios. The 2014 IRP demonstrated the most significant cost driver in that analysis was the level of DSM spend.

> Evaluating on a five-year net present value (NPV) basis, the IRP has shown that the near term spending level for demand side management is the primary driver of increased customer costs among the most economic plans.[1]

Figure 4.1 of NS Power's Evidence shows the NPVs out to the 2020 time window. The "No DSM" profile has the lowest NPV (in $ millions) at 3,679 followed by the "Low" DSM savings profile at Half-Low costs. This profile coincides with the DSM savings NS Power proposes for 2016-2018, and is the next most affordable at NPV (in $ millions) of 3,690.

[1] NS Power 2014 Final IRP Report, Matter Number M05522, October 15, 2014, page 8, lines 16-18.

Request IR-36:

Identify the categories of NSPI costs which NSPI expects to decrease over the period 2015 through 2019 and by how much NSPI expects each to decrease. Provide all evidence, studies or analysis relevant to NSPI's expectation.

Response IR-36:

Please refer to CA IR-35.

Request IR-37:

What is the present expectation of NSPI as to when it will make an application seeking an increase in rates? Provide the present expectation as to the amount of the increase. Provide all evidence, studies or analysis relevant to NSPI's expectation.

Response IR-37:

The Company is managing its expenses within its UARB-approved rates and expects to continue to manage its expenses within UARB-approved rates absent additional expenditures not currently accounted for in UARB-approved rates like DSM or significant, unforeseen cost increases to items currently in rates.

Request IR-38:

In determining whether a given amount of DSM spending in a given year is affordable, over what period of time should the impact of the DSM spending be calculated?

Response IR-38:

With respect to DSM affordability, Section 79L (9) of the Nova Scotia *Public Utilities Act* (Act) states:

> (9) The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval must take into account their affordability to Nova Scotia Power Incorporated's customers, along with any other matters considered appropriate by the Board or as may be prescribed.[1]

The Company has stated in its Evidence at page 31, lines 12-19 and page 32, lines 1-12 what level and cost profile of DSM best balances affordability and cost effectiveness. However, the ultimate determination of DSM affordability remains the purview of the UARB under the Act. The Company's Evidence states:

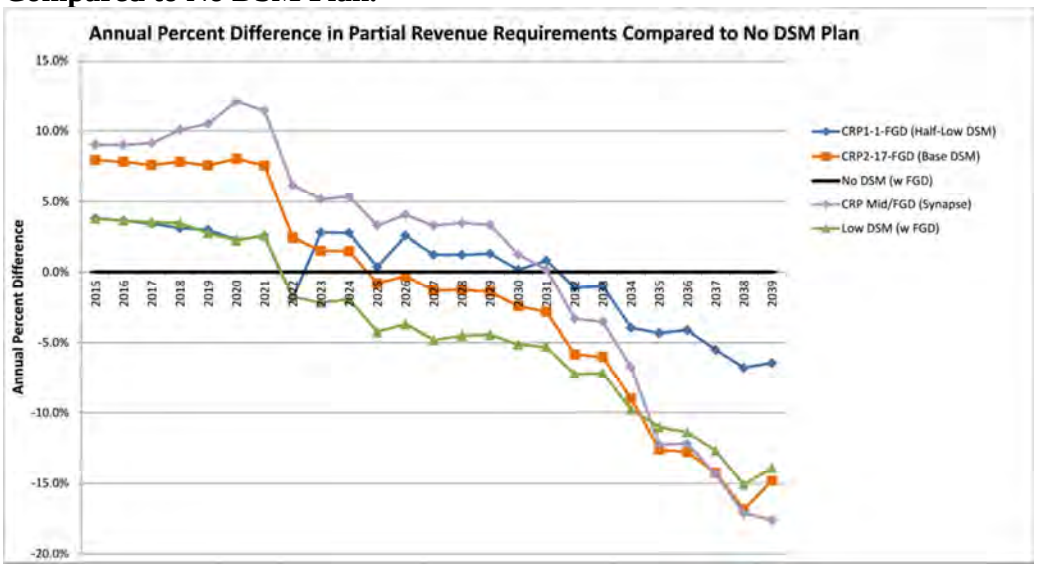
> NS Power's proposed DSM savings and spend profile for the Contract Period would provide the "Low" level of capacity and energy savings at the "Half-Low" price. This DSM profile would provide the best balance between affordability in the short-term and overall cost effectiveness out beyond 2030 for the following reasons:
>
> (a) it aligns with near-term utility requirements for energy and capacity;
>
> (b) it recognizes greater confidence in near-term forecasts; and

[1] Bill 41, *Electricity Efficiency and Conservation Restructuring (2014) Act*, 1st Sess., 62nd General Assembly, Nova Scotia, 2014 (First Reading: April 7, 2014).

(c) it is most economic at years 2025 and 2030, and the cross-over point (where it becomes less cost-effective than the higher DSM option) is not until 2034.

The delay required for a DSM plan to become economic indicates that a more moderate level of DSM should be undertaken to mitigate near-term rate pressure for customers, while not sacrificing the future.

Figure 3.7: Annual Percent Difference in Partial Revenue Requirements Compared to No DSM Plan.[2]



Please also refer to AEC IR-4 and AEC IR-5.

[2] NS Power, DSM Evidence, April 10, 2015, page 31, line 12 to page 32, line 12.

Request IR-39:

Refer to section 3.0 of the 2016-2018 DSM Plan NS Power Evidence. What is meant by the term "affordability?"

Response IR-39:

Please refer to CA IR-38.

Request IR-40:

To the extent that a proposed expenditure will increase rates does that mean that the expenditure is not affordable or is not to be incurred or how else is it to be treated?

Response IR-40:

Increases to general rates are considered by the UARB through the General Rate Application (GRA) process. The Company considers affordability to be an important concern for the UARB and stakeholders when rate applications are evaluated. In considering the Company's most recent GRA, the UARB cited cost minimization as one of the factors assessed in determining appropriate customer rates:

> The Board considered all the comments made in the written submissions and during the evening session in making its decision on the Application. The Board is mindful of its responsibility to protect the public interest and does give due weight to the comments received from the public. **The Board has to balance this with the needs of the Utility to provide a safe and reliable service at a minimum cost.** No one likes rate increases; however, the Utility's costs are increasing, similar to other businesses, and rates need to be adjusted in order to recover these cost increases.[1]
>
> [**emphasis added**]

In the context of DSM, Section 79L (9) of the Nova Scotia *Public Utilities Act* makes it clear affordability is to be a key consideration in assessing the DSM Supply Agreement:

> (9) The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval must take into account their affordability to Nova Scotia Power Incorporated's customers, along with any other matters considered appropriate by the Board or as may be prescribed.

[1] NSUARB, 2013 GRA Decision, December 21, 2012, page 5, paragraph 14.

The Company's GRA also highlighted affordability as a key criterion in determining the costs it included in the Application:

> We know Nova Scotians are frustrated with rising prices. We receive customer complaints every time we have to file a rate application. The message in those complaints is clear: Customers are concerned that electricity will no longer be affordable.
>
> We understand this concern. That's why we work hard to keep our costs as low as possible, while ensuring safe, reliable service that meets all environmental and regulatory requirements. We have sharpened our focus on operating as efficiently as possible. Consultants regularly conduct value for money audits of our business, and invariably find it to be efficiently run. The latest performance audit, by UMS Group, can be found in OP-03.[2]

[2] NS Power 2013 GRA, May 8, 2012, page 18, lines 9-18.

Request IR-41:

Does NS Power agree that the term affordability is also to be considered in relation to any request by NS Power to increase its rates?

Response IR-41:

Affordability has been a focus for NS Power's regulatory Applications. This has resulted in (among other initiatives);

- Affordability focus in ACE process
- Reductions in capital expenditures
- Utilization of regulatory deferrals
- Committed OM&G reductions
- Deferred implementation of Depreciation Study results
- Cash taxes