BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of an Application by EfficiencyOne (E1) to the Nova Scotia Utility and Review Board for Approval of Supply Agreement for Electricity Efficiency and Conservation Activities between E1 and Nova Scotia Power Inc. (NS Power), the establishment of a final agreement between the parties, and approval of a 2020-2022 Demand Side Management (DSM) Resource Plan

(NSUARB M09096)

Evidence of
Alice Napoleon

On Behalf of
Counsel to Nova Scotia Utility and Review Board

On the Topic of
EfficiencyOne's 2020-2022 DSM Plan

May 28, 2019

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Alice Napoleon. I am a Senior Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, environmental groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Synapse has a professional staff of 30 with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Since joining Synapse in 2005, I have provided economic and policy analysis of electric systems and emissions regulations, with a focus on energy efficiency program design, administration, cost recovery, and cost-benefit analysis. In my 14 years at Synapse Energy Economics, I co-authored dozens of reports and led major projects for the U.S. Environmental Protection Agency on quantifying the benefits of clean energy resources and for the U.S. Department of Energy (DOE) on strategic energy management. I have provided testimony and testimony assistance before public utility commissions across the United States and Canada, including in California, Delaware, Illinois, Kentucky, Missouri, New Jersey, New York, Nova Scotia, South Carolina and Virginia. In Colorado, Maryland, and South Carolina, I facilitated and provided expert analysis on program costs and benefits for demand-side resource policy working groups. In Nova Scotia, I have

also provided ongoing expert advice on a range of DSM issues including incentive setting methodologies, cost-benefit analysis, load forecasting, and locational DSM.

Before joining Synapse, I worked at Resource Insight, Inc., where I supported investigations of electric, gas, steam, and water resource issues, primarily in the context of reviews by state utility regulatory commissions.

I hold a Master's in Public Administration from the University of Massachusetts at Amherst and a Bachelor's in Economics from Rutgers University. My resume is attached as Appendix A.

Q. Have you previously testified before the Nova Scotia Utility and Review Board?

A. Yes. I provided evidence in Matter Nos. M06247 and M08604 regarding the 2015 and 2019 Demand-Side Management Plans on behalf of counsel to the Nova Scotia Utility and Review Board. I also provided evidence in the Advanced Meter Infrastructure cases (Matter Nos. M07767 and M08349). Further, I supported Tim Woolf in Matter No. M06733 regarding EfficiencyOne's 2016 to 2018 demand-side management plan.

Q. On whose behalf are you providing evidence in this case?

A. I am providing evidence on behalf of Counsel to the Nova Scotia Utility and Review Board ("Board").

Q. What is the purpose of this evidence?

A. The purpose of this evidence is to describe and assess EfficiencyOne's (E1) 2020-2022 Demand Side Management (DSM) Resource Plan, including its preferred and alternate scenarios. Further, this evidence describes and critiques NS Power's evidence and preferred investment level. In addition, this evidence provides my recommendations to E1 and to the Board.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please describe your conclusions.

A. I find that the Preferred Plan would continue or increase first-year and lifetime savings relative to historical savings. This plan would come closer to, but not achieve, DSM levels associated with the lowest cost scenario in the 2014 IRP. The budget for the Preferred Plan is higher than historical levels, but the cost of the resources in terms of dollars per kWh is lower than the cost of saved energy experienced in other jurisdictions historically.

The Alternate Plan would continue historical lifetime energy savings trends in the province, but it would decrease annual energy savings relative to historical spending. While this plan would require an increase in investment over recent spending amounts, lifetime cost of saved energy for the Alternate Plan is in line with or below recent historical unit costs.

I find that both the Preferred and Alternate plans proposed by E1 will secure cost-effective DSM resources. Over the 2020-2022 period, the Preferred Plan has a benefit/cost ratio of 2.0 for the total resource cost test, and 4.8 for the program administrator cost test. Similarly, the Alternate Plan over the 2020-2022 period has a benefit/cost ratio of 2.0 for the total resource cost test and 4.9 for the program administrator cost test. These benefit/cost ratios imply that there is a significant level of additional DSM resources that are available above the Preferred Plan, and even more resources available above the levels in the Alternate Plan.

Further, I make the following additional conclusions:

1. Increased emphasis on capacity savings—as proposed by E1—is likely to yield benefits, given peak demand growth in the province.

2. E1's proposal is designed to continue a shift towards a more diversified portfolio (i.e., less emphasis on lighting measures). This shift is reasonable, given the transformation of the lighting market.

3. The Alternate Plan does not appear to represent an optimized portfolio. Further, relative to the Preferred Plan, the Alternate plan sees much larger reductions in low-income savings than non-low-income savings.

4. The rate and bill impacts of the Preferred and Alternate plans are relatively small, even when assuming a 25 percent decrease in both avoided energy and capacity costs relative to the 2014 Integrated Resource Plan avoided costs. On the other hand, a 25 percent increase in avoided energy and capacity costs would result in rate and non-participant bill impacts that are consistently negligible if not negative across all rate classes.

Q. What are your recommendations?

A. I recommend that the overall savings levels associated with E1's Preferred Plan should be approved, in light of the high cost-effectiveness of the DSM resource.

Further, I recommend that NS Power's proposed modifications to the rate and bill impact analysis should be reviewed by the Demand Side Management Advisory Group (DSMAG) outside of this proceeding, including the issue that I identify in this evidence regarding allocation of avoided costs to rate classes.

3. BACKGROUND AND OVERVIEW

Q. Please provide an overview of the previous DSM plan.

A. E1 filed its proposal for the 2019 DSM plan on April 6, 2018 in M08604. Generally, this plan proposed to continue the budget and savings levels of the previous three years, as well as introduce new demand reduction pilots and shift the measure mix to reduce the share of savings from lighting measures (2019 DSM Plan, p. 17). The 2019 DSM Plan included incremental annual savings of 127.2 GWh, and incremental lifetime savings of 1,638.4 GWh. E1's 2019 Plan included incremental demand savings of 20.2 MW. On July 23, 2018, the Board approved E1's proposed plan with a budget of $34.1 million.

Q. Please provide a high-level overview of E1's 2020-2022 DSM Plan.

A. On February 28, 2019, E1 filed its 2020-2022 DSM Plan, including two scenarios: a Preferred Plan and an Alternate Plan. According to E1, the Preferred Plan provides "the best value for Nova Scotians at an affordable investment level while delivering a carefully balanced portfolio that has been developed through EfficiencyOne's expertise and DSM market knowledge" (E1 Evidence, p. 6). E1 also provided a lower cost Alternate Plan, which sees lower savings levels and lower participation than the Preferred Plan (E1 Evidence, p. 52).

Other elements of E1's filing include descriptions of the portfolio development process and program designs, benefit-cost analysis (BCA) results, a forward-looking rate and bill impact analysis (RBIA) for the Preferred Plan and the Alternate Plan, evidence regarding lighting market transformation, and evidence comparing E1's performance to other jurisdictions. E1's filing indicated that agreement on a level of energy savings and funding had not been reached with NS Power (E1 Evidence, p. 2.)

Q. Did NS Power file evidence in this case?

A. Yes, NS Power filed evidence on April 12, 2019. This evidence generally supports a lower level of investment. The evidence did not include a short-term rate impact analysis, although workbooks on this analysis were filed in response to discovery (NS Power's response to NSUARB IR-20).

4. E1'S DSM PLAN

Energy savings

Q. What level of energy savings does E1 propose in the Preferred Plan and the Alternate Plan?

A. Table 1 and Table 2 show annual energy savings and lifetime energy savings, respectively, for the Preferred and Alternate plans for each of the three plan years. Both the Preferred Plan and the Alternate Plan would produce relatively flat annual and lifetime energy savings throughout the 2020 to 2022 period.

Table 1. Total Annual Program Savings (GWh)

Year	BNI	Residential	Total
Preferred			
2020	83.3	56.9	140.2
2021	86.3	55	141.3
2022	88.9	51.3	140.2
Alternate			
2020	74.4	50	124.4
2021	77.2	48.4	125.4
2022	79.5	44.9	124.4

Table 2. Total Lifetime Program Savings (GWh)

Year	BNI	Residential	Total
Preferred			
2020	1165.5	802.4	1,968
2021	1212.2	802.3	2,015
2022	1251.6	762.3	2,014
Alternate			
2020	1041.2	703.2	1,744
2021	1083.0	703.1	1,786
2022	1118.0	667.4	1,786

Table 5 shows peak demand savings for the Preferred and Alternate plans. Both the Preferred Plan and the Alternate Plan would involve an increase in demand savings over the 2020 to 2022 period.

Table 3. Peak Energy Savings (MW)

Year	BNI	Residential	Total
Preferred			
2020	19.1	19.5	38.7
2021	20.6	19.8	40.3
2022	21.7	19.5	41.1
Alternate			
2020	16.5	16.9	33.4
2021	17.5	17	34.5
2022	18.4	16.5	34.9

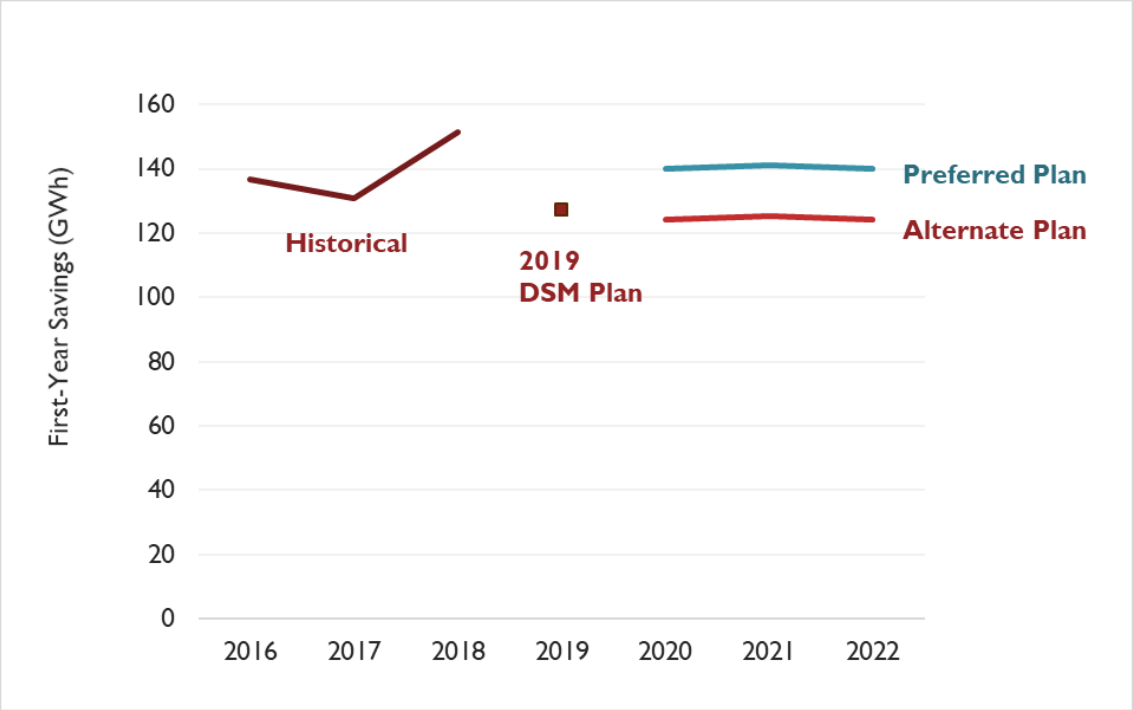
Q. How do energy savings in the Preferred Plan compare with the savings in the Alternate Plan?

A. Total Alternate Plan annual energy savings over the 2020-2022 period are 11 percent lower than total Preferred Plan annual savings. Likewise, lifetime savings are 11 percent lower for the Alternate Plan than for the Preferred Plan. Alternate Plan demand savings are roughly 14 percent lower than demand savings for the Preferred Plan.

Q. How do the savings of the Preferred and Alternate Plans compare with historical savings?

A. For the Preferred Plan, annual energy savings in 2020 (140.2 GWh) are higher than planned 2019 savings (127.2 GWh). As shown in Figure 3, 2020 first-year savings for the Preferred Plan are less than the savings levels E1 achieved in 2018 (151 GWh).

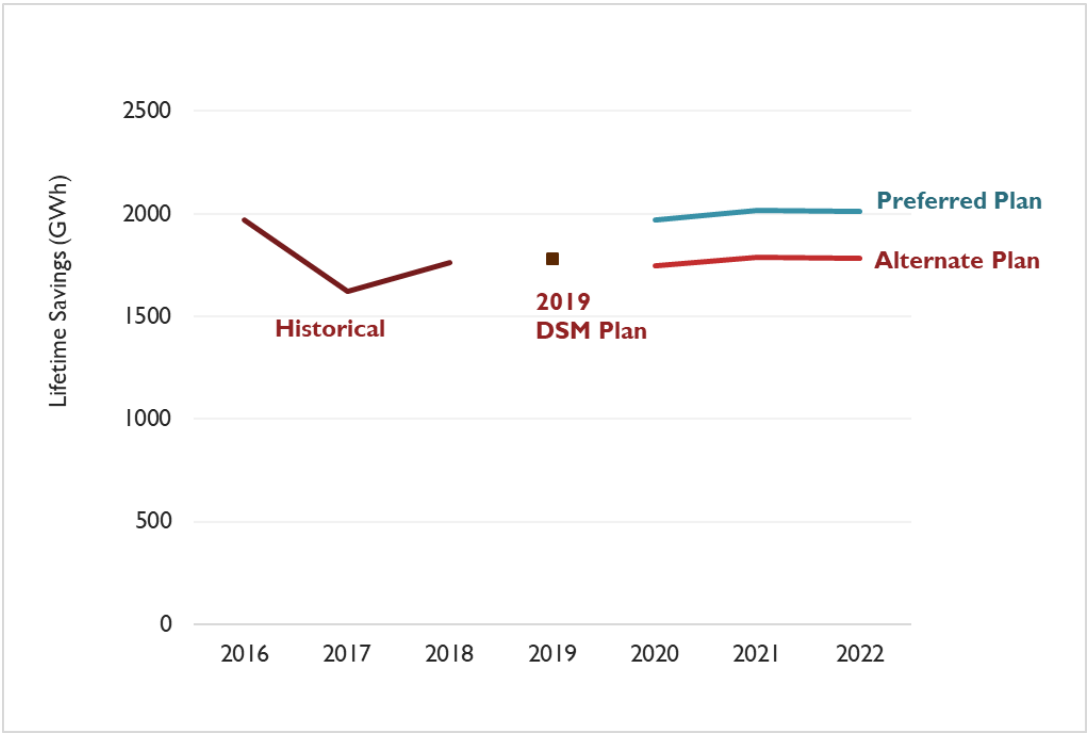
Figure 1. Total Annual Program Savings (GWh): Historical, Preferred Plan, and Alternate Plan



Annual energy savings for the Alternate Plan, 124.4 GWh in 2020, are less than both 2018 achieved savings (151 GWh) and 2019 planned energy savings (127.2 GWh).

In terms of lifetime savings, the Preferred Plan would produce higher savings than both actual 2018 results and projected 2019 savings. As shown in Figure 2, lifetime savings for the Alternate Plan are roughly in line with actual 2018 achievements and projected 2019 savings.

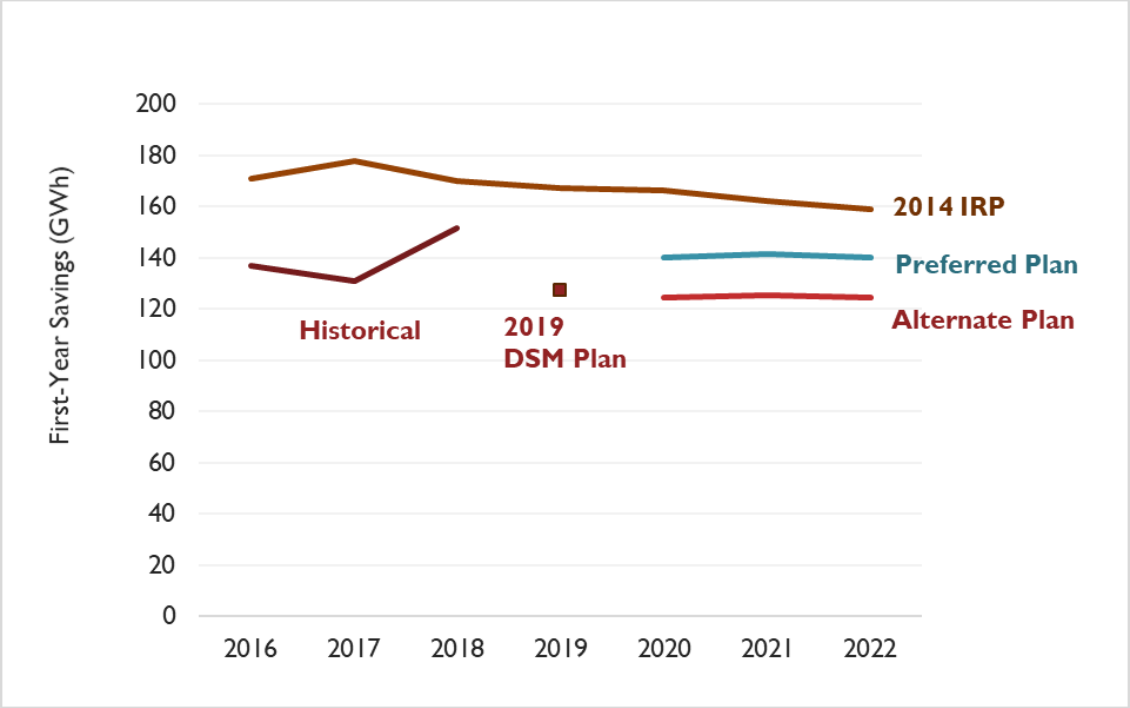
Figure 2. Total Lifetime Program Savings (GWh): Historical, Preferred Plan, and Alternate Plan



Q. How do the Preferred and Alternate plan savings compare with the 2014 IRP?

A. As shown in Figure 3, neither of the plans reach the savings levels modeled in the 2014 IRP Mid-DSM scenario, the scenario with the lowest net present value of revenue requirements. The Preferred Plan gets far closer to the Mid-DSM scenario than the Alternate Plan does.

Figure 3. Total Annual Program Savings (GWh): Historical, 2014 IRP, Preferred Plan, and Alternate Plan



Budget

Q. Please describe E1's proposed budget for the Preferred and Alternate plans.

A. As shown in Table 4, E1's proposed budget for the Preferred Plan is $129 million over the three-year term of the plan. Of that budget, half is dedicated to Business, Non-Profit, and Institutional (BNI) programs, while residential programs would receive 41 percent of the budget.

Table 4. Proposed budget for the Preferred and Alternate plans

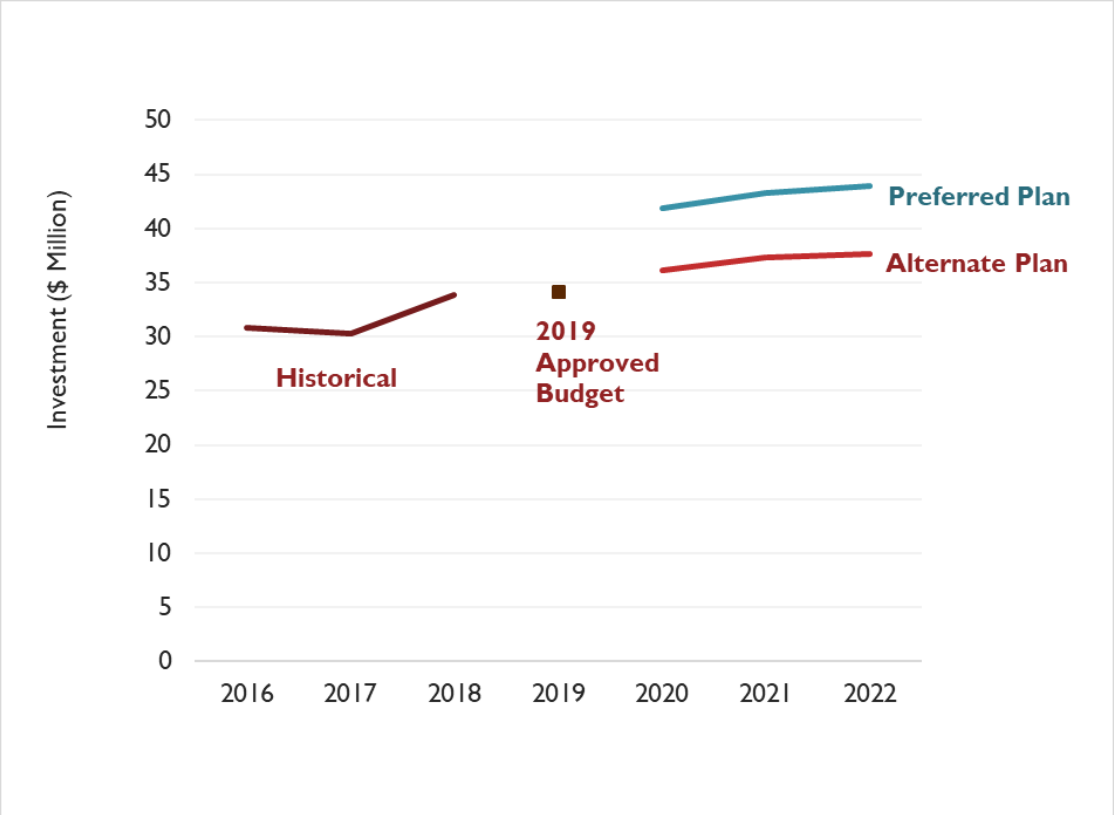
	Preferred Plan		Alternate Plan		Preferred vs. Alternate
2020-2022	Investment ($ million)	Share of Total	Investment ($ million)	Share of Total	Difference (%)
Residential	53.4	41%	44.7	40%	-16.3%
BNI	64.3	50%	56.5	51%	-12.1%
Enabling Strategies	11.6	9%	10.3	9%	-11.2%
Total	129.1	100%	111	100%	-14.0%

The proposed budget for the Alternate Plan is a total of $111 million over the 2020 to 2022 period. As a whole, the budget for the Alternate Plan is 14 percent lower than the budget for the Preferred Plan. Relative to the Preferred Plan, investment in residential programs under the Alternate Plan declines by a greater percentage (16 percent) than investment in BNI does (12 percent).

Q. How do these budgets compare to historical budgets?

A. E1's Preferred Plan and Alternate Plan would both involve an increase in spending over recent spending amounts. As shown in Figure 4, proposed spending for the Alternate Plan ($36.1 million in 2020) is 6 percent higher than the level approved by the Board for 2019, $34.1 million. Proposed spending for the Preferred Plan, $41.9 million in 2020, is 23 percent higher than the Board-approved budget for 2019.

Figure 4. Total Program Investment ($ Million): Historical, 2019 Approved, Preferred Plan, and Alternate Plan



Q. In recent years, has E1 generally spent its entire budget?

A. No, E1 has historically not spent all of its planned budget. Comparing E1's actual spending with planned, E1 has spent less than it budgeted for each of the years from 2015 to 2018. On average, E1 spent almost 10 percent less than budget, as shown in Table 5.

At the same time, E1 has exceeded its savings targets in recent years. Comparing E1's achievements for 2015, 2016, 2017, and 2018 with its savings projections for the same years, it is evident that actual energy and peak demand savings have exceeded planned targets by substantial margins. For example, 2018 energy savings exceeded E1's target by about 15 GWh, or roughly 11 percent. Demand savings achieved in 2018 (25.5 MW) exceeded E1's target for that year (21.0 MW) by 4.5 MW, or about 21 percent (ENS 2018 DSM Annual Progress Report, p. 2).

Table 5. Historical DSM energy and demand savings versus planned

Year	Results / Filed					
	Absolute Difference			Percent Difference		
	Energy Savings (GWh)	Demand Savings (MW)	Budget ($ million)	Energy Savings	Demand Savings	Budget
2015	16.7	1.5	-7	13.8%	7.1%	-17.9%
2016	3.8	5.6	-2.4	2.9%	27.5%	-7.2%
2017	-5.8	2.7	-3.7	-4.2%	12.9%	-10.9%
2018	15.1	4.5	-1.0	11.1%	21.4%	-2.9%
Average	7.45	3.6	-3.5	5.9%	17.2%	-9.7%

Q. What do these data show?

A. The historical trend is clear. These data appear to indicate an upward bias in E1's estimates of resource costs. I recommend that E1 investigate factors that led to the overestimation of the budget in the past DSM plans.

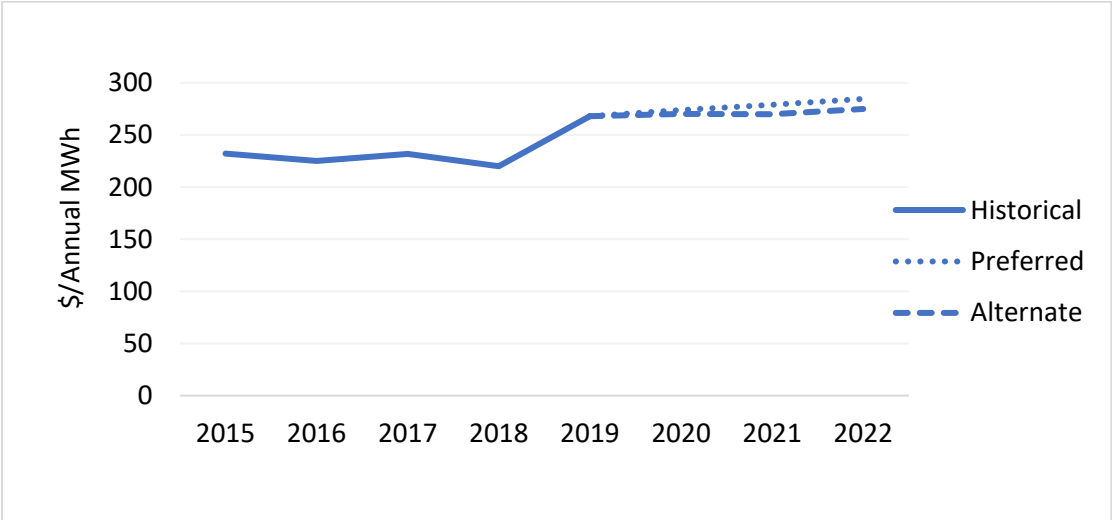
Cost of Saved Energy

Q. Please describe the first-year cost of saved energy for the Preferred and Alternate plans.

A. The first-year cost of saved energy of the Preferred Plan is $0.31 per kWh (E1 Evidence, p. 6.) The Alternate Plan's first-year unit cost is $0.30 per kWh (E1 Evidence Appendix C.) Both proposed plans represent an increase relative to the first-year unit cost of $0.23 per kWh during the 2016-2018 period and the approved first-year unit cost of $0.27 per kWh in 2019 (E1 Evidence, p. 21-22.)

Figure 5 shows the first-year cost of saved energy excluding cross sector costs, including enabling strategies.

Figure 5. Cost of first-year savings, historical versus Preferred and Alternate plans



Q. Please describe the lifetime cost of saved energy for the Preferred and Alternate plans.

A. The lifetime cost of saved energy of the Preferred Plan is $0.022 per kWh (E1 Evidence, p. 7). The Alternate Plan's lifetime unit cost is $0.021 per kWh, in line with the lifetime cost of saved energy based on the approved 2019 plan (E1 Evidence Appendix C).

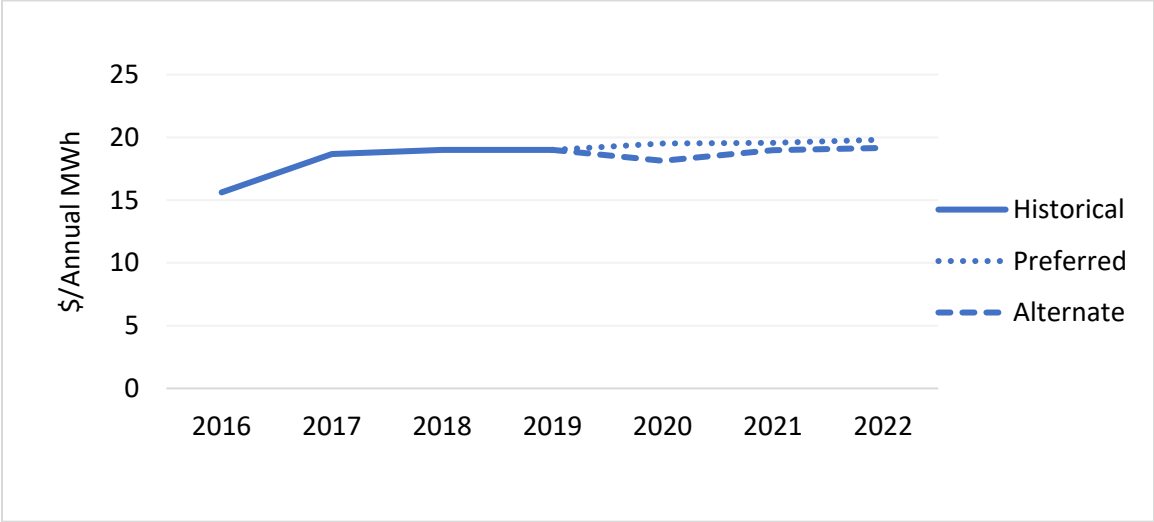
It is worth noting that E1's Preferred and Alternate lifetime unit costs are much lower than the cost of saved energy that was found in Synapse's 2016 study of 2010 to 2015 energy efficiency program costs based on U.S. Energy Information Administration data.[1] This study found a lifetime, straight average program administrator cost of saved energy equivalent to $0.051 CAD per kWh of savings.[2] The E1 value is also less than Synapse's finding for the utility cost of providing energy efficiency when the average was weighted by saved energy, $0.034 CAD per kWh.[3]

Figure 6 shows trends in the cost of lifetime savings, excluding cross-program costs. Lifetime unit costs have stayed relatively flat for several years. The lifetime cost of saved energy for the Preferred Plan is slightly higher than the levels seen

[1] Synapse Energy Economics. 2016. Estimating the Cost of Saved Energy: The EIA 861 database.
[2] Assumes an exchange rate of $1 USD : $1.3 CAD.
[3] Ibid.

in recent years, while the lifetime cost of saved energy for the Alternate Plan is in line with or below recent historical unit costs.

Figure 6. Cost of lifetime savings, historical versus Preferred and Alternate plans



As noted by E1, the Preferred and Alternate average cost of saved energy deviates from historical cost of saved energy in part because of changes in the program measure mixes, specifically diversification of the portfolio to include more non-lighting savings (E1 Evidence, p. 21-22) and measures that provide savings on peak. Both of these shifts are likely to yield ratepayer benefits.

Q. Do you think the cost of saved energy is likely to be as high as modeled by E1?

A. I think it is likely that the cost of saved energy will be lower than E1 estimates, for two reasons. First, E1 has a history of achieving savings levels using fewer funds than budgeted. Second, the DSM Plan does not appear to take into account opportunities to lower costs using AMI capabilities. AMI could facilitate customer targeting and reduce acquisition costs. During the 2020-2022 period, it will be important for E1 to continue working with NSPI and the DSMAG on opportunities to leverage AMI functionality.

Q. NS Power's witness Mr. Levitan claims that the cost of saved energy for the Preferred Plan is 77 percent higher than the 2019 cost of saved energy. Do you agree?

A. No. Mr. Levitan applies the cost of saved energy in terms of dollars per kWh of the 2019 DSM Plan to 127.2 GWh of the savings in the Preferred Plan for 2020. He then attributes all of the 2020 investment in excess of the 2019 investment level (i.e., $6 million, equivalent to the proposed $39 million budget in 2020 less the 2019 budget of $33 million) to the 2020 savings in excess of the 2019 planned savings (13.0 GWh, equal to 140.2 GWh in energy savings for the Preferred Plan in 2020 less 2019 planned savings). The result of this calculation is a cost of saved energy of $0.46 per kWh, which is 77 percent higher than the cost of saved energy for the 2019 DSM plan as approved. Mr. Levitan's evidence is misleading on this point.

Q. In what way is this calculation misleading?

A. This calculation assumes that the first 127.2 GWh of the 2020 Preferred portfolio has the same cost of saved energy as in 2019, when in reality, those resources may be more or less expensive than the 2019 DSM resources. The assumptions underlying this calculation appear to assume that the first 127.2 of resources in the 2020 Preferred portfolio were optimized and can be readily separated out from the remaining 13.0 GWh. This is unlikely to be the case.

Cost effectiveness

Q. Has E1 provided cost-effectiveness results for the Preferred and Alternate plans?

A. Yes. E1's cost-effectiveness results, in terms of the Program Administrator Cost (PAC) test and the Total Resource Cost (TRC) test, are shown in Table 6.

Table 6. Cost-Effectiveness of the Preferred and Alternate Plans

Year	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)
Preferred		
2020	1.9	4.7
2021	1.9	4.8
2022	2.0	5.0
2020-2022	2.0	4.8
Alternate		
2020	1.9	4.7
2021	1.9	4.9
2022	2.0	5.0
2020-2022	2.0	4.9

Source: Appendix A, p. 10 and 14-16; Appendix C, p.1-4.

Q. How do you interpret the cost-effectiveness results?

A. E1's Preferred and Alternate plans are both highly cost-effective. The PAC result for the portfolio means that for every dollar of investment in DSM, the system realizes $4.80 in benefits with the Preferred Plan and $4.90 in benefits with the Alternate Plan. The high cost-effectiveness of the programs and the portfolio further suggests that there is headroom for increasing DSM investment beyond current levels while maintaining a cost-effective portfolio.

Portfolio design

Lighting Market Transformation

Q. Is the lighting market transformation accounted for in E1's 2020-2022 DSM Plan?

A. Yes. E1 indicates that "the Preferred Plan reduces its reliance on savings from lighting, a strategy consistent with industry trends" and "the Preferred Plan increases funding for comprehensive, non-lighting upgrades that achieve deeper energy savings" (E1 Evidence, p. 21). Further, E1 presented evidence by David Hill on the transformation of the lighting market.

Q. What is the cost impact of diversifying the portfolio to include more savings from non-lighting measures?

A. Displacing lighting savings, which are typically low-cost compared with other DSM resources, results in a higher cost portfolio. Resources that displace lighting are often more complex and require a higher level of customer engagement, thereby increasing cost (E1 evidence, p. 21-22). As an illustration, E1 shows the cost impact of removing lighting measures not included in the 2020-2022 plan from the 2016-2018 portfolio and finds a roughly 17 percent increase in the cost per kWh saved.

Q. Do you have any comments on the proposed shift in the DSM portfolio?

A. E1's proposal to reduce emphasis on lighting measures will diversify the DSM portfolio and is appropriate. E1 should continue to achieve cost-effective savings in lighting, while gradually diversifying its portfolio.

Reducing peak load growth in the province

Q. What is the projected energy load growth in the province?

A. According to NS Power's 2018 Load Forecast Report, energy consumption is projected to decline slightly over the next 10 years, as shown in

Table 7.[4]

[4] NS Power's 2019 Load Forecast Report has filed, but that the review of that report is ongoing.

Table 7. Forecast Total System Energy, 2018-2028

Year	Total Energy	Growth
	GWh	%
2018	10,960	0.80%
2019	11,000	0.40%
2020	11,003	0.00%
2021	10,916	-0.80%
2022	10,881	-0.30%
2023	10,835	-0.40%
2024	10,802	-0.30%
2025	10,740	-0.60%
2026	10,705	-0.30%
2027	10,670	-0.30%
2028	10,659	-0.10%
Compound Annual Growth		-0.28%
10-year Growth		-2.75%

*Source: 2018 Load Forecast Report, Figure 1. *Includes municipal load and losses.*

Unlike energy, demand is projected to grow over the next six years. As shown in

Table 8, peak demand is expected to increase through 2024, then slowly decline in the following years. Peak demand in 2028 is projected to be 1.5 percent higher than projected 2018 demand.

Table 8. Forecast Total System Demand, 2018-2028

Year	Net System Peak (MW)	Growth (%)
2018	2,139	6.00%
2019	2,157	0.86%
2020	2,172	0.71%
2021	2,174	0.05%
2022	2,178	0.20%
2023	2,184	0.29%
2024	2,191	0.28%
2025	2,187	-0.18%
2026	2,183	-0.17%
2027	2,177	-0.25%
2028	2,172	-0.23%
Compound Annual Growth		0.15%
10-year Growth		1.54%

Source: 2018 Load Forecast Report, Figure 2.

Q. What do these forecasts suggest for DSM planning?

A. Targeting demand growth with DSM, as proposed by E1, is appropriate in light of peak load growth trends.

Q. What are the benefits of DSM in terms of peak load?

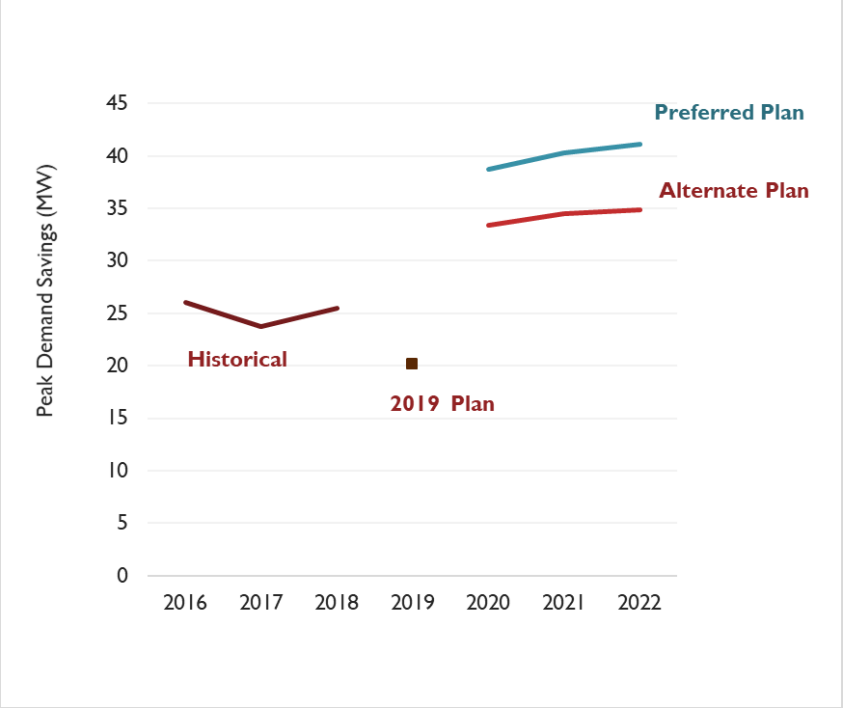
A. DSM has a role in avoiding future capacity costs. The Final Report of the Thermal Generation Utilization and Optimization process (Matter No. M08059) found that "there is no CC [combined cycle] unit built in any of the medium DSM scenarios without forced coal retirements" (p. 3). Further, it indicated that the "net present value of wholesale system revenue requirements (NPVRR, 2018-2042 period) across the modeled scenarios is clearly seen to be lowest for scenarios incorporating moderate ("medium") levels of demand-side management (DSM), reflecting an increase to existing efforts up to a level eventually (within 4 years, as modeled) reaching incremental annual energy efficiency achievements equal to 2 percent of NSPI's retail sales. This occurs even when using first-year costs of incremental saved energy that is on the order of twice as expensive (per unit) as

the efficiency savings Efficiency One currently procures" (p. 2). These findings support the value of DSM in avoiding capacity costs, even at much higher unit costs.

Q. Does E1 plan to address peak demand growth during 2020-2022?

A. Yes. As shown in Figure 7, E1 proposes to increase peak demand savings with both the Preferred and the Alternate plans relative to historical and 2019 planned savings.

Figure 7. Peak Demand Savings (MW): Historical, 2019 DSM Plan, Preferred Plan, and Alternate Plan

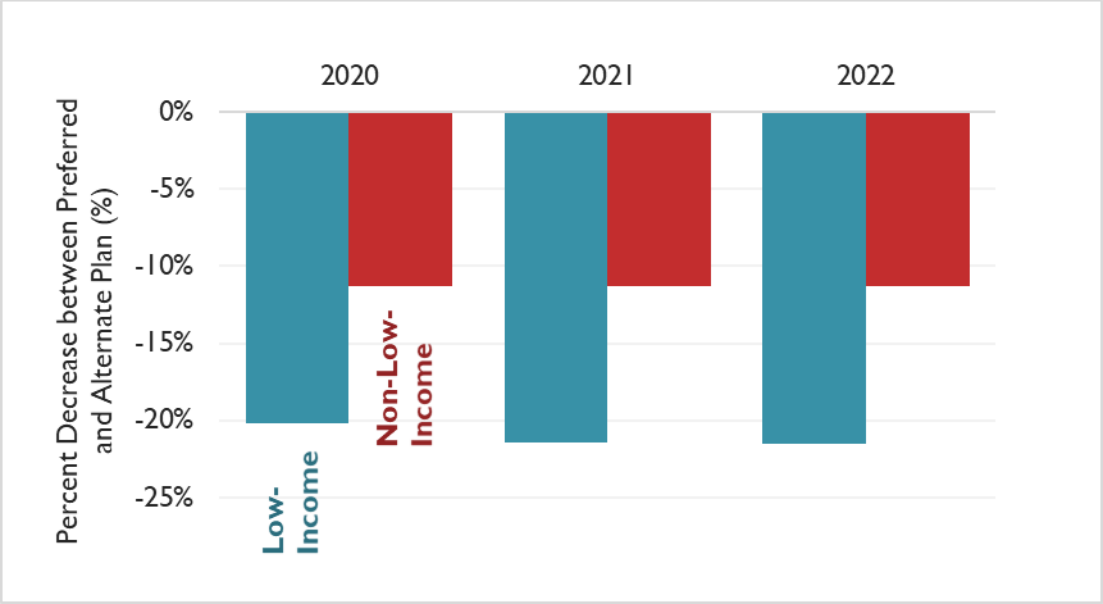


Portfolio Emphasis on Low Income

Q. Do you have concerns related to savings for low-income customers in the Preferred and Alternate plans?

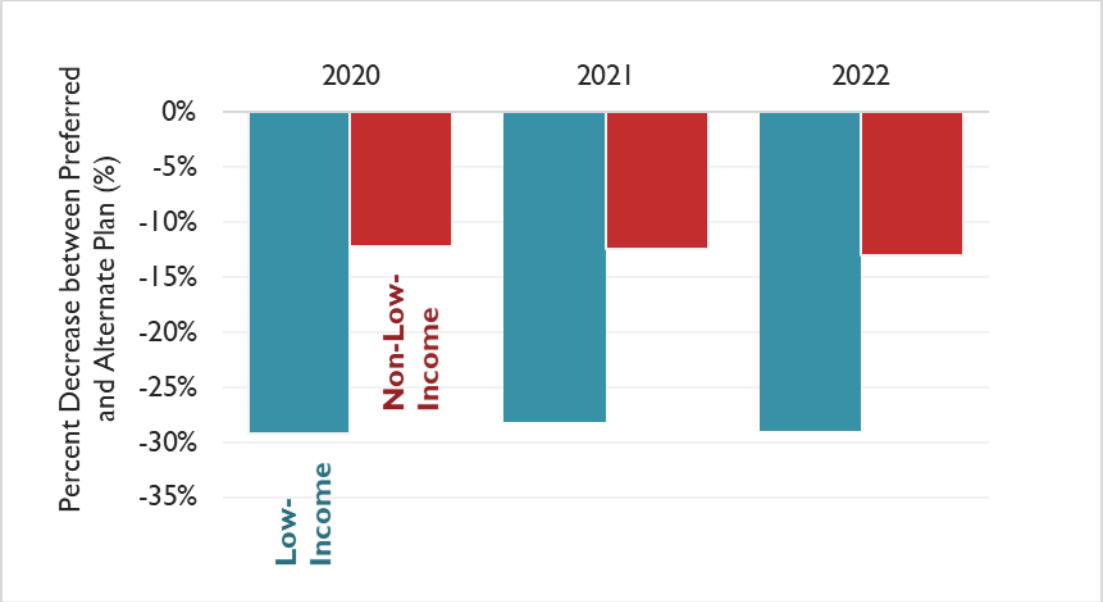
A. Yes. Relative to the Preferred Plan, the Alternate Plan would achieve substantially lower savings for the low-income sector. As shown in Figure 8, projected annual savings for low-income customers in the Alternate Plan are about 21 percent lower than savings in the Preferred Plan. In comparison, savings associated with non-low-income efforts take a smaller cut (11 percent) in the Alternate Plan.

Figure 8. Difference in first-year energy savings associated with low-income participation, Preferred vs. Alternate Plan



Likewise, investment in efforts that target low-income customers takes a steep cut from the Preferred Plan to the Alternate Plan. As seen in Figure 9, investment in low income energy efficiency is roughly 29 percent lower in the Alternate Plan than in the Preferred Plan, while non-low-income investment in the Alternate Plan is only about 12 percent lower than proposed in the Preferred Plan.

Figure 9. Difference in investment associated with low-income participation, Preferred vs. Alternate Plan



Q. Has E1 explained why DSM efforts for low-income customers in the Alternate Plan take a larger cut than efforts for other customers?

A. In response to Synapse IR-25, E1 indicates that program components with a larger share of low-income participation (the Affordable Multi-Family Housing and First Nations Home Energy Efficiency Program) were reduced to a greater extent under the Alternate Plan than were other programs and program components. The reason for this is the higher costs of the program components with higher low-income participation rates.

Q. Do you agree that DSM efforts for low-income customers in the Alternate Plan should take a larger cut than efforts for other customers?

A. No. This disproportionate reduction in savings for low-income customers seems short-sighted. Energy efficiency targeting low-income populations offer these customers a way to manage their bills. Low-income customers generally spend a large portion of household income on energy bills; that is, they have high energy burdens. In general, reducing energy burdens for this population produces proportionally large benefits, both for these customers and for ratepayers as a whole (e.g., through reductions in arrearages and collection expenses).

Overall Plan Development

Q. Do you have concerns with the development of the Alternate Plan?

A. Yes. The Alternate Plan does not appear to reflect an optimized path. In response to NS Power's IR-52, E1 indicated that "The ProCESS optimization model function was used for the Preferred Plan....The Alternate Scenario does not materially change the mix of programs and measures offered in the Preferred Plan. For this reason, the optimizer tool was not used in the creation of the Alternate Scenario. Participation levels in the Preferred Plan were reduced to produce the Alternate Scenario as described in EfficiencyOne's response to NS Power IR-67."

Without that optimization, there may be combinations of programs and measures that achieve a given level of savings at a lower cost. In the event that the current proceeding results in a level of savings associated with the Alternate Scenario, E1 should optimize the portfolio.

5. NS POWER'S PREFERRED PLAN

Q. What investment level does NS Power favor?

A. NS Power suggests that an investment level in the range of $27 to $34 million per year is appropriate.

Q. What are the savings levels associated with the $27 million investment level?

A. Both annual and lifetime savings levels associated with NS Power's preferred path are substantially lower than E1's preferred and alternate plan savings, and lower than savings levels currently being achieved in the province. As shown in Figure 10, annual energy savings associated with the $27 million scenario would be far below historical and 2019 projected savings. Figure 11 shows that peak savings for the $27 million DSM scenario are slightly higher than 2019 projected savings, but lower than 2016-2018 actual demand savings.

Figure 10. First-year Savings (GWh): Historical, 2019 DSM Plan, Preferred Plan, Alternate Plan, and $27 million scenario

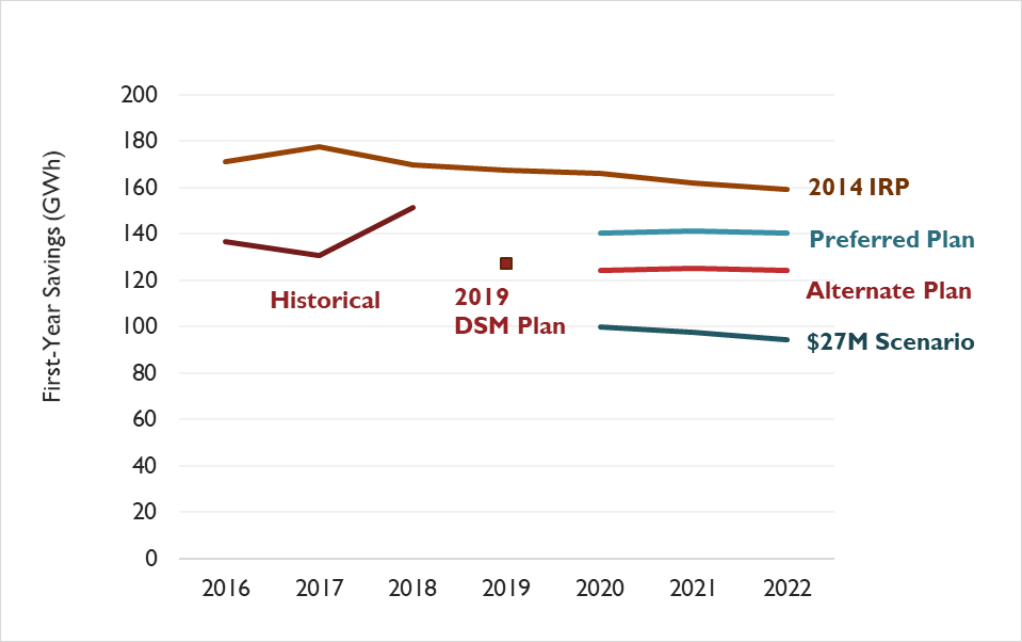
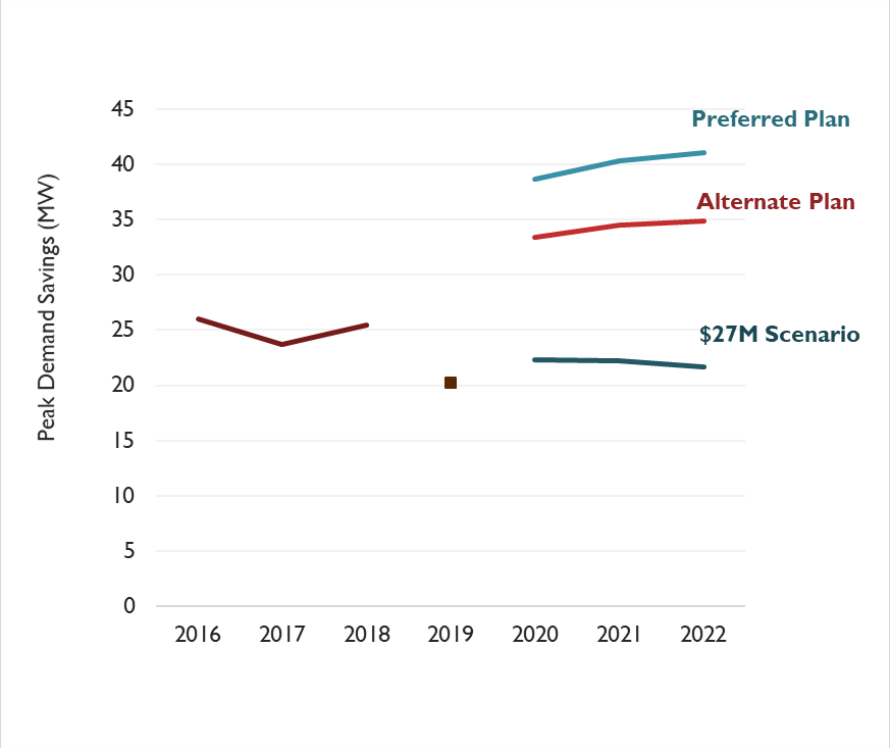
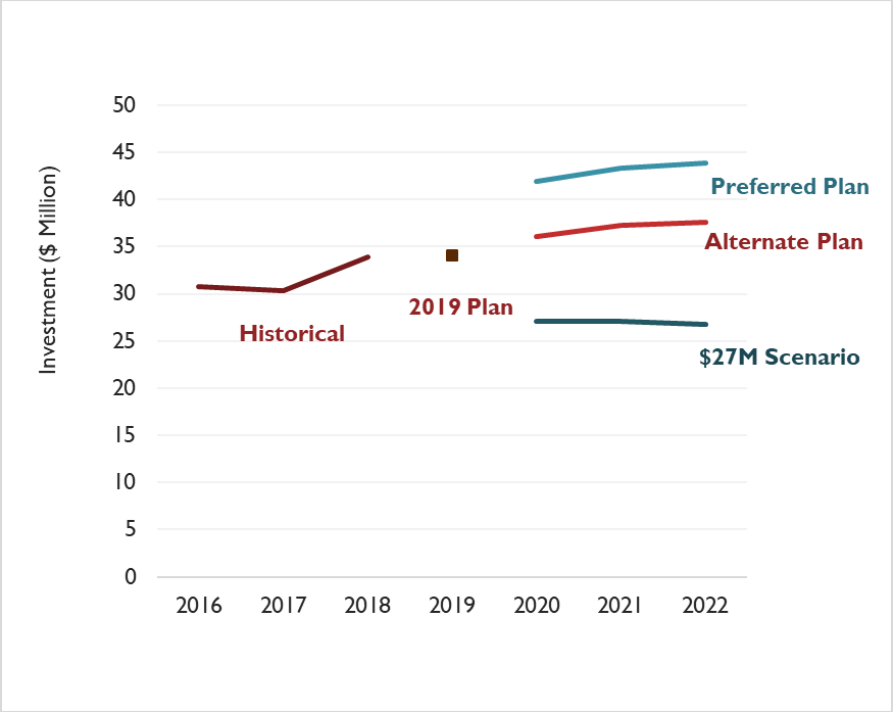


Figure 11. Peak Savings (MW): Historical, 2019 DSM Plan, Preferred Plan, Alternate Plan, and $27 million scenario



As shown in Figure 12, investment levels for the $27 million DSM scenario are lower than both 2019 planned investment and 2016 to 2018 annual investment.

Figure 12. Investment (million $): Historical, 2019 DSM Plan, Preferred Plan, Alternate Plan, and $27 million scenario



Q. Is this level of investment more affordable?

A. While this level of investment may produce lower rate impacts, it provides far fewer benefits to the system overall. Furthermore, the $27 million level of investment would require a reduction in savings, a reduction in participants, or both, relative to the E1's proposed plans. In addition to providing more system-wide benefits, higher levels of DSM spending should provide more customers the opportunity to manage their bills, thus improving affordability.

Q. NS Power's witness, Richard Levitan, characterizes E1's proposal as "inconsistent with and unsupported by the DSM experience in the U.S. over the past several years" (p. 35). Is NS Power's preferred level of spending in step with DSM experience in other jurisdictions?

A. No. In response to Synapse IR-27, Mr. Levitan acknowledged that his analysis found that more states are increasing spending than are decreasing spending. A decrease in spending, as suggested by NS Power, would not be consistent with the experience in the United States.

6. RATE AND BILL IMPACTS

Avoided Energy and Capacity Costs

Q. Please describe the rate and bill impact analyses put forth by E1.

A. E1's RBIA models the rate and bill impacts of the Preferred and Alternate plans through 2035, when the modelled impacts of 2022 measures expire. For each of these plans, the RBIA compares a scenario that does not include 2020-2022 DSM impacts with a scenario in which the impacts of 2020-2022 DSM activities in terms of investments, avoided costs, and recovery of lost revenues are allocated to each participating rate class. The RBIA model provided by E1 relies on avoided energy and capacity costs from the 2014 IRP.[5]

Q. Do you have concerns about these avoided energy and capacity costs?

A. Yes. The avoided energy and capacity costs developed during the 2014 IRP process are outdated. As NS Power notes on Page 11 of 37 of its evidence, "the 2014 IRP is not highly correlated with changes to the NS Power system over the last five years." Avoided energy and capacity costs should reflect NS Power's current system and the current state of the energy sector.

Q. Have you asked E1 about its decision to use the 2014 IRP avoided costs in its RBIA?

A. Yes. In its response to Synapse IR-02, E1 states that it "acknowledges there may have been changes to the energy landscape in Nova Scotia since 2014 that would impact costs" but that "[u]ntil a new Integrated Resource Plan (IRP) is completed and undergoes rigorous stakeholder and regulatory review, EfficiencyOne is unable to comment on how those changes may impact avoided costs." Asked whether E1 expects an updated integrated resource plan to correspond to an increase or decrease in plan benefits, E1 states that "it would be imprudent to

[5] Notably, NS Power's model also draws on the 2014 IRP avoided costs. See Page 10 of 19 of NS Power's 2020-2022 DSM Plan Evidence Appendix B and Page 59 of 62 of EfficiencyOne's 2020-2022 DSM Resource Plan Filing.

presume an outcome [of the Plan benefits from updated avoided costs] in advance of conducting the analysis."

Q. Do you agree with E1's decision to use only the 2014 IRP avoided costs in its RBIA?

A. No. While E1 may be hesitant to make precise predictions of updated avoided costs, it can and should make reasonable and educated projections in advance of the 2020 IRP. The lag in developing updated costs from the 2014 IRP is too long, and it is in the interest of all parties to attempt to identify the direction and the magnitude of the change in current avoided costs and plan benefits relative to the outdated assumptions from the 2014 IRP. These educated projections can inform sensitivities that can be used until the 2020 IRP process is complete and updated avoided costs are provided.

Q. Are there any publicly available estimates of the current avoided energy and capacity costs?

A. Yes, there are several estimates of avoided energy and capacity costs that are more current than those developed in the 2014 IRP. First, as an outcome of the Generation Utilization and Optimization process, Synapse provided a memo on DSM Avoided Costs on October 19, 2018. This document contains projections of avoided energy and avoided capacity costs that can, at a minimum, be used within a sensitivity analysis. For a comparison of the avoided costs from the Synapse memo with the 2014 IRP avoided costs, see Figure 13 and Figure 14 below.

Figure 13. Avoided energy costs from 2014 IRP and 2018 Synapse (2018 $/MWh)

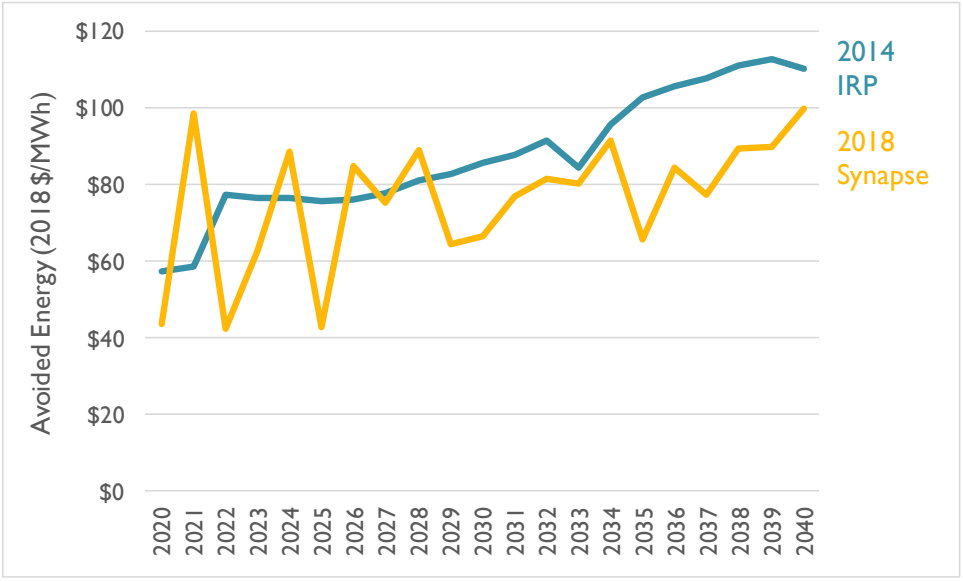
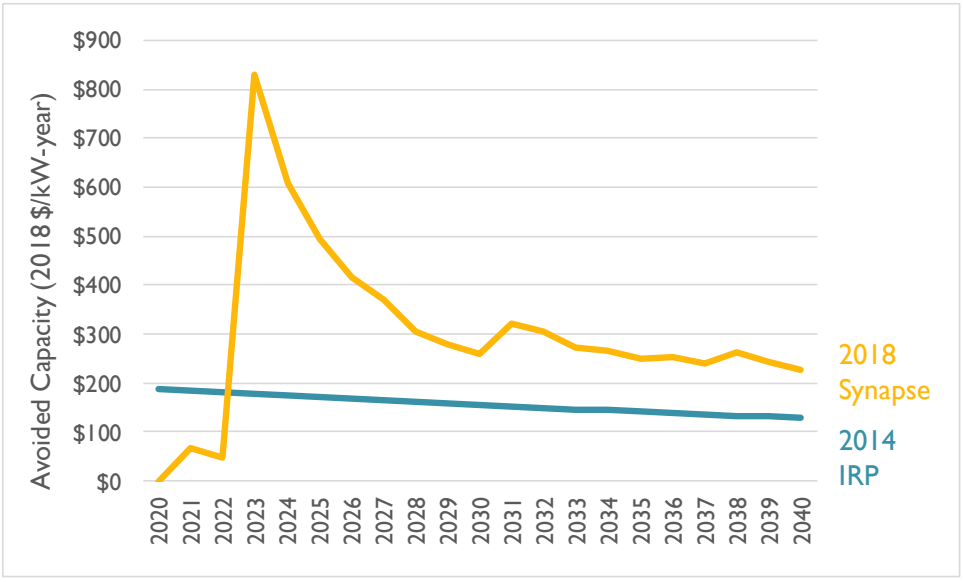


Figure 14. Avoided capacity costs from 2014 IRP and 2018 Synapse (2018 $/kW-year)



The avoided energy costs from Synapse's 2018 memo are, on average over the years 2020 to 2040, 11 percent lower than the 2014 IRP avoided energy costs. The avoided capacity costs from Synapse's 2018 memo average 93 percent higher than the 2014 IRP avoided capacity costs.

Second, NS Power states in its evidence, "[a]s a result of the construction of the Maritime Link and the escalating adoption of must-take, third-party generated energy, NS Power will have access to market-based clean energy forecast to be

priced in the $50/MWh range" (NS Power evidence, page 6). The $50/MWh price is, on average over the period of analysis, 41 percent lower than the 2014 IRP avoided energy costs. In addition to the educated projections referenced above, a sensitivity analysis using the $50/MWh value should be conducted.

Q. What can a sensitivity analysis tell us?

A. In situations where there is uncertainty about key assumptions used in an analysis, a sensitivity analysis sheds light on the range of possible outcomes based on a potential range of uncertain factors. Given that the avoided costs used by NS Power and E1 are very outdated, there is significant uncertainty about the accuracy of those avoided costs. Thus, NS Power and E1 should conduct a sensitivity analysis that captures a range of possible outcomes with different avoided cost estimates.

Q. Have you performed any sensitivities on the avoided capacity and energy costs?

A. Yes. I performed two sensitivities using E1's preferred RBIA model.[6] The first sensitivity considers changes in rate and bill impacts resulting from a 25 percent increase in both avoided capacity and avoided energy costs over the levels modeled in the 2014 IRP. The second sensitivity looked at the impacts of a 25 percent decrease in avoided capacity and energy costs relative to 2014 IRP levels. Also, a symmetrical analysis seemed appropriate given that both E1 and NS Power have been unable to convey the likely direction of the likely difference in avoided costs.[7]

The selection of +/-25 percent for the sensitivity is for illustrative purposes and is not intended to map to a likely range of avoided cost values. It is entirely possible that the current avoided costs are outside the range I considered in these

[6] See: Appendix B – 2020-2022 Plan Rate and Bill Impact Analysis Model – preferred.xlsx, provided with EfficiencyOne's 2020-2022 DSM Resource Plan Filing.

[7] See NSPI(Synapse) IR-3 (d-e).

sensitivity analyses. The alternative avoided energy costs noted above are between 11 and 41 percent lower than the 2014 IRP avoided energy costs, while the avoided capacity costs from Synapse's 2018 memo average 93 percent higher than the 2014 IRP avoided capacity costs. These ranges speak to the significant differences that likely exist between current potential avoided costs and those from the 2014 IRP.

Q. What are the results from the two sensitivity analyses?

A. Please refer to Table 9 comparing the rate impacts associated with the 2014 IRP avoided costs and the +/-25 percent avoided cost scenarios. Table 10 presents participant bill and non-participant bill impacts. Please also refer to Figure 15, Figure 16, and Figure 17, presenting the same results in graphical format.

Table 9. Rate Impacts Under Sensitivity Analyses (2020-2035 Average)

Rate Class	2014 IRP	+25% Avoided Costs	-25% Avoided Costs
Residential	+0.80%	-0.08%	+1.69%
Small General	+1.09%	-0.14%	+2.32%
General	+1.31%	+0.32%	+2.29%
Large General	+1.52%	+0.67%	+2.36%
Small Industrial	+1.66%	+0.78%	+2.54%
Medium Industrial	+0.77%	+0.13%	+1.42%
Large Industrial	+1.00%	+0.00%	+2.00%
Municipal	+1.00%	+0.00%	+1.99%

Table 10. Average Participant Bill Impacts Under Sensitivity Analyses (2020-2035 Average)

	Participant Bill Impacts			Non-Participant Bill Impacts		
Rate Class	2014 IRP	+25% Avoided Costs	-25% Avoided Costs	2014 IRP	+25% Avoided Costs	-25% Avoided Costs
Residential	-10.7%	-11.4%	-10.0%	+0.7%	-0.2%	+1.5%
Small General	-5.3%	-6.4%	-4.3%	+1.0%	-0.1%	+2.1%
General	-3.2%	-4.1%	-2.2%	+1.0%	+0.0%	+2.0%
Large General	-3.5%	-4.3%	-2.7%	+1.1%	+0.2%	+1.9%
Small Industrial	-4.4%	-5.2%	-3.6%	+1.1%	+0.3%	+2.0%
Medium Industrial	-1.2%	-1.8%	-0.6%	+0.5%	-0.1%	+1.1%
Large Industrial	-1.0%	-2.0%	-0.0%	+0.7%	-0.3%	+1.7%
Municipal	-3.6%	-4.5%	-2.6%	+0.7%	-0.3%	+1.7%

Figure 15. Rate Impacts Under Sensitivity Analyses (2020-2035 Average)

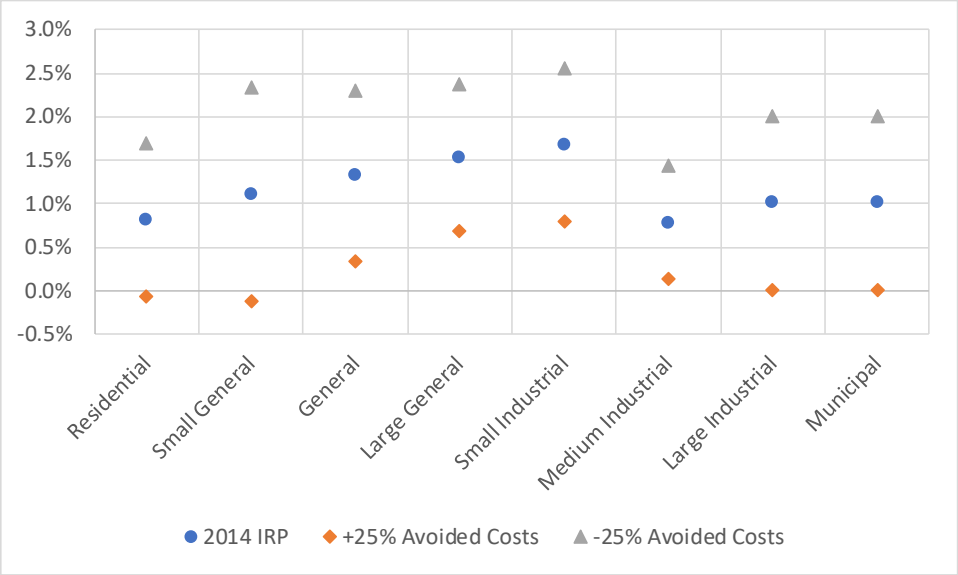


Figure 16. Participant Bill Impacts Under Sensitivity Analyses (2020-2035 Average)

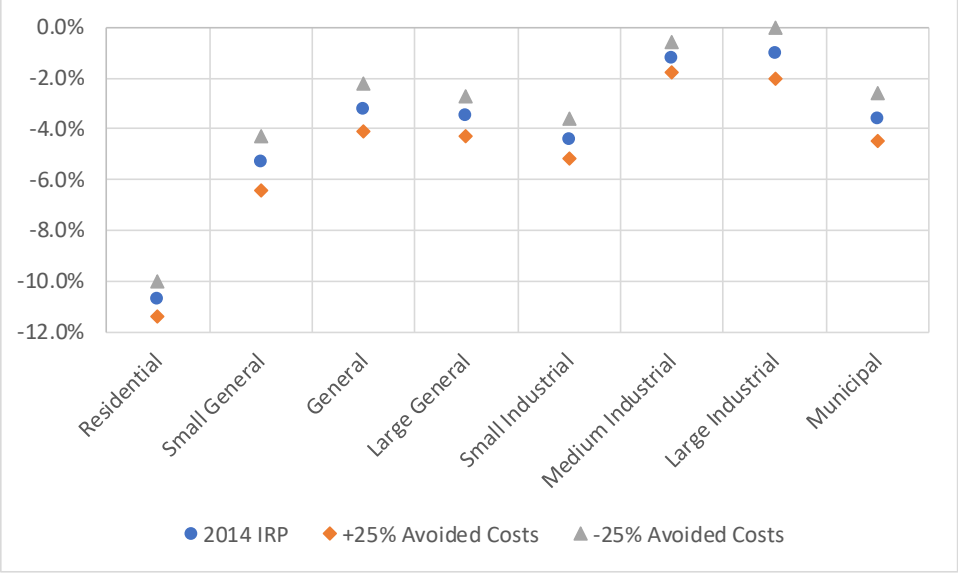
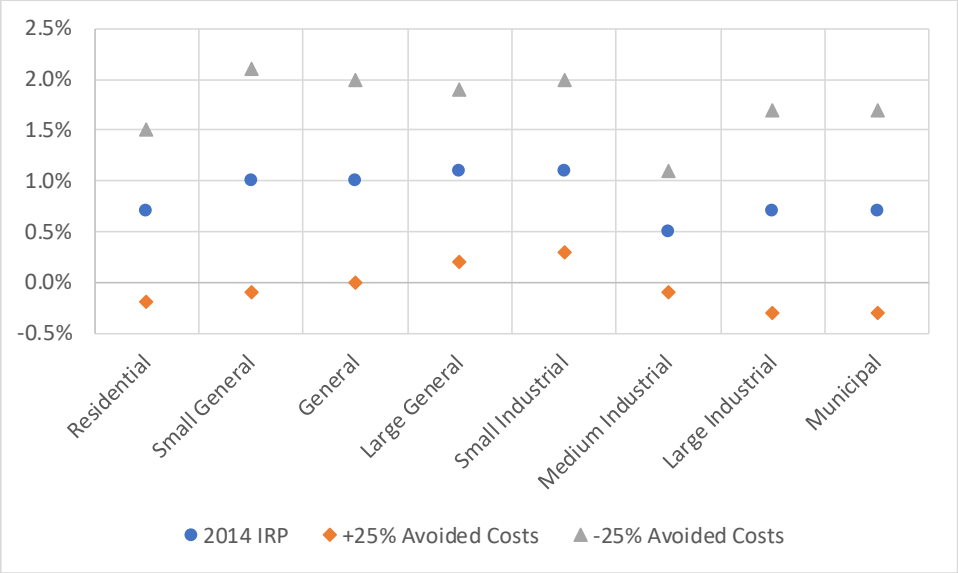


Figure 17. Non-Participant Bill Impacts Under Sensitivity Analyses (2020-2035 Average)



The results from the sensitivities show that even when assuming a 25 percent decrease in both avoided energy and capacity costs, the rate impacts and non-participant impacts remain relatively small, with the rate impacts ranging from +1.42 percent for the medium industrial class to a maximum of +2.54 percent for the small industrial rate class. Non-participant bill impacts range from a low of +1.1 percent for the medium industrial class to a maximum of +2.1 percent for the small general rate class.

On the other hand, a +25 percent increase in energy and capacity costs would result in rate and non-participant bill impacts that are consistently negligible if not negative across all rate classes. If the HST funds are applied to DSM programs rather than provided as a refund to ratepayers, these rate and bill impacts would be even smaller.

Avoided T&D costs

Q. Do you have concerns about the other avoided costs used in E1's model?

A. Yes. The avoided transmission and distribution (T&D) costs that are included in E1's RBIA model appear to be based on an incorrect calculation.[8] In a February 11, 2019 memorandum provided to Efficiency Nova Scotia and the DSMAG, Paul Chernick of Resource Insight, Inc. notes: "[w]hile NS Power has not provided the derivation of its values, it appears to have divided the T&D investments related to load growth by the entire NS Power load." If this is how NS Power derived its avoided T&D costs, it has used an incorrect approach. Instead, the load-related T&D investments should be divided only by the amount of load growth.

Q. What are more reasonable avoided T&D costs?

A. As Mr. Chernick explains in his memorandum, avoided transmission and distribution costs should be calculated by dividing load-related T&D investments by load growth (in MW). As an example, he divides NS Power's $9 million in load-related T&D for 2016 by the 96 MW of load growth from 2013 to 2014. The resulting value, an avoided T&D cost of $94,000/MW, is much larger than the $8,365/MW and $3,524/MW values for avoided transmission and avoided distribution, respectively, presented by NS Power on page 16 of its 2020-2022 DSM Plan Evidence, Appendix B. If NS Power's values were calculated by dividing load-related investments by the entire NS Power load, this calculation should be corrected, and documentation of corrected results, sources, and inputs to that calculation should be provided to E1 and the DSMAG for review and incorporation into future rate and bill analyses.

[8] NS Power's RBIA model also uses these incorrect avoided transmission and distribution costs.

Allocation of avoided costs to rate classes

Q. Are there any other issues with E1's rate and bill impact analysis model?

A. Yes. The way the model estimates avoided costs for each rate class is not appropriate. E1's RBIA model calculates avoided costs expected from its energy efficiency program plan in "Avoided Costs" sheet in the "Appendix B - 2020-2022 Plan Rate and Bill Impact Analysis Model – preferred" workbook. The model also calculates total avoided costs by rate class in the same worksheet. However, the model does so by simply allocating the total avoided costs expected for the entire portfolio of the programs among rate classes based on rate class revenue shares (as presented in "Attribution" worksheet) instead of projected energy savings by rate class. This methodology could become problematic when the share of projected energy and capacity savings among different rate classes differ from the share of revenues among different rate classes. This same issue is applicable to NS Power's model because NS Power's model is built upon E1's model without correcting this problem.

Q. What is the potential impact of this error?

A. I will explain this with a simple example. Suppose a large share of energy savings, say 80 percent, is expected from the residential customer class, but the revenue share of this rate class is 40 percent. Based on E1's model, the avoided cost for the residential sector would be half of the projected avoided cost for the rate class (i.e., 40 percent divided by 80 percent). This would result in higher than expected rate impacts for the rate class because the avoided cost for the rate class is underestimated.

Q. Do you recommend this error be fixed?

A. Yes. However, the differences in rate impacts and bill impacts for non-participants among rate classes are small for the proposed program as I presented above. They differ just by up to 0.5 percent. Given that Nova Scotia has an annual

process of updating the RBIA models, I recommend E1 and NS Power investigate and consider correcting this issue in the RBIA process in the next year.

NS Power's recommended changes to the RBIA model

Q. Has the Board required NS Power to file a rate impact analysis?

A. Yes. In the 2016-2018 DSM Plan proceeding, the Board directed NS Power to file a rate impact analysis. In the Board's August 12, 2015 Decision in Matter M06733, the Board indicated that "in future applications, E1 is to provide one or more alternate scenarios of DSM budgets for the Board to consider, and NSPI is to provide rate impact analysis caused by these scenarios."

Q. Please describe what has transpired in the interim.

A. On October 10, 2018, NS Power circulated its comments on the long-term RBIA to the DSMAG, two weeks before E1 filed its 2018 long-term RBIA. NS Power reviewed its comments at the October 24, 2018 DSMAG meeting. NS Power also shared Excel files supporting its comments with the group on November 21, 2018.

On January 21, 2019, E1 provided a document summarizing its recommended approach to addressing nine existing open issues and six new issues with E1's long-term RBIA, including changes proposed by NS Power. In our comments on E1's RBIA recommendations, Synapse requested that NS Power provide a short-term rate impact analysis early enough in the 2020-2022 Plan proceeding to allow an opportunity to ask information requests on it in that context. However, NS Power did not provide its short-term rate impact analysis with its evidence. Workbooks were provided in response to information request, at which point there was no opportunity to ask additional questions.

Q. Does NS Power propose any modifications to E1's RBIA model?

A. Yes. NS Power proposed the following four modifications in its evidence (NS Power evidence, p. 33-34):

1. The allocation of annual fuel costs reduced by avoided fuel cost of DSM programs to each rate class by their shares of annual GWh requirement each year;

2. The classification of annual fixed generation and transmission costs, reduced by avoided marginal capacity costs, to energy and demand and reallocated to rate classes using their shares of energy sales (GWh) and coincident demand (MW) each year;

3. The reduction of annual fixed demand-related distribution costs by avoided marginal distribution costs and the apportionment of these costs to rate classes using their shares in the annual sum of non-coincident class demand each year; and

4. The exclusion of customer-related costs from the allocation of costs and benefits.

Q. Do you recommend E1 incorporate the modifications proposed by NS Power at this time?

No. While the modifications themselves may be reasonable, they need time to be properly vetted by the DSMAG.

Additionally, I am concerned that the requested modifications will result in undue complexity within the model, and that the implementation process will be time-intensive. It is unclear that the benefits of these modifications outweigh the costs associated with model complexity and time-intensive implementation.

Q. Do you have concerns regarding the inputs required to implement these modifications?

A. Yes. In its response to Synapse's IR-20, NS Power provides a table describing the inputs required for each modification, the data sources for these inputs, and the frequency with which these inputs are updated. The table shows that each modification requires inputs that are updated when "COSS is updated in GRAs." GRAs happen on an irregular basis. As such, the four modifications require the incorporation of additional inputs that are unlikely to be updated on a regular

basis, and therefore have the potential to become out-of-date (like the avoided energy and capacity costs).

Q. Has NS Power provided its short-term rate and bill impact analysis?

A. Yes, in its response UARB's IR-20, NS Power provided four workbooks: a short term RBIA model of the Alternate Scenario, a long term RBIA model of the Alternate Scenario, a short term RBIA model of the Preferred Plan, and a long term RBIA model of the Preferred Plan.

Q. Have you reviewed this model?

A. Yes, I have reviewed these models, although there was insufficient time to review them in depth.

Q. Do you have any concerns with the contents of these models?

A. Yes. The models appear to add additional levels of complexity to the analysis by including more tabs, calculations, and required inputs than E1's model. Additionally, several of the new inputs may not be updated on a regular schedule, which could result in the model results becoming out-of-date.

Q. Do NS Power's models contain any errors?

A. Potentially. Each of the four models provided as attachments in NS Power's response to UARB's IR-20 contain the following warning upon opening: "There are one or more circular references where a formula refers to its own cell either directly or indirectly. This might cause them to calculate incorrectly." These circular references may be the result of model errors. However, I have not had time to identify the location of these circular references. The DSMAG needs sufficient time to review and provide feedback on these models.

Q. Do the results between E1 and NS Power's models differ notably?

A. No, the results between E1's model and NS Power's models do not differ significantly. In fact, the differences are negligible for nearly all rate classes. Table 11 below presents the differences in the rate impacts, participant bill

impacts, and non-participant bill impacts, respectively, between NS Power's results and E1's results in NS Power's long-term RBIA model, filed as "2020-2022 DSM NSUARB IR-20 Att 3 ELECTRONIC.xlsx." The deltas are generally between -1.5 percent and 1.5 percent, meaning the results for most rate classes are within 1.5 percent in both E1's model and NS Power's long-term model. Due to these negligible differences in results, it becomes more unclear what benefit comes from updating E1's model to align with NS Power's more complex model.

Table 11. Comparison of NS Power and E1 Rate and Bill Impacts (2020-2035)

	Rate Impacts			**Participant Bill Impacts**			**Non-participant Bill Impacts**		
Rate Class	E1	NS Power	Delta	E1	NS Power	Delta	E1	NS Power	Delta
Residential	0.8%	1.2%	0.4%	-10.7%	-10.4%	0.2%	0.7%	1.0%	0.3%
Small General	1.1%	2.7%	1.5%	-5.3%	-4.2%	1.1%	1.0%	2.1%	1.2%
General	1.3%	1.4%	0.1%	-3.2%	-3.5%	-0.3%	1.0%	1.5%	0.5%
Large General	1.5%	0.2%	-1.3%	-3.5%	-5.7%	-2.2%	1.1%	1.9%	0.8%
Small Industrial	1.7%	2.2%	0.5%	-4.4%	-4.8%	-0.4%	1.1%	1.7%	0.6%
Medium Industrial	0.8%	0.8%	0.0%	-1.2%	-1.4%	-0.2%	0.5%	0.6%	0.1%
Large Industrial	1.0%	0.2%	-0.8%	-1.0%	-2.3%	-1.3%	0.7%	0.6%	-0.1%
Municipal	1.0%	0.5%	-0.5%	-3.6%	-5.2%	-1.7%	0.7%	0.6%	-0.1%

Q. Should E1 replace its rate and bill impact model with these models?

A. It is my opinion that E1 should not replace its rate and bill impact model with NS Power's short- and long-term rate and bill impact models, for the reasons described above.

7. SYSTEM IMPACTS

Q. NS Power maintains that as solar installations increase, it would be "reasonable to reduce the energy savings funded by DSM by commensurate amounts, as customers are getting the benefit of the reduced load without providing a subsidy through their power bills" (NS Power Evidence, p. 20-21). Do you agree?

A. No. First, solar installations still represent a small fraction of NS Power's load. Even a large ramp-up in solar installations would not have large impacts on NS Power's system.

Second, DSM resources provide benefits to the system and to ratepayers, regardless of the presence or absence of other demand-side or supply-side resources. DSM is an investment, not a subsidy.

8. COST RECOVERY

Q. What does NS Power propose for recovery of DSM costs?

A. NS Power recommends recovering DSM costs through the Fuel Adjustment Mechanism (FAM). (NS Power Evidence, p. 30). Currently, DSM cost recovery methodology is proposed by NS Power and is subject to approval by the Board. (E1 response to Synapse IR-1.)

Q. Do you have concerns about this proposal?

A. Yes. The implications of recovering DSM costs through the FAM are not clear. Doing so may reduce transparency relative to the current approach. Furthermore, it is unclear whether doing so would be consistent with legislation, per UARB's IR-16 to NS Power.

Q. Does this conclude your evidence at this time?

A. Yes, it does.

APPENDIX A: RESUME

Alice Napoleon, Senior Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Associate*, June 2013 – present; *Associate*, July 2008 – June 2013; *Research Associate*, April 2005 – July 2008.

- Provide expert analysis, ongoing stakeholder support, and consulting services in regulatory proceedings regarding energy efficiency program design and performance, funding and incentive mechanisms, evaluation, cost-effectiveness screening, avoided costs, potential studies, and plans. Develop and sponsor testimony and formal comments on electric and natural gas energy efficiency plans, advanced metering infrastructure (AMI) proposals, and innovative programs and regulatory structures.
- Develop a cost effectiveness tool, program designs, and case studies to facilitate incorporating strategic energy management programs into energy efficiency program administrators' portfolios for commercial and industrial customers.
- Design research approach, manage team, and conduct a sweeping analysis of energy efficiency potential studies from utilities, states, and regions across the U.S.
- Conduct extensive research on low-income energy efficiency efforts in U.S. states. Analyze energy burden differences between low-income and non-low-income households, and across factors that can impact participation in and efficacy of energy efficiency programs, to inform efficiency program design and targeting efforts. Provide consulting services and testimony on low-income energy efficiency programs and proposals.
- Facilitate residential, commercial, and industrial policy working groups and manage technical analysis of working group recommendations to reduce greenhouse gas (GHG) emissions in Colorado, South Carolina, and Maryland.
- Research and analyze historical emissions of criteria and hazardous air pollutants, greenhouse gases, and coal combustion wastes. Research and develop potential state and local emissions mitigation strategies, such as strategies for reducing ambient fine particulates in New York City.
- Conduct surveys of regional, state, and utility policies and practices regarding ratemaking for energy efficiency, power procurement, risk management, and fuel diversity. Research federal, regional, and state policies and case histories on integrated resource planning, power procurement, power plant operations, renewable portfolio standards, and market power.
- Conduct research for modelling macroeconomic impacts of policies that reduce oil production.

Resource Insight, Inc., Arlington, MA. *Research Assistant*, 2003-2005.

Responsible for conducting research and analysis of electric, gas, steam, and water resource issues. Conducted discounted cash flow analysis for asset valuation. Developed market-price benchmarks for analysis of power-supply bids including energy, capacity, ancillary services, transmission, ISO services, losses, and adjustment for load shape. Prepared discovery responses, formal objections, comments, and testimony; collaboratively wrote and edited reports; created and formatted exhibits. Participated in drafting an Energy Plan for New York City. Edited solicitation for competitive power supply to serve aggregated municipal load.

University of Massachusetts, Amherst, MA. *Teaching Assistant*, 2001-2002.

Developed and taught lessons on applied math to a diverse group of incoming graduates; tutored students in microeconomic theory and cost benefit analysis; graded problem sets and memoranda.

International Council for Local Environmental Initiatives, Berkeley, CA. *Cities for Climate Protection Intern for the City of Northampton, MA*, 2001.

Compiled primary and secondary source data on energy consumption and solid waste generation by the municipal government, city residents, and businesses; applied emissions coefficients to calculate total GHG emissions; identified current and planned municipal policies that impact GHG emissions; researched the predicted local effects of global warming ; gathered public feedback to provide acceptable and proactive policy alternatives. Composed a GHG emissions inventory describing research findings; wrote and distributed a policy report and press releases; gave newspaper and radio interviews; addressed public officials and the public during a televised meeting.

University of Massachusetts, Amherst, MA. *Research Assistant*, 2000-2001.

Located federal data sources, identified changes, and updated a research database to evaluate the Habitat Conservation Program; proofread articles and white papers; composed a literature review on land use modelling. Collaboratively administered, tested, and proposed interface enhancements for a web-based data warehouse of regional habitat change research; formally presented the system to an independent research group.

Court Square Data Group, Inc., Springfield, MA. *Administration Manager*, 1998-2000; *Project Administrator*, 1996-1998.

As Administration Manager, analysed profitability and diversity of income sources; managed cash flow, expense, and income data; created budgets; devised and implemented procedures to increase administrative efficiency; implemented new accounting system with minimal disruption to workflow.

As Project Administrator, coordinated implementation of software features; identified opportunities for future development; monitored problem resolution; wrote and coordinated production of a user's manual and questionnaires; edited technical proposals and a business plan.

EDUCATION

University of Massachusetts, Amherst, MA
Master of Public Administration, 2002

Rutgers University, New Brunswick, NJ
Bachelor of Arts in Economics, 1995

Syracuse University, Syracuse, NY, 1994

PUBLICATIONS

Kallay, J., A. Napoleon. 2019. *Comments and Revised Comments on EfficiencyOne's Proposed Enhancements to its Rate and Bill Impact Model.* Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Napoleon, A., D. Goldberg, K. Takahashi, T. Woolf. 2019. *An Assessment of Prince Edward Island Energy Corporations' 2018 - 2021 Energy Efficiency and Conservation Plan.* Synapse Energy Economics for Carr, Stevenson and MacKay as Counsel to the Island Regulatory and Appeals Commission.

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Hall, J., J. Kallay, A. Napoleon, K. Takahashi, M. Whited. 2018. *Locational and Temporal Values of Energy Efficiency and other DERs to Transmission and Distribution Systems.* Synapse Energy Economics.

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Fagan, B., A. Napoleon, S. Fields, P. Luckow. 2017. *Clean Energy for New York: Replacement Energy and Capacity Resources for the Indian Point Energy Center Under New York Clean Energy Standard (CES).* Synapse Energy Economics for Riverkeeper and Natural Resources Defense Council.

Kallay, J., A. Napoleon, M. Chang. 2016. *Opportunities to Ramp Up Low-Income Energy Efficiency to Meet States and National Climate Policy Goals*. Synapse Energy Economics.

Woolf, T., A. Napoleon, P. Luckow, W. Ong, K. Takahashi. 2016. *Aiming Higher: Realizing the Full Potential of Cost-Effective Energy Efficiency in New York.* Synapse Energy Economics for Natural Resources Defense Council, E4TheFuture, CLEAResult, Lime Energy, Association for Energy Affordability, and Alliance for Clean Energy New York.

Napoleon, A., K. Takahashi, J. Kallay, T. Woolf. 2016. "Evaluation, Measurement, and Verification in Virginia." Memorandum prepared by Synapse Energy Economics for Clean Energy Solutions Inc., Virginia Energy Efficiency Council, and Virginia Department of Mines, Minerals and Energy.

Woolf, T., A. Napoleon, M. Whited. 2015-2016. *Comments and Reply Comments in the New York Public Service Commission Case 14-M-0101: Reforming the Energy Vision*. Comments related to Staff's (a) a benefit-costs analysis framework white paper, (b) ratemaking and utility business models white paper, and (c) Distributed System Implementation Plan guide. Prepared by Synapse Energy Economics on behalf of Natural Resources Defense Council and Pace Energy and Climate Center.

Kallay, J., K. Takahashi, A. Napoleon, T. Woolf. 2015. *Fair, Abundant, and Low-Cost: A Handbook for Using Energy Efficiency in Clean Power Plan Compliance.* Synapse Energy Economics for the Energy Foundation.

Woolf, T., K. Takahashi, E. Malone, A. Napoleon, J. Kallay. 2015. *Ontario Gas Demand-Side Management 2016-2020 Plan Review.* Synapse Energy Economics for the Ontario Energy Board.

Biewald, B., J. Daniel, J. Fisher, P. Luckow, A. Napoleon, N. R. Santen, K. Takahashi. 2015. *Air Emissions Displacement by Energy Efficiency and Renewable Energy.* Synapse Energy Economics.

Takahashi, K., A. Napoleon. 2015. "Pursue Behavioral Efficiency Programs." Ed. John Shenot. In *Implementing EPA's Clean Power Plan: A Menu of Options.* National Associate of Clean Air Agencies.

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Whited, M., T. Woolf, A. Napoleon. 2015. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*. Synapse Energy Economics for the Western Interstate Energy Board.

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Napoleon, A., W. Steinhurst, M. Chang, K. Takahashi, R. Fagan. 2010. *Assessing the Multiple Benefits of Clean Energy: A Resource for States*. US Environmental Protection Agency with research and editorial support from Stratus Consulting, Synapse Energy Economics, Summit Blue, Energy and Environmental Economics, Inc., Demand Research LLC, Abt Associates, Inc., and ICF International.

Napoleon, A., D. Schlissel. 2009. *Economic Impacts of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia*. Synapse Energy Economics for Sierra Club, and Appalachian Center for the Economy and the Environment.

Napoleon, A., J. Fisher, W. Steinhurst, M. Wilson, F. Ackerman, M. Resnikoff. 2008. *The Real Costs of Cleaning Up Nuclear Waste: A Full Cost Accounting of Cleanup Options for the West Valley Nuclear Waste Site*. Synapse Energy Economics for Citizens' Environmental Coalition.

Napoleon, A., G. Keith, C. Komanoff , D. Gutman, P. Silva, D. Schlissel, A. Sommer, C. Chen, A. Roschelle, J. Levy, P. Kinney. 2007. *Quantifying and Controlling Fine Particulate Matter in New York City*. Synapse Energy Economics for Coalition Helping Organize a Kleaner Environment, Natural Resources Defense Council (NRDC), Reliant Energy.

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Hausman, E., R. Fagan, D. White, K. Takahashi, A. Napoleon. 2007. *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers*. Synapse Energy Economics for American Public Power Association.

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Steinhurst, W., A. Napoleon, K. Takahashi. 2006. *Energy in the Northern Forest Region: A Situation Analysis*. Synapse Energy Economics for Northern Forest Center and The North Country Council.

Synapse Energy Economics. 2006. *Ensuring Delaware's Energy Future: A Response to Executive Order Number 82*. Synapse Energy Economics for Delaware Public Service Commission Staff by the Delaware Cabinet Committee on Energy and others.

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TESTIMONY

Nova Scotia Utility and Review Board (Matter No. M08604): Evidence of Alice Napoleon regarding the 2019 Demand Side Management Resource Plan. On behalf of Counsel to the Nova Scotia Utility and Review Board. June 13, 2018.

Nova Scotia Utility and Review Board (Matter No. M08349): Evidence of Alice Napoleon regarding Nova Scotia Power's Advanced Meter Infrastructure Proposal. On behalf of Counsel to the Nova Scotia Utility and Review Board. January 18, 2018.

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Public Service Commission of South Carolina (Docket No. 2016-223-E): Direct Testimony of Alice Napoleon regarding South Carolina Electric and Gas Energy Efficiency Efforts. On behalf of South Carolina Coastal Conservation League. September 1, 2016.

Nova Scotia Utility and Review Board (Case No. M06247): Direct evidence in the matter of an application by Efficiency Nova Scotia Corporation for approval of its electricity demand-side management plan for 2015. On behalf of Counsel to the Nova Scotia Utility and Review Board. July 14, 2014.

TESTIMONY ASSISTANCE

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State of New Jersey Board of Public Utilities (Docket No. EO14080897): Direct testimony of Kenji Takahashi regarding the Petition of Public Service Electric & Gas Company to continue its Energy Efficiency Economic Extension Program on a Regulated Basis (EEE Extension II). On behalf of New Jersey Division of the Ratepayer Advocate. November 7, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony of Tim Woof regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

State of New Jersey Board of Public Utilities (Docket No. GO12050363): Direct testimony of Maximilian Chang regarding South Jersey Gas Company's proposal to extend and modify its energy-efficiency programs. On behalf of New Jersey Division of the Ratepayer Advocate. November 9, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO11070399): Direct testimony of Robert Fagan regarding Elizabethtown Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. December 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR11070425): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. November 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR10030225): Direct testimony of David Nichols regarding New Jersey Natural Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. July 9, 2010.

Virginia State Corporation Commission (Case number PUE-2009-00097): Direct testimony of William Steinhurst regarding Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq. On behalf of the Southern Environmental Law Center, Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of The Sierra Club. March 23, 2010.

Delaware Public Service Commission (Docket No. 07-20): Jointly authored an expert report, with Robert Fagan, William Steinhurst, David White, and Kenji Takahashi, In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

State of New Jersey Board of Public Utilities (BPU Docket EM05020106): Direct and surrebuttal testimony of Bruce Biewald, Robert Fagan, and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct testimony of William Steinhurst regarding Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

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