
Nova Scotia Utility and Review Board

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

2020-2022 DSM Plan

NS Power
Evidence

M09096

April 12, 2019

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1.0 INTRODUCTION

Nova Scotia Power Inc. (NS Power, the Company) has a long history of supporting demand side management (DSM), having introduced the first energy efficiency programs in Nova Scotia. NS Power believes that efficiency programming is an important part of Nova Scotia's overall energy portfolio. The Company has supported and worked collaboratively with EfficiencyOne (E1) since it assumed responsibility for the delivery of energy efficiency programs in Nova Scotia and will continue to do so in the future. In 2018 NS Power worked closely with E1 to execute a supply agreement for 2019 that complies with the requirements of the *Electricity Plan Implementation (2015) Act* and provides benefits similar to the 2016-2018 DSM Supply Agreement. At that time, the Company noted that a new potential study was required to assess the availability of cost-effective DSM going forward.¹

NS Power had discussions with E1 several times leading up to the filing of E1's current Application; however, the Company and E1 were not able to reach agreement with respect to the appropriate level of spending for the 2020-2022 DSM Supply Agreement period. E1 is seeking a first year budget increase of approximately 23 percent which, as shown in the evidence of Richard Levitan, Levitan & Associates, Inc., attached as **Appendix A**, is inconsistent with the annual DSM spending growth rates in other jurisdictions. While NS Power remains supportive of a meaningful level of cost-effective DSM, it is not able to support such a significant increase. Increases of this magnitude do not properly account for the economic realities in Nova Scotia, the current amount of non-customer funded efficiency initiatives available to E1, or naturally occurring DSM. Therefore NS Power does not believe such an increase is in the best interest of customers.

Nova Scotia is a leader in Canada in terms of reducing environmental emissions and increasing renewable generation. But these improvements have come at a cost which

¹ M08604, EfficiencyOne Application for Approval of the 2019 DSM Resource Plan and Supply Agreement, NSPI Reply Evidence, June 20, 2018.

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1 customers pay through electricity rates, which are among the highest in the country.
2 Additional rate pressure in 2020 needs to be considered when determining what amount
3 of incremental DSM spending is affordable for customers.
4

5 DSM spending must also be weighed against NS Power's opportunity cost of avoided
6 energy. As a result of the construction of the Maritime Link and the escalating adoption
7 of must-take, third-party generated energy, NS Power will have access to market-based
8 clean energy forecast to be priced in the \$50/MWh range. This is more favourable than
9 the incremental DSM costs of \$64/MWh in E1's Preferred Plan.
10

11 More significantly, NS Power is not forecasting new baseload generation in the near and
12 mid term. Distributed energy resources (DER) and non-regulated DSM are curbing load
13 growth organically, without the need for electricity incentives. An example of this
14 impact is the exclusion of the 2023 combustion turbine forecast as part of the 2014
15 Integrated Resource Plan (IRP) from the Company's most recent 10 Year System
16 Outlook.
17

18 The issue for NS Power in this proceeding is not whether energy efficiency and
19 conservation are desirable, but rather what level of DSM spending is in the best interests
20 of customers for the 2020-2022 DSM Supply Agreement period.
21

22 The Nova Scotia Utility and Review Board (UARB, the Board) directed E1 to provide
23 one or more alternate scenarios in future DSM applications for the Board and
24 stakeholders to consider. NS Power had encouraged E1 prior to filing its Application to
25 develop additional DSM plans with current and reduced levels of investment which
26 would provide a full array of options for consideration in determining the best interests of
27 customers, taking into account affordability and targeted outcomes. After E1 determined
28 that it was only providing its \$43 million Preferred Plan and \$37 million Alternate
29 scenario for submission to the UARB, NS Power requested and obtained from E1 and its
30 consultant, Navigant Consulting, Inc. (Navigant), plans that show a range of outcomes for

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1 DSM funding from \$27 to \$34 million. NS Power considers this range to be a more
2 reasonable level of funding, given the other components and associated costs of Nova
3 Scotia's clean energy transformation.

4
5 The Company's goal is to arrive at a DSM plan that recognizes the benefits of initiatives
6 such as peak shaving and demand reduction which will allow NS Power to maintain
7 stable, affordable and predictable rates for customers in the near term while continuing to
8 provide a reasonable level of longer-term benefits.

9
10 The following is a brief outline of the Company's concerns with E1's proposed increased
11 DSM budget for 2020-2022. These concerns are addressed in greater detail later in this
12 evidence. The Company's evidence includes the evidence of Mr. Levitan, who
13 concludes, among other things, E1's Preferred Plan does not meet the requirements of
14 affordability and that it is possible to adopt a more affordable DSM plan than what E1
15 proposes in its Application.²

16
17 **Affordability / Proportionality**

18
19 Affordability of electricity service continues to be of paramount concern to NS Power
20 customers. E1 is seeking a first-year increase over its 2019 plan of approximately 23
21 percent with its Preferred Plan (and 9 percent with its Alternate Plan). By comparison,
22 Residential rates have increased an average of 0.8 percent per year since 2014.
23 Customers expect NS Power as a regulated public utility to manage its expenses so that it
24 can continue to provide stable, affordable electricity rates. NS Power's focus is on
25 keeping its costs as low as possible, while improving its service to customers, and
26 customers have seen an effective decrease in costs since 2014 as NS Power has been able
27 to maintain non-fuel rates in the face of inflationary cost pressures. In implementing its
28 mandate on behalf of customers, E1 should be held to the same standard.

² Appendix A, Evidence of Richard Levitan, page 74, lines 4-6 and 14-15.

Historic under-spending

Historically, E1 has been capable of delivering higher energy savings at lower than forecast spending levels, while still meeting or exceeding its energy and capacity savings goals. Since 2015, E1 has underspent its budget by about \$3 million annually. For the 2016-2018 DSM Supply Agreement period E1 underspent by a total of \$7.1 million, while still exceeding its energy and capacity savings goals over the period. This demonstrates that E1 is capable of meeting efficiency targets with less spending and does not require a material increase to its approved budget.

System requirements

Requirements for energy and capacity in Nova Scotia are being well served by the current system configuration, and NS Power does not currently forecast new baseload generation additions within the primary period for DSM programs proposed.

DSM Options

NS Power believes that sufficient DSM measures can be funded within the existing 2019 funding envelope. NS Power is not currently forecasting further capacity additions in the near to mid term, and the renewable energy sources over the Application window are forecast to provide more economic energy than the incremental DSM proposed by E1. As such, it is necessary to review a lower level of DSM to be funded by customers from 2020 to 2022.

2.0 AFFORDABILITY

While NS Power embraces energy efficiency and conservation for the benefit of customers, it is important to ensure that pursuing these efforts is cost-effective.

Section 79I of the *Public Utilities Act* (Act) directs NS Power to undertake cost-effective electricity efficiency and conservation activities:

79I (1) On and after the Implementation Date, Nova Scotia Power Incorporated shall undertake cost-effective electricity efficiency and conservation activities that are reasonably available in an effort to reduce costs for its customers.

Section 79L(9) of the Act directs that an assessment of efficiency and conservation activities must take into account affordability for customers:

79L (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.

Affordability must be balanced with a view to achieving long-term benefits for customers. In its Decision approving the 2016-2018 DSM Plan, the UARB determined that it is not appropriate to focus entirely on short-term costs without considering the long-term cost savings available from a balanced and properly implemented DSM program.³ However, the UARB also found that the inclusion of Section 79L(9) of the Act directed it to take into account an increased focus on short term rate impacts when determining the level of DSM spending that is in the best interests of customers.⁴ DSM

³ M06733, EfficiencyOne Application for Approval of the 2016-2018 DSM Resource Plan and Supply Agreement, UARB Decision, August 12, 2015, page 29, paragraph 82.

⁴ M06733, EfficiencyOne Application for Approval of the 2016-2018 DSM Resource Plan and Supply Agreement, UARB Decision, August 12, 2015, page 29, paragraph 82.

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1 spending levels must balance the long-term cost savings against the short-term cost
2 impacts to customers.

3
4 Over the last four years, the cost of DSM to customers has alternately increased or
5 decreased, but the largest single-year increase was the 4.2 percent increase in DSM from
6 2016 to 2017.

7
8 **Figure 1: Changes in E1 DSM Budget 2016-2022**

	2015	2016	2017	2018	2019	2020	2021	2022
DSM Budget (\$ millions)	35	33.2	34.6	34.9	34.05	41.9*	43.3*	43.9*
Change from previous year		-5.4%	+4.2%	+86%	-2.4%	+23%	+3.3%	+1.3%

9 *Proposed

10
11 An increase in the first year of over 20 percent in customer-funded DSM does not
12 adequately consider short-term rate impacts. NS Power requested and Navigant produced
13 plans ranging between \$27 million and \$34 million that focus on maximizing demand
14 response programs. If E1 were to develop a similar plan in that range through its iterative
15 vetting process, customers would benefit from the peak reduction required by the system
16 at a lower cost.

17
18 As noted by Mr. Levitan, the \$27 million DSM scenario is much lower than that
19 proffered by EfficiencyOne, but it “appears achievable, affordable, and conservative” and
20 “[r]elative to the EfficiencyOne’s 2019 budget of approximately \$34 million (2019
21 DSM), it is reasonable to review the comparative merit of a DSM scenario with a much
22 lower budget than EfficiencyOne’s Preferred Plan once it is fully developed and made
23 deliverable.”⁵

⁵ Appendix A, Evidence of Richard Levitan, page 9, lines 2-5.

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1 E1 justifies its long-term outlook based on the 2014 IRP. However, the 2014 IRP is not
2 highly correlated with the changes to the NS Power system over the last five years. At
3 the time of the 2014 IRP, NS Power highlighted its concerns that the DSM spending
4 levels in the IRP Preferred Plan were not optimal and suggested that DSM levels were
5 more appropriately determined in the DSM process.⁶
6

7 A material change since the 2014 IRP Power has been the forecast in DER. Given
8 government subsidy programs and as a result of customer feedback, NS Power currently
9 anticipates greater increases in DER than were forecast for in the 2014 IRP.
10

11 Additionally, the 2014 IRP's forecast of the cost of avoided energy is significantly higher
12 than what has occurred and what is forecast to occur. The 2014 IRP included a forecast
13 levelized cost of avoided energy of \$107/MWh, but the actual marginal cost has been in
14 the range of \$44 to \$62/MWh. The 2009 IRP had avoided energy costs of \$167/MW.
15 When incremental DSM above E1's current funding level is considered, its affordability
16 should be balanced against the actual avoided energy cost. The Company recognizes that
17 there is a difference between the calculation of marginal and avoided costs; however, NS
18 Power anticipates that over the short to medium term these costs are comparable. In
19 addition, NS Power is forecasting marginal energy costs to be more aligned with avoided
20 costs due to access to an abundance of market-priced non-emitting import energy. E1's
21 proposed incremental DSM is replacing cost-effective energy and therefore is not
22 providing a decrease to customer fuel costs.
23

24 E1 contends that there is less and less available moderately-priced DSM.
25 Correspondingly, there are fewer areas each year where NS Power can reduce its
26 spending in order to avoid an increase which must be passed on to customers. To avoid
27 any rate impact from E1's proposed Preferred Plan, NS Power will have to achieve a
28 further \$9 million reduction each year during the 2020-2022 period. On a variable

⁶ M05522, Nova Scotia Power 2014 Integrated Resource Plan, NSPI letter to the UARB, December 10, 2014.

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1 OM&G budget in the range of \$250 million per year, an additional \$9 million per year
2 would need to be absorbed to fund E1's additional budget increase as proposed in the
3 Application. The Company does not believe this to be a reasonable expectation.
4

5 As a regulated public utility, E1 should also look to its structure and supplier network
6 with the goal of reducing its forecast costs instead of seeking higher budgets from
7 customers.
8

9 In its Application, E1 described the DSM increase as a small movement of 1.2 to 1.3
10 percent of NS Power's overall revenue requirement.⁷ This is not an accurate
11 characterization of the actual impact to customers due to the way rates are set in Nova
12 Scotia. While NS Power's overall revenue requirement is \$1.4 billion annually, the
13 amount of costs over which NS Power has control is a fraction of this amount.

⁷ E-1, Efficiency One Application for Approval of the 2020-2022 DSM Resource Plan and Supply Agreement, Page 61, line 13.

3.0 PROPORTIONALITY

The increases proposed by E1 in its Preferred Plan are not in the best interests of customers and do not account for the current amount of non-customer funded efficiency initiatives available⁸ or the economic realities in Nova Scotia. They are not in alignment with the economic reality in Nova Scotia for a number of reasons:

- Nova Scotia has the highest market-basket measure⁹ poverty rate in the country;
- Over the past five years the average gross domestic product growth in Nova Scotia has been less than 1 percent;¹⁰
- The cost of other products and services has not increased at the same rate;
- Customers, businesses and governments are investing in programs and projects that improve efficiency and reduce electricity demand outside of E1's programs; and
- The incremental DSM activities in E1's Preferred Plan cost over twice as much as current DSM programs.
- NS Power has not increased its non-fuel rates since 2014.

Through its proposed Preferred Plan E1 is effectively seeking to have Nova Scotian households spend significantly more on DSM when, in most other cost areas, customers are reducing their spending.

Figure 2 shows the decrease in household spending on goods and services in Nova Scotia between 2016 and 2017.¹¹

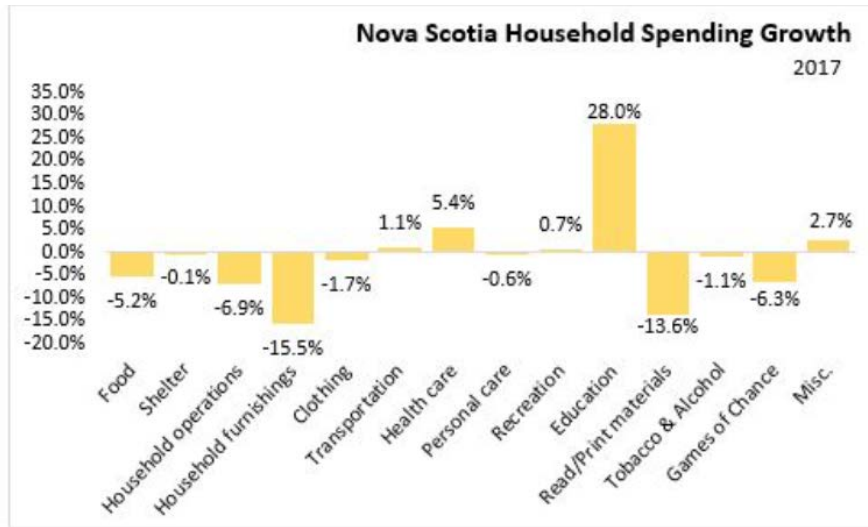
⁸ Examples include: solar funding, electric baseboard to electric heat pump initiatives, NS Power's Intelligent Feeder pilot project (CI 49787) and HomeWarming program and significant Federal funding in support of green initiatives.

⁹ <https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1110013501>.

¹⁰ <http://www.rbc.com/economics/economic-reports/pdf/provincial-forecasts/provtbl.pdf>.

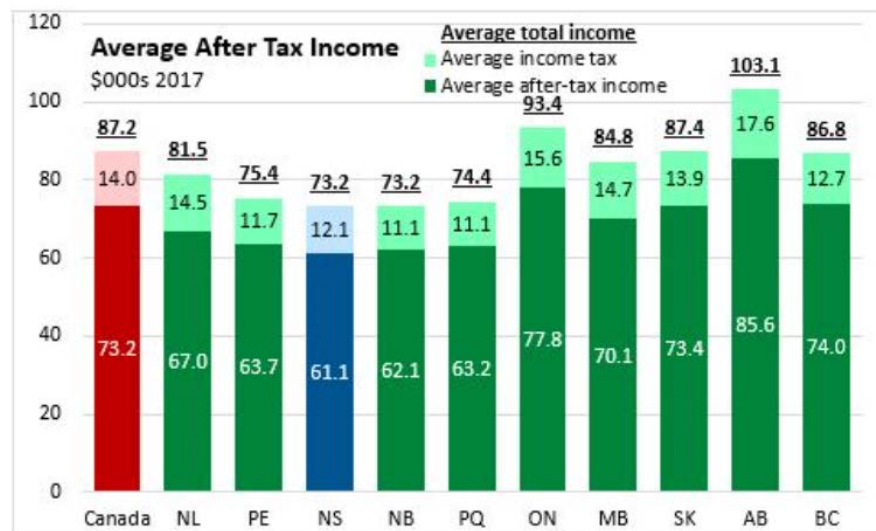
¹¹ https://www.novascotia.ca/finance/statistics/archive_news.asp?id=14410&dg=&df=&dto=0&dti=3.

Figure 2: Nova Scotia Household Spending Growth (2017)



Nova Scotians have to reduce spending because economic growth has averaged below 1 percent over the past five years while the price of most goods and services has increased more quickly than household income. Nova Scotians also have the lowest income in Canada, tied with New Brunswick.¹² Figure 3 below shows the average household incomes across Canada after taxes.

Figure 3: Average Canadian After-Tax Household Income (2017)



¹² https://www.novascotia.ca/finance/statistics/archive_news.asp?id=14410&dg=&df=&dto=0&dti=3.

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1 In his evidence, Mr. Levitan notes that incomes are significantly lower in Nova Scotia
2 than in the US states E1 has put forward as a comparator group to justify its proposed
3 increase in DSM funding.¹³ All of the comparator state household incomes materially
4 exceed those of Nova Scotians and some of the US states in E1's proposed peer group
5 have household incomes that are more than double those of the average Nova Scotian
6 household. These jurisdictions should not set the bar for Nova Scotia, given its
7 materially different economic circumstances.

8 In establishing a DSM budget for 2020-2022, NS Power supports continuing to assist
9 under-served communities in Nova Scotia such as low-income and First Nations
10 customers. However, in order to maximize the support for these communities, it may be
11 necessary to modify the subsidies proposed by E1, including reducing the incentives
12 provided to higher-income Nova Scotians on products with short payback periods. NS
13 Power supports income testing to ensure that the first people to receive help in becoming
14 more energy efficient are those who need it the most.

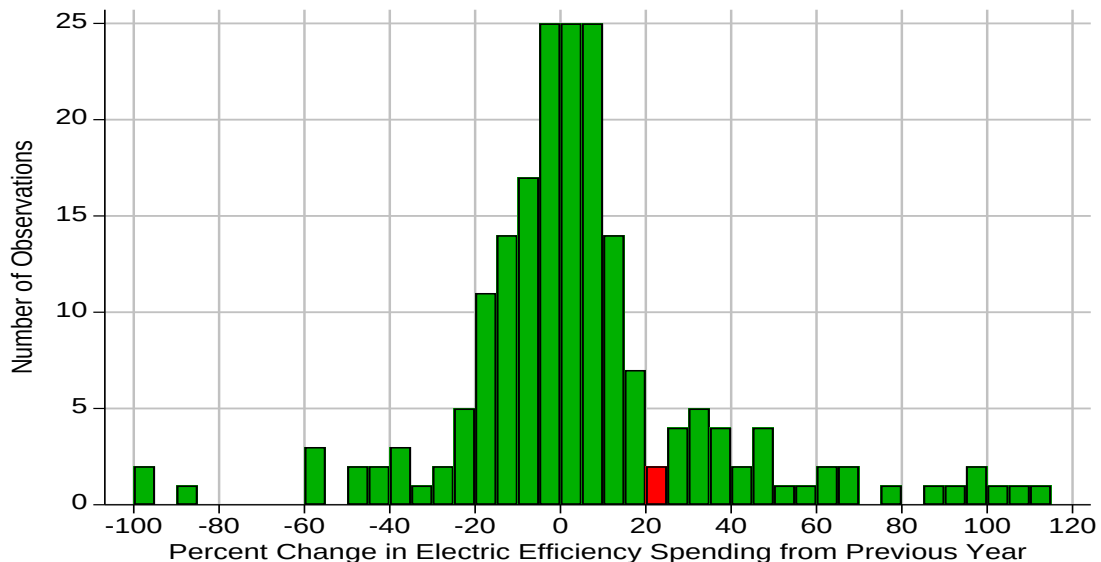
¹³ Appendix A, Evidence of Richard Levitan, page 29, lines 18-24.

4.0 DSM SPENDING LEVELS

E1's proposed spending increase, when compared to other jurisdictions in the United States and Canada, is outside industry norms. In fact, many states with mature DSM programming similar to what exists in Nova Scotia are proposing decreases to their DSM spending. As noted in Mr. Levitan's evidence, "At a time when almost one-half the states are decreasing their spending, EfficiencyOne is proposing a substantial increase. I would therefore classify EfficiencyOne's proposed increase as inconsistent with and unsupported by the DSM experience in the U.S. over the past several years."¹⁴

A more detailed jurisdictional analysis of DSM spending levels in the United States and Canada is set out in Mr. Levitan's evidence. However, Figure 4 shows how E1's proposed increase compares generally to changes in DSM spending in other US jurisdictions.

Figure 4: Proposed DSM Increases in the United States (2018)



Source: ACEEE State Energy Efficiency Scorecards for 2013-2018

¹⁴ Appendix A, Evidence of Richard Levitan, page 35, lines 6-9.

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1 Based on the data above and the evidence of Mr. Levitan it is clear that E1 is proposing a
2 large increase when many jurisdictions have decreased their DSM spending. The data
3 also shows a fairly normal distribution curve, meaning that the majority of budget
4 changes cluster around a specific point (0 percent with some slightly above and some
5 slightly below). The requested E1 increase is at the higher end of the increases being
6 asked for, and is certainly outside the norm of what is occurring in most jurisdictions.

7
8 E1 justifies the increase in spending in large part because it is moving away from lighting
9 measures and into other more expensive measures. The result is that in E1's Preferred
10 Plan customers would save an incremental (above 2019) 14 GWh at a cost of \$9 million.
11 This translates to a first year per-unit cost of \$0.64/kWh. Historically E1's cost per kWh
12 has been in the \$0.25/kWh range.

13
14 E1 could follow the trend in other jurisdictions and wait to allow the benefit of the more
15 expensive DSM measures to become more effective, much the way lighting measures
16 have decreased over the past ten years. The US Department of Energy has calculated that
17 the cost of LED lighting has dropped by 85 percent since 2008 and is projected to fall
18 another 50 percent by 2020.¹⁵ If the more expensive measures that E1 is proposing to
19 invest in now rather than in three to five years follow the same trend, customers will have
20 paid more than double what they could have for efficiency measures. In NS Power's
21 view it is in the best interests of customers for E1 to adopt a more conservative approach
22 and monitor the costs and benefit of these measures.

23
24 Historically, E1 has not spent up to its approved budget and it continued that trend under
25 the 2016-2018 DSM Supply Agreement. At the end of 2018 E1 was carrying a surplus of
26 approximately \$7.1 million from the 2016-2018 DSM period. Assuming this trend
27 continues into 2019, this would equate to a \$2.4 million underspend per year. This
28 represents a 7 percent budget increase if E1's budget is set at 2019 levels and it spends at

¹⁵<https://www.climatechangenews.com/2014/03/20/led-costs-to-halve-as-efficiency-doubles-by-2020-us-dept-of-energy/>.

1 2019 budget amounts. This amount should be sufficient to maintain energy and demand
2 savings, while increasing focus on traditionally under-served communities such as low-
3 income and First Nations customers.

4
5 E1 is requesting a significant increase in electricity customer-funded DSM at a time when
6 it has access to non-electricity funds. In June 2018, the Government of Canada
7 announced that it was providing E1 with \$56 million over four years to:

8
9 ...support efforts to improve energy efficiency in homes. Nova Scotia's
10 funded projects will help homeowners adopt energy-efficiency measures,
11 save money, and manage energy costs throughout the province.”¹⁶

12
13 In addition to this funding, the provincial government announced on March 18, 2019 that
14 it will be providing E1 with \$14.2 million in funding for efficiency programs over the
15 coming year. This includes an increase in the affordable rental program from \$1 million
16 to \$2 million, and an increase in the First Nations efficiency upgrade budget from
17 \$750,000 to \$1 million. E1, along with the Clean Foundation, is also a partner in
18 administering the \$37 million HomeWarming program funded by NS Power and its
19 shareholder.

20
21 Given the level of energy efficiency funding that currently exists, the UARB should
22 consider decreasing the financial burden on electricity customers. By using the federal
23 and provincial funding to support efficiency and greenhouse gas reduction, E1 could
24 expand its reach and impact on Nova Scotians. At the same time it could reduce
25 electricity sector spending.

26
27 Figure 5 below outlines funding available to E1 in 2020, in addition to the UARB-
28 approved budget for customer-funded DSM, for combined efficiency and green
29 initiatives.

¹⁶ <https://www.canada.ca/en/environment-climate-change/news/2018/06/low-carbon-economy-leadership-fund.html>.

Figure 5: Additional Funding Sources available to E1 in 2020

Funding source	Amount (\$ millions)
Province of NS Non-electricity DSM	\$14
Federal Low Carbon Economy Fund	\$14
Total	\$28

The federal government has also established a funding plan for green initiatives, including improvements to building efficiency, which extends out to 2030. The total amount of funding available to Nova Scotia in this time period is over \$380 million.¹⁷

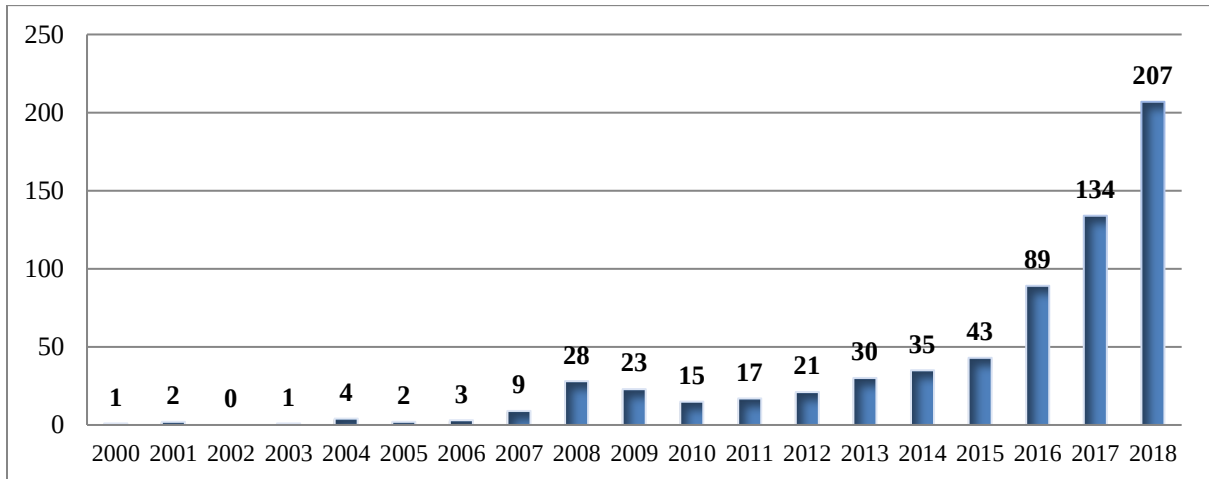
All of this represents a significant increase in the funding available for greenhouse gas reduction and energy efficiency for E1 and Nova Scotians in general. Given these alternate resources that are already impacting Nova Scotia, NS Power believes serious consideration should be given to reflecting this new reality of additional funding resources in E1's proposed customer-funded DSM program.

¹⁷ <https://www.infrastructure.gc.ca/prog/agreements-ententes/2018/2018-ns-eng.html>.

5.0 SYSTEM IMPACT AND REQUIREMENTS

The power system is undergoing a period of rapid change. As technology improves and resources become more cost effective, there has been an increase in customers choosing to install self-generation to meet a portion or all of their energy needs. This is happening in Nova Scotia and across the world. Figure 6 below is filed annually with the Net Metering Report and shows the beginning of what is forecast to be exponential growth in the residential solar sector:¹⁸

Figure 6: Increase in Number of Residential Solar Energy Installations



With government funding supporting solar adoption (much of which is managed by E1) this trend has continued in 2019. As of 2018, over 600 customers had installed some form of self-generation and NS Power is forecasting over 22,000 such systems by 2030.¹⁹ The energy savings from these systems are similar to DSM in that they reduce the net system requirement and were considered as part of the 3 TWh of load variability between the various IRP Candidate Resource Plans.²⁰ As this number increases it would be

¹⁸ Nova Scotia Power Enhanced Net Metering Report, January 31, 2019, Attachment 1, page 1.

¹⁹ M08349, Nova Scotia Power Advanced Metering Infrastructure Project Application, Appendix B02, Electronic Version, October 19, 2017.

²⁰ M05522, Nova Scotia Power 2014 Integrated Resource Plan Final Report, October 15, 2014, Appendix B, page 79.

1 reasonable to reduce the energy savings funded by DSM by commensurate amounts, as
2 customers are getting the benefit of the reduced load without providing a subsidy through
3 their power bills.

4
5 In NS Power's view, using the DSM levels from the 2014 IRP is problematic. The DSM
6 Supply Agreement approval process is the process through which DSM spending levels
7 are to be justified and approved. NS Power cautioned against using the IRP DSM levels
8 when it filed its 2014 IRP Preferred Resource Plan and advised that DSM levels are best
9 determined through the DSM process where the UARB must consider both short and
10 long-term affordability when approving the Supply Agreement.²¹

11
12 E1 relies on the DSM levels in the 2014 IRP to justify its proposed increase in DSM
13 spending over the 2020-2022 period. Apart from the issues relating to short-term
14 affordability identified in 2014, several issues have emerged with using the DSM levels
15 in the 2014 IRP as a benchmark for current levels of customer-funded DSM. These
16 issues include the following:

- 17
- 18 • Adoption of DER results in reduction of customer load;
 - 19 • There is significant non-customer funded DSM which provides system benefits;
 - 20 • E1 has historically achieved savings for less than its budgeted amounts;
 - 21 • NS Power has not identified a need to build more baseload generation in the short
22 and medium term;
 - 23 • The 2014 IRP included a forecast levelized cost of avoided energy of \$107/MWh,
24 but the actual marginal cost has been in the \$50/MWh range; and
 - 25 • The upcoming IRP will reflect updated system information and will provide
26 information about the level of DSM required in the longer term.
- 27

²¹ M05522, Nova Scotia Power 2014 Integrated Resource Plan, NSPI letter to the UARB, December 10, 2014.

The utility industry across North America is changing as homes and businesses turn to technology and self-generation which is a shift from the traditional centralized generation and large-scale grid service. Figure 6 above illustrates the exponential growth of solar power in the residential sector, but self-generation is also becoming more prevalent in the commercial and industrial sectors. Figure 7 below lists proposed customer DER projects.

Figure 7: Customer Proposed DER Projects in Nova Scotia

Generation Type	Size in MW
Combined Heat & Power	25.5
Combined Heat & Power / Distributed Energy	22
Combined Heat & Power / Distributed Energy plus Solar / Wind	28
Combined Heat & Power / Solar / Wind / Storage	10
District Energy Plant	25.5
Solar	25.6
Solar & Wind	154
Solar / Wind	5
Wind	2
Total	297.6

NS Power estimates that up to 75 percent of these DER projects will be built. The impact on the system from an energy and capacity perspective is similar to investing in DSM resources but without the socialized customer costs in electricity rates. For example, the Combined Heat and Power projects may be firm generation and may free up equal amounts of firm capacity on the NS Power system. Customers could avoid a proportionate investment in DSM demand reduction and will experience the same benefit at no cost.

Subsidies available for solar either through Halifax's Solar City program or through the non-electric customer-funded programs offered by E1 and funded by the Government of Canada will promote energy savings that provide customers with similar benefit to doing additional DSM. NS Power has forecast that in 2030 there will be approximately 170 GWh of solar adoption in Nova Scotia.

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1 Non-customer funded DSM occurring in the electricity sector is helping reduce the need
2 for subsidized DSM. One example of this is the adoption of heat pumps. Since 2012, NS
3 Power has been supporting the conversion from electric baseboard heat to heat pumps
4 which are a cleaner, less expensive and more efficient way to use energy. In 2017 there
5 were 19,030 customers who benefitted from this program. Approximately 45 percent of
6 those who benefitted from the program replaced electric baseboard heat (8,563
7 customers). Of those, 1,629 took advantage of E1's Green Heat and were counted
8 towards regulated energy savings.²² Each customer that participated in the NS Power
9 program without participating in the Green Heat program provided the system with 3000
10 kWh of non-subsidized energy savings, which means that in a single year there were 21
11 GWh of unregulated DSM that occurred organically in Nova Scotia.²³

12
13 Figure 22 of NS Power's 2018 10-Year System Outlook shows the capacity requirements
14 of the Company on a go-forward basis for 10 years.²⁴ NS Power is not forecasting any
15 new baseload generation requirement over this period and has a sufficient planning
16 reserve margin for the period. E1 states it needs more DSM on a go-forward basis
17 because the DSM levels have been below the 2014 IRP amounts since 2014.²⁵ However,
18 the 10 Year System Outlook shows that from a generation capacity perspective, funding
19 less DSM for the last five years has provided rate relief to customers without sacrificing
20 value in the medium term.

²² EfficiencyOne 2017 Progress and Evaluation Report, page 17, line 13.

²³ $(8,563 - 1,629) * 3,000 / 1,000,000$.

²⁴ Nova Scotia Power 10 Year System Outlook 2018 Report Revised, July 12, 2018, page 47, Figure 22.

²⁵ E-1, Efficiency One Application for Approval of the 2020-2022 DSM Resource Plan and Supply Agreement, Page 61, line 13, Section 4.2.1, page 13, lines 5-24, and page 14, line 1.

6.0 DSM NEGOTIATION

In the 2016 to 2018 DSM Supply Agreement process E1 presented a single DSM Plan to the UARB for approval. The UARB in its Decision directed as follows:

Finally, 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.²⁶

For the 2020-2022 DSM plan, E1 provided a Preferred Plan and an Alternate Plan and both represented a significant increase over the spending levels in the 2016-2018 and 2019 DSM Supply Agreements. Unfortunately, E1 developed the Preferred Plan and Alternate scenario without consultation about alternatives that would assist in informing the process.

E1 began modelling work on the 2020-2022 DSM Preferred Plan in Q3 2018 with Navigant using the ProCESS model on the Analytica platform. ProCESS is a DSM program optimizer that allows measures to be selected based on a number of constraints. Navigant produced a plan which was then vetted by E1 to determine whether the plan could be implemented in NS. E1 then worked with Navigant to customize the measures from the ProCESS output and finalize the design of its Preferred Plan. The Alternative scenario was then designed by scaling back the measures of the Preferred Plan to reach a lower level of spending (\$37 million vs. \$43 million). E1 did not engage NS Power during this process.

NS Power later encouraged E1 to develop additional DSM plans with current and reduced levels of investment in order to provide a full slate of options for consideration. At NS Power's request, E1 provided plans that show a range of outcomes for DSM

²⁶ M06733, EfficiencyOne Application for Approval of the 2016-2018 DSM Resource Plan and Supply Agreement, UARB Decision, August 12, 2015, page 29, paragraph 93.

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1 funding from \$27 to \$34 million. The Company considers this to be a reasonably
2 affordable envelope of DSM funding for customers.

3
4 NS Power proposed that Navigant model two versions of each of the \$27 million and \$34
5 million DSM funding scenario. The first was optimized to produce the maximum amount
6 of peak reduction at each price point. NS Power asked Navigant to use the ProCESS
7 model optimization capability to solve for a DSM program that included the highest
8 capacity reductions at the \$27 million and \$34 million price points. Under a second
9 scenario, NS Power requested that Navigant model DSM programs that were optimized
10 based on price. NS Power further requested the plans be optimized to select the lowest
11 cost DSM measures available. E1 produced the scenarios but did not include them as
12 part of its Application and did not vet them through its iterative process.

13
14 The information presented by E1 does not provide a meaningful scenario analysis of what
15 different levels of DSM spending can be achieved. E1's Preferred Plan is a first-year 23
16 percent increase over the status quo and its Alternate plan is a 9 percent increase over the
17 status quo. In NS Power's view, in order to fully assess the affordability of E1's
18 proposed DSM budget, E1 should have provided, at a minimum, a high, medium and low
19 DSM plan relative to its current budget.

20
21 In response to NS Power IR-07 and IR-09, E1 provided the results from the scenarios
22 requested by NS Power. The Company has concluded from the results of this modelling
23 that it would have been possible for E1 to present an application that was optimized
24 either for demand savings or economics somewhere in the \$27 to \$34 million range. NS
25 Power requests that E1 be directed to either vet the scenarios Navigant produced at these
26 levels or produce a second alternate plan in this range.

27
28 Otherwise, given that the Alternate scenario is a derivative of the Preferred Plan, the
29 UARB and stakeholders only have access to one fully vetted plan. Although presentation

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1 of these alternatives provides options for consideration by the UARB and stakeholders, it
2 still leaves a gap in relevant information.

7.0 LIFETIME ENERGY SAVINGS PERFORMANCE METRIC

In its Application, E1 has proposed the inclusion of a Lifetime Energy Savings (LES) performance metric in addition to the first-year energy savings currently used. NS Power does not object to the inclusion of LES for informational purposes, but does have concerns with the proposed methodology. These concerns are set out in Mr. Levitan's evidence.²⁷ Mr. Levitan concluded that, "using Long-term Energy Savings (LES) as a Performance Target is premature and therefore ill-timed. EfficiencyOne has not gained enough experience with LES. EfficiencyOne should continue using LES as a Performance Indicator over the 2020-2022 time period."²⁸

²⁷ Appendix A, Evidence of Richard Levitan, page 57.

²⁸ Appendix A, Evidence of Richard Levitan, page 9, lines 6-9.

8.0 HST/SURPLUS

Over the term of the 2016-2018 DSM Supply Agreement, E1 exceeded the targeted amount of DSM at a lower cost than its UARB-approved budget. Schedule B of the 2016-2018 DSM Supply Agreement provides that this money is to be returned to NS Power for the benefit of customers.²⁹ Specifically, Schedule B states:

The Parties acknowledge that any surplus realized by EfficiencyOne in delivering the Performance Targets at the end of the Term shall be reported to the UARB and refunded to NSPI unless EfficiencyOne is directed otherwise by the UARB.

There is currently a \$7.1 million surplus for 2016-2018. NS Power requests that the UARB confirm that the funds are to be returned to NS Power as soon as they are available.

In its Application, E1 advised that it had successfully appealed the collection of Harmonized Sales Tax (HST) from the Canada Revenue Agency. The amount available to be returned to NS Power for the benefit of customers is just over \$15 million. E1 has proposed that these HST settlement funds be applied on an equal basis over each year of the 2020-2022 DSM plan to reduce the DSM investment level. If the funds were applied in this manner, it would reduce the average annual investment level for the Preferred Plan from \$43 million to approximately \$38 million, effectively the cost of the Alternate Scenario. NS Power strongly disagrees with this proposed treatment of the funds and requests that the UARB order the money to be returned to NS Power for the benefit of customers, in accordance with the requirements of the *Electricity Efficiency and Conservation Restructuring (2014) Act*, which provides as follows:

²⁹ Schedule B of the 2016-2018 DSM Supply Agreement states: The Parties acknowledge that any surplus realized by EfficiencyOne in delivering the Performance Targets at the end of the Term shall be reported to the UARB and refunded to NSPI unless EfficiencyOne is directed otherwise by the UARB.

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1 8 Any assets of the Corporation acquired on or after the Implementation
2 Date must be transferred to Nova Scotia Power Incorporated for the
3 benefit of the customers of Nova Scotia Power Incorporated as directed by
4 the [Review] Board. 2014, c. 5, s. 8.
5

6 The HST settlement funds were collected from all customers as part of the DSM Rider
7 and should be returned to all customers, not just those participating in DSM programs.
8 As discussed above, customers face short-term rate pressure and should have the benefit
9 of these funds to help alleviate that pressure. In addition, E1 is using the application of
10 these customer funds to justify a higher DSM expenditure level than is necessary in the
11 circumstances. These funds can only be used for this purpose if E1 is able to justify that
12 it is in the best interests of customers to do so, and as noted by Mr. Levitan, “relative to
13 the Board-approved targets in previous DSM Resource Plans, EfficiencyOne’s proposed
14 2020-2022 Preferred Plan’s targets are high and overly aggressive.”³⁰
15

16 These funds should not influence the amount of DSM to be approved. If the status quo
17 funding is maintained or decreased, then both the decrease and the HST amounts could
18 be applied to the FAM account for the direct benefit of customers.

³⁰ Appendix A, Evidence of Richard Levitan, page 5, lines 8-10.

9.0 DSM AS A FAM EXPENDITURE

NS Power proposes that DSM costs be dealt with either as part of the FAM or in a similar manner. As NS Power has \$34.05 million in its non-fuel budget apportioned to DSM, the Company proposes that any variation from that amount (whether a decrease or an increase) approved by the Board for the 2020-2022 DSM Supply Agreement period be apportioned to the FAM account prior to the next General Rate Application (GRA). At the time of the next GRA, NS Power proposes that 100 percent of the customer-funded DSM budget be dealt with through the FAM or a similar mechanism. This will provide greater transparency for customers and is a more appropriate mechanism to address these types of expenses.

10.0 RATE AND BILL IMPACT ANALYSIS

NS Power has made several submissions to the DSM Advisory Group (DSMAG) and the UARB about the Rate and Bill Impact Analysis (RBIA) and reiterates the concerns raised with the E1 RBIA model. NS Power developed an alternative RBIA based on the E1 model capable of providing both short and long-term analysis of the effects of DSM costs on rates and bills and presented it to the DSMAG. The suggested modifications to align the NS Power and E1 models are detailed below.

10.1 Levelized avoided fuel costs

Consistent with the Company's position provided in comments on the 2016 RBIA Report, due to the manner in which fuel costs have been incorporated, the use of levelized fuel costs from the 2014 IRP based on the period 2015-2039 does not reflect the actual rate and bill impacts experienced by customers.³¹ Unlike future fixed costs, which arise from future investments under the no-DSM case, fuel costs are recovered as the fuel is used. The RBIA should reflect this recovery pattern.

Over the 25-year term, levelized costs used by E1 show \$167/MWh in years 2011-2014 from the 2009 IRP Update study, and \$107/MWh in years 2015-2033 from the 2014 IRP study. These values are significantly above the actual marginal costs reported in 2011-2016, as well as those currently projected for the next several years. These values are also much higher than the avoided fuel costs from the two IRP proceedings levelized over shorter time horizons aligned with those used in the RBIA analyses: 2011-2027 and 2011-2033, respectively. The ten-year average of annual actual marginal fuel cost from 2011-2016 and the forecast for 2017-2020, as used for the purposes of the 2017-2019 Rate Stability Proceeding, is only \$47/MWh. The average marginal fuel cost for the 23-year period from 2011-2033, comprised of a hybrid of actual and recently projected

³¹ M07730, EfficiencyOne – 2016 Rate and Bill Impact Analysis (E-ENSC-R-16), NSPI letter to the UARB, November 30, 2016.

1 marginal costs for the period 2011-2020, and the 2021-2033 annual marginal cost
2 forecast from the 2014 IRP, is \$74/MWh and is higher than what has been experienced.
3 When the actual annual incremental cost from the 2014 IRP is used in the RBIA, the
4 average rate change increases from +0.5 percent to +2.2 percent. The use of actual
5 annual fuel costs from 2011 to 2016 in combination with the 2017-2020 forecast,
6 discussed above, and the 2014 IRP figures from years 2021- 2033, brings the overall rate
7 effect to +3 percent.

8
9 The use of levelized avoided costs in the RBIA does not accurately reflect when
10 customers experience real savings. The use of avoided fuel costs levelized over periods
11 of time which do not align with the time horizons of the RBIA further distorts the rate
12 and bill impact results.

13
14 **10.2 Methodology for determination of fuel and fixed cost savings or losses by rate class**

15
16 In its letter dated March 6, 2017 the UARB stated that the DSMAG should review several
17 assumptions to be used in E1's October 2017 RBIA. Under action items (c) and (e) the
18 Board provided as follows:

- 19
20 (c) Discuss NS Power's suggested alternate method of accounting for
21 marginal fuel costs in avoided cost and lost fixed cost recovery
22 calculations, and discuss the extent to which the current method
23 estimates the actual lost fixed costs.
24 ...
25
26 (e) Continue to discuss the variability in the rate impact graphs,
27 especially in the outer years of the analysis.
28

29 NS Power considered an alternative method of accounting for marginal fuel costs in
30 avoided cost and lost fixed cost recovery calculations using the 2016 model and assessed
31 the ensuing rate and bill impact results from the perspective of their variability by rate
32 class.
33

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1 NS Power believes that the current RBIA model filed by E1 does not reflect the
2 variability in bill and rate impacts among rate classes.³²

3
4 As proposed by NS Power in its comments on the 2016 RBIA report, the effect of fuel
5 cost savings should be determined and shown separately from fixed cost savings or
6 losses. This means that the difference between the lost revenues and avoided costs
7 should be further broken down by the fuel and fixed components for each class.³³ This
8 would improve the accuracy of the RBIA results, reflecting the fact that cost causation
9 varies between rate classes for fuel consumption and their use of fixed infrastructure.³⁴

10
11 Fuel costs are recovered through energy charges, but fixed costs are recovered by a
12 combination of energy, demand and customer charges. Given the difference in the
13 system cost savings associated with energy-reducing versus demand-reducing measures,
14 the above distinction by fuel versus fixed cost savings has a material effect on the RBIA
15 analysis.

16
17 NS Power proposes the following modifications to the RBIA model for consideration:

³² The current methodology and cost inputs used in the 2016 and 2017 RBIA models are essentially the same. Both models use the same avoided cost assumptions and input parameters such as discount and escalation rates. Accordingly the rate impact results are very similar, yielding average class rate impacts which fall within +/-1% of the no-DSM scenarios in the 2016 and 2017 models.

³³ The current RBIA model intends to track class savings attributable to energy separate from those attributable to demand. However, the method employed does not compare compatible cost standards and measures on the avoided cost and revenue sides of the equation. Avoided levelized fuel costs are compared to forecast annual revenues collected through application of energy charges comprised of both fuel and fixed costs. There is a mismatch in terms of cost standard: levelized versus actual/forecast annual; and cost type: fuel versus fuel and fixed cost combined.

³⁴ For example, the current RBIA model uses a uniform cost allocator to determine both the fuel and fixed cost savings or losses for the residential class based on the residential class share of 53 percent of the total of all class revenues. However, the residential class share of total fixed costs for all classes is about 57 percent, and its share of the total fuel costs for all classes is 47 percent.

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1. Annual fuel costs reduced by avoided fuel cost of DSM programs should be allocated to rate classes based on their shares in annual GWh requirement in each year.
2. Annual fixed generation and transmission costs, reduced by avoided marginal capacity costs, should be classified to energy and demand and reallocated to rate classes based on their shares in GWh Energy and MW coincident demands in each year.
3. Annual fixed demand-related distribution costs should be reduced by avoided marginal distribution costs and apportioned to rate classes based on their changing shares in annual sum of non-coincident class demands each year.
4. Customer-related costs should be excluded from the allocation of costs and benefits.

The above modifications, as tested by NS Power on the 2016 RBIA, were presented to the DSMAG on October 24, 2018. A copy of NS Power's presentation is attached as **Appendix B**. The modified calculations show that the average net impact on rates is more diverse than +/-1 percent, as indicated in the 2016 and 2017 RBIA models filed by E1.

The apportionment of DSM costs and benefits to rate classes in the current RBIA methodology uses a static allocator factor based on class shares in one historic year (2014 test year) revenue requirement throughout the RBIA period of 2011-2033.

The E1 RBIA model does not distinguish between differences in class responsibilities for energy versus demand-related costs in areas of generation, transmission and distribution consistent with the UARB-approved Cost of Service Study methodology. It incorporates customer-related costs (billing) which distorts the allocation of benefits and costs

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1 associated with DSM load reductions, especially for the residential and general
2 customers. Further, it does not recognize year-over-year dynamics in class usage in
3 response to long-term load forecast and DSM effects. Finally, it does not account for line
4 losses in the determination of reduced usage for behind the customer meters.

5
6 The use of levelized fuel costs from 2011-2040 rather than the approved 2011-2033
7 RBIA time horizon overstates the rate reduction and bill savings in the early years and
8 understates them in the outer years. In addition, it overstates the average benefits due to
9 the inclusion of higher costs from years 2034-2040 which extend beyond the time
10 horizon of the RBIA.

11
12 NS Power requests the Board order E1 to incorporate these changes into its RBIA so that
13 the E1 and NS Power RBIA is the same and can be filed by E1 annually.

11.0 CONCLUSION

NS Power supports DSM and recognizes that a balanced, affordable and properly implemented DSM program provides value for all Nova Scotians.

NS Power also recognizes the work EfficiencyOne (E1) has undertaken since it was awarded the first DSM franchise in 2015. While NS Power continues to support E1 in its overall mandate of cost savings for customers, the parties were unable to reach a consensus with respect to the issue of the appropriate level of spending for the 2020-2022 DSM Supply Agreement period. E1 is proposing an approximate 23 percent budget increase from the 2019 DSM Plan to the first year of its 2020-2022 Preferred Plan, which is inconsistent with the annual DSM spending growth rates in other jurisdictions. NS Power is unable to support increases of this magnitude in an initiative paid for by electricity customers, particularly in light of additional funding available from other sources.

Although E1 needs to achieve clear and transparent long-term cost savings in carrying out its mandate, it must take into account the realities of the short-term rate impacts which result from its proposed DSM budget. The UARB is required to take these impacts into account under section 79L(9) of the Act in its assessment of any DSM Supply Agreement. Achieving long-term cost savings and avoiding short-term rate impacts is not an either/or proposition. Both can be delivered by a prudent, cost-effective DSM plan.

While an assessment of the appropriate DSM expenditure level requires consideration of the long-term cost savings, it cannot ignore issue of short-term affordability such as near-term rate impacts. Appropriate DSM spending levels must balance the long-term cost savings against the short-term cost impacts to customers.

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1 It is important to note that historically E1 has been capable of delivering higher energy
2 savings at lower than its budget forecast. This suggests E1 is able to achieve energy
3 savings without an increase to its budget.

4
5 NS Power respectfully requests the UARB:

- 6
- 7 1. Not approve E1's Preferred Plan for the 2020-2022 DSM Supply
8 Agreement period.
9
 - 10 2. Direct that E1 develop a lower cost DSM Plan at an expenditure level in the range
11 of \$27 - 34 million E1 DSM budget for the 2020-2022 DSM Supply Agreement
12 period.
13
 - 14 3. Notwithstanding the level of DSM spending that is ultimately approved, direct
15 that any variation in the DSM expenditure level approved for the 2020-2022 DSM
16 Supply Agreement period from the current \$34.05 million in NS Power's non-fuel
17 budget for DSM (whether a decrease or an increase) be apportioned to the FAM
18 account.
19
 - 20 4. Not approve E1's request to implement Life Time Energy Savings as a new
21 Performance Target.
22
 - 23 5. Direct E1 and NS Power to finalize the form of the 2020-2022 DSM Supply
24 Agreement based on the expenditure level approved by the UARB.
25
 - 26 6. Direct E1 to return any surplus funds from the 2016-2018 DSM Supply
27 Agreement period to NS Power.
28
 - 29 7. Direct E1 to return the HST settlement funds to NS Power for the benefit of
30 customers.

**Evidence of
Richard L. Levitan, President
Levitan & Associates, Inc.**

**Nova Scotia Utility and Review Board
on behalf of
Nova Scotia Power, Inc.
2020-2022 DSM Resource Plan**

April 12, 2019

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1 INTRODUCTION

2 **Q. Please state your name and business address.**

3 A. My name is Richard L. Levitan. My business address is Levitan & Associates, Inc. (LAI),
4 20 Custom House Street, Suite 830, Boston, MA, 02110.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am President of LAI, a Boston-based energy management consulting firm specializing
7 in the electricity and natural gas markets. I lead the firm's advisory services in the electric
8 power and natural gas industries, as well as providing expertise on matters related to
9 wholesale market design, both conventional and renewable energy procurement,
10 gas/electric interdependencies, valuation, and resource assessment.

11 **Q. Please summarize the advisory services LAI offers clients in the power industry.**

12 A. LAI provides financial, economic, and engineering consulting services to gas and electric
13 utilities, generation companies, investors, large end-users, state regulatory commissions,
14 and independent system operators (ISOs) in the U.S. and Canada. LAI also provides
15 wholesale power procurement oversight in many states. We have helped guide the
16 procurement of thermal resources, renewable energy technologies, and the array of
17 physical and financial products that trading entities use to buy and sell electricity,
18 capacity, and renewable energy credits. LAI conducts due diligence on gas storage and
19 pipeline transportation options, as well as high voltage direct current (HVDC) and AC
20 transmission projects throughout the greater Northeast, mid-Atlantic, and Atlantic
21 Canada. Transmission evaluations often include the comparative assessment of non-
22 transmission alternatives, including demand side management (DSM). For various ISOs
23 in the Eastern Interconnection, as well as for North American Electric Reliability
24 Corporation and Northeast Power Coordinating Council, LAI has conducted many
25 technical studies on gas pipeline and storage network resiliency. We have represented the
26 U.S. Department of Energy on the grid of the future for the 2017 Quadrennial Energy
27 Review. We have been an integral part of various state solicitations to reduce carbon

1 emissions through the addition of offshore wind resources and HVDC transmission from
2 Quebec to New England. We have evaluated at-risk nuclear power plants in Connecticut,
3 New York, Vermont and Illinois. LAI currently represents the Connecticut Department of
4 Energy and Environmental Protection (DEEP). Previously, we have represented
5 consumer advocates in Connecticut and Nova Scotia. We have advised Nova Scotia
6 Power, Inc. (NS Power) on DSM options and fuel assessment. Finally, LAI represented
7 ISO-New England in its recent submission at the Federal Energy Regulatory Commission
8 regarding a return to cost of service regulation for the Mystic 8 & 9 combined cycle
9 plants.

10 **Q. What is your professional experience and background?**

11 A. I have 40 years of experience in the energy industry. Since LAI's formation in 1989, I
12 have advised stakeholders, in particular, utilities, ISOs, and private equity investors on
13 diverse matters pertaining to resource adequacy, wholesale market design, and
14 economics. More recently, I have advised state regulatory commissions and utilities on
15 carbon reduction initiatives through long term procurements. I have assisted many
16 electric utilities and generation companies on the procurement of natural gas and pipeline
17 transportation rights. I have represented electric utilities throughout the U.S. on long term
18 contracts with independent power producers. In my procurement oversight role, I have
19 been responsible for ensuring the objectivity, fairness and transparency of various electric
20 distribution companies' (EDCs') selection of rival bidders to meet resource needs,
21 including carbon reduction goals. I have represented the Connecticut Public Utilities
22 Regulatory Authority (PURA), the Long Island Power Authority, the New York Power
23 Authority, the Maryland Public Service Commission, the New Jersey Board of Public
24 Utilities, the New York State Energy Research Development Authority, and the
25 California Public Utilities Commission on a broad spectrum of wholesale power
26 procurement matters involving new transmission, non-transmission alternative resources,
27 offshore wind, and both conventional generation and financial products. I have testified
28 many times in the U.S. and Canada.

29 I have advised state regulatory commissions on Integrated Resource Planning (IRP),
30 wholesale market design, and financial contracts. On behalf of the Connecticut Office of

Consumer Counsel (OCC), I reviewed and assessed the IRPs filed by EDCs and by the Connecticut Energy Advisory Board in the IRP proceedings administered by PURA. In my review, I focused on procurement and policy recommendations offered by the parties regarding energy efficiency (EE) and active demand response (DR). I advised the Gas Company of Hawaii on its IRP, including cultural and aesthetic considerations affecting demand side measures. Presently, I am advising DEEP on the preparation of the IRP. On behalf of an EDC doing business in Massachusetts, I analyzed the economic impact and reliability benefits of a proposed 345 kV transmission line in relation to EE and active DR. I have represented gas utilities in Connecticut on the demerit of the Environmental Defense Fund's allegations of vertical market power abuse in New England. For many ISOs, including Ontario's Independent Electric System Operator (IESO), I served as project manager on a series of studies that examined gas/electric interdependencies.

Prior to LAI, I was a consultant for about ten years at Stone & Webster Management Consultants, Inc. where I worked on the implementation of Canada Energy Mines Resources Distribution System Expansion Program in British Columbia, Ontario and Québec. In this capacity I performed many analyses of infrastructure potential across Canada, including the Northwest Territories and Yukon. From 1978 to 1980, I was an Economist at Pacific Gas & Electric Co. I received my undergraduate degree from Cornell University (B.A., Arts & Sciences) and my masters from Harvard University where I specialized in energy economics. I attended a post-graduate executive management program at Stanford University.

My resume can be found in Attachment RLL-1. A summary of my testimony experience is provided in Attachment RLL-2.

Q. On whose behalf are you submitting this testimony?

A. My testimony has been prepared on behalf of NS Power.

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

A. Yes. I have testified before the Utility and Review Board (Board) on behalf of the Consumer Advocate and Small Business Advocate evaluating non-transmission

alternatives to the proposed Maritime Link (ML) Project. My testimony was filed in April 2013. I appeared before the Board in order to present the results of the economic analysis of the proposed ML project and the project alternatives, as presented in the Application by NS Power Maritime Link Inc.¹ Part of the analysis also included a review of the commercial terms between NS Power and Nalcor. In my testimony I covered a subset of Board issues pertaining to the ML Project in relation to other technology options for Nova Scotia, potential customer benefits, transmission tariff provisions, the benefit / cost distribution associated with the Nova Scotia Block, and the potential for increased operating reserves.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the results of my assessment of EfficiencyOne's (E1) Application for Approval of the 2020-2022 DSM Resource Plan filed with the Board on February 28, 2019.

Q. What Attachments are you sponsoring?

A. My Attachments are as follows:

RLL-1 – Resume of Richard L. Levitan

RLL-2 – Testimony Experience of Richard L. Levitan (Partial)

RLL-3 – 2017 Firm Generating Capability for NS Power and IPPs

Q. Were the attachments prepared by you or under your supervision?

A. Yes, they were.

¹ See Docket NSUARB M05419, January 2013.

SUMMARY OF EVIDENCE

Q. Based on your review of the E1 application and the evidence before you, what are your primary findings and observations?

A. My primary findings and observations are as follows:

First, the history of DSM in Nova Scotia shows that the province has made good, steady and reasonable progress incorporating energy efficiency and energy conservation measures.

Second, relative to the Board-approved targets in previous DSM Resource Plans, EfficiencyOne's proposed 2020-2022 Preferred Plan's targets are high and overly aggressive.

Third, the Alternate scenario is a scaled down version of the Preferred Plan. Therefore EfficiencyOne may have produced a second plan that does not appear to be properly optimized.

Fourth, empirical evidence exists that some incremental EE penetration will occur naturally and therefore does not warrant subsidization.

Fifth, EfficiencyOne failed to demonstrate that its Preferred Plan meets the Board's affordability requirements. The plan's long-term benefits are uncertain. Moreover, the plan is not affordable in the short term.

Sixth, the accuracy of the estimated peak demand reductions is questionable because the estimates are based on the unconfirmed results of the peak demand reduction pilot programs under the 2019 DSM Plan. The long-term benefits ascribable to the estimated peak demand reductions hinge on avoided capacity costs. Such avoided capacity savings are uncertain.

Seventh, the proposed 23% budget increase from the 2019 DSM Plan to the first year of the 2020-2022 Preferred Plan is inconsistent with the annual DSM spending growth rates in other comparable states and provinces. The budget increase is excessive as a substantial portion of the proposed increase is for measures that undermine operational efficiency goals.

Eighth, Mr. Reed chose an inappropriate peer group of only "leading" program administrators to compare the Preferred Plan to in his benchmarking analysis.

1 Ninth, the \$27 million DSM scenario is much lower than that proffered by
2 EfficiencyOne, but it appears achievable, affordable, and conservative. Relative to the
3 EfficiencyOne's 2019 budget of approximately \$34 million (2019 DSM), it is reasonable
4 to review the comparative merit of a DSM scenario with a much lower budget than
5 EfficiencyOne's Preferred Plan once it is fully developed and made deliverable.

6 Tenth, using Long-term Energy Savings (LES) as a Performance Target is premature and
7 therefore ill-timed. EfficiencyOne has not gained enough experience with LES.
8 EfficiencyOne should continue using LES as a Performance Indicator over the 2020-2022
9 time period.

10 Finally, Navigant's modelling using ProCESS and post-modelling adjustments may have
11 resulted in skewed results.

1 MAIN EVIDENCE

2 **Q. Mr. Levitan, please describe in general terms the state of DSM programs in Nova**
3 **Scotia.**

4 A. Nova Scotia's DSM programs are designed to shift electricity consumption to off-peak
5 periods as well as to reduce consumer energy usage overall. DSM programs include
6 education, subsidization, energy auditing, and smart grid initiatives. Implementation of
7 utility customer-funded DSM has been administered by EfficiencyOne since 2015.²
8 EfficiencyOne has the right to develop and deliver DSM programs.³ In 2016,
9 EfficiencyOne developed a 3-year plan that projected the cost and benefits of DSM
10 programs from 2016 to 2018, *i.e.*, the 2016-2018 DSM Resource Plan. In 2019,
11 EfficiencyOne developed a similar plan, which was a one-year plan that was agreed upon
12 by NS Power and approved by the UARB in a separate proceeding. EfficiencyOne is
13 currently proposing another 3-year plan to cover 2020-2022. EfficiencyOne's DSM
14 programs are paid for by NS Power, which recovers the costs of these programs from its
15 ratepayers.

16 In 2015, 2016 and 2018, DSM programs in Nova Scotia resulted in more energy and
17 demand savings in the residential and business, not-for-profit and institutional (BNI)
18 sectors at a lower cost than what was originally filed for Board approval.⁴ However, in
19 2017, a lower investment than was originally filed for Board approval resulted in lower
20 energy savings, but higher demand savings.⁵ This is summarized in Figure 1.

² NSUARB Electricity Mandate – Demand Side Management (Energy Efficiency), Document Number 231831

³ Ibid.

⁴ Table 1 in 2015, 2016 and 2018 DSM Annual Progress Reports.

⁵ Table 1 in 2017 DSM Annual Progress Report.

Figure 1. DSM Programs Investment and Savings (Planned and Actual), 2015-2018

		2015	2016	2017	2018
Energy Savings (GWh)	Planned	121.2	133.1	136.5	136.3
	Actual	137.9	136.9	130.7	151.4
Peak Demand Reduction (MW)	Planned	21.2	20.4	21.0	21.0
	Actual	22.7	26.0	23.7	25.5
Investment (\$ million)	Planned	39.0	33.2	34.0	34.9
	Actual	32.0	30.8	30.3	33.9

In my opinion, it is reasonable to infer that some additional savings occurred organically, that is, without any incentives. This is because customers see benefits ascribable to energy efficiency and energy conservation and therefore take action using their own money to achieve energy efficiency and conservation objectives without the incentive of any utility subsidy. Hence, some costs were not incurred by EfficiencyOne and funded by NS Power while benefits were nevertheless realized. I explain this phenomenon in more detail below.

Q. Are you familiar with the IRP and Generation Utilization and Optimization (GUO) proceedings in Nova Scotia?

A. Yes.

Q. Please summarize the objectives of the IRP and GUO.

A. As highlighted in the Terms of Reference,⁶ the objectives of the 2014 IRP were to develop a long-term Preferred Resource Plan to help NS Power meet demand, energy and environmental requirements in a cost-effective, safe and reliable manner. The last IRP was issued in 2014 to develop an action plan to implement a strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon.⁷

The GUO study was prepared in 2018 to assess the extent to which it is cost effective from a customer perspective to retain a portion of NS Power's thermal generation fleet through 2030 and, under certain circumstances, beyond 2030. The thermal fleet includes

⁶ The NS Power IRP 2014 Terms of Reference is a document that discusses the objective and defines the approach, scope and framework of the IRP.

⁷ 2014 Integrated Resource Plan, NS Power Final Report, October 15, 2014.

one oil- and gas-fired facility and four remaining coal-fired plants. Nameplate capacity and fuel type for the thermal fleet is summarized in Figure 2.

Figure 2. NS Power Thermal Facilities

Facility Name	Nameplate Capacity (MW)	Fuel Type
Tufts Cove (Units 1-6)	500	Gas / Oil
Lingan (Units 1, 3, 4)	620	Coal
Point Aconi	171	Coal
Point Tupper	154	Coal
Trenton (Units 5, 6)	307	Coal

In my opinion, additional investment in DSM is likely to reduce the capacity factors of NS Power's thermal fleet going forward. From a carbon reduction and overall emissions standpoint, the reduction in thermal capacity factors is laudable. However, additional investment in DSM may not be effective in reducing the need for thermal generation capacity and grid services to ensure system reliability during the critical peak heating season. NS Power's coincident demand during the peak heating season requires NS Power to rely on the availability and dispatch of most of the thermal facilities identified in Figure 2.

Q. Please characterize NS Power's resource mix.

A. NS Power's resource mix is composed of coal, petroleum coke, light and heavy oil, natural gas, biomass, wind, tidal, and hydro resources. In addition, NS Power purchases energy from independent power producers and imports power across the NS Power / New Brunswick Power intertie. Attachment RLL-3 shows the generation assets in service in Nova Scotia as of July 2018.

Q. Will additional hydro generation from Newfoundland / Labrador obviate the need to maintain the availability of NS Power's thermal fleet to meet peak demand in the next five to ten years?

A. No. Substantial amounts of additional hydro generation from Newfoundland and Labrador via Maritime Link will enhance NS Power's ability to ensure grid reliability.

1 However, the onset of clean energy from Newfoundland / Labrador will not obviate NS
 2 Power's reliance on various thermal facilities for grid reliability in the decade ahead. On
 3 page 2 of the GUO Report,⁸ Synapse states:

4 Retention of the thermal fleet (all coal units except Lingan 2 and the Tufts Cove
 5 units) is indicated through 2030 under Scenario 1's parameters⁹, which included:
 6 Load levels from NSPI's 2017 load forecast and 2017 sustaining capital forecast.

7 **Q. Is EE an integral part of NS Power's resource mix?**

8 A. Yes. Like other EDCs across North America, EE is an integral part of NS Power's
 9 resource mix. The effect of recent high EE penetration, which has been boosted by
 10 financial incentives and environmental goals, is reflected in North American EDCs' load
 11 forecasts, including that of NS Power. While EE is an integral part of NS Power's
 12 resource mix, from a system planning standpoint it is not a good substitute for
 13 dispatchable resources. Therefore, NS Power's thermal fleet is still needed to meet peak
 14 demand. Moreover, a portion of the thermal fleet is needed to provide the operating
 15 reserves for grid security when wind resources produce less generation than expected, or
 16 unanticipated weather conditions cause a faster-than-anticipated morning or evening
 17 ramp.

18 **Q. How was DSM program potential assessed in the context of the latest IRP and GUO**
 19 **proceedings?**

20 A. On behalf of EfficiencyOne, Navigant conducted an analysis of DSM, *i.e.*, EE programs
 21 from 2015 to 2040 to support NS Power's IRP and GUO efforts. On January 7, 2014,
 22 Navigant issued the report,¹⁰ which presented estimates of EE measure adoption to

⁸ Nova Scotia Power Inc. Thermal Generation Utilization and Optimization, Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059, Prepared for Board Counsel Nova Scotia Utility And Review Board, May 1, 2018.

⁹ Scenario 1 is the Reference Case. It was formed by combining the NS Power database created to conduct long-term optimization planning with fuel cost information from November 2017.

¹⁰ Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study, January 7, 2014.

1 achieve potential savings targets. Four scenarios of achievable potential (Low, Base, Mid
2 and High) were developed using specific incentive levels.¹¹

3 **Q. Did you review Navigant's report?**

4 A. Yes, I reviewed the Navigant report and also relied on the assessment of my colleagues at
5 LAI for additional technical insight.

6 **Q. Please summarize Navigant's primary assumptions.**

7 A. The 2014 Navigant DSM Potential Study relied on the results of Navigant's 2012
8 Baseline Study.¹² The primary source of data used in determining the residential baseline
9 was a 2012 online general population panel survey conducted by Corporate Research
10 Associates (CRA), Inc. on behalf of Navigant, *i.e.*, the Energy Usage Study. The primary
11 source of data used in determining the BNI baseline was a 2012 telephone business
12 survey conducted by CRA on behalf of Navigant. On-site data collection was used to
13 supplement the surveys. In addition to the sources mentioned above, Navigant used many
14 others dating back to as early as 2006.¹³

15 The results of this DSM study may be used to develop DSM investment strategies, as
16 well as to define specific objectives to meet provincial goals. Recognizing that benefits
17 are driven by energy savings and peak demand reduction, Navigant assessed a
18 comprehensive array of DSM measures.

¹¹ Base: incentive in the calibration year is set to what was offered in that calibration year.

Low: incentive is set to one-half the calibration year incentive;

Mid: incentive is set to 1.5 times the calibration year incentive (up to a maximum of 100% of incremental cost);

High: incentive is set to twice the calibration year incentive (up to a maximum of 100% of incremental cost);

¹² Nova Scotia 2012 Baseline Study: Residential Sector & Business, Nonprofit and Institutional Sector Presented to Efficiency Nova Scotia Corporation, November 20, 2013.

¹³ Statistics Canada, 2006 Census of Population: Statistics Canada Catalogue no 97-554-XCB2006022 (2006); Natural Resources Canada (NRCan), Office of Energy Efficiency 2007 Survey of Household Energy Use (SHEU-2007) (2007); Navigant Consulting, on behalf of NS Power, 2009 Nova Scotia Residential Baseline Study (2010); Corporate Research Associates, Inc. on behalf of Efficiency Nova Scotia, 2011 Socket Study (2011); Statistics Canada, 2011 Census of Population: Statistics Canada Catalogue no.98-313-XCB2011022 (2011); and Natural Resources Canada (NRCan), Comprehensive Energy Use Database, 1990 to 2010 (2012).

1 **Q. Can you summarize how NS Power proposed to treat DSM programs in the IRP?**

2 A. Yes. NS Power proposed using a separate regulatory process outside of the IRP, *i.e.*, the
3 2016-2018 DSM Resource Plan.¹⁴ Consensus on the appropriate level of EE was not
4 reached. Some stakeholders advocated for higher EE levels. Other stakeholders
5 advocated for lower EE levels. However, it appears that consensus was reached in regard
6 to the importance of establishing an optimal EE level for the IRP process. In order to
7 determine an optimal level of EE that can be adjusted over time, the IRP supplied the
8 information necessary to determine the range of resource needs.

9 **Q. Please describe how the 2016-2018 DSM Resource Plan was developed.**

10 A. The 2016-2018 DSM Resource Plan was developed by ENS with the support of Navigant
11 and Dunskey Energy Consulting. The 2016-2018 DSM Resource Plan included a summary
12 of the projected electricity savings and the investment associated with the adopted DSM
13 programs.

14 The plan was designed to respond to changes in the market, to incorporate the findings of
15 conducted research, and to maintain access to residential and BNI programs. The plan
16 was designed to include a reasonable balance of investments between the residential and
17 commercial sectors. Also, the plan provided details on how the different DSM programs
18 were designed and should be promoted within their target groups.

19 **Q. Did the 2016-2018 DSM Resource Plan strike a reasonable balance between**
20 **investment in EE and the uncertainties associated with the potential benefits of these**
21 **programs?**

22 A. Yes. The Board approved the plan, so it therefore follows that the 2016-2018 DSM
23 Resource Plan strikes an appropriate balance between investment and anticipated
24 benefits. I believe that the approval of any additional investment beyond what was
25 approved to support EE programs that barely passed the cost-effectiveness test would

¹⁴ 2014 Integrated Resource Plan NS Power Final Report, October 15, 2014, page 19 of 84.

1 have resulted in investment with an increased level of uncertainty regarding potential
2 benefits.

3 **Q. What were the investment and savings levels in the Board-approved 2016-2018**
4 **DSM Resource Plan?**

5 A. The Board approved a 3-year aggregate investment amount of \$102.15 million with
6 targeted total energy savings of 405.9 GWh. The target peak demand reduction was 62.5
7 MW.

8 **Q. How do these values compare to the previous 3-year DSM Plan?**

9 A. The 3-year aggregate investment amount, energy savings and peak demand reduction in
10 the 2013-2015 DSM Resource Plan were \$144.4 million, 410.8 GWh and 79.8 MW,
11 respectively.

12 **Q. Did the 2013-2015 DSM Plan have a much higher approved investment than the**
13 **2016-2018 DSM Plan to achieve similar levels of energy savings?**

14 A. Yes. It appears that the much higher investment in the 2013-2015 DSM Plan relative to
15 the 2016-2018 DSM Plan is explained by a correction in the 2016-2018 DSM Plan.
16 EfficiencyOne may have underestimated the natural penetration of DSM. NS Power
17 informed the Board about EfficiencyOne's investment overestimation:

18 In its initial evidence for the 2013-2015 DSM Plan Evidence, EfficiencyOne
19 proposed an increase in installed DSM costs. Actual results to-date show that
20 EfficiencyOne actually achieved significantly lower costs than proposed. The
21 approved price for 2014 was \$0.35/kWh, with actuals being \$0.26/kWh, a 28
22 percent reduction from projected unit cost, and \$0.25/kWh after accounting for
23 ITC effects.¹⁵

¹⁵ 2016-2018 DSM Plan, NS Power Evidence, April 10, 2015, page 21 of 51.

Q. Did an intervenor in the 2016-2018 DSM Resource Plan proceeding recommend a different investment and savings level?

A. Yes. Synapse Energy Economics, Inc. (Synapse) recommended that EfficiencyOne adopt investments comparable to investments in the Base DSM Case while seeking to achieve the DSM savings levels in the Mid DSM Case presented in the 2014 NS Power IRP.¹⁶

Q. Is Synapse's recommended investment in the Base DSM Case and the Mid DSM Case savings level much different than the plan approved by the Board?

A. Yes, it is materially different. The Base DSM Case would cost \$153 million and the Mid DSM Case would be expected to save 519 GWh. Hence, to reduce NS Power's load by 519 GWh, an investment of \$153 million would be required. Synapse recommended that EfficiencyOne adopt an investment that is \$50.9 million higher than the approved plan in order to achieve 113 GWh of additional savings.¹⁷

Q. What is your overall assessment of the Mid DSM Case relative to the approved 2016-2018 DSM Plan?

A. I believe the Mid DSM Case is unnecessarily aggressive. As proposed, it would require NS Power to commit to a much higher dollar spend level than what was approved by the Board. It may result in saturation as significantly increased efforts for DSM measures beyond what is recommended would accelerate adoption of measures that barely passed the cost-effectiveness test through the brute force of regulatory fiat. It may also be unreasonable for certain measures. In my experience, it is desirable to set appropriate targets that align with the evolution of the market, that is, the decisions that residential and commercial customers make independently to embrace additional DSM measures. As before, some DSM penetration will likely occur organically, which should give the Board pause on whether or not to mandate investment in discretionary DSM measures that are likely to happen anyway.

¹⁶ Direct Testimony of Tim Woolf On The Topic of The EfficiencyOne 2016-2018 DSM Plan On Behalf of Counsel to Board, June 2, 2015, page 3.

¹⁷ Ibid, page 5.

Q. Why is critical consideration of the Mid DSM Case important in the context of these proceedings?

A. It is important because EfficiencyOne continues to use the Mid DSM Case as a benchmark for assessing the reasonableness of the targets proposed for the 2020-2022 DSM Plans.¹⁸ In its Evidence, EfficiencyOne states that it “is entitled to, and must, rely upon the 2014 IRP Preferred Resource Plan as the best available data to guide development of its Preferred Plan.”¹⁹

The level of energy savings in the IRP Mid DSM Case was used by EfficiencyOne as a directional target in preparing the Preferred Plan. In my opinion, using this level of energy savings is problematic because it is sourced from a 5-year old study and will not result in a proposal that reflects the current reality of energy savings in the province.

Q. Under what legislation was the 2019 DSM Resource Plan developed?

A. EfficiencyOne developed the 2019 DSM Resource Plan for the supply of electricity and conservation activities to NS Power, in accordance with the *Electricity Plan Implementation (2015) Act*, SNS 2015, c 31, s. 20(1) and the *Public Utilities Act*, RSNS 1989, c 380, s. 79.

Q. Was the 2019 DSM Resource Plan designed as a continuation of the 2016-2018 DSM Resource Plan?

A. Yes. The overall 2019 DSM investment, energy, and demand targets were developed based on the approved 2016-2018 DSM Resource Plan, following the approach established in the *Electricity Plan Implementation (2015) Act*. This Act extended the 2016-2018 contractual term to include 2019 and set a corresponding 2019 DSM investment amount of not greater than \$34.05 million. This investment amount was a continuation of the average planned 2016-2018 DSM Resource Plan investment amounts. The energy and demand targets for 2019 were similar to the annual averages in the previously approved 2016-2018 DSM Resource Plan.

¹⁸ EfficiencyOne Evidence, Sections 4.1 and 4.2.

¹⁹ EfficiencyOne Evidence, page 12 of 62.

1 **Q. What specific targets did the Board approve for the 2019 DSM Resource Plan?**

2 A. According to the approved 2019 DSM Resource Plan, in 2019 \$34.05 million will be
3 invested to achieve 127.2 GWh and 20.2 MW of incremental annual net energy and peak
4 demand savings at the generator, respectively.²⁰

5 **Q. What was the intent of legislation for establishing the limit on investment for the**
6 **2019 DSM Resource Plan?**

7 A. The intent was to support the creation of a rate stability period that expires at the end of
8 2019.

9 **Q. Did the 2019 DSM Resource Plan include any pilot programs?**

10 A. Yes. The 2019 Plan included demand reducing pilots developed in collaboration with NS
11 Power. The 2019 DSM budget includes \$1 million for exploring demand reduction and
12 developing and implementing pilot activities.

13 **Q. Describe the demand reduction DSM pilot programs.**

14 A. In April 2018, when EfficiencyOne was preparing its 2019 DSM Resource Plan, planning
15 for the DSM pilot programs was in the early stages. EfficiencyOne was considering the
16 development of two demand reduction pilots. One pilot would be focused on residential
17 customers, while the other would focus on BNI customers. These pilots were expected to
18 demonstrate the benefits of demand reduction activities, including decreased capacity-
19 related costs for all customer groups, access to time-of-use rates for certain customer
20 classes, and the direct benefits of reductions in billed demand, at least for those customer
21 groups billed for facility peak demand.²¹

22 In its 2020-2022 DSM Resource Plan Application, EfficiencyOne is more specific since
23 the pilots have already been launched. Thus, demand reduction in the residential sector
24 focuses on installing electric thermal storage (ETS) units and electric storage domestic
25 water heater timers in the Green Heat and Home Energy Assessment program

²⁰ 2019 DSM Resource Plan, page 3 of 24, Table 1.

²¹ 2019 DSM Resource Plan, page 21 of 24, lines 11-17.

components.²² Demand reduction initiatives in the BNI sector include rebates for a wide range of ETS units suitable to business customers in the Efficient Product Rebates and Direct Installation programs and incentives for projects that focus exclusively on system peak demand savings in the Custom Incentives program. These demand reduction initiatives in the BNI section are effectuated through direct financial incentives and financing options as well as in the form of support for scoping and feasibility studies.²³ I will address various parameters and features of the demand reduction DSM programs proposed in the 2020-2022 DSM Resource Plan in more detail in the following sections of my testimony.

Q. Describe the scope of the EfficiencyOne Application for approval of the 2020-2022 DSM Resource Plan.

A. The 2020-2022 DSM Resource Plan was proposed and filed with the UARB as Appendix A to the EfficiencyOne Application on February 18, 2019. In addition, EfficiencyOne's Application included Evidence and other Appendices with Forward Looking Rate & Bill Impact Analysis, Alternate Scenario, expert witnesses' testimony, and other supporting materials.

Q. You mentioned an Alternate Scenario. What is the Alternative Scenario and why did EfficiencyOne include it in its Application?

A. EfficiencyOne was directed by the Board to provide one or more alternate scenarios of DSM budgets for the Board's consideration.²⁴ In response to this direction, EfficiencyOne presented two options: the Preferred Plan and the Alternate Scenario.²⁵ The Alternate Scenario was included in the Application as Appendix C.

Q. Please describe the major targets and the proposed budget of the Preferred Plan.

A. According to EfficiencyOne, the Preferred Plan is the DSM Plan which "will provide the best value to Nova Scotians by delivering the most energy and demand savings at an

²² EfficiencyOne Evidence, page 32 of 62, lines 11-13.

²³ Ibid, page 33 of 62, lines 3-8.

²⁴ UARB Decision in Matter 06733, approval of the 2016-2018 DSM Plan, page 48, August 12, 2015.

²⁵ We use the terms Alternative Scenario and Alternative Plan interchangeably throughout this Testimony.

affordable price and within a balanced portfolio over the 2020-2022 term.”²⁶
 EfficiencyOne estimates that the “Preferred Plan will deliver approximately 141 GWh of
 affordable incremental, first-year energy savings to Nova Scotians during each year of its
 operation.”²⁷ In addition, EfficiencyOne estimates that the Preferred Plan will deliver
 120.1 MW of peak demand savings over three years.²⁸ The Preferred Plan will require an
 investment of approximately \$43 million per year.²⁹ For the first time the Application
 proposes to include Lifetime Energy Savings (LES) as a Performance Target instead of a
 Performance Indicator. EfficiencyOne estimates that the Preferred Plan will deliver
 5,996.3 GWh of LES in total.³⁰

Q. What are the major targets and the proposed budget for the Alternate Scenario?

A. According to EfficiencyOne’s estimates, the Alternate Scenario will deliver
 approximately 125 GWh of incremental energy savings annually over the three-year plan
 period. In addition, EfficiencyOne estimates that the Alternate Scenario will deliver a
 total of 102.7 MW of peak demand savings and a total of 5,316.0 GWh of LES over three
 years.³¹ The average annual investment is approximately \$37 million.³²

²⁶ EfficiencyOne Evidence, page 1 of 62, lines 9-11.

²⁷ Ibid., page 1 of 62, lines 13-14.

²⁸ Ibid., page 6 of 62, Table 1.

²⁹ Ibid., page 6 of 62, lines 16-17.

³⁰ Ibid., page 6 of 62, Table 1.

³¹ Ibid., page 1 of 4, Table 1.

³² EfficiencyOne application, Appendix C, page 1 of 4, lines 1-3.

Q. How do the targets and budgets proposed for the Preferred and Alternate Plans compare to the 2019 DSM Resource Plan?

A. The targets and corresponding budgets for the Preferred and Alternate Plans are more expensive, more aggressive and more uncertain than the 2019 DSM Plan. The targets of the two plans are uniformly higher with one exception, namely, the first-year energy savings are slightly lower in the Alternate Scenario than in the 2019 DSM Plan. Figure 3 below provides summary data for the 2019 and proposed 2020-2022 DSM Plans.

Figure 3. Budgets and Savings Compared

Plan	Average Investment (\$/year)	First-Year Energy Saving (GWh)	Average Peak Demand Reduction (MW/year)
Preferred Plan	43.0	140.6	40.0
Alternate Plan	37.0	125.4	34.2
2019 DSM Plan	34.1	127.2	20.2

Q. Why are the First-Year Energy Savings in the Alternate Scenario lower than in the 2019 DSM Plan?

A. It appears that the investment under the Alternate Scenario is focused more on peak demand savings, as it provides a 14-MW increase in peak demand reduction compared to the 2019 DSM Plan. This result is achieved by increasing the annual budget by approximately \$3 million. The demand reduction measures attributed to the timing of the load, or load shifting, do not result in any energy savings.³³

Q. How does the Preferred Plan compare to the Alternate Plan?

A. In terms of peak demand savings, the additional \$6 million investment in the Preferred Plan results in about 5.8 MW of additional peak demand savings, so the cost of the incremental demand reduction is \$1.03 million per MW.³⁴ In terms of value for price, this

³³ EfficiencyOne's Evidence, page 31 of 62, lines 23-24.

³⁴ \$6 million / 5.8 MW = \$1.03 million per MW.

level of savings is significantly less effective compared to the incremental investment in the Alternate Scenario when compared to the 2019 DSM Plan level, *i.e.* \$1.03 million per MW vs. \$0.21 million per MW.³⁵ However, the Preferred Plan delivers additional 15.2 GWh of first-year energy savings, which is a 12% increase over the Alternate Scenario level.

Q. What characteristics make the Preferred and the Alternate Plans different from each other?

A. As EfficiencyOne explained, the development of the Alternate Scenario follows the same key considerations used in the Preferred Plan: energy savings (customer value), balanced portfolio approach (customer need); and investment level (customer affordability).³⁶ However, the intent of the Alternate Scenario is to provide a lower-cost plan option.³⁷ The significant difference between the Alternate Scenario and Preferred Plan is that participation levels are reduced due to lower energy savings and investment levels.³⁸

Q. What would the EE first-year cost beyond the investment in the 2019 DSM Plan be under the 2020-2022 Preferred Plan?

A. After deducting the \$1 million in demand reduction from the total DSM investment in the 2019 Plan and \$2.9 million from the first year of the Preferred Plan,³⁹ the EE investment in the 2019 Plan and first year of the Preferred Plan are \$33.05 million and \$39.0 million, respectively.⁴⁰ Hence, the EE first-year cost beyond the investment in the 2019 Plan would be \$5.95 million in the first year of the Preferred Plan.

Q. What would the first-year energy savings beyond those in the 2019 DSM Plan be?

³⁵ The cost of incremental investment in the peak demand reduction in the Alternate Scenario v. the 2019 DSM Plan is calculated as follows: (\$37.0 million - \$34.05 million) / (34.2 MW - 20.2 MW) = \$0.21 million per MW.

³⁶ EfficiencyOne Evidence, page 51 of 62, lines 11-15.

³⁷ Ibid. page 51 of 62, lines 6-7.

³⁸ EfficiencyOne application, Appendix A, page 45 of 95, lines 4-6.

³⁹ The Preferred Plan proposes an increased investment in demand reduction initiatives from \$1 million in the 2019 pilot to \$2.9 million in the first year (\$1.2 million Prescriptive plus \$1.7 million Custom). IR-40, page 2 of 4, Attachment 1, page 1 of 1.

⁴⁰ \$41.9 million - \$2.9 million = \$39 million.

A. The energy savings in the 2019 Plan, first year of the Preferred Plan and first year of the Alternate Scenario are 127.2 GWh, 140.2 GWh and 125.4 GWh, respectively. The first year energy savings beyond the energy savings in the 2019 Plan would be 13.0 GWh in the first year of the Preferred Plan. The first year of the Alternate Scenario would result in an energy savings deficit of 1.8 GWh relative to the energy savings in the 2019 Plan.

Q. Mr. Levitan, did you calculate the first year energy savings unit cost beyond the investment in the 2019 DSM Plan?

A. Yes. I did this by dividing the difference of the proposed budget of \$39 million for the first year of the Preferred Plan and the approved budget of \$33.05 million in the 2019 Plan by the difference of the projected energy savings of 140.2 GWh for the first year of the Preferred Plan and the projected 127.2 GWh savings in the 2019 Plan. The result of this calculation is a first year unitized cost of \$0.46/kWh for the Preferred Plan.⁴¹

Q. Is a \$0.46/kWh rate reasonable for achieving additional energy savings in the first year of the 2020-2022 DSM Preferred Plan?

A. No, it is not. The unitized cost of energy savings in 2019 is \$0.26/kWh.⁴² A 77% price increase in the unitized cost of energy savings from 2019 to 2020 is unnecessary when the additional energy savings are only 10.2%.⁴³ The cost of chasing additional energy savings in Nova Scotia, where energy is abundant and there is more clean energy on the horizon, should be subject to a sensibility test involving economic tradeoffs, affordability, and fairness. The 77% price increase raises significant concerns about each of these considerations.

Q. Mr. Levitan, in forming your opinion about EfficiencyOne's Preferred Plan, the Alternate Scenario, and a lower cost DSM scenario, did you rely on the benchmarking analysis performed by Mr. Glenn Reed as attached to EfficiencyOne's application as Appendix E?

⁴¹ $\$5.95/13.0 = \$0.46/\text{kWh}$

⁴² $\$33.05/127.2\text{GWh} = \$0.26/\text{kWh}$.

⁴³ $(0.46-0.26)*100\%/0.26=77\%$
 $(140.2-127.2)*100\%/127.2=10.2\%$

1 A. Yes, I have.

2 **Q. What was the objective of Mr. Reed’s benchmarking analysis?**

3 A. According to Mr. Reed, the goal of his benchmarking analysis was “to assess where
4 EfficiencyOne falls compared to its North American peers on commonly used
5 benchmarking metrics.”⁴⁴

6 **Q. What conclusions did Mr. Reed reach from his benchmarking analysis?**

7 A. Mr. Reed stated that his “analysis ... supports the contention that EfficiencyOne’s
8 proposed budget in its Preferred 2020-2022 DSM Plan is affordable, will lower the long-
9 term costs of power generation in Nova Scotia, generate significant bill savings to many
10 customers, and will have little long-term impact on rates.”⁴⁵

11 **Q. Do you agree with Mr. Reed’s conclusions?**

12 A. No, I do not. I believe Mr. Reed’s benchmarking analysis is flawed. Therefore, I question
13 the reasonableness of his conclusions. I recommend that the Board not put significant
14 weight on Mr. Reed’s conclusions as they relate to E1’s Preferred Plan.

15 **Q. Why not?**

16 A. The main problem I have with Mr. Reed’s benchmarking analysis is that he chose to
17 compare EfficiencyOne’s Preferred Plan only to those in a non-representative peer group
18 of leading program administrators. This comparison is arbitrary and unreasonable.
19 Moreover, Mr. Reed did not consider other details and metrics about the jurisdictions in
20 the peer group that limit their applicability to Nova Scotia. By not addressing or not
21 considering other relevant details and metrics, Mr. Reed’s comparison of EfficiencyOne’s
22 Preferred Plan versus other leading program administrators is both inconsistent and
23 misleading. Also, as I explain in more detail below, Mr. Reed’s consideration of only
24 future data unnecessarily restricted his peer group’s sample size, thereby limiting its
25 usefulness in the present context. While Mr. Reed acknowledges problems related to

⁴⁴ EfficiencyOne Evidence, Appendix E, page 4 of 16, line 24 - page 4 of 16, line 25.

⁴⁵ Ibid, page 3 of 16, line 17- page 3 of 16, line 20.

1 comparing DSM plans across state or provincial jurisdictions, such inherent limitations
 2 do not appear to dissuade Mr. Reed from reaching definitive conclusions about program
 3 cost-effectiveness and customer impacts.

4 **Q. How did Mr. Reed determine a peer group for purposes of comparing**
 5 **EfficiencyOne's Preferred Plan against those in other jurisdictions?**

6 A. As I understand it, Mr. Reed developed a peer group based on "several leading North
 7 American DSM program administrators." He selected one or more "leading" program
 8 administrators in each state in the top ten list of the American Council for an Energy
 9 Efficient Economy's (ACEEE) 2017 State Efficiency Scorecard. If there was more than
 10 one program administrator in one of these states he chose the one that was also in the list
 11 of top ten ranked utilities from ACEEE's 2017 Utility Energy Efficiency Scorecard.⁴⁶ He
 12 then added the rest of the top ten program administrators from ACEEE's 2017 Utility
 13 Energy Efficiency Scorecard. Lastly, he considered non-utility program administrators, as
 14 the "ACEEE Utility Energy Efficiency Scorecard was restricted to utilities with a retail
 15 distribution function and did not include efficiency utilities."⁴⁷ No Canadian provinces
 16 were included in the peer group.

17 **Q. In your opinion, is this peer group consistent with Mr. Reed's objective of**
 18 **comparing EfficiencyOne's Preferred Plan to those of its North American peers?**

19 A. No. Mr. Reed said his objective was to consider EfficiencyOne's "North American"
 20 peers. Therefore, I do not understand why his chosen group of program administrators
 21 does not include any program administrators in British Columbia, Manitoba, New
 22 Brunswick, Newfoundland and Labrador, Ontario, Québec or Saskatchewan, as each of
 23 these provinces has customer-funded energy efficiency programs.⁴⁸ Contrary to Mr.
 24 Reed's representation that he used a North American peer group in his analysis, he in fact
 25 only considered states for inclusion. While American jurisdictions are indeed relevant in

⁴⁶ IR-59, page 1, lines 21-24.

⁴⁷ EfficiencyOne Evidence, Appendix E, page 4 of 16, line 29 -page 5 of 16, line 9.

⁴⁸ Page 20 of 23 of "Efficiency Program Industry by State and Region Appendices, 2017," Consortium for Energy Efficiency; March 21, 2018 available at https://library.cee1.org/system/files/library/13566/2017_AIR_Data_Tables.pdf

1 evaluating EfficiencyOne's Preferred Plan, the Canadian experience is just as relevant,
 2 perhaps more so given similar temperature patterns, winter peak season demand patterns,
 3 cultural / aesthetic considerations, and affordability measures.

4 Mr. Reed stated that he did not include any Canadian program administrators because
 5 there "are no comparable reports or studies that we are aware of that duplicate the
 6 ACEEE Scorecard methodology for Canadian utilities, program administrators or
 7 provinces," and that "[A]bsent such comprehensive analyses we thought that the selection
 8 and inclusion of any particular Canadian program administrators or provinces in the
 9 benchmarking would possibly be considered arbitrary."⁴⁹ I disagree with Mr. Reed's
 10 assessment that there are no similar reports in Canada. Even though the methodology is
 11 not identical to ACEEE's, the data table appendix to the Consortium for Energy
 12 Efficiency's 2017 State of the Efficiency Program Industry report contains information
 13 on historical DSM spending in provinces broken down into subcategories for that year.⁵⁰
 14 Canadian DSM plans are also readily available and should have been reviewed by Mr.
 15 Reed. In particular, as I discuss in more detail below, provinces such as New
 16 Brunswick, Quebec, British Columbia, Newfoundland and Labrador, and Saskatchewan,
 17 to name just a few, all have DSM programs. I disagree with Mr. Reed's logic of
 18 excluding all provinces and program administrators because he could not find a study that
 19 exactly duplicated the ACEEE Scorecard methodology. To be useful and relevant, there
 20 is no reason why a study must *duplicate* the ACEEE Scorecard methodology. Doing so,
 21 as Mr. Reed has done, omits program administrators and provinces that have more in
 22 common with Nova Scotia and EfficiencyOne than many states. Lastly, Mr. Reed says
 23 that he was concerned that including Canadian program administrators and provinces
 24 could be considered arbitrary. But, in my opinion, Mr. Reed's defined peer group is itself
 25 arbitrary for benchmarking analysis, because there is no justification for the leading PAs
 26 only comparison. Peer groups are supposed to be generally representative, not skewed to
 27 the most convenient category. Inclusion of one or more similarly situated provinces
 28 would have lessened the arbitrariness, not heightened it.

⁴⁹ IR-57, page 2 of 2, lines 15-19

⁵⁰ "2017 Data Tables Appendix of the 2017 State of the Efficiency Program Industry," Consortium for Energy Efficiency; March 21, 2018 (https://library.cee1.org/system/files/library/13566/2017_AIR_Data_Tables.pdf)

1 **Q. In your opinion, is this peer group representative of the U.S. DSM market?**

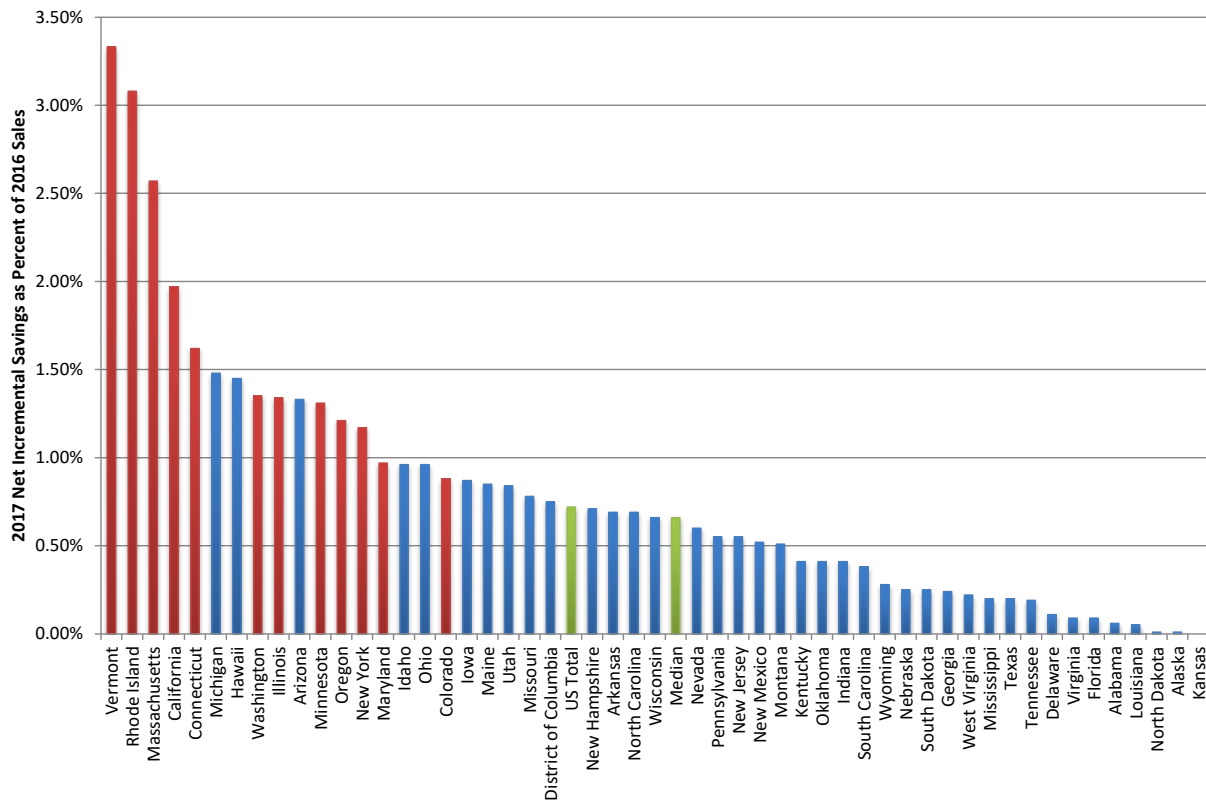
2 A. No. The methodology Mr. Reed chose to select his peer group resulted in a peer group
3 that is biased toward program administrators that spend the most on DSM. Containing
4 only leading program administrators, the peer group omits program administrators in
5 states that spend lower amounts on DSM. As set out below, in reality, there are many
6 more states spending lower amounts on DSM, but those states that have been more
7 cautious and systematic have not been represented in Mr. Reed’s benchmarking analysis.

8 **Q. Can you put the current U.S. EE market in perspective?**

9 A. Yes. I have created a bar graph of 2017 net incremental savings by state (as well as the
10 District of Columbia) as a percentage of 2016 sales. The data underlying the graph are
11 from ACEEE in its 2018 State Energy Efficiency Scorecard.⁵¹ See Figure 4. I chose
12 2017 because it was the latest year such data are available. U.S. states with higher
13 percentages of savings generally have to spend more to achieve them, while states with
14 lower savings percentages generally spend less.

⁵¹ Table 8 of “The 2018 State Energy Efficiency Scorecard,” American Council for an Energy-Efficiency Economy; October 4, 2018 (<https://aceee.org/sites/default/files/publications/researchreports/u1808.pdf>)

Figure 4. 2017 DSM Savings by State



The states represented in Mr. Reed's peer group of program administrators are colored red. The U.S. Median and U.S. Total (average) are colored green. All of the program administrators chosen by Mr. Reed are located in the top 20 states that had the highest percentages of EE savings in 2017. In fact, over one-half of the states represented in Mr. Reed's peer group are located in the top ten states with the highest percentages of EE savings in 2017, not one program administrator in Mr. Reed's group is located in the bottom 30 states with the lowest percentages of EE savings in 2017. Every state represented in Mr. Reed's peer group is well above the U.S. median savings of 0.66% of sales. Figure 4 shows that Mr. Reed's peer group is not representative of all jurisdictions and program administrators in the U.S. The peer group merely reflects what strikes me as an *a priori* decision to rely on program administrators in states that have authorized the highest spending levels to produce more EE savings.

Q. Does Mr. Reed's chosen group of leading U.S. program administrators consist of EfficiencyOne's peers?

1 A. No. Mr. Reed's own analysis does not support classifying EfficiencyOne as a leading
 2 North American DSM program administrator in the same manner as his chosen group. In
 3 my view, a leading DSM program administrator is an entity that has consistently
 4 developed and administered comprehensive DSM programs with significant budgets
 5 expressed as percentage of the utility's revenue. For example, the program administrators
 6 in Massachusetts and Rhode Island certainly fit this criterion, *i.e.*, National Grid and
 7 Eversource. However, Figure 3 in Mr. Reed's testimony shows that EfficiencyOne is
 8 proposing a plan that has a significantly lower 2020 budget as a percentage of 2017
 9 revenue than the top three leading program administrators.⁵² In turn, EfficiencyOne is
 10 readying itself to achieve a lower percentage of savings with this budget. This is revealed
 11 in Mr. Reed's Figure 1. EfficiencyOne's percentage of savings is 1.4% compared to
 12 2.6%, 2.6% and 3.1% for the three leading program administrators. Figures 2 and 4 in
 13 Mr. Reed's testimony display a similar trend for 2021.⁵³

14 Mr. Reed based his decision to categorize EfficiencyOne as a leading program
 15 administrator on annual savings levels from 2011-2013. The march back in time for
 16 purposes of defining annual savings levels results in a comparison that is much closer to
 17 the average of the top ten states in the ACEEE dataset. Since then these states have
 18 increased their savings percentages, thereby weakening the case that EfficiencyOne is to
 19 be considered a leading program administrator. While EfficiencyOne has made steady
 20 and consistent progress in Nova Scotia, it has come at a price. Notwithstanding this
 21 progress, I question Mr. Reed's assertion that EfficiencyOne is a leading program
 22 administrator like those in his peer group.⁵⁴

23 EfficiencyOne has proposed a smaller DSM budget for Nova Scotia relative to the DSM
 24 budget for the peer group. I support EfficiencyOne's judgment in this regard, but
 25 question the mechanics of EfficiencyOne's economic justification for the total rate of
 26 spend underlying the Preferred Plan. Notably, the program administrators in Mr. Reed's
 27 peer group are different than EfficiencyOne. My interpretation of Figures 1-4 in Mr.

⁵² According to EfficiencyOne Evidence, Appendix E, Figure 3, EfficiencyOne's 2020 budget as a percentage of 2017 revenue is 3.2% compared to 11.8%, 12.9% and 13.9% for the top three leading program administrators.

⁵³ EfficiencyOne Evidence, Appendix E, pages 10 -11 of 16.

⁵⁴ IR-11, Table 1, Table 2 and Figure 1.

1 Reed's analysis underscores the differences about leadership as EfficiencyOne's
 2 percentage of energy savings is eclipsed by the leading program administrators. Because
 3 EfficiencyOne differs from the peer group of program administrators, comparing
 4 EfficiencyOne's Preferred Plan to the top ten program administrators is more ideological
 5 than representative of broad industry patterns of relevance in calibrating how best to
 6 gauge the optimum DSM spend in Nova Scotia.

7 Mr. Reed's approach to peer group definition is inappropriate because the DSM achieved
 8 in Nova Scotia would inevitably be considered underdeveloped. If, on the other hand, the
 9 DSM in Nova Scotia were measured against a representative sample of all jurisdictions
 10 where DSM programs have been implemented the inescapable conclusion would be the
 11 opposite, namely, that the DSM achieved saving levels in Nova Scotia are in line with
 12 the majority of the jurisdictions. Figure 4 dramatizes this comparison. While Mr. Reed's
 13 stated objective was to "assess where EfficiencyOne falls compared to its North
 14 American peers," in the final analysis he compared where EfficiencyOne falls in relation
 15 to the leading U.S. program administrators. The leading program administrators are all
 16 on the left-hand side of the DSM savings distribution. Many of these states with milder
 17 winter seasons are in the more affluent, progressive New England and mid-Atlantic
 18 regions, as well as California. By defining the peer group in this fashion, it is no surprise
 19 that Nova Scotia comes up short in regard to DSM savings and other performance metrics
 20 associated with energy efficiency and peak demand reduction. States such as Minnesota
 21 and Oregon, which fall near the middle of the range in Figure 4, would represent a more
 22 reasonable benchmark for Nova Scotia based on the ambient temperature patterns,
 23 seasonal peak demand, cultural and aesthetic considerations, and affordability measures.

24 **Q. Is Mr. Reed's decision to examine only leading program administrators consistent**
 25 **with his stated objective?**

26 A. No. As I discussed earlier, Mr. Reed's testimony stated that his objective was "to assess
 27 where EfficiencyOne falls compared to its North American peers on commonly used
 28 benchmarking metrics."⁵⁵ It is important to note that there are no restrictions on "North

⁵⁵ EfficiencyOne Evidence, Appendix E, from page 4 of 16, line 24, to page 4 of 16, line 25.

American peers.” Nevertheless, Mr. Reed imposes a restriction by deciding to only consider leading program administrators. Mr. Reed has contradicted his stated objective in response to an information request. He further adds that “It was our intent to benchmark EfficiencyOne’s efforts against leading efficiency PAs.” He says “We saw no value in including PAs with minimal investment or commitment to DSM to develop a potentially broader, [though] less representative, benchmarking group.”⁵⁶ I find Mr. Reed’s explanation problematic. First, Mr. Reed does not assert in his testimony that it was his intent to benchmark EfficiencyOne’s efforts against leading efficiency program administrators. His stated intent was to benchmark against its “North American peers.” Second, Mr. Reed did not stop at excluding states with minimal investment or commitment to DSM. He also omitted states that spend average amounts as well. In effect, he only included jurisdictions with the highest levels of DSM spending. Simply put, including some of these program administrators that spend less than average or average amounts would have made the benchmarking group more representative, not less, as Mr. Reed claims.

Q. Does Nova Scotia differ from the states represented in Mr. Reed’s chosen group of program administrators in other important ways?

A. Yes. When it comes to average income, the states Mr. Reed chose are enjoying a more robust economy than Nova Scotia. According to Statistics Canada, in 2017 Nova Scotians had an average income of \$41,400.⁵⁷ I compared average Nova Scotian income to average income in those states represented in Mr. Reed’s peer group.⁵⁸ The resulting 2017 per capita incomes by state are shown in Figure 5 below. The six states represented in Mr. Reed’s group of program administrators are among the most prosperous in the U.S. and have an average per capita annual income of \$81,435, about twice that in Nova

⁵⁶ IR-61, page 2 of 3, lines 24-26

⁵⁷ “Income of individuals by age group, sex and income source, Canada, provinces and selected census metropolitan areas,” Statistics Canada; March 21, 2019 (<https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1110023901>)

⁵⁸ I converted the average 2017 income for the states represented by Mr. Reed’s chosen program administrators using the U.S. Internal Revenue Service’s conversion factor for 2017 of \$1 USD = \$1.350 CAD.

“Yearly Average Currency Exchange Rates,” Internal Revenue Service; January 30, 2019

(<https://fred.stlouisfed.org/release/tables?rid=151&eid=257197&snid=257218>)

“Release Tables: Per Capita Personal Income by State, Annual,” Federal Reserve Bank of St. Louis; September 25, 2018 (<https://fred.stlouisfed.org/release/tables?rid=151&eid=257197&snid=257218>)

Scotia. The gap between state per capita incomes in the peer group versus that in Nova Scotia raises issues about affordability and fairness. Spending more on DSM now means sacrificing in the short term for benefits that are expected to materialize in the long term. I recommend that the Board consider this tradeoff, namely, whether customer pain in the short term, that is, the next three years, is worth the anticipated dividend payout from 2020 to 2035, perhaps longer. Adverse customer impacts in the short term may be more painful in Nova Scotia relative to Mr. Reed's peer group because the affordability of more aggressive DSM implementation is challenged in Nova Scotia where income is lower.

Figure 5. 2017 Per Capita Annual Income by Province/State

Jurisdiction	NS	CO	CT	IL	MD	MA	RI	Average of 6 States
Per Capita Income	\$41,400	\$73,772	\$96,961	\$73,174	\$82,143	\$91,301	\$71,261	\$81,435

Q. Did Mr. Reed compare EfficiencyOne's Preferred Plan to a sufficiently large number of DSM plans from other program administrators?

A. No. Out of the thirteen program administrators Mr. Reed chose, only seven had plan data available for 2020. Four had plan data available for 2021. No program administrator had plan data available for 2022.⁵⁹ This means that Mr. Reed relied on a small sample that shrinks from seven plans in 2020, to four plans in 2021 and zero plans in 2022. In this context, I believe that four is too small a sample size to enable useful conclusions.

Q. Could Mr. Reed have taken reasonable steps to increase the sample size of DSM plans available to benchmark EfficiencyOne's Preferred Plan against?

A. Yes. He could have expanded his benchmarking group to include additional program administrators. This would have allowed more plan data to be available for comparison purposes. Also, program administrators from states with medium or low spending on EE could have been included to make the sample more representative of the U.S. market.

⁵⁹ EfficiencyOne Evidence, Appendix E, page 6 of 16.

Mr. Reed also might have considered historical plan data for his chosen group of program administrators rather than rely only on future plan data. While it is likely better to use future plan data when such data are available, Mr. Reed might have used historical plan data to compute the percentage increase in DSM spending year over year. This metric is useful to determine if a proposed increase in DSM spending is in line with those of other program administrators. There is no evidence that Mr. Reed formulated or examined this metric.

Q. Is Mr. Reed’s benchmarking analysis between EfficiencyOne and other program administrators a true apples-to-apples comparison?

A. No, but a strict apples-to-apples comparison may not be possible. Program administrators account for DSM differently, thereby making a strict standardized comparison infeasible. As the Consortium for Energy Efficiency notes in the data it reports on efficiency budgets, expenditures and savings, “variation in state policies and reporting requirements, and inconsistent use of terms complicate our efforts ... we do not believe these data are suitable for comparisons at any level other than the levels represented within this report.”⁶⁰ Mr. Reed lists many “program design, implementation, and planning considerations that should be considered when comparing benchmarking metrics across PAs.” These include support of delivered fuel efficiency activities, annual vs. lifetime savings, low income program activity, residential vs. Commercial and Industrial program spending, depth of savings, presence of residential behavioral programs, differences in how energy savings are determined, program administrator size, program maturity and provision of account management and technical services.⁶¹ Mr. Reed has acknowledged significant differences among program administrators. I agree with this acknowledgment. However, Mr. Reed does not mention any steps taken to adjust for these differences in his analysis. Mr. Reed also acknowledges that “No comparison of two or more different PAs’ DSM program performance will ever be an exact apples-to-apples comparison.”⁶²

⁶⁰ Page 1 of 23 of “Efficiency Program Industry by State and Region Appendices, 2017,” Consortium for Energy Efficiency; March 21, 2018 (https://library.cee1.org/system/files/library/13566/2017_AIR_Data_Tables.pdf)

⁶¹ EfficiencyOne Evidence, Appendix E, from page 8 of 16, line 5, to page 9 of 16, line 12.

⁶² IR-62, page 1 of 2, lines 28-29

1 That may be true; however, the lack of indication that any adjustments were made to
 2 address these differences raises concerns regarding justification for his conclusions.

3 **Q. Mr. Levitan, did you examine any metrics that were not included in Mr. Reed's**
 4 **benchmarking analysis?**

5 A. Yes. EfficiencyOne's Preferred Plan proposes an investment level of \$41.9 million for
 6 2020,⁶³ a 23.1% increase from the \$34.05 million the Board approved for 2019.⁶⁴ In order
 7 to determine how this percentage change compared to other jurisdictions, I reviewed the
 8 ACEEE State Energy Efficiency Scorecards for years 2014-2018⁶⁵, a resource Mr. Reed
 9 relied on. The appendices contain total electric efficiency spending for all U.S. states as
 10 well as the District of Columbia. I used these data to compute the percent changes in total
 11 spending for each state that had electric efficiency programs over the four-year period
 12 2013 through 2017. My review resulted in a dataset of 196 observations of percentage
 13 change in electric efficiency spending over this four-year period. The average percentage
 14 change was 0.87%. I have included histograms of these data as Figure 6, Figure 7, and
 15 Figure 8.

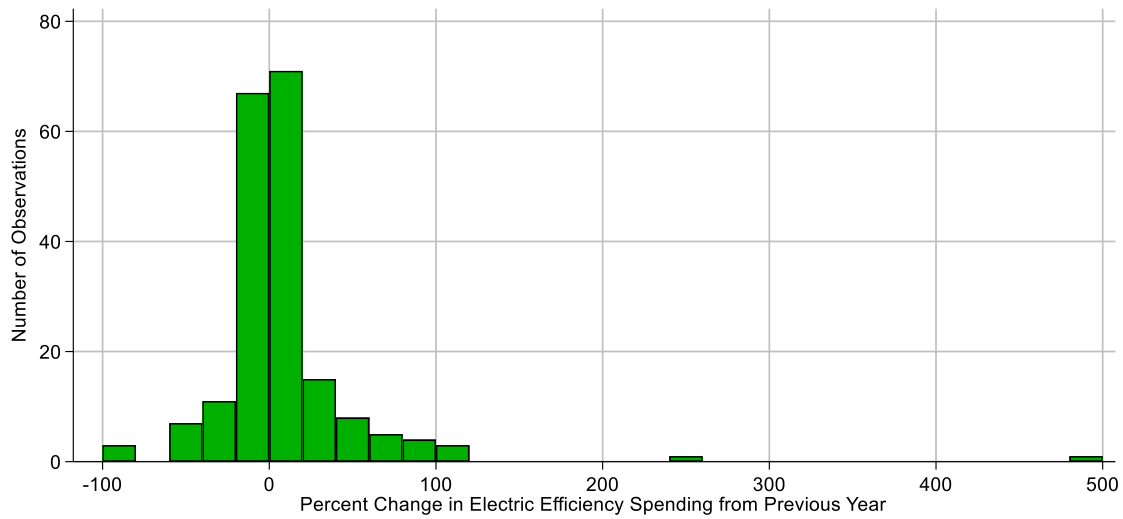
⁶³ EfficiencyOne Evidence, Appendix A, Table 2.

⁶⁴ See the Board's decision in M08604.

⁶⁵ Appendix B of "The 2018 State Energy Efficiency Scorecard," American Council for an Energy-Efficient Economy; October 4, 2018 (<https://aceee.org/sites/default/files/publications/researchreports/u1808.pdf>)
 Appendix B of "The 2017 State Energy Efficiency Scorecard," American Council for an Energy-Efficient Economy; September 27, 2017 (<https://aceee.org/sites/default/files/publications/researchreports/u1710.pdf>)
 Appendix B of "The 2016 State Energy Efficiency Scorecard," American Council for an Energy Efficient Economy; September 26, 2016 (<https://aceee.org/sites/default/files/publications/researchreports/u1606.pdf>)
 Appendix B of "The 2015 State Energy Efficiency Scorecard," American Council for an Energy Efficient Economy; October 21, 2015 (<https://aceee.org/sites/default/files/publications/researchreports/u1509.pdf>)
 Appendix A of "The 2014 State Energy Efficiency Scorecard," American Council for an Energy Efficient Economy; October 21, 2014 (<https://aceee.org/sites/default/files/publications/researchreports/u1408.pdf>)

1

Figure 6. Percentage Changes in State EE Spending, With Outliers

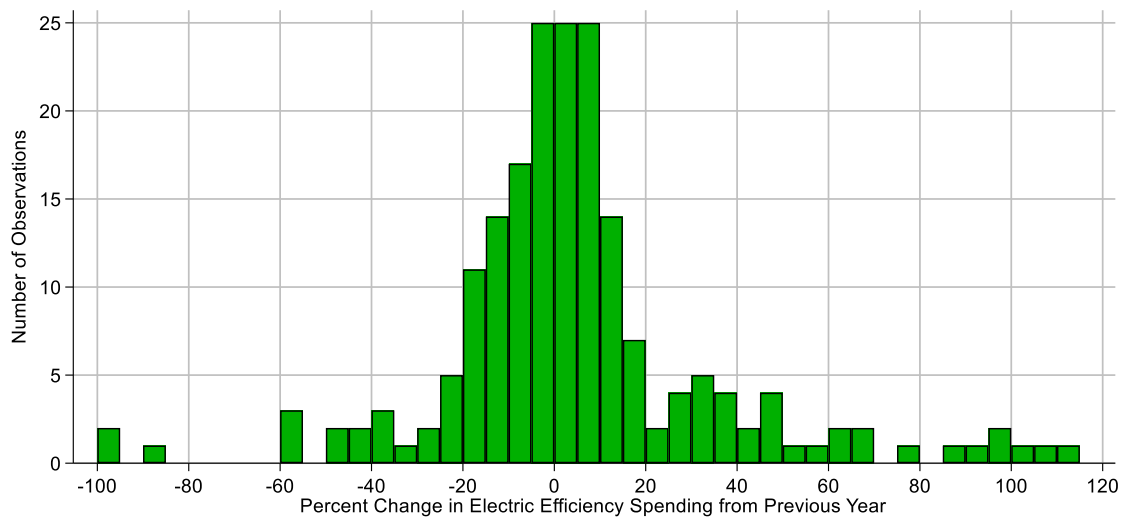


Source: ACEEE State Energy Efficiency Scorecards for 2014-2018

2

3

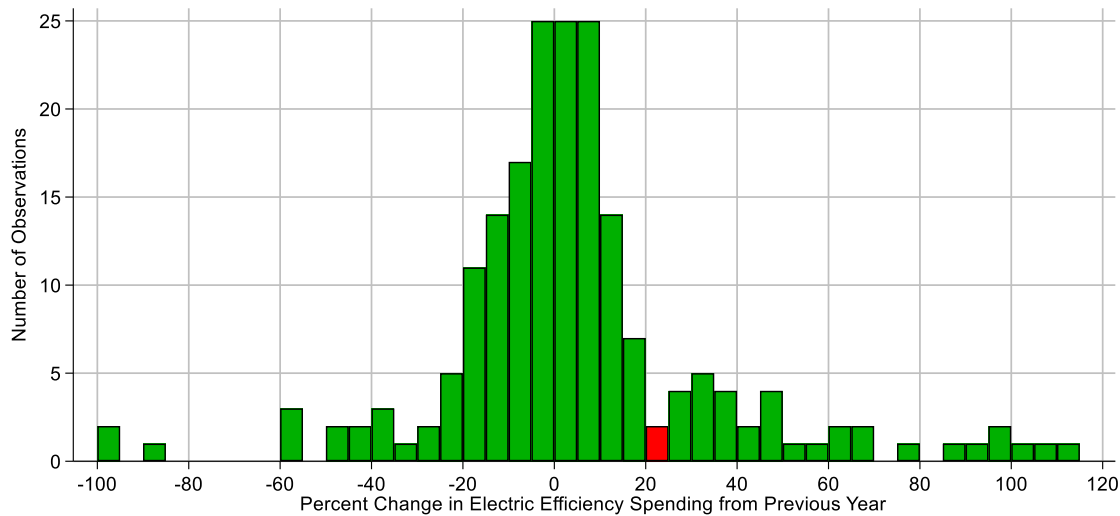
Figure 7. Changes in State EE Spending, Without Outliers



Source: ACEEE State Energy Efficiency Scorecards for 2014-2018

4

Figure 8. Percentage Changes in State EE Spending, Without Outliers, EfficiencyOne Bin Highlighted



Source: ACEEE State Energy Efficiency Scorecards for 2014-2018

Figure 6 contains all 196 observations, including two extreme outliers. From 2014-2015, Louisiana increased its electric efficiency spending from \$2.2 million to \$13.4 million, nearly a five-fold increase. In 2017, Louisiana had decreased its EE spending to \$7.3 million. Louisiana is a poor comparison to Nova Scotia as it is far behind in DSM penetration and its DSM programs are immature. From 2016-2017, Delaware increased its EE spending from \$5.3 million to \$18.2 million, nearly a 2.5x increase. While these are both valid data points, I removed these outliers in Figure 7 to make the figure easier to interpret. Although not included in the dataset, for ease of comparison the bin in which EfficiencyOne's proposed increase for 2019-2020 would fall is colored red in Figure 8. This chart illustrates that the approval of EfficiencyOne's proposal would place Nova Scotia among a relatively small group of jurisdictions that have increased their DSM spending by 20%-25%. The majority of jurisdictions have either approved a lower increase or reduced their DSM spending.

Q. What do these figures tell us about EfficiencyOne's proposed 23.1% increase in DSM investment from 2019 to 2020?

A. The histograms shown in Figure 6, Figure 7, and Figure 8 put in perspective how aggressive EfficiencyOne's recommended increase from 2019-2020 is in relation to U.S. DSM spending norms. Twice as many states actually reduced their EE spending rather than increased it by the magnitude EfficiencyOne is proposing for 2019-2020. Eighty-eight of the 196 observations (44.9%) reflect a decrease in spending, while only 35 (17.9%) reflect an increase of greater than 23.1%. At a time when almost one-half the states are decreasing their spending, EfficiencyOne is proposing a substantial increase. I would therefore classify EfficiencyOne's proposed increase as inconsistent with and unsupported by the DSM experience in the U.S. over the past several years.

Similar to Louisiana, many of the states with extreme increases have lower levels of DSM penetration than Nova Scotia, rendering them less relevant for comparison sake. Louisiana, Mississippi and Virginia each have one of the top five increases and fall into this category. While it makes sense for these states that are new to DSM to significantly ramp-up their respective spending, in contrast, Nova Scotia already has an established history of DSM. I agree with EfficiencyOne's assertion that the cheaper and most cost-effective DSM measures have already been implemented in Nova Scotia. As the low-hanging fruit has already been plucked, future DSM measures will be more expensive relative to those in previous years. I do not think that these more expensive DSM measures are worth the higher upfront cost to NS Power's customers.

Q. Are any data available for percent changes in spending in future years?

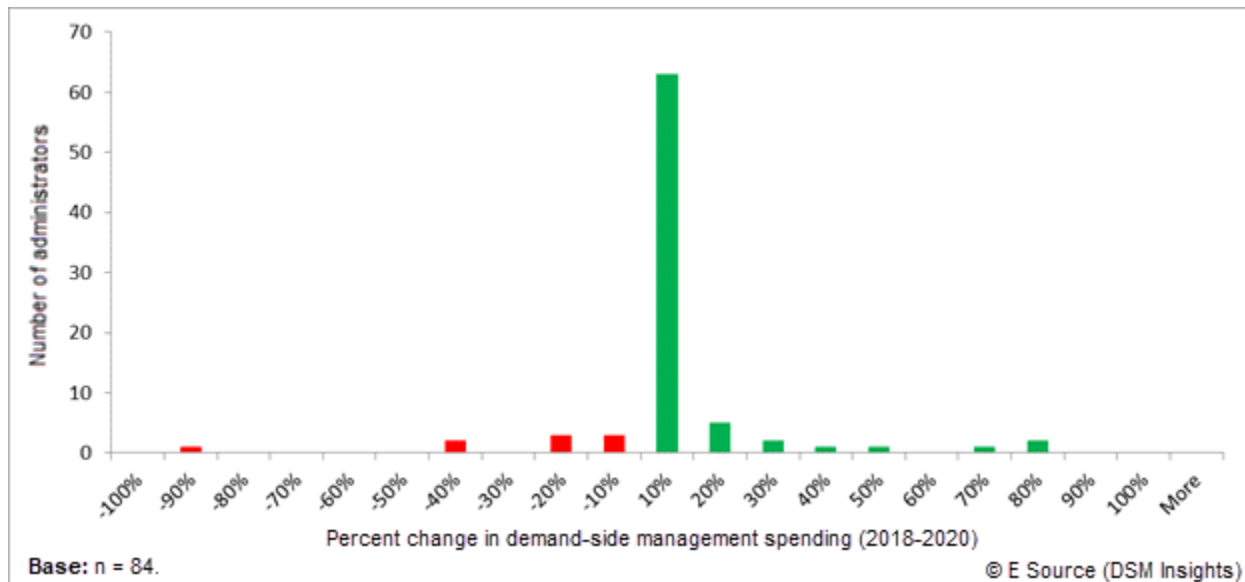
A. Yes. E Source published an article this past summer on future trends in DSM spending. They examined program goals, budgets, spending and savings from DSM regulatory filings and expect to, "see DSM spending level off in 2020, with a number of notable pockets of big increases and decreases in spending, netting out in a slight decline."⁶⁶

E Source's article also included a graph of percent changes in DSM spending over the 2018-2020 period for 84 program administrators. Representing a national trend, I have

⁶⁶ "Total Planned DSM Spending Will Decline Through 2020," Liza Minor and Rachel Reiss Buckley of E Source Companies LLC; July 17, 2018 (<https://www.esource.com/10044-007/total-planned-dsm-spending-will-decline-through-2020>)

1 included this information from E Source as Figure 9. The vast majority of program
 2 administrators are decreasing their spending or increasing it by 10% or less over the
 3 entire three-year period. This trend is in opposition to the much larger increase
 4 EfficiencyOne has proposed in its Preferred Plan.

5 **Figure 9. E Source Analysis of 2018-2020 DSM Spending**



6
 7 **Q. You have criticized Mr. Reed for excluding Canada from his benchmarking**
 8 **analysis' peer group. Are you aware of any Canadian program administrators that**
 9 **are reducing their DSM spending?**

10 **A.** Yes. I have identified several Canadian program administrators that are decreasing DSM
 11 spending. BC Hydro is decreasing its DSM spending significantly, from an approved
 12 value of \$127.9 million in Fiscal 2019 to proposed values of \$90.8 million and \$89.1
 13 million in 2020 and 2021, respectively. Newfoundland and Labrador Hydro and
 14 Newfoundland Power are planning to decrease their DSM spending in every year from
 15 2016-2020, from \$8.3 million in 2016 to \$4.4 million in 2020. Saskatchewan decreased
 16 its proposed DSM spending from \$11.9 million in 2017 to \$8.05 million in 2018, the
 17 latest year for which data is available. Manitoba and Québec are not currently decreasing
 18 their DSM spending, but have decreased it in previous years. The Canadian experience is

generally consistent with the American DSM experience in recent years of decreasing or mostly flat DSM spend.

Q. Are there any Canadian program administrators that would serve as particularly good benchmarks for EfficiencyOne's Preferred Plan?

A. Yes. New Brunswick shares many similarities with Nova Scotia and can serve as a good comparison.

Q. In what ways is New Brunswick similar to Nova Scotia?

A. NB Power and NS Power have similar generation infrastructure levels (2,853 MW⁶⁷ vs. 2,453 MW⁶⁸) and customers (394,000⁶⁹ vs. 500,000⁷⁰). According to the 2016 Canadian Census, Nova Scotia and New Brunswick have similar populations (923,598 vs. 747,101) and median incomes (\$31,813 vs. \$30,961).⁷¹ Being next-door neighbors, it is sensible to consider New Brunswick as a better source to benchmark EfficiencyOne's Preferred Plan against the U.S. peer group Mr. Reed used.

Q. How does the spending in EfficiencyOne's Preferred Plan compare to DSM spending in New Brunswick?

A. EfficiencyOne's Preferred Plan would result in Nova Scotians paying significantly more for DSM than the cost of DSM in New Brunswick. NB Power is proposing to spend \$27.5 million and \$31.6 million on DSM in 2019/20 and 2020/21 respectively.⁷² Although the rate of DSM spend in New Brunswick is increasing in the next two years,

⁶⁷ "Generation," New Brunswick Power; 2019 (<https://www.nbpower.com/en/about-us/divisions/generation>)

⁶⁸ "Who We Are," Nova Scotia Power; 2017 (<https://www.nspower.ca/en/home/about-us/who-we-are/default.aspx>)

⁶⁹ "Customer Service," New Brunswick Power; 2019 (<https://www.nbpower.com/en/about-us/divisions/customer-service>)

⁷⁰ "Who We Are," Nova Scotia Power; 2017 (<https://www.nspower.ca/en/home/about-us/who-we-are/default.aspx>)

⁷¹ "Census Profile, 2016 Census – Nova Scotia [Province] and New Brunswick [Province]," Statistics Canada; February 28, 2019 (<https://www12.statcan.gc.ca/census-recensement/2016/dp-prof/details/page.cfm?Lang=E&Geo1=PR&Code1=12&Geo2=PR&Code2=13&Data=Count&SearchText=New%20Brunswick&SearchType=Begins&SearchPR=01&B1=All&TABID=1>)

⁷² Page 7 of 46 "DSM Plan 2018/19-2020/21: Energy Efficiency and Demand Response Initiatives," New Brunswick Power. This document can be accessed at <https://filemaker.nbeub.ca/fmi/webd/NBEUB%20Toolkit13>. The Matter# is 0375 and the document is NBP1.50 Appendix AA.i.

the absolute level is far lower than the \$41.9 million EfficiencyOne has proposed in 2020 under its Preferred Plan.

Q. Mr. Levitan, is EfficiencyOne's Preferred Plan inconsistent with the current experience in the DSM market in both Canada and the U.S.?

A. Yes. I believe EfficiencyOne's Preferred Plan is too aggressive when compared to other program administrators, especially in Canada. At a time when most program administrators are tapping the brakes, EfficiencyOne is proposing a 23.1% jump in 2020, followed by additional increases in 2021 and 2022. British Columbia, Newfoundland and Labrador and Saskatchewan are all currently decreasing their DSM spending. EfficiencyOne already spends far more than NB Power is proposing to spend in either of the next two years. EfficiencyOne's Preferred Plan widens the gap.

Q. Would additional EE measures beyond those in the Approved 2019 DSM Plan be more expensive than existing measures?

A. Yes. Since the beginning of its DSM efforts, Nova Scotia has prioritized measures that result in high energy savings and peak demand reductions at low cost. Since its initial filing with the Board in 2005 – updated in 2006 – there have been many years of near continuous DSM planning and implementation. Again, it is reasonable to assume that most of the low-hanging fruit has been plucked. My opinion is based, for example, on EfficiencyOne's statement that beginning in 2019, certain LED-related incentives have been discontinued.⁷³ It will be more difficult and therefore more costly to achieve additional energy savings and peak demand reductions in 2020-2022 than in 2019, 2016-2018, or any other previous year. While the cumulative addition of incremental EE measures over many years is not tantamount to a market saturation effect, the additional EE spend may have hit or be close to hitting the point of diminishing returns in regard to energy savings or peak demand reductions.

Q. Do you believe higher-priced EE measures beyond those in the 2019 DSM Plan are needed in Nova Scotia?

⁷³ EfficiencyOne's Evidence, page 20 of 62, lines 3-4.

A. No. Higher-priced EE measures would likely reduce air emissions, including lessening NS Power's carbon footprint. But at what cost? The higher priced EE measures would lock Nova Scotians into paying much more for each additional kWh saved than they pay under the 2019 DSM Plan. In my opinion, the environmental benefits and energy savings do not outweigh the higher electricity rates that result from higher-cost EE measures, particularly in the short run when customers incur such costs long before realizing the benefit of the bargain over time.

Q. What has been the energy savings impact of DSM programs on Nova Scotia's load in recent years?

A. The 2015 – 2018 DSM Annual Progress Reports are available in the Nova Scotia Utility and Review Board public documents database. These reports show that the energy savings impact of DSM programs on Nova Scotia's load in 2015 – 2018 were as shown in Figure 10.

Figure 10. Energy Savings Impact of DSM Programs on NS Power Load Forecast

	Energy Requirement with DSM Program Effects (GWh)⁷⁴	DSM Program Effects (GWh)⁷⁵	DSM Program Load Reduction
2015	11,099	138	1.2%
2016	10,809	137	1.3%
2017	10,873	131	1.2%
2018	10,960	151	1.4%

Q. Relative to other provinces, how would you characterize the energy savings impact of DSM programs on Nova Scotia's energy requirements?

A. In 2016, Nova Scotia had the second largest impact of DSM on energy requirements among the provinces that have DSM programs.⁷⁶ This is shown in Figure 11.

⁷⁴ NS Power 2018 Load Forecast Report, Appendix A – Forecast Values Table A1, page 60 of 101.

⁷⁵ 2015 – 2018 DSM Annual Progress Reports.

⁷⁶ The results are not for the same year for all provinces because actuals are not available for the same year for all provinces. LAI used the most recent actuals available for this comparison.

Figure 11. Energy Savings Impact of DSM Programs in Canadian Provinces

Utility	Year	Energy Requirement (GWh)	Energy Savings (GWh)	Energy Savings Impact of DSM (%)
Newfoundland	2014	6,351 ⁷⁷	84 ⁷⁸	1.3%
NS Power	2016	10,809	133	1.2%
NB Power ⁷⁹	2016-17	13,039	39	0.3%
SaskPower ⁸⁰	2016-17	22,080	76	0.3%
Manitoba Hydro ⁸¹	2017	33,232	370	1.1%
BC Hydro	2016	51,023 ⁸²	369 ⁸³	0.7%
IESO ⁸⁴	2016	137,000	1,267	0.9%
HQ ⁸⁵	2016	217,165	534	0.2%

The most recent available data on the impact of DSM on energy requirements in the provinces range from 0.2% in Quebec to 1.3% in Newfoundland and Labrador, as shown in Figure 12.

⁷⁷ Newfoundland Power – 2016/2017 General Rate Application, Appendix B, pg. 1 of 1.

(<http://www.pub.nl.ca/applications/np2016gra/index.htm>)

⁷⁸ Newfoundland Power Five-Year Conservation Plan: 2016-2020 Schedule D pg. 1 of 2.

(<http://www.pub.nl.ca/applications/np2016gra/index.htm>)

⁷⁹ NB Power 2016/2017 Annual Report, pg. 20 and 43. (https://www.nbpower.com/media/759035/2016-2017-annualreport-en_web_ready.pdf?1)

⁸⁰ SaskPower 2017-2018 Annual Report, pg. 14 and 125. (<https://www.saskpower.com/about-us/Our-Company/Current-Reports>)

⁸¹ Manitoba Hydro-Electric Board 66th Annual Report For the Year Ended March 31, 2017, pg. 21 and 33.

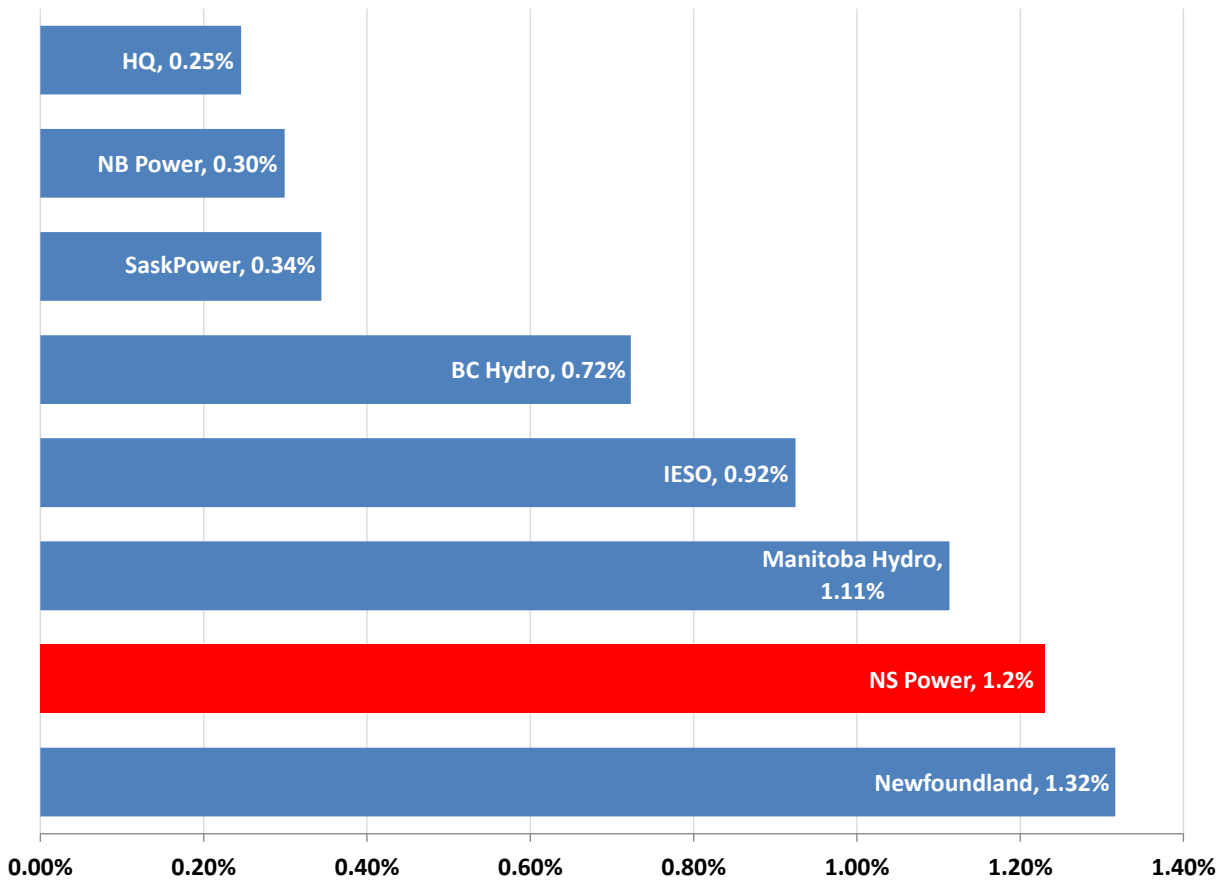
(https://www.hydro.mb.ca/corporate/ar/pdf/annual_report_2016_17.pdf)

⁸² BC Hydro Deferral Account Report, F2016 Annual Report For the Twelve Months Ended March 31, 2016, pg. 3 of 11. (<https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf>)

⁸³ BC Hydro Fiscal 2017 to Fiscal 2019, Revenue Requirements Application, Appendix W, Demand-Side Management Data Tables, pg. 1 of 10. (<https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf>)

⁸⁴ IESO 2016 Conservation Results Report, pg. 3 and 6. (<http://www.ieso.ca/Document-Library/Search-Results?c=54DA0459-93DB-43D8-AB94-7EDED52812D>)

⁸⁵ Hydro Quebec Sustainability Report 2016, pg. 15 and 42. (<http://www.hydroquebec.com/data/documents-donnees/pdf/sustainability-report-2016.pdf>)

Figure 12. Rank of Energy Savings Impact of DSM in the Provinces

In 2018, the 1.4% impact of DSM on energy requirements in Nova Scotia was larger than the 1.3% impact in Newfoundland in 2014.

Q. Should Nova Scotia pursue implementation of high-cost measures to achieve higher levels of energy savings?

A. No. Nova Scotia has achieved satisfactory levels of energy savings and should forego implementation of high cost measures in light of affordability considerations, industry norms, as well as recognition of NS Power's operating conditions in the decade ahead. I have previously mentioned affordability considerations and will return to income numbers later in my testimony. NS Power is capacity constrained, not energy constrained. Instead of pursuing implementation of high-cost energy efficiency measures, NS Power can use the abundant cheap energy available in the province at least through 2022 to meet demand and maintain emissions below the national average. The anticipated

energy surplus going forward in the decade ahead enables postponing implementation of energy efficiency measures that are costly now to a time when these measures are more cost-effective. I therefore encourage the Board to consider the inherent tradeoffs associated with implementation of more expensive EE measures that provide environmental benefits at high cost without the concomitant operating advantages observed in provinces or states where energy reserves are tight.

Q. Are the claimed benefits also based on avoided energy cost assumptions?

A. Yes. The claimed customer benefits depend on the assumptions that EfficiencyOne has made. As I understand, EfficiencyOne has used high levelized fuel costs from the 2014 IRP over the period 2015-2039. These assumed costs do not reflect the actual costs and bill impacts experienced by NS Power's customers. Both residential and BNI customers pay for fuel costs actually incurred by NS Power on a monthly basis. Based on the 2016 Rate and Bill Impact Analysis (RBIA), over the 25-year term, levelized costs used by EfficiencyOne were \$166/MWh for 2011-2014 (from the 2009 IRP Update Study) and \$107/MWh for 2015-2033 (from the 2014 IRP Study). The levelized avoided fuel cost used to compute customer benefits gives a misleading account of who pays what and when. According to NS Power, "the levelized marginal unit fuel costs of \$166/MWh used by ENS in years 2011-2014 and \$106.93/MWh used by E1 in years 2015-2030 are significantly above the 10-year average of \$44.28/MWh from the 2011-2020 period on the regulatory record."⁸⁶ The actual and marginal cost of fuel for 2010 through 2014 was about 33% of the current avoided energy cost used in the RBIA analysis, and roughly 50% of the current value used from 2015 through 2024.

The 10-year average of the actual annual marginal fuel cost from the 2011-2016 and the forecast for 2017-2020 as used in the 2017-2019 Rate Stability Proceeding is \$47/MWh. The average marginal fuel cost for the 23-year period from 2011 to 2033 is \$74/MWh. The gulf between the assumed avoided energy costs used by EfficiencyOne for derivation of ratepayer benefits and actual marginal costs is large and has not been acknowledged. If

⁸⁶ See NS Power comments on E1's RBIA, M07730-E1- Application for Approval of its Rate and Bill Impact Analysis Report (E-ENSC-R-16),pg. 3 of 9.

EfficiencyOne used more realistic fuel cost data in calculating avoided energy costs, the customers' DSM benefits would be dramatically lower. The lower benefits, in turn, would significantly reduce the scope of measures considered to be cost effective.

Q. What does this mean in terms of customer benefits and avoided cost?

A. EfficiencyOne says that it considers the determination of affordability to be a balancing of short- and long-term bill impacts.⁸⁷ In the context of EfficiencyOne's Preferred Plan, they note "that the 3-year investment for Nova Scotians is \$129.1 million with corresponding lifetime energy savings that produce a present value savings of \$622.7 million, a return of \$4.80 for every \$1 of investment." At first blush, the dividend payout on this \$129.1 million sounds irresistible. However, because there is comparatively inexpensive energy available in the province from existing and new clean hydro generation resources through 2022, benefits may be more fragile than represented. In part, this is due to EfficiencyOne's use of a long-term levelized fuel cost convention, as well as questions about intergenerational equity. By intergeneration equity I mean the basic fairness associated with one generation bearing the weight of cost incurrence up front while the following generation realizes net economic benefits over decades to come. Because the marginal cost of energy is much lower than the long-run levelized avoided cost, I recommend that the Board temper principle with practicality by finding a sensible middle ground where the most expensive EE measures are cancelled or postponed. This would lessen the short-term adverse customer impact while preserving Nova Scotia's options about electrification and resource utilization.

Q. Mr. Levitan, does EfficiencyOne state that its Preferred Plan is affordable?

A. Yes, in its evidence EfficiencyOne states that the "Preferred Plan is affordable based upon the guidance provided by this Board. The Preferred Plan strikes an appropriate balance between short and long-term considerations that promote affordability."⁸⁸

⁸⁷ IR-10, from page 1 of 4, lines 19-26 to page 2 of 4, lines 1-8.

⁸⁸ EfficiencyOne Evidence, from page 40 of 62, line 23, to page 40 of 62, line 25.

1 **Q. Are you familiar with the previous Board guidance on affordability that**
 2 **EfficiencyOne is referring to?**

3 A. Yes. In its decision approving the 2016-2018 DSM Plan, the Board stated:

4 The Board finds that the inclusion of Section 79L (9) of the PUA directs the
 5 Board to take into account an increased focus on short term rate impacts. Having
 6 said that, the Board notes that there will be a review of the DSM program every
 7 three years. There will always be rate pressures to be taken into account in both
 8 determining rates and in determining the DSM program. A focus exclusively on
 9 short term affordability means that the Board would never get to consider long
 10 term costs. That would be to the detriment of customers. The Board does not
 11 believe that customers are well-served or that it is in their best interests to focus
 12 only on short term costs and thereby deny customers the real long term cost
 13 savings that are possible from a balanced and properly implemented DSM
 14 program. Accordingly, while the Board finds that there has been a change in focus
 15 mandated by the Legislature, and an increased emphasis on short term rate
 16 impacts, the overarching consideration continues to be “the best interests of Nova
 17 Scotia Power Incorporated’s customers” as stated in Section 79L(8) of the PUA.⁸⁹

18 **Q. How did EfficiencyOne determine that its Preferred Plan is affordable?**

19 A. EfficiencyOne stated that it “considers the determination of affordability to be a
 20 balancing of short term and long term rate and bill impact considerations to electricity
 21 customers,” and that DSM is affordable “when [its] acquisition is analyzed and is deemed
 22 to be worth the resources it takes to manage it.”⁹⁰ However, EfficiencyOne did not
 23 conduct any surveys related to affordability of the Preferred Plan.⁹¹

24 **Q. Do you agree with EfficiencyOne that the Preferred Plan strikes an appropriate**
 25 **balance between short and long-term considerations?**

⁸⁹ See paragraph 82 of the Board’s decision in M06733.

⁹⁰ IR-10, page 1 of 4, lines 20-22.

⁹¹ Ibid.

A. No, I do not. It is my opinion that the Preferred Plan is too aggressive in pursuing uncertain long-term benefits, based, in large part, on inflated energy value savings, therefore resulting in certain short-term costs that are unfair and burdensome to Nova Scotians.

Q. Why is the Preferred Plan too aggressive in pursuing long-term benefits?

A. Simply put, the level of targeted savings in the Preferred Plan is significantly higher than in previous years. The average first-year energy savings approved by the Board in the past five years was 130.9 GWh.⁹² The Preferred Plan proposes an average first-year energy savings amount of 140.6 GWh.⁹³ This is a 7.4% increase over the current five-year average savings level. From 2016-2019, the Board approved capacity savings ranging from 20.2-21 MW⁹⁴. The Preferred Plan proposes first-year capacity savings of 38.7 MW, an increase of over 84% from 2016-2019.⁹⁵ While I have not conducted any technical analysis on point, in my view, these percentage increases for the targeted energy and capacity increases are steep and therefore concerning.

Q. Why are the long-term benefits uncertain?

A. The long-term benefits are uncertain because they depend on many variables that are difficult to predict. These variables could cause the avoided energy and capacity costs to deviate greatly from the projections over time. New technologies may evolve that would make the currently proposed EE measures obsolete. Many factors, such as macroeconomic conditions, may affect the level of participation in the DSM programs too.

Q. What are the short-term costs required to achieve the DSM savings in the Preferred Plan?

A. The targeted 7.4% increase in energy savings and 84% increase in capacity savings over the historical averages will necessitate a 23.1% increase in DSM investment in 2020

⁹² See Table 2 in EfficiencyOne Evidence, page 13 of 62.

⁹³ See Table 1 in EfficiencyOne Evidence, page 6 of 62.

⁹⁴ See Board decisions M06733 and M08604.

⁹⁵ See Table 1 in EfficiencyOne Evidence, page 6 of 62.

1 compared to the 2019 level of investment. As I discussed previously, most other
 2 jurisdictions comparable to Nova Scotia are currently keeping DSM spending mostly flat
 3 or even decreasing it, not proposing significant increases in savings and investment.

4 **Q. Are Nova Scotians well-equipped to tolerate these increased short-term costs?**

5 A. In my opinion, the answer is no. As mentioned previously, the six states in Mr. Reed's
 6 benchmarking analysis are among the most prosperous in the U.S. In 2017 the average
 7 annual income was \$81,435. This is nearly twice Nova Scotia's average 2017 annual
 8 income of \$41,400.

9 More light can be shed on affordability through per capita data from The Conference
 10 Board of Canada. This metric is similar to the data I used to compare Nova Scotia to the
 11 states. Eight provinces had higher per capita incomes than Nova Scotia in 2016 -- only
 12 Prince Edward Island had lower. Alberta leads the pack with a per capita income of USD
 13 \$59,249. This is nearly double Nova Scotia's per capita income of USD \$32,531.⁹⁶ The
 14 Board should be aware that this income discrepancy between Nova Scotia and other
 15 jurisdictions means that any increase in DSM spending would impose a
 16 disproportionately greater economic burden on Nova Scotians than either the peer group
 17 states or the other provinces.

18 **Q. In contrast to expensive EE measures for energy conservation and efficiency, would**
 19 **customers in Nova Scotia benefit from DSM measures oriented toward the**
 20 **reduction in peak demand?**

21 A. Yes. DSM investment oriented toward shaving or materially reducing coincident peak
 22 demand has operational merit. Again, the Board must examine whether the cost of
 23 reducing peak demand is offset by the benefits. From a directional standpoint, investment
 24 in DSM aimed at reducing peak demand would be highly likely to significantly increase
 25 electricity rates in Nova Scotia in order to achieve EfficiencyOne's proposed targets. This
 26 adverse initial rate impact would likely be tempered over time, however. The

⁹⁶ "Income Per Capita - Economy Provincial Rankings - How Canada Performs," The Conference Board of Canada; 2019 (<https://www.conferenceboard.ca/hcp/provincial/economy/income-per-capita.aspx>)

“bankability” of the benefits is at the core of program efficacy. If, on one hand, the benefits are bankable and outweigh the program costs, the investment in peak demand reduction is worthwhile. If, on the other hand, the benefits are tenuous or otherwise insufficient, the investment in peak demand reduction may not justify adverse customer effects.

Q. In your analysis of the peak demand reduction component of the proposed DSM plans, have you considered the potential for near-term rate increase associated with EfficiencyOne’s Application from 2020 -2022?

A. Yes. I relied on EfficiencyOne’s account of customer effects. Across the board, it is significant and adverse. From 2020 to 2022, the annual impact resulting from DSM activities in Nova Scotia will peak in 2021⁹⁷. For residential customers, retail rates will increase 3.25%. For small general and general customers, retail rates will increase 4.28% and 5.75%, respectively. For large general customers retail rates will increase by 7.07%. Small industrial customers will experience a 7.78% increase, while medium and large industrial customers will see a 3.38% and 4.11% increase, respectively. Municipal customers will see a 4.10% increase.⁹⁸ Unfortunately, I have not been able to unpack the rate increase attributable to all DSM measures for the sake of separating the potentially meritorious peak demand reduction programs from the much less-valuable incremental EE measures.

Q. Can you describe the average long-term rate increases associated with EfficiencyOne’s proposed DSM activities?

A. Yes. From 2020 to 2035, the average annual impact will be 0.8% for residential customers, 1.1% for small general customers, 1.3% for general customers, 1.5% for large general customers, 1.7% for small industrial customers, 0.8% for medium industrial customers, 1.0% for large industrial customers and 1.0% for municipal customers.⁹⁹ These percentages represent rate impacts of \$97.4 million, \$5.7 million, \$53.2 million,

⁹⁷ EfficiencyOne Application, Appendix B, page 19 of 37, Figure 3.

⁹⁸ The rate increase values derived from the Excel file “Appendix B - 2020-2022 Plan Rate and Bill Impact Analysis Model – preferred.”

⁹⁹ Ibid.

\$9.3 million, \$7.1 million, \$6.9 million, \$9.4 million and \$2.4 million for residential, small general, general, large general, small industrial, medium industrial, large industrial and municipal customers, respectively, from 2020 to 2035.

Q. Mr. Levitan, do you think that the benefits associated with peak demand reduction are uncertain and may not fully justify the immediate additional cost to customers?

A. Yes. One main reason is that the DSM programs centered on peak demand reduction represent an expansion of the DSM pilots included in the 2019 DSM Resource Plan. But the results of the 2019 DSM pilots are not yet available, so it is difficult to make the leap of faith that the claimed benefits are real, bankable, and of sufficient quality to outweigh adverse customer impacts. Also, the claimed benefits are based on avoided capacity costs. NS Power's ability and cost to avoid capacity remains uncertain in the next five to ten years, perhaps longer in response to NS Power's seasonal peak demand, the need for operating reserves as a safeguard for intermittent generation, and structural changes in the market. Such structural change pertains to increased electrification for transport. Finally, consumer preference is an evolving dynamic. Investment in peak demand reduction measures will confer benefits over the intermediate to long term only if the peak demand reduction measures remain relevant.

Q. Does EfficiencyOne believe that the portion of the DSM spending in the Preferred Plan allocated to peak demand reduction initiatives meets the affordability requirement?

A. Yes. EfficiencyOne stated that:

EfficiencyOne considers affordability at the DSM Plan investment level, given the portfolio of cost-effective programs. Attachment 1 to Appendix A of the Application provides the Total Resource Cost screening tests for demand reduction measures, which are relatively high, providing an indication of their affordability.¹⁰⁰

¹⁰⁰ IR-40, page 4 of 4, lines 1-4.

1 **Q. Do you agree with EfficiencyOne’s explanation?**

2 A. No, I disagree. EfficiencyOne appears to believe that cost-effectiveness and affordability
3 are synonymous. In my view, EfficiencyOne has incorrectly interpreted the high Total
4 Resource Cost (TRC) test results of the demand reduction measures as indicative of
5 affordability. The TRC test indicates cost-effectiveness, not affordability. The dictionary
6 says something is cost-effective if it is “producing optimum results for the
7 expenditure.”¹⁰¹ Cost-effectiveness does not take into account what share of the
8 customer’s income the initial expenditure represents. On the other hand, the dictionary
9 states that something is affordable if it is “believed to be within one’s financial
10 means.”¹⁰² Affordability only considers the upfront cost, and not any future benefits or
11 cost savings. The Board’s definition of affordability, which I discussed previously,
12 combines these two definitions in an effort to balance short-term costs and long-term
13 benefits. In the case of these demand reduction measures, I think the upfront costs are too
14 high. In my opinion, it therefore does not meet the Board’s definition of affordability.

15 **Q. Why do you think the proposed demand reduction measures are not affordable?**

16 A. EfficiencyOne proposes to invest \$3.3 million per year in the peak demand reduction
17 program and assumes these measures will reduce peak demand by 20.7 MW over the
18 2020-2022 DSM Plan.¹⁰³ While the spending level is certain and substantial, the long-
19 term benefits are uncertain because they are based on the unconfirmed results of the 2019
20 peak demand reduction pilots. Moreover, the projections for savings appear to be a
21 simplified linear extrapolation of the 2019 experience. The 2019 peak demand reduction
22 pilots had a much lower level of participation. Whether participation is scalable to
23 investment is unknown. Also, the projected savings are based on the assumption that all
24 the residential participants in the peak demand reduction programs would be served under
25 the time-of-use (TOU) tariff, which is not certain. Without switching to the TOU, the
26 participants would be much less likely to change behavior to achieve the desired diurnal

¹⁰¹ “Cost-effective | Define Cost-effective at Dictionary.com,” Dictionary.com; 2019 available at <https://www.dictionary.com/browse/cost-effective>

¹⁰² “Affordable | Define Affordable at Dictionary.com,” Dictionary.com; 2019 available at <https://www.dictionary.com/browse/affordable>

¹⁰³ EfficiencyOne Evidence, from page 31 of 62, line 28, to page 32 of 62, line 2.

shift, thereby failing to realize the expected savings. The effectiveness of this program depends greatly on the parameters of the TOU rates. If the rates are too high during peak hours, ratepayers will be much less likely to switch to the TOU due to perceived cost and risk. Likewise, if the TOU rate during peak hours is too low, the economic incentive to use less energy during the peak hours may be ignored.

Q. Mr. Levitan, what do you think about technology remaining relevant over the intermediate to long term?

A. EDCs' experience with technology investment in EE and peak demand reduction measures indicate that certain technologies that are relevant based on current planning and cost parameters can become less relevant or irrelevant with the passage of time. This is apparent in EfficiencyOne's application where Figure 3 of Appendix D conveys this point.¹⁰⁴ Here, the relevance of the most popular lighting technologies in 2015, i.e., incandescent, halogen, CFL, T12, T8, T5, HID among others, are predicted to lose almost all relevance to LED lamp and luminaire technologies by 2035. Another example of technology substitution is the penetration of smart thermostats in the U.S. market. According to Parks Research, more than 100 million of the approximately 117 million households in the U.S. did not have a smart device in 2016. However, by 2020, more than 40 million households will have a smart thermostat.¹⁰⁵ While LED and smart thermostat substitution effects are to be encouraged, the speed, cost efficiency and environmental benefits associated with LED and smart thermostat replacements for traditional lighting and temperature control sources reminds us that disruptive technologies can turn the energy economic equation about net economic benefits upside down over time.

Q. What are the peak demand reductions proposed by EfficiencyOne under the Preferred Plan and Alternate scenario?

A. Under the Preferred Plan, the peak demand reductions are 38.7 MW in 2020, 40.3 MW in 2021 and 41.1 MW in 2022 or 120.1 MW in total from 2020 to 2022. Under the Alternate

¹⁰⁴ EfficiencyOne Application, Appendix D, Figure 3. This appendix does not have page numbers.

¹⁰⁵ <https://www.greentechmedia.com/articles/read/100-million-plus-us-homes-lack-smart-devices#gs.2fgrhc>

scenario, the peak demand reductions are 33.4 MW in 2020, 34.5 MW in 2021 and 34.9 MW in 2022 or 102.7 MW from 2020 to 2022.

Q. What was the peak demand reduction under the Board approved 2019 DSM Plan?

A. Under the 2019 DSM Plan, the peak demand reduction was 20.2 MW.

Q. What portion of the budget in the Board approved 2019 DSM Plan and the proposed 2020-2022 DSM Preferred Plan is dedicated to peak demand reduction efforts?

A. In the 2019 DSM Plan, \$1 million was allocated for peak demand reduction pilots. The investment in demand reduction initiatives increases from \$1 million in the 2019 DSM Plan to \$3.3 million per year over the term of the proposed 2020-2022 DSM Preferred Plan. According to EfficiencyOne, this additional investment is expected to reduce demand by 20.7 MW during 2020-2022.¹⁰⁶

Q. Do you agree with EfficiencyOne's assessment?

A. It is too soon to tell. The demand reduction initiatives from the 2019 DSM Plan serve as a basis for the estimated demand reduction benefits contemplated for 2020-2022. But the results are not in, have not been studied, and appear speculative.

Q. Can you report the demand reduction cost on a dollar per watt basis for the Board approved 2019 DSM Plan, the proposed 2020-2022 DSM Preferred Plan and the proposed 2020-2022 DSM Alternate scenario?

A. Yes. The total DSM investment in the Board approved 2019 DSM Plan is \$34 million. For the proposed 2020-2022 Preferred Plan it is \$129.1 million. For the 2020-2022 Alternate Scenario it is \$111.0 million. The dollar per watt demand reduction cost is \$1.69/W for the Board approved 2019 DSM Plan, \$1.07/W for the 2020-2022 Preferred Plan and \$1.08/W for the 2020-2022 Alternate scenario. Relative to baseline 2019,

¹⁰⁶ EfficiencyOne Evidence, from page 31 of 62, line 28, to page 32 of 62, line 2.

EfficiencyOne's Preferred Plan and Alternate Scenario are cheaper than the approved 2019 DSM plan.

Q. How would you characterize the differences in total peak demand reduction costs amongst the Board approved 2019 DSM Plan, the proposed 2020-2022 DSM Preferred Plan and the proposed 2020-2022 DSM Alternate scenario?

A. The 2020-2022 cost projections on a dollar per watt of peak demand reduction basis in both the Preferred Plan and Alternate Scenario appear significantly lower than in the 2019 DSM Plan.

Q. Do you have an opinion regarding the ostensible decrease in demand reduction cost from the 2019 Board approved value to the 2020 EfficiencyOne proposed value?

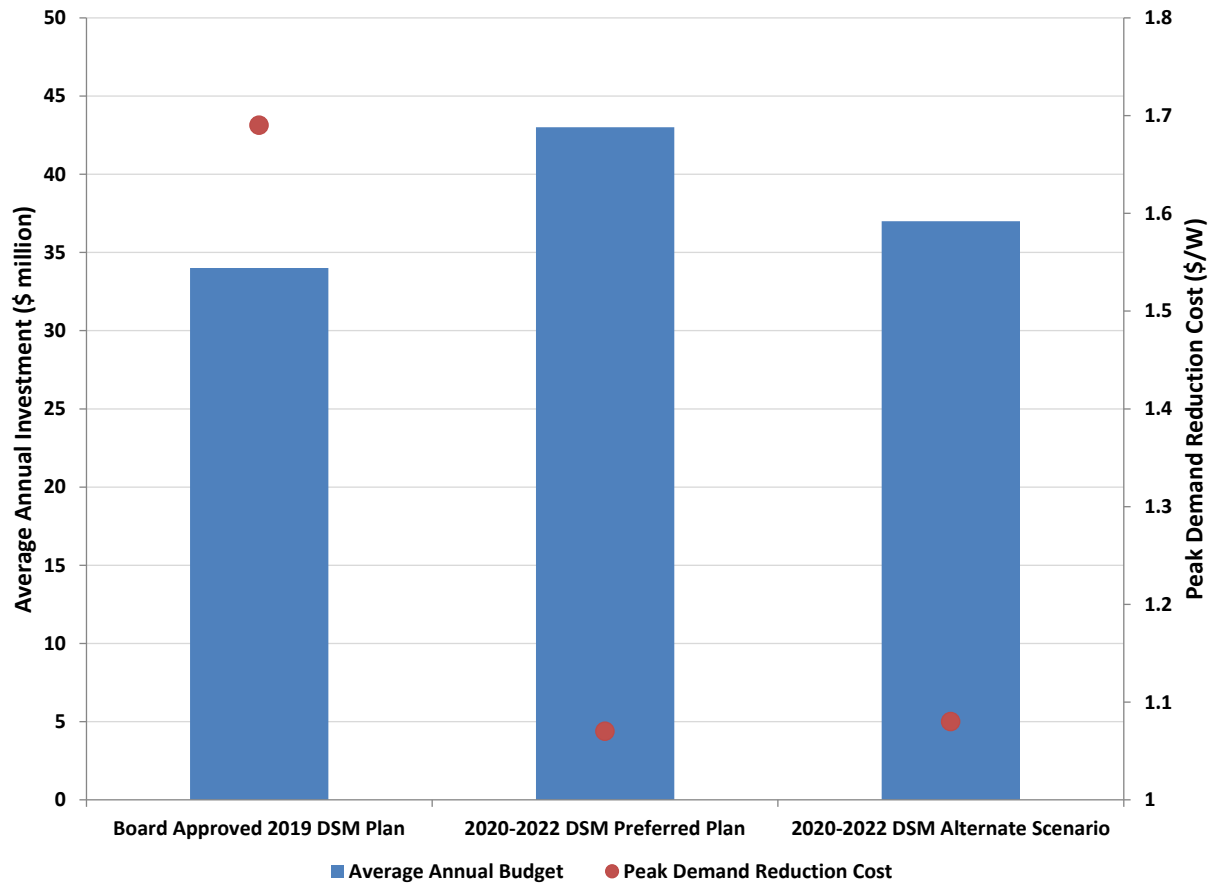
A. Yes. The decline can be attributed to the differences in composition of the DSM portfolios. In the proposed 2020-2022 DSM Plan, EfficiencyOne shifted the focus from the traditional EE to the peak demand reduction measures. Except for the relatively minor peak demand reduction impact of the pilot programs, the 2019 DSM Plan was prepared with a focus on EE measures. On the one hand, traditional EE measures are implemented to reduce energy consumption, but typically produce minor demand reduction effects. With a small denominator, the cost per watt of the demand reduction is high. On the other hand, a DSM program focused on peak demand reduction does not typically reduce energy use in a significant way, but does clip coincident kW use, thereby conferring valuable capacity and operating benefits at the system level. Accordingly, the demand reduction cost per watt may be lower. As peak demand reducing technologies are more expensive than passive EE, whether or not such technologies are "in the money" from a customer perspective in Nova Scotia warrants rigorous assessment.

The cost in dollar per watt is synonymous with peak demand reduction cost.¹⁰⁷ It is expected to remain constant or change slightly with changes in the DSM budget as seen

¹⁰⁷ Some DSM costs have nothing to do with the peak demand reduction programs. However, in this analysis I make a simplified assumption that all DSM measures contribute to peak demand reduction.

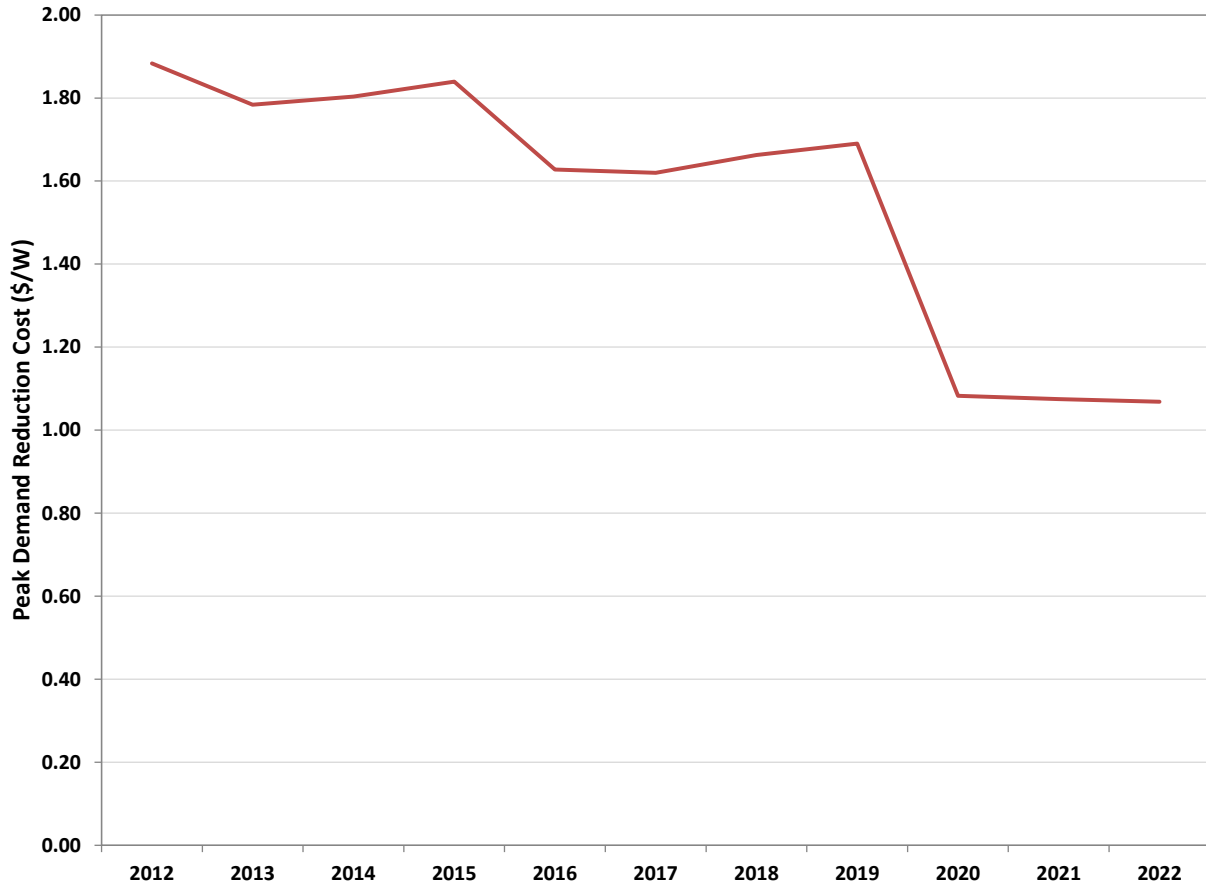
in Figure 13, which compares the 2020-2022 DSM Preferred Plan and Alternate scenario peak demand reduction costs are compared.

Figure 13. Peak Demand Reduction Cost – Board Approved 2019 DSM Plan, 2020-2022 DSM Preferred Plan and 2020-2022 DSM Alternate Scenario



Q. How have peak demand reduction costs varied from 2012 to 2019?

A. As shown in Figure 14, peak demand reduction costs included in the Board approved DSM plans did not vary significantly from 2012 to 2019. They started at \$1.88/W in 2012, dropped to \$1.62/W in 2017 and rebounded to \$1.69/W in 2019. The 13.8% cost reduction from 2012 to 2017 was much smaller than the proposed 36.1% reduction from 2019 to 2020.

Figure 14. Peak Demand Reduction Cost, 2012-2022

Q. Did DSM plans include specific peak demand reduction programs prior to 2019?

A. No, not to the best of my knowledge. The first year that pilot DSM peak demand reduction programs were included was 2019. This explains why the costs per watt of the peak demand reduction for the previous years were so high.

Q. Do you have any concerns about the estimated lower costs on a dollar per watt basis in the 2020-2022 DSM Preferred Plan and Alternate scenario?

A. Yes. Again, these estimates are based on the assumption that the results of the 2019 DSM pilot peak demand reduction programs would be successful. But we do not yet know whether or not the pilot peak demand reduction programs performed in accord with expectations, below par, or, for that matter, better than anticipated. Another concern relates to extrapolation risk, namely, whether the results of the pilot programs apply to much broader participation levels.

Q. Did EfficiencyOne break down its proposed investment under the Preferred Plan and Alternate scenario by customer class?

A. Yes. The proposed investment and projected peak demand reductions under both plans were provided for residential and business, not-for-profit and institutional (BNI) programs.

Q. Please describe the investments, peak demand reductions and energy savings in each customer class under both plans.

A. Under the Preferred Plan, a total investment of \$53.4 million is projected to result in 58.8 MW of peak demand reduction and 163.2 GWh of energy savings over 2020-2022 in the residential class. A total investment of \$64.3 million is projected to result in 61.4 MW of peak demand reduction and 258.50 GWh of energy savings over 2020-2022 for BNI customers. Under the Alternate scenario, a total investment of \$44.7 million is projected to result in 50.4 MW of peak demand reduction and 143.3 GWh of energy savings over 2020-2022 for residential customers. A total investment of \$56.5 million is projected to result in 52.4 MW of peak demand reduction and 231.1 GWh of energy savings over 2020-2022 for BNI customers. The annual investments and peak demand reductions under both plans are summarized in Figure 15.

Figure 15. Investment and Demand Reduction by Customer Class under the Preferred Plan and Alternate Scenario

Program	Investment (\$ million)				First Year Demand Reduction (MW)				First Year Energy Savings (GWh)			
	2020	2021	2022	Average	2020	2021	2022	Average	2020	2021	2022	Average
Preferred												
Residential	\$17.70	\$18.00	\$17.70	\$17.80	19.5	19.8	19.5	19.6	56.9	55	51.3	54.4
BNI	\$20.70	\$21.40	\$22.20	\$21.43	19.1	20.6	21.7	20.5	83.3	86.3	88.9	86.2
Alternate												
Residential	\$14.90	\$15.10	\$14.70	\$14.90	16.9	17.0	16.5	16.8	50	48.4	44.9	47.8
BNI	\$18.20	\$18.80	\$19.50	\$18.83	16.5	17.5	18.4	17.5	74.4	77.2	79.5	77.0

1 **Q. Please describe the investments, peak demand reductions and energy savings in each**
2 **customer class under the Board approved 2019 DSM Plan.**

3 A. Under the Board approved 2019 DSM Plan, the \$14.3 million investment in residential
4 programs is projected to result in 10.1 MW of peak demand reduction and 51.2 GWh of
5 energy savings and the \$15.4 million investment in BNI programs is projected to result in
6 additional 10.2 MW of peak demand reduction and 76.1 GWh of energy savings.

7 **Q. Mr. Levitan, do you find it odd that substantially similar investments in residential**
8 **programs under the Board-approved 2019 DSM Plan and the Alternate scenario**
9 **result in much different peak demand reductions but similar energy savings?**

10 A. Yes. In both the Preferred Plan and the Alternate scenario, it appears that EfficiencyOne
11 formulated an optimistic projection of the peak demand reductions assuming scalability
12 from the 2019 pilot results to the aggressive peak demand reduction targets for the 2020-
13 2022 period. Similar investments resulting in much different peak demand reduction but
14 similar energy savings can be explained by the shift in investment from LED lighting
15 energy savings in the 2019 DSM Plan to peak demand reduction DSM programs in the
16 Alternate scenario. It appears that EfficiencyOne assumed that the LED lighting energy
17 savings would occur naturally and peak demand reductions would increase proportionally
18 to the incremental investment relative to the 2019 DSM pilot investment. While
19 EfficiencyOne may be correct about the LED lighting energy savings assumptions,
20 reliance on the pilot program results, which are not yet confirmed, is premature.

21 **Q. What do you recommend regarding the proposed DSM programs focused on the**
22 **peak demand reduction?**

23 A. I recommend that the Board consider going slower than EfficiencyOne has proposed.
24 Small steps in lieu of big strides are sensible until the results of the 2019 DSM Plan are
25 available, that is, the pilot programs test out and extrapolation risk is addressed. Until
26 then the additional peak demand reduction DSM programs should not be authorized by
27 the Board.

1 **Q. Mr. Levitan, have you reviewed EfficiencyOne’s proposal to add Lifetime Energy**
 2 **Savings (LES) as a third Performance Target?**

3 A. Yes, I have.

4 **Q. Have LES been used previously to evaluate DSM plans in Nova Scotia?**

5 A. Yes. LES have been used in Nova Scotia as a Performance Indicator.¹⁰⁸

6 **Q. Why does EfficiencyOne propose to upgrade the use of LES from a Performance**
 7 **Indicator to a Performance Target?**

8 A. According to EfficiencyOne, as a Performance Target LES will allow it to “more
 9 comprehensively measure the Plan’s direct impact on ratepayers.”¹⁰⁹

10 **Q. Do you agree with EfficiencyOne’s reasoning in support of their LES proposal?**

11 A. No, I do not. The proposed LES metric has shortcomings. In addition, the DSMAG has
 12 not had sufficient time or opportunities to provide feedback on the proposed LES metric
 13 or offer other alternatives.

14 **Q. What are the shortcomings of the proposed LES metric?**

15 A. EfficiencyOne states that “Lifetime Energy Savings account for the lifetime of individual
 16 measures, and track more closely to Lifetime Benefits, when compared to first-year
 17 energy savings.”¹¹⁰ In my opinion, there is too much uncertainty regarding the lifetimes
 18 of measures for this metric to be accurate enough for immediate reliance. Many factors,
 19 including unexpected technological innovation, can result in measures having a shorter
 20 life than assumed. For example, subsidized CFL lighting programs were replaced with
 21 LED lighting programs. The rapid fall in price of LED bulbs could cause some
 22 consumers to replace their older CFL bulbs prematurely, thus resulting in only a portion
 23 of the CFL bulb’s expected lifetime energy savings being realized. If the LES metric
 24 were in use in this case, it would have incorrectly overestimated the savings of the CFL

¹⁰⁸ See paragraph 108 of the Board’s decision in M06733.

¹⁰⁹ EfficiencyOne Evidence, page 48 of 62, lines 11-13.

¹¹⁰ EfficiencyOne Evidence, page 49, lines 10-12.

bulb because of the unanticipated fall in LED lighting prices. EfficiencyOne acknowledges this uncertainty in its justification of a lower threshold level. It claims that “lifetime energy savings may still be subject to volatility not encountered in more established targets.”¹¹¹

Q. Does the LES metric rely on any other uncertainties?

A. Yes, it does. The lifetime benefits in the LES metric are themselves based on the measure’s avoided costs, which are subject to similar uncertainty as I described above. It is my understanding that the LES metric recommended by EfficiencyOne as an additional Performance Target is a simple undiscounted sum of invariable annual savings for a number of years corresponding to the lifetime of the measure.¹¹² EfficiencyOne confirms that it used avoided costs from the 2014 IRP for the 2020-2022 DSM Resource Plan.¹¹³ My concern is that the 2014 IRP modelled avoided costs (e.g., energy and capacity) may be obsolete, inaccurate, and therefore inappropriate if used for the purpose of establishing a long-term Performance Target.

Q. Has EfficiencyOne acknowledged the large amount of uncertainty regarding the LES metric?

A. Yes, they have. EfficiencyOne explained that:

EfficiencyOne’s relative experience with LES is significantly less than for Incremental Energy and Demand Savings at the time they were proposed and accepted as Performance Targets. Incremental Energy and Demand savings were first proposed and accepted as Performance Targets for the purposes of the 2015 DSM Resource Plan. At that time, these metrics had been foundational in DSM planning and implementation since 2008, which facilitated detailed tracking and management system development, as well as organizational alignment to achieve these important Performance Targets. This is not the case for LES, for which

¹¹¹ Ibid, page 50 of 62, lines 21-22.

¹¹² Ibid, page 49 of 62, Table 10 and Table 11.

¹¹³ Ibid, page 58 of 62, lines 29-30.

EfficiencyOne has three years' experience tracking and managing, and within an evolving methodology.¹¹⁴

Q. What do you think of EfficiencyOne's proposed threshold for the LES metric?

A. I think it is arbitrary. EfficiencyOne "proposes the Lifetime Energy Savings performance target be established with a threshold of 75 percent, as opposed to the 90 percent threshold established for shorter term cumulative annual energy and peak demand savings."¹¹⁵ EfficiencyOne justifies this threshold by citing its volatility. It is not sensible that EfficiencyOne have it both ways. I do not think that the metric can be certain enough to make it a useful metric of a measure's lifetime savings while volatile enough to justify a lower threshold. Importantly, the 75% threshold proposed by EfficiencyOne is based on the results of the 2017 third-party evaluation which found that LED lighting technology was driving the 25% decrease for LES when comparing tracked to evaluated values.¹¹⁶ However, LED lighting technology is no longer a dominant component of the EE portfolio proposed by EfficiencyOne in the 2020-2022 DSM Resource Plan. Hence, the proposed 25% discount is no longer applicable.

Q. Mr. Levitan, do you think it would be premature for the Board to approve the use of LES as a third Performance Target in the 2020-2022 DSM plan?

A. Yes, I do. EfficiencyOne has acknowledged that there they have less experience with LES than they did with the other Performance Targets when they were proposed and accepted. Rather than wait until they have the requisite experience to justify including LES as a Performance Target, EfficiencyOne is proposing to include it now with an arbitrary and less-stringent threshold. There also has not been enough stakeholder input regarding the LES metric. I think the DSMAG members should be given time to thoroughly discuss LES and other potential long-term Performance Metrics, rather than rushing to include the LES metric in this proceeding. For these two reasons I think the Board would be prudent in rejecting EfficiencyOne's proposal to add LES as a

¹¹⁴ IR-46, page 1 of 1, line 24 to page 2 of 2, line 6.

¹¹⁵ EfficiencyOne Evidence, page 50 of 62, lines 3-5.

¹¹⁶ Ibid, page 50 of 62, lines 17-19.

1 Performance Target. I recommend that the LES metric should continue to be used as a
2 Performance Indicator.

3 **Q. Did EfficiencyOne engage Navigant Consulting (Navigant) to provide its ProCESS**
4 **short-term DSM planning tool to design the 2020-2022 DSM portfolio?**

5 A. Yes. Navigant’s ProCESS model replaced the ELRAM model that Navigant used in the
6 previous DSM Plan development processes.¹¹⁷

7 **Q. Are you familiar with the functionality of the optimization tool which is part of the**
8 **ProCESS model?**

9 A. In a general sense, yes. One of the enhancements of the ProCESS model over ELRAM is
10 its optimization modeling capability. As EfficiencyOne explained, this embedded
11 optimization tool allows various combinations of measures to be optimized based on the
12 specified objective function equation together with a set of constraints. Constraints can
13 be included in the model for a variety of reasons.¹¹⁸

14 **Q. Why were the constraints introduced?**

15 A. According to EfficiencyOne constraints were added “to ensure results are more realistic
16 and achievable.”¹¹⁹ Each additional constraint that is binding further restricts the feasible
17 region for the objective function to be maximized or minimized.

18 **Q. How did EfficiencyOne and Navigant determine that the results of the optimization**
19 **are more realistic and more achievable?**

20 A. Using the Residential Efficient Products Installation program as an example,
21 EfficiencyOne explained that such an indication would be that “the results are more in
22 line with what can be expected from existing programs given historical and forward-

¹¹⁷ EfficiencyOne Evidence, Appendix A, page 7 of 95, lines 10-13.

¹¹⁸ Ibid, page 8 of 95, lines 10-16.

¹¹⁹ IR-31, page 3 of 7, lines 9-13.

1 looking trends.”¹²⁰ As EfficiencyOne described, the “process was iterative, with
2 constraints being added as needed.”¹²¹

3 **Q. Did this iterative model development process continue until the final Preferred Plan**
4 **and Alternate Plan were formulated?**

5 A. As I understand from EfficiencyOne’s response to the information request, the use of the
6 optimization tool ended before DSM plan development was completed.¹²² As
7 EfficiencyOne pointed out, “[a]s more constraints are added, finding a solution with the
8 optimizer tool becomes increasingly difficult (i.e., the model becomes over-
9 constrained)... Further, there is the danger of introducing false-precision due to data
10 limitations populating constraints.”¹²³ Beyond the point where the optimization model
11 had narrowed and guided the range of possible alternative plans as a type of preliminary
12 screening tool, other non-model information and judgment by the analysis team were
13 used to formulate the final Preferred and Alternate plans in the “vetting” stage of
14 planning.

15 **Q. What is your assessment of the effectiveness of this iterative model development**
16 **approach?**

17 A. In my view, it may have some usefulness as an initial screening procedure. However, the
18 iterative process of model revision based on how realistic and desired each model
19 version’s solution appears raises four concerns.

20 First, the need for model development from scratch indicates that the final model that was
21 applied may still be an experimental exercise or an immature tool for planning. As such,
22 I caution against reliance on an under-tested and unproven model.

23 Second, not formulating the constraint sets for a few alternative model specifications in
24 advance of viewing the optimal solutions implies that there had been little thinking or
25 analysis of what considerations should be included in a good, realistic, objective model at

¹²⁰ Ibid, page 3 of 7, lines 18-19.

¹²¹ Ibid, page 3 of 7, lines 12-14.

¹²² Ibid, page 4 of 7, lines 5-6.

¹²³ Ibid, page 3 of 7, lines 21-26.

the beginning of the modeling process. Before results were known would have been a good time for sharing the proposed model specifications with stakeholders in order to vet model characteristics in a transparent manner.

Third, this approach has the potential for bias favorable to EfficiencyOne's interests. When the modeler does not like a result, other constraints and data can be added that would lead closer to the desired outcome. This behind-the-curtain capability defeats much of the purpose of using modelling as a planning tool.

Fourth, the process is not completed at this stage, because the vetting process follows the optimization process. As EfficiencyOne conceded, the model could become overly-constrained, so while the post-modelling vetting process may aid in making the final plan more realistic and achievable, various possible superior model solutions for final solution polishing may have been missed because of the inadequacies of the constraints that were added.

Q. Please describe the vetting process as part of the DSM portfolio determination.

A. As EfficiencyOne explained, the vetting process is the crucial step in the DSM portfolio development.¹²⁴ According to EfficiencyOne, it allows for the alignment of EfficiencyOne's qualitative and quantitative design efforts. The vetting process involves analysis of the model outputs. The review includes an examination of energy savings at the program component and measure level to consider the reasonableness of the model output.¹²⁵

Q. Mr. Levitan, what is your assessment of the vetting process?

A. In my view, the vetting process is another way to allow for skewing the modelling results in the desired direction, which may not be necessarily in the best interests of customers.

Q. What would be your recommendations as related to using modelling tools such as ProCESS in the future DSM Resource Plan designs?

¹²⁴ EfficiencyOne Evidence, Appendix A, page 10 of 95, line 14.

¹²⁵ Ibid, page 11 of 95, lines 1-6.

A. I would recommend that the stakeholders be allowed early access to setting the constraints to be modelled in ProCESS runs, so that the initial model formulation and the process of refinement are made more transparent and reproducible. This requirement would lessen the chances of the optimization outcome being biased, and reduce subjectivity. Also, EfficiencyOne explained that refinements to the model were performed in response to the analysis in the vetting process and updated model runs were completed. This was an iterative process and several cycles occurred.¹²⁶ I believe that the vetting process should not result in an undocumented sequence of iterations as appears to be the case under the current approach.

Q. Did EfficiencyOne consider more DSM scenarios other than Preferred Plan and Alternate scenario?

A. Yes. According to EfficiencyOne, in response to stakeholder requests, EfficiencyOne jointly with Navigant produced 3 additional scenarios: one with an average annual investment of \$34 million without demand reduction, one with an average annual investment of \$34 million with demand reduction (status quo) and one with an average annual investment of \$27 million also with demand reduction.¹²⁷ However, EfficiencyOne concedes that these scenarios were not vetted and EfficiencyOne does not know if they are deliverable.¹²⁸

Q. Were these 3 scenarios the only additional scenarios processed by Navigant?

A. No. According to EfficiencyOne, at NS Power's request, Navigant prepared 4 additional scenarios. Two scenarios were based on a \$34 million budget and the other two were based on a \$27 million budget.¹²⁹ These scenarios will be referred to as 34M E1-Navigant A, 34M E1-Navigant B, 27M E1-Navigant A and 27M E1-Navigant B in my testimony.

Q. Please describe the outputs generated by running ProCESS under these seven additional scenarios.

¹²⁶ Ibid, page 11 of 95, lines 10-12.

¹²⁷ IR-07 (b), page 2 of 4, lines 28-29 and page 3 of 4, lines 1-4 .

¹²⁸ IR-07, Attachment 1, page 1 of 1, and Attachment 2, page 1 of 1, see note at bottom of IR and IR-07b, page 3 lines 4-5.

¹²⁹ IR-09, page 2 of 3, lines 23-28.

A. Under the \$34 million E1 scenario, a total investment of \$102.0 million over 2020-2022 would result in 99.5 MW of first-year peak demand reduction and 370.5 GWh of first year energy savings. Under the \$34 million (status quo) E1 scenario, a total investment of \$102.1 million over 2020-2022 would result in 103.0 MW of first year peak demand reduction and 354.9 GWh of first year energy savings. Under the \$27 million E1 scenario, a total investment of \$81.0 million over the 2020-2022 period would result in 66.2 MW of first year peak demand reduction and 292.0 GWh of first year energy savings. Under the \$34 million E1-Navigant A scenario, a total investment of \$102.2 million over the 2020-2022 period would result in 125.8 MW of first year peak demand reduction and 384.7 GWh of first year energy savings. Under the \$34 million E1-Navigant B scenario, a total investment of \$102.2 million over the 2020-2022 period would result in 119.2 MW of first year peak demand reduction and 403.4 GWh of first year energy savings. Under the \$27 million E1-Navigant A scenario, a total investment of \$81.0 million over the 2020-2022 period would result in 109.4 MW of first year peak demand reduction and 305.5 GWh of first year energy savings. Under the \$27 million E1-Navigant B scenario, a total investment of \$81.0 million over the 2020-2022 period would result in 101.5 MW of first year peak demand reduction and 318.2 GWh of first year energy savings.

The results for these seven scenarios broken down by year are shown below in Figure 16.

Figure 16. Additional Scenarios Annual Outputs

Scenario	Peak Demand Reduction (MW)			Energy Savings (GWh)			Investment (\$ million)		
	2020	2021	2022	2020	2021	2022	2020	2021	2022
34 M E1	32.8	33.5	33.3	123.2	124.1	123.2	\$33.4	\$34.2	\$34.4
34 M (status quo) E1	32.7	34.6	35.7	118.0	118.9	118.0	\$33.1	\$34.2	\$34.7
27 M E1	22.3	22.2	21.7	99.8	97.8	94.5	\$27.1	\$27.1	\$26.8
34 M E1-Navigant A	42.0	41.9	41.9	128.6	127.7	128.5	\$34.1	\$34.1	\$34.1
34 M E1-Navigant B	39.8	39.7	39.7	134.7	134.0	134.7	\$34.1	\$34.1	\$34.1
27 M E1-Navigant A	36.5	36.4	36.5	102.0	101.7	101.8	\$27.0	\$27.0	\$27.0
27 M E1-Navigant B	33.9	33.7	33.9	106.6	105.1	106.5	\$27.0	\$27.0	\$27.0

Q. What are the key differences amongst the outputs of the Preferred Plan, the Alternate scenario and the seven additional scenarios?

A. The proposed investment in DSM under the nine different scenarios (Preferred Plan, Alternate Plan and 7 scenarios) varies from \$81 million under the \$27 million E1-Navigant A and B scenarios to \$129.3 million under the Preferred Plan. The projected energy savings under these scenarios vary from 292.0 GWh under the \$27 million E1 scenario to 421.7 GWh under the Preferred Plan. The projected peak demand reductions under these scenarios vary from 66.5 MW under the \$27 million E1 scenario to 125.8 MW under the \$34 million E1-Navigant A scenario. The differences in investment, energy savings and peak demand reduction amongst the 9 scenarios are shown below in Figure 17.

Figure 17. Summary of Outputs under All Scenarios

Plan	Investment (\$ million)	Energy Savings (GWh)	Peak Demand Reduction (MW)
Preferred	\$ 129.30	421.7	120.2
Alternate	\$ 111.50	374.4	102.8
34 M E1	\$ 102.40	370.6	99.7
34 M (status quo) E1	\$ 102.50	354.8	103.1
27 M E1	\$ 81.30	291.8	66.5
34 M E1-Navigant A	\$ 102.15	384.7	125.8
34 M E1-Navigant B	\$ 102.15	403.4	119.2
27 M E1-Navigant A	\$ 81.00	305.5	109.4
27 M E1-Navigant B	\$ 81.00	318.2	101.5

Relative to the Preferred Plan, all scenarios will require lower investments to achieve different, i.e. lower or higher, energy savings and peak demand reductions. All scenarios would produce lower energy savings. However, the \$34 million E1-Navigant A scenario, even with an investment of \$21.2 million less than the Preferred Plan, would produce higher peak demand reduction. These differences, on a percentage basis, are shown in Figure 18.

Figure 18. Additional Scenarios Output Differences Relative to Preferred Plan

Plan	Investment (\$ million)	Energy Savings (GWh)	Peak Demand Reduction (MW)
Alternate	-13.8%	-11.2%	-14.5%
34 M E1	-20.8%	-12.1%	-17.1%
34 M (status quo) E1	-20.7%	-15.9%	-14.2%
27 M E1	-37.1%	-30.8%	-44.7%
34 M E1-Navigant A	-21.0%	-8.8%	4.7%
34 M E1-Navigant B	-21.0%	-4.3%	-0.9%
27 M E1-Navigant A	-37.4%	-27.5%	-9.0%
27 M E1-Navigant B	-37.4%	-24.5%	-15.6%

Q. Mr. Levitan, did you compare the energy savings and peak demand reduction unit costs that would result from adopting the aforementioned scenarios?

A. Yes. The energy savings and peak demand reduction unit costs broken down by year are shown below in Figure 19.

Figure 19. Energy Savings and Demand Reduction Annual First Year Unit Cost by Scenario

Plan	First Year Energy Savings (\$/kWh)			First Year Demand Reduction (\$/W)		
	2020	2021	2022	2020	2021	2022
27M E1	\$ 0.27	\$ 0.28	\$ 0.28	\$ 1.21	\$ 1.22	\$ 1.23
34M E1	\$ 0.27	\$ 0.28	\$ 0.28	\$ 1.02	\$ 1.02	\$ 1.03
34M SQ E1	\$ 0.28	\$ 0.29	\$ 0.30	\$ 1.02	\$ 0.99	\$ 0.97
27M E1-Navigant A	\$ 0.26	\$ 0.27	\$ 0.27	\$ 0.74	\$ 0.74	\$ 0.74
27M E1-Navigant B	\$ 0.25	\$ 0.26	\$ 0.25	\$ 0.80	\$ 0.80	\$ 0.80
34M E1-Navigant A	\$ 0.26	\$ 0.27	\$ 0.27	\$ 0.81	\$ 0.81	\$ 0.81
34M E1-Navigant B	\$ 0.25	\$ 0.25	\$ 0.25	\$ 0.86	\$ 0.86	\$ 0.86
Preferred	\$ 0.30	\$ 0.31	\$ 0.31	\$ 1.09	\$ 1.07	\$ 1.07
Alternate	\$ 0.29	\$ 0.30	\$ 0.30	\$ 1.08	\$ 1.09	\$ 1.08

The annual energy savings unit cost differences between the Preferred Plan and another scenario vary from -2.8% in 2021 under the Alternate Plan to -19.3% in 2022 under the \$34 million E1-Navigant B. The peak demand reduction unit cost differences between the Preferred Plan and another scenario vary from -0.4% in 2020 under the Alternate Plan to

-32.0% in 2022 under the \$27 million E1-Navigant A scenario. These annual energy savings and peak demand reduction differences are shown below in Figure 20.

Figure 20. Energy Savings and Demand Reduction Annual First Year Unit Cost Differences Relative to the Preferred Plan

Plan	First Year Energy Savings (\$/kWh)			First Year Demand Reduction (\$/W)		
	2020	2021	2022	2020	2021	2022
27M E1	-8.9%	-9.4%	-9.0%	11.6%	13.5%	15.8%
34M E1	-9.0%	-10.1%	-10.6%	-5.9%	-4.7%	-3.1%
34M SQ E1	-5.5%	-6.3%	-5.5%	-6.1%	-8.0%	-8.5%
27M E1-Navigant A	-11.7%	-13.6%	-15.3%	-32.0%	-30.9%	-30.5%
27M E1-Navigant B	-15.5%	-16.4%	-19.0%	-26.8%	-25.5%	-25.2%
34M E1-Navigant A	-11.6%	-13.2%	-15.4%	-25.5%	-24.4%	-23.8%
34M E1-Navigant B	-15.6%	-17.3%	-19.3%	-21.3%	-20.1%	-19.5%
Alternate	-2.9%	-2.8%	-3.0%	-0.4%	1.2%	1.6%

Q. In your opinion, which of the aforementioned plans offers best balances costs and benefits?

A. In my view, the \$27 million E1-Navigant A and the \$34 million E1-Navigant A scenarios offer a better balance of costs and benefits than EfficiencyOne's Preferred Plan. At lower investment levels, more DSM benefits can be achieved at a much lower capital outlay. The \$27 million E1-Navigant A 3-year average investment is 37.4% lower than the Preferred Plan. However, the 3-year average energy savings and peak demand reduction under the \$27 million E1-Navigant A would be only 27.5% and 9% lower, respectively, than the 3-year average energy savings and peak demand reduction under the Preferred Plan. Likewise, the \$34 million E1-Navigant A scenario 3-year average investment is 21.0% lower than the investment under the Preferred Plan. Again, the 3-year average energy savings under the \$34 million E1-Navigant A scenario would be 8.8% lower than the 3-year average energy savings under the Preferred Plan. However, the peak demand reduction under the \$34 million E1-Navigant A scenario would be 4.7% higher than the 3-year average peak demand reduction under the Preferred Plan.

The Alternate scenario is almost as cost-effective as the Preferred Plan as the Alternate scenario reduction in investment, energy savings and peak demand reduction levels

relative to the Preferred Plan are similar. The Alternate scenario 3-year average investment is 13.8% lower than investment in the Preferred Plan. But the average energy savings and peak demand reduction in the Alternate scenario is expected to be 11.2% and 14.5% lower, respectively, than the average energy savings and peak demand reduction in the Preferred Plan.

These numbers attest to the reasonableness of making sensible tradeoffs between total investment in EE and peak demand reduction measures and consequent “dividend payout,” that is the actual annual energy savings and avoided coincident kW demand.

The annual differences between the \$27 million E1-Navigant A and the Preferred Plan and between the \$34 million E1-Navigant A and the Preferred Plan from 2020 to 2022 are shown below in

Figure 21, Figure 22, Figure 23, and Figure 24.

Figure 21. Annual Investment and Energy Savings Differences between the Preferred Plan and the \$27 million E1-Navigant A Scenario

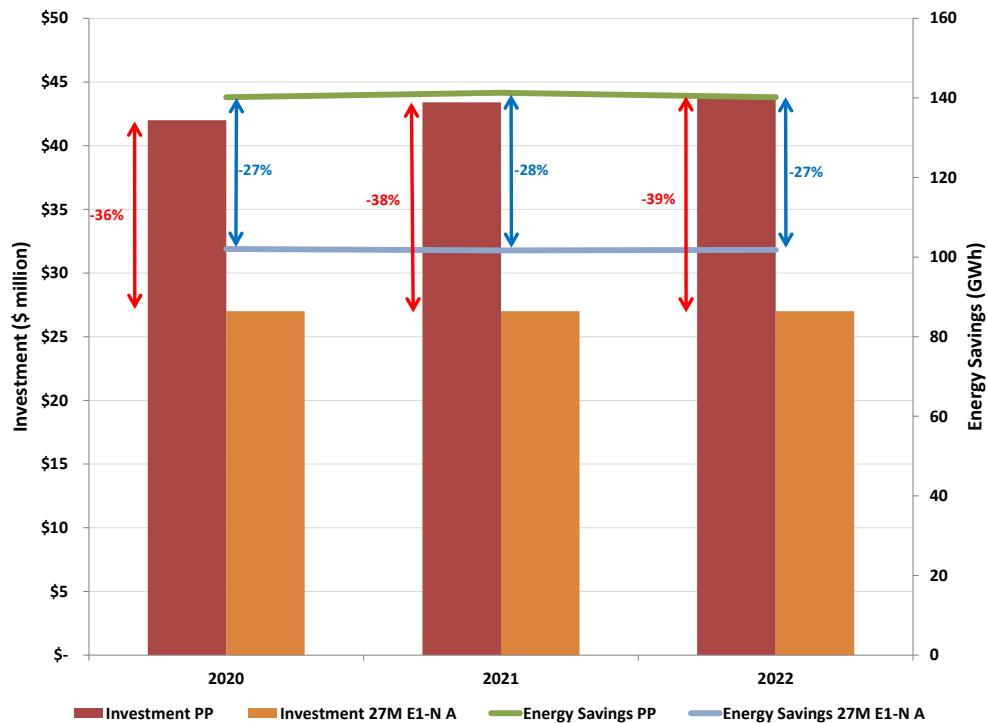


Figure 22. Annual Investment and Peak Demand Reduction Differences between the Preferred Plan and the \$27 million E1-Navigant A Scenario

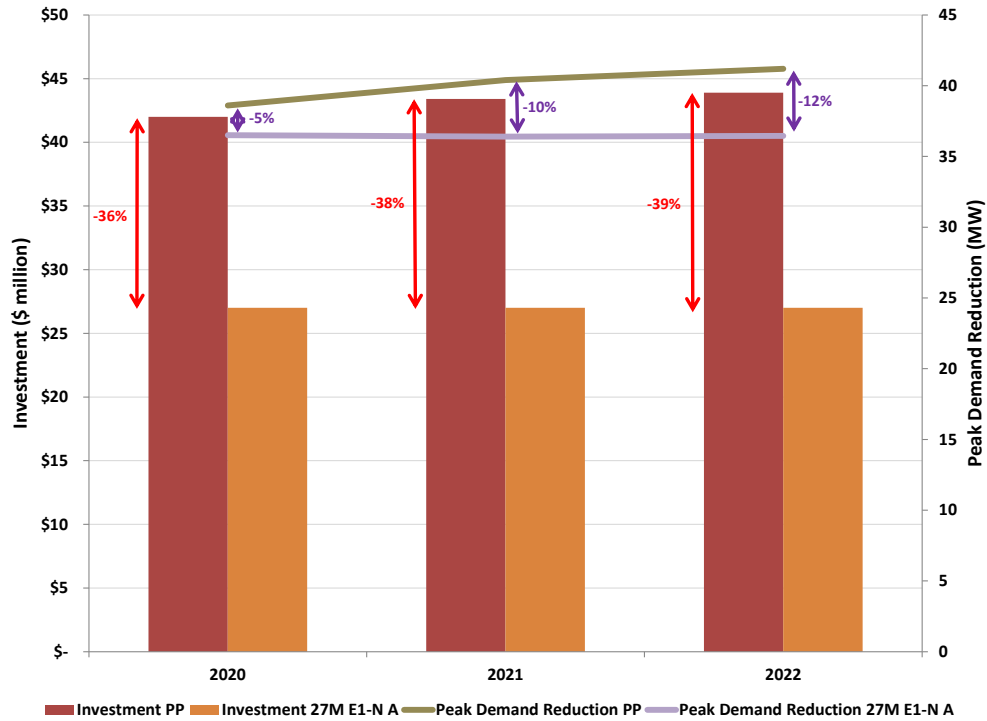


Figure 23. Annual Investment and Energy Savings Differences between the Preferred Plan and the \$34 million E1-Navigant A Scenario

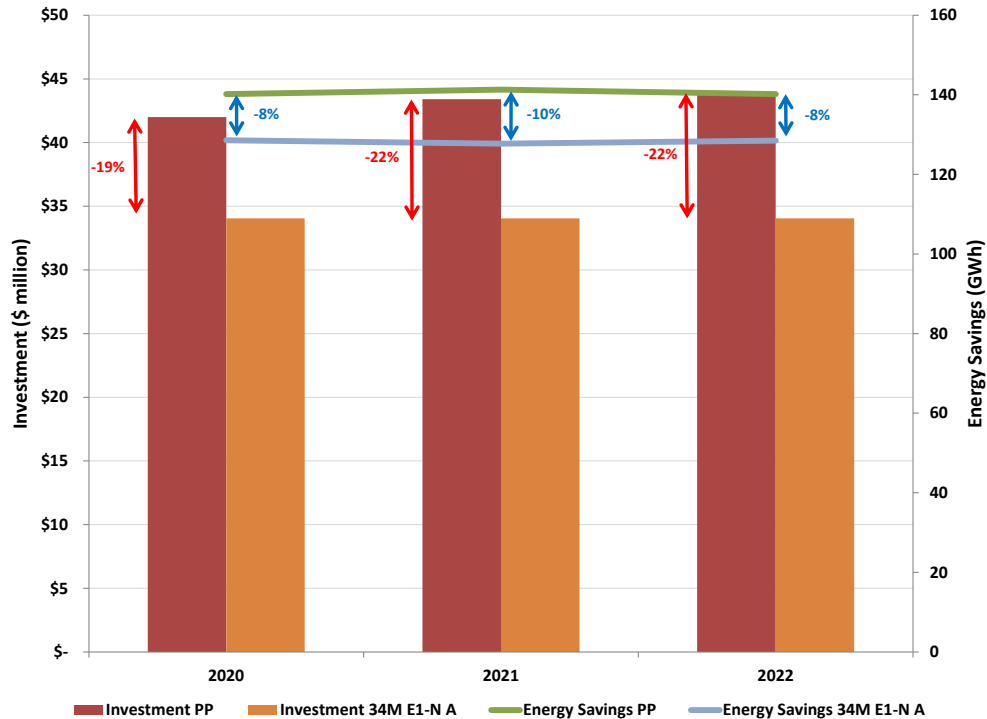
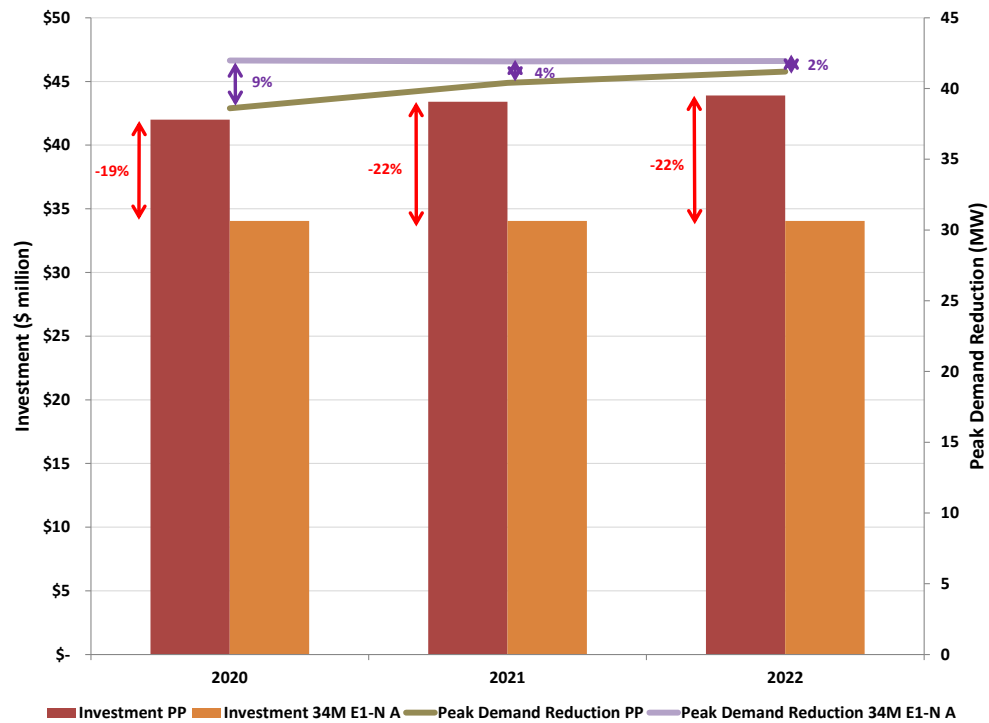


Figure 24. Annual Investment and Peak Demand Reduction Differences between the Preferred Plan and the \$27 million E1-Navigant A Scenario



1 FINDINGS

2 **Q. Mr. Levitan, what are your key findings and observations?**

3 A. I have eight key findings and observations.

- 4 ➤ First, EfficiencyOne's Preferred Plan does not meet the Board's definition of
5 affordability as the certain and significant near-term costs outweigh the uncertain
6 long-term benefits.
- 7 ➤ Second, the Alternate scenario is less costly than the Preferred Plan but it has
8 certain shortcomings. It has not been properly optimized and it is still more
9 expensive than the 2019 DSM Plan.
- 10 ➤ Third, there is too much uncertainty regarding lifetime energy savings for it to be
11 relied on as a performance target for 2020-2022. It should remain a performance
12 indicator until more broadly accepted and proven methods for calculating
13 performance targets are available.
- 14 ➤ Fourth, the adoption of a much less costly DSM plan than what EfficiencyOne
15 proposes under the Preferred Plan and the Alternative scenario is possible.
16 Relative to status quo, it is reasonable to formulate less expensive DSM plans to
17 stress test incremental value derived from EE and peak reduction measures. The
18 deliverability of a less costly DSM plan should be assessed in relation to the cost-
19 effectiveness of the Preferred Plan and Alternate scenario.
- 20 ➤ Fifth, the Board should consider the organic penetration of energy efficiency and
21 peak demand reduction measures. This penetration is evidenced by the results of
22 the latest DSM plans and occurs without utility subsidy, ratepayer impacts, and
23 the level of uncertainty associated with measures that did not pass or barely
24 passed the cost-effectiveness test due to the use of the TRC test on a program
25 level rather than on a measure level.
- 26 ➤ Sixth, the conclusions of the jurisdictional analysis are suspect because an
27 arbitrary and biased peer group of only leading program administrators was
28 utilized. The percentage change in DSM spending in the U.S. from 2013-2017
29 suggest that spending is mostly decreasing or increasing slightly, not increasing
30 dramatically as EfficiencyOne has proposed. Moreover, per capita income

1 comparisons between Nova Scotia and other jurisdictions suggest the short-term
2 pain to ratepayers from increased DSM spending will be more severe relative to
3 the peer group states or other provinces. The Board should consider the inherent
4 risk of overspending.

5 ➤ Seventh, ProCESS optimization modeling and vetting approach allow for too
6 much subjectivity, manipulation, and manual intervention resulting in the DSM
7 portfolios that are consistent with a modeler's agenda. Lack of stakeholder
8 upfront assessment of a model and ad hoc model development and refinement
9 without a full record of why the model was modified do not protect customer
10 interests.

11 ➤ Eighth, EfficiencyOne relied on the inflated fuel costs in determination of the
12 avoided energy costs used in computation of the ratepayers' benefits associated
13 with the DSM measures. Reliance on the marginal cost of fuel in lieu of a
14 levelized construct would reduce the cost-effectiveness of the proposed DSM
15 measures, in particular, energy efficiency measures.

16 **Q. Mr. Levitan, does that complete your testimony?**

17 **A.** Yes, it does.

RICHARD L. LEVITAN

SUMMARY

A management consultant experienced in conventional and renewable energy procurement, pipeline transportation and storage management, wholesale market design, long-term contracts, transmission pricing, and gas/electric simulation analysis.

PROFESSIONAL EXPERIENCE

- 1989 - **Levitan & Associates, Inc.**
President

- 1980 - 1989 **Stone & Webster Management Consultants, Inc.**
Vice President and Managing Officer (Boston)
Vice President
Executive Consultant
Senior Consultant
Consultant

- 1978 - 1980 **Pacific Gas & Electric Company**
Economist

CONSULTING ASSIGNMENTS

AUCTIONS & PROCUREMENT

Advised New York State Energy Research & Development Authority on the design and procurement of the first round offshore wind solicitation in downstate New York.

Advised New Jersey Board of Public Utilities on the design and procurement of the first round offshore wind solicitation up to 1100 MW.

Advised Connecticut Department of Energy and Environmental Protection on renewable energy and natural gas pipeline capacity procurement.

Served as Independent Evaluator (IE) on behalf of the California Public Utilities Commission (CPUC) regarding Southern California Edison's (SCE's) 2011 All Source Request for Offers (RFO) and 2012 Renewables RFO.

Served as IE on behalf of the CPUC regarding SCE's Non-Gas QF RFO.

Served as IE on behalf of the CPUC regarding SCE's Gas RFO.

Served as Agent on behalf of the New Jersey Board of Public Utilities (BPU) on the Long-Term Capacity Agreement Pilot Program (LCAPP). Responsible for implementation of the LCAPP, including formulation of Contracts-for-Differences

covering 1,947 MW of new combined cycle plants. Applied Minimum Offer Price Rule. Performed simulation analysis of energy price effects. Testified before the BPU and in Federal District Court.

Provided technical support to the Long Island Power Authority (LIPA) regarding new generation and transmission projects, including Neptune Transmission, Caithness, fast track projects, and gas pipeline / local transportation contracts.

Conducted simulation analysis and transmission studies for LIPA in PJM and New England to support firm transmission withdrawal rights.

Responsible for Standard Service procurements for the Connecticut Public Utilities Regulatory Authority (PURA) regarding the standard service solicitations of Connecticut Light & Power (CL&P) and United Illuminating (UI). Procurement oversight has been provided six times annually since 2006.

Prepared the 2012 Connecticut Standard Service Procurement Plan governing changes to the UI and CL&P procurement paradigm, including self-management.

Provided testimony before CT PURA regarding the hedge benefits of long term contracts.

Served as “Prosecutorial” arm of PURA to support the selection of 540 MW of new quick-start peakers in Connecticut to meet ISO-NE’s Locational Forward Reserve Market requirement.

Prepared procurement paradigm and contract framework on behalf of the Maryland Public Service Commission to support four electric distribution companies’ (EDCs’) long term resource requirements.

Provided technical support to four Massachusetts EDCs regarding long term renewable energy solicitation, including NStar’s entitlement to Cape Wind.

Provided transmission and regulatory assistance in PJM in relation to NYPA’s selection of the Hudson Transmission HVDC project.

Managed project team’s market advisory and quantitative assessment of generation, fuel deliverability, and DC transmission options for LIPA’s 2007 RFP. Identified primary risk factors associated with competing long term strategic alternatives. Submitted expert reports to the Governor’s Office to support the selection of the Neptune HVDC project, including expected RTEP cost allocation for firm transmission withdrawal rights.

Managed project team’s due diligence for LIPA regarding the election of Unforced Capacity Deliverability Rights (UDRs) on Neptune and Cross Sound Cable. Technical assessment covered transmission withdrawal rights, auction revenue rights, firm v. non-firm point-to-point transmission rights, and scheduling of internal bilateral transactions.

Evaluated wholesale procurement options for Freeport-McMoran (formerly, Phelps Dodge).

Represented Potomac Electric Power Co. in the transference of long term energy purchase contracts to Mirant.

INFRASTRUCTURE ASSESSMENT

Assessed LNG fuel supply options in New England for the Connecticut Department of Energy and Environment Protection (DEEP) as part of the 2019 Integrated Resource Plan.

Assessed going concern value of the Exelon Distrigas LNG import facility in light of the Reliability Must Run Cost of Service Contract with the Mystic units for ISO-NE.

Conducted due diligence on behalf of the Nova Scotia Consumer Advocate and Small Business Advocate on the proposed Maritime Link (ML) transmission project from the Lower Churchill Falls in Labrador to Nova Scotia. Assessed the project economics of the ML in relation to other renewable energy and import options to meet Nova Scotia's energy and environmental objectives. Submitted expert testimony before the Board.

Represented LIPA in the technical assessment of gas pipeline and local delivery adequacy on the New York Facilities System to fuel proposed new combined cycle plants.

Conducted due diligence on behalf of NYPA in RFP #5 regarding pipeline and local delivery conditions to support new combined cycle plants in New York City. This effort encompassed extensive production simulation modeling, culminating in the Astoria Energy II PPA.

Assessed transportation options for Bayonne Energy Center into New York City, including pipeline transport quality assessment on the Transco mainline and Leidy line.

Provided commercial support to LIPA regarding NGrid's on-Island buildout on the New York Facilities System to serve Fast Track Units. Provided commercial support to LIPA's Executive Management regarding the Omnibus Agreement between LIPA and NGrid governing local transportation service, imbalance resolution, netting, and other commercial provisions.

As LCAPP Agent for the BPU, evaluated delivery conditions on Transco and Texas Eastern to support fuel infrastructure adequacy for proposed new combined cycle plants in central and northern New Jersey.

Conducted due diligence on the proposed Broadwater Floating Storage Regasification Unit for the State of New York, including hydraulic delivery conditions, homeland security, environmental, and economic impacts.

Evaluated pipeline and local gas utility infrastructure to support the proposed quick start peakers in Connecticut on behalf of PURA.

Assessed fuel adequacy assessment for PJM, NYISO, and ISO-NE following hurricanes Katrina and Rita. Recommended risk mitigation measures for the winter of 2005/2006.

Evaluated storage and pipeline deliverability constraints for Stagecoach high deliverability storage field development in the Marcellus Shale basin. Identified system improvements on Tennessee required for phase two high deliverability expansion.

Advised ISO-NE on fuel diversity issues associated with the potential retirement or conversion of the Salem Harbor generation station.

Conducted steady state and transient flow analyses for PJM of pipeline and storage capability to serve core and non-core loads when contingencies occur.

Advised NextEra on pipeline infrastructure adequacy on Tennessee to serve the combined cycle plant in Rhode Island.

Advised TransCanada on bulk power transmission limitations affecting market options in the Northeast.

GAS/ELECTRIC INFRASTRUCTURE ADEQUACY

Advised New Jersey Natural Gas Co. on pipeline and storage adequacy over the intermediate term in light of contract flexibility options incorporated in downstream entitlement holders contracts.

Advised Northeast Power Coordinating Council on gas/electric adaptability in New England under diverse contingencies.

Served as project manager on behalf of the Eastern Interconnection Planning Collaborative (PJM, NYISO, ISO-NE, MISO, TVA and the IESO of Ontario) on gas / electric interdependencies. Funded by DOE, this multi-year study included extensive mapping of all pipeline, storage and gas-fired generation infrastructure, constraint analysis of the frequency and duration of pipeline bottlenecks affecting scheduled gas-fired generation, hydraulic analysis of the resiliency of the pipeline network under postulated gas or electric side contingencies, and technical assessment of dual fuel capability, including local options.

Performed pipeline and storage deliverability assessment for NYISO, including quantification of at-risk generation when gas or electric side contingencies occur.

Served as project manager on US DOE second installment of the Quadrennial Energy Review regarding gas system capability in response to high renewable electricity assessment. Electric and gas simulation analyses covering the bulk energy system

incorporated hydraulic analysis of constrained and unconstrained regions across the Eastern Interconnection.

Assessed residual oil and ULSD infrastructure across the New York Control Area for NYISO, including economic engineering assessment of dual-fuel capability in relation to firm transportation entitlements.

Assessed market expansion prospects for major pipeline company doing business in PJM.

Served as project manager on the Multi-Region Gas Study for PJM, IESO of Ontario, NYISO, ISO-NE, and NERC regarding pipeline and storage adequacy affecting bulk power security. Contingency analysis was conducted using electric and gas hydraulic models to determine the magnitude and duration of generation at risk, and the feasibility of short term pipeline workarounds. Economic / market modeling of supply chain management was performed to identify bottlenecks and throughput patterns under varying demand conditions.

Served as project manager on the steady state and transient flow analysis of the consolidated network of pipeline and storage resources to serve core and non-core generation load across PJM when gas or electric side contingencies are tested.

Provided support to ISO-NE Market Monitor regarding pipeline delivery conditions and market participant behavior during the cold snap of January 2004. Advised ISO-NE on formulation of cold weather protocols affecting gas-fired generator availability.

Served as project manager on the steady state and transient flow analyses for ISO-NE of gas infrastructure capability in New England to serve core and non-core loads when electric and gas side contingencies are postulated.

Advised ISO-NE and NEPOOL System Restoration Working Group on restart procedures governing natural gas plants in New England following a black out.

Conducted due diligence on two proposed off-shore LNG import terminals for the Massachusetts Department of Energy Resources, including hydraulic modeling to evaluate physical flow constraints and capacity benefits.

Assessed transportation deliverability constraints in the transient state on El Paso Natural Gas Co.'s pipeline network across metropolitan Phoenix for Salt River Project.

Evaluated post-restructuring transportation and natural gas supply procurement options for the Canal Unit. Conducted assessment of interruptible transportation quality and capacity release options on Algonquin's "G" lateral from Mendon.

TRANSACTION SUPPORT

Advised Eversource and United Illuminating Holdings on the economic and financial criteria to incorporate in a long term PPA with Dominion Energy's Millstone nuclear plant to retain carbon free energy.

Advised ISO-NE on Mystic 8&9 Cost of Service.

Advised Orsted Energy and Eversource on economic, market and regulatory issues affecting development of up to 800 MW of offshore wind in New England.

Represented leading private equity investor on storage asset acquisition in the Northeast.

Represented the State of Connecticut in its review of the NStar and Northeast Utilities merger.

Represented Con Edison Co. in its proposed acquisition of Northeast Utilities, including risk management assessment and ongoing litigation support.

Advised global investors on the acquisition of a wind portfolio in New York, New England, and New Brunswick.

Represented AllCapital on the acquisition of power plants located in New York City.

Represented TransCanada on the acquisition of power plants in the Northeast.

Represented Goldman Sachs in the acquisition of the 730 MW Linden generation asset in New Jersey and the 300 MW Variable Frequency Transformer Project into Staten Island.

Represented Power Gen on the acquisition of LG&E.

Provided market support for Public Service Resources Corporation on storage asset lease dispute under FERC jurisdiction in Nevada.

Restructured long term PPAs for Con Edison, including technical simulation analyses of replacement energy under Standard Market Design and NYSRC reliability procedures.

Advised Con Edison on the consolidation of several PPAs supporting the Brooklyn Navy Yard contract.

Restructured long term PPAs for Puget Sound Energy, Potomac Electric Power Co., Commonwealth Electric, Public Service Electric & Gas, and Bonneville Power Administration.

Advised various U.S. and European investors groups regarding the purchase of generation assets divested by the New England Electric System, Boston Edison, Commonwealth Electric, Eastern Utilities Associates, Northeast Utilities, Pacific Gas & Electric Co., among others.

Represented Con Edison on the consensual termination of nine long term PPAs resulting in over \$1.5 billion in ratepayer savings, including transactional support before the NYPSC.

Advised Con Edison on the securitization values of its QF portfolio, including all contracts covering gas supply, transportation, and steam.

Conducted resource planning studies regarding Con Edison's potential repowering opportunities at Ravenswood and Astoria.

Represented Puget Sound Energy, Commonwealth Electric, JCP&L, Bonneville Power Administration, Orange & Rockland Utilities, and PEPCO on the consensual termination or restructuring of long term PPAs.

Advised Associated Industries of Massachusetts on electric utility restructuring initiatives in New England.

Represented the Association Québécoise des Consommateurs Industriels d'Electricité (pulp and paper companies and aluminum smelters) on the potential restructuring of Hydro Québec.

Represented Bay State Gas Co. on the sale of a small power production facility.

Submitted expert testimony regarding competitive effects, market power effects, and opportunity costs attributable to NEES' transfer of non-nuclear assets to USGenNE.

LITIGATION SUPPORT

Represented Pio Pico combined cycle plant in its lawsuit against San Diego Gas & Electric Co. regarding PPA breach.

Represented NJ BPU on LCAPP litigation regarding the standard contract awards to LCAPP awardees, i.e., Hess, NRG, CPV.

Served as expert witness on behalf of NSTAR regarding its proposed 345 kV AC project submittal before the Massachusetts Facilities Siting Board.

Conducted continuing unit operation study of the 400 MW Newington Station for Public Service Co. of New Hampshire. Served as expert witness before NH Public Utilities Commission.

Advised Verde Energy on definition of class in response to class action suit.

Served as project manager for Puget Sound Energy, Portland General Electric, Avista, Cascade Natural Gas, and Northwest Natural Gas Company on Gas Transmission Northwest rate case before FERC.

Served as expert witness for Southwest Gas Corporation on pipeline transportation matters before FERC.

Served as expert witness to eCORP on financial damages associated with AIG Highstar and West LB's administration of project loan covenants.

Provided support to Con Edison counsel on contract matters pertaining to cogeneration facilities in New York State and New Jersey.

Served as expert witness for Puget Sound Energy and Bonneville Power on diverse matters pertaining to Tenaska Ferndale, Tenaska Frederickson, Encogen and March Point.

Represented a financial estate on the matter of MMWEC's lawsuit arising from delays completing Seabrook.

Performed net income analysis of fossil generation facilities owned by Northeast Utilities and Public Service Co. of New Hampshire for property tax valuations.

Represented Salt River Project, Arizona Public Service Co., Phelps Dodge, Magma Copper, Asarco and Cyprus before FERC on multiple FERC dockets pertaining to transportation options on El Paso, Transwestern and Mojave pipelines, including both cost of service and certificate proceedings.

Represented Wheelabrator-Frackville in its contract disputes with Pennsylvania Power & Light on min-gen emergencies and economic dispatch.

Evaluated pipeline alternative cost allocation methods, capacity release mechanisms, buy/sells, and other general rate case issues for the Arizona Directs.

Provided expert testimony and litigation support on behalf of Pan Alberta Gas-U.S. on the matter of rolled-in rates on Gas Transmission Northwest and the potential expansion of PG&E's intra-state transmission system in California.

Represented Northern Municipal Distributors Group and Midwest Region Gas Task Force Association, a group of gas utilities in eight states served by Northern Natural Gas Co.

Represented New England Cogeneration Association before FERC regarding Northeast Utilities' merger with Public Service Co. of New Hampshire. Conducted market power concentration analysis.

Represented Industrial Gas Users group in Northern Nevada before FERC in Southwest Gas Co.'s spin-off of transmission properties to Paiute Pipeline Co.

Directed project team's assessment of El Paso Natural Gas Co.'s transportation service enhancements on behalf of gas and electric utilities in Texas, Arizona and New Mexico.

Conducted fuel supply and transportation analysis on CNG and Columbia including expert testimony on behalf of Doswell Energy Ltd. Partnership in its civil litigation with Virginia Power.

Led project team's assessment of financial risk for major offshore Arctic pipeline (Endicott) owned by British Petroleum, Exxon, Amoco and UNOCAL. Performed analysis of Endicott risks for ratemaking capital structure and return under FERC's trended original cost methodology prescribed in Order Nos. 154-B and C.

Determined appropriate ratemaking capital structure and rates of return for the Cochin Pipeline under Williams methodology.

Assisted in the prudence determination of South Jersey Gas Co.'s Distrigas LNG take-or-pay commitments in light of FERC order No. 380 and merchant service options on Transco.

PROJECT FINANCIAL ANALYSIS (OTHER THAN DIVESTITURE RELATED)

Conducted real options valuation of the Newington Station for Public Service Company of New Hampshire (PSNH). Performed financial and engineering assessment of PSNH's thermal fleet in light of changing wholesale market design changes.

Evaluated onshore and OSW project economics for NRG BluewaterWind, including financial assessment of loan guarantees and production tax credits.

Provided enterprise valuation of eCORP's Stagecoach ownership interest under option value measures.

Represented Westchester County on the potential decommissioning of the Indian Point nuclear power plants, including enterprise valuation analysis under Fair Market Value.

Represented Cornell University on the master energy plan for expansion of generation assets. Conducted real option value (ROV) analysis pertaining to solid fuel and natural gas based energy infrastructure improvements.

Represented University of Rochester on the selection and optimization of a cogeneration facility to meet UR's long term energy requirements.

Represented Rochester Institute of Technology on the selection and optimization of a cogeneration facility to meet RIT's long term energy requirements.

Represented The State University of New York on the development of combined heat and power facilities on 26 campuses.

Represented Great Bay Power Corporation's equity investors in the purchase of a minority share of the Seabrook station.

Evaluated financial merit of power technology options for the Massachusetts Water Resources Authority on Deer Island, including NStar's distribution rate unbundling proposal. Advised MWRA on modifications to operating procedures related to combustion turbine generators served by Spectra Energy off the Hubline lateral.

Evaluated the competitive economic merits of rival steam and power production technology options to serve the UMass at Amherst's energy plant requirements.

Performed fuel-related contract restructuring services for various gas-fired generators throughout New England.

Served as financial advisor to the various pension funds holding Osceola and Okeelanta bonds resulting from Florida Power & Light's *de facto* termination of the PPAs.

Evaluated NUG profitability levels for various developers under alternative project financing arrangements for competitive solicitations.

Evaluated QF power purchase contracts using decision risk analysis for leverage lease transactions and non-recourse debt financing for thermal and hydro projects in various stages of development.

Evaluated the financial and business risks surrounding a proposed new pipeline from Canada to New England. Supervised the market need assessment conducted by Stone & Webster to support Champlain's certificate application at FERC.

Conducted gas valuation condemnation study for City of Mesa, AZ; determined economic value of Mesa's gas properties; advised City Council on strategic options with Southwest Gas.

Evaluated impact of the National Energy Board's proposed market-oriented price regime on TransCanada's transportation toll methodology.

Revised internal accounting procedures for capital budgeting techniques for Union Gas, CentraGas, and Gaz Metro in Ontario and Quebec.

Structured loan guarantees and price supports for Synthetic Fuels Corporation filing on behalf of New England Energy Park coal gasification facility.

Conducted comprehensive review of financial modeling capability of Energy, Mines and Resources (EMR), Canada for a national distribution system expansion program. Derived real cost of capital for EMR used to support distribution system expansion in Ontario, Quebec, and British Columbia.

Performed financial analysis for the Territorial governments of Yukon and the Northwest Territories in regard to local gas distribution systems, small-scale LNG, and methanol.

RESOURCE ASSESSMENT & MARKET DESIGN

Evaluated (in)validity of the Environmental Defense Fund's allegations about vertical market power abuse by gas utilities in Connecticut for Eversource Energy.

Submitted testimony before FERC on behalf of ISO-NE regarding gas/electric scheduling protocols affecting generation unit availability in the Day Ahead Market.

Represented NSTAR on proposed 345 kV AC transmission project from Carver to Cape Cod to provide reliability benefits in Lower SEMA, including production simulation modeling of energy price impacts with the Carver to Cape Cod project relative to other resource options for Lower SEMA.

Assessed long term on-shore and off-shore wind potential in New England for ISO-NE.

Represented the Connecticut Office of Consumer Counsel on the state's two EDCs' 2010 Integrated Resource Plan, including technical assessment of demand side initiatives, renewables, and natural gas infrastructure. Provided testimony before the Department regarding procurement recommendations over a 10-year horizon.

Represented NRG, TransCanada Power, and USPowerGen (in-City generators) on the NYISO Demand Curve Reset procedure, including the derivation of the Cost of New Entry, the econometric determination of net energy profits, and other fuel-related parameters affecting the reset process.

Represented PURA on the potential restructuring of ISO-NE's Forward Capacity Market.

Conducted engineering economic analysis of conventional generation and renewable technology options to meet Maryland's long term resource options for the Maryland Public Service Commission (PSC). Evaluated the impact of backbone transmission projects in SWMAAC. Evaluated onshore and offshore wind options culminating in the MD PSC's selection of USWind and Skipjack to develop offshore wind resources to serve EDCs in Maryland. Assessed the economic merit of the return to rate base regulation in Maryland using stochastic modeling techniques.

Represented Avista, Portland General Electric, Puget Sound Energy, and Northwest Natural Gas on pipeline transportation service options and pricing on Gas Transmission Northwest.

Conducted short and long term fuel price forecasts for ISO-NE.

Represented TransCanada regarding the competitive impacts among merchant generators associated with rival commodity gas pricing arrangements.

Evaluated pipeline decontracting initiatives associated with consensual termination of a large QF's gas supply, transportation and energy purchase contracts for El Paso Merchant Energy.

Conducted market forecasts of merchant income streams for major merchant power producers in New England, New York, and PJM.

Evaluated the feasibility of inside-the-fence cogeneration for Freeport McMoran at primary rod mill production plant.

Evaluated the feasibility of inside-the-fence cogeneration for a large paper mill in the inland southwest.

Evaluated the feasibility of inside-the-fence cogeneration for the MWRA.

Assessed competitive economics and merchant risk of a proposed 1,500 MW pumped storage facility in Ohio for Consolidated Hydro. Negotiated long-term preliminary arrangements for pumping power with Commonwealth Edison.

Evaluated power pricing and contract options for Enron Power's Milford project.

Advised HYDRA-CO Enterprise's cogeneration project at the Domtar Mill in Cornwall, Ontario in response to Vermont Department of Public Service RFP.

Prepared Gas Company of Hawaii's IRP, including demand side management. Analysis included formulation of DSM strategy and alternative propane supply acquisition strategies on the islands.

Conducted market analysis of New England utilities' long-term resource requirements for Texaco's integrated gasified combined cycle plant.

Conducted inter-fuel substitution analyses for NGrid (formerly, KeySpan).

Evaluated pipeline deliverability impacts attributable to El Paso's proposed San Juan Triangle and Northern Mainline expansions, and East End Manifold proposal for the Arizona Directs. Assessed pipeline interconnection arrangements on Northern Natural and Natural Gas Pipeline of America.

Assessed rival NO_x and SO₂ pollution control strategies, emission effects, and compliance costs for Clark Public Utility District, WA.

Responsible for audit of West Ohio Gas Co.'s gas purchase and transportation policies. Conducted management audit of West Ohio Gas purchasing practices under state mandated least cost planning standards.

Responsible for Stone & Webster's audit of Florida Power & Light Co.'s Resource Plan, including transmission effects and third party project development potential.

Assessed impact of Florida Gas Transmission Co.'s expansion on third-party gas use. Advised CEO on investment strategies and investor relations.

Project manager on engineering economic and financial assessment of Texaco's coal gasification technology; examined IGCC merits under various ownership structures; conducted preliminary market study of IGCC suitability in Florida and California.

Acted as project manager for economic/financial analysis of proposed IGCC for Florida Progress Corporation utilizing decision risk-evaluation techniques.

Determined market and resource/economic strategy for the proposed 1500 MW IGCC at New England Energy Park.

Served as project manager for technical/economic assessment of natural gas/liquid fuel substitution prospects in Newfoundland/Labrador, and the Yukon and Northwest Territories.

Evaluated monetary / financial issues related to a natural gas optimization study for the Government of Argentina, Energy Ministry. Activities included derivation of shadow prices for tradable petroleum products and recommended gas rate tariffs.

Determined the economic feasibility of a proposed oil to coal conversion project for GE's Pittsfield Plant.

RETAIL & WHOLESALE CHOICE

Formulated risk management option programs for University of Rochester, Cornell University, Phelps Dodge, and Visy Paper.

Negotiated gas supply and transportation contracts for Texas Instruments. Profiled and aggregated gas and oil usage data from various plant facilities for purposes of energy procurement package.

Designed contract options for natural gas, oil and electricity for CareGroup, a network of Harvard hospitals in Massachusetts and Rhode Island.

Designed RFP and negotiated contracts for natural gas, oil and energy tolling for a Massachusetts municipal electric utility.

Represented GPU Energy on the transition to competitive choice in New Jersey.

Evaluated retail procurement options for the Massachusetts Water Resources Authority.

Evaluated retail purchasing options for Abitibi Consolidated in Ontario and Quebec.

Evaluated retail purchasing options for Visy Paper in New York.

Represented L'Association des Industries Forestières du Québec (Quebec's association of pulp and paper manufacturers) in the matter of design and implementation of unbundled electricity rates under a new regulatory framework in Quebec.

Renegotiated intermediate term retail electricity contracts for Holoyke Industrials, a large group of energy users in Central Massachusetts.

Negotiated contracts for fuel and/or transportation services for various electric utilities in Arizona.

Valued Northern Natural Gas Co.'s Canadian gas supply and transportation contracts for Northern Illinois Gas Co. in the pipelines Order 636 reverse auction.

Renegotiated Paramount Resources gas supply agreement with Selkirk Cogeneration Ltd.

Negotiated preliminary Canadian gas supply contract for major proposed cogeneration venture in Eastern Ontario.

Obtained gas supply from major producer for South Jersey Cogeneration project.

Negotiated gas and transportation contracts with British Gas on behalf of Lakeland Energy (the first commercial IPP in U.K.). Also led consortium negotiations for power sales agreement with the North Western Electricity Board.

Negotiated PPAs for first planned coal gasification facility in New England with Boston Edison, EUA, and MMWEC.

Assisted in the formulation of transportation contracts between New England utilities and Champlain Pipeline Co.

Negotiated power sales agreements for various hydro small power producers with Southern Company affiliates, and various California and New England utilities.

Conducted analysis of power contract pricing terms and conditions, including wheeling provisions, for various cogeneration projects.

Formulated tipping fees and steam power values for proposed Puerto Rican biomass facility. Negotiated letters of intent with cities of San Juan and Guaynabo.

Designed terms and conditions for interruptible and curtailable contract rates for Barbados Light & Power Co.

DUE DILIGENCE

Evaluated transmission requirements and economic impacts associated with firm transmission withdrawal rights to support NYPA's Hudson Transmission Project.

Derived generation asset portfolio value of existing gas assets in New England for Exelon.

Responsible for project financial valuations underlying generation asset valuations for international investors acquiring generation assets in New England, New York, and PJM.

Evaluated LG&E's market exposure in SERC for PowerGen.

Conducted due diligence on behalf of BankBoston regarding Constellation Power's acquisition of EDE Noreste in Panama.

Evaluated short list respondents' fuel supply plans for Clark Public Utilities District.

Provided senior lenders with technical opinions regarding the (re)financing of power plants in New York State.

Analyzed California border and burner-tip gas prices affecting contract avoided costs in loan covenants for Deutsche Morgan Grenfell.

Responsible for Stone & Webster's engineering and financial / economic assessment of Reading Culm circulating fluidized bed facility, including fuel and power purchase contracts with Pennsylvania Power & Light Co. for The Deerpath Group.

Responsible for Stone & Webster's economic, financial, and regulatory risk analysis for The Deerpath Group, the lessor of the 1370 MW Midland Cogeneration Venture.

RATE DESIGN

Evaluated NGrid's imbalance resolution, daily scheduling procedures, and penalty exposure for PSEG-Long Island associated with gas/electric scheduling.

Evaluated open access transmission tariffs in PJM, New York and New England for import / export from New York State on behalf of EDCs or generation companies.

Evaluated Noreste's distribution rates in Panama under alternative performance based ratemaking methods.

Evaluated commercial implications of various utility unbundling mechanisms for purposes of installing inside-the-fence cogeneration or third-party energy procurement.

Derived transportation rates and competitive impacts under roll-in versus incremental tolling proposals for shippers on Northwest Pipeline, Pacific Gas Transmission, El Paso Natural Gas, Iroquois, and others.

Performed technical rate calculations for LDCs and electric utilities. Conducted or assisted in the preparation of marginal costs studies for electric and gas utilities throughout the U.S., Canada and Barbados.

Assessed the refunctionalization of El Paso's and Northwest's transportation rates under FERC Policy Statement and Orders 637/636/500.

Formulated rates for firm/non-firm cogeneration purchases for various utilities. Applied various revenue reconciliation methods for marginal cost-based rates.

Evaluated Bonneville Power Administration's trigger price rate proposal for Intalco Aluminum Co., an aluminum manufacturer in the Pacific Northwest.

Determined promotional off-peak power rates for Barbados Light & Power.

PRIOR BACKGROUND

UTILITY EXPERIENCE

Conducted production simulation analysis to support long term cogeneration rates for standardized contracts for Pacific Gas & Electric Co. Assisted in cost of service studies and rate cases (1978-1980).

OTHER INDUSTRY

Evaluated the impact of airline deregulation on major U.S. trunk carriers as a Research Assistant at the Harvard Business School (1977-1978).

EXPERT TESTIMONY (ADMINISTRATIVE ONLY)

Federal Energy Regulatory Commission

- ISO-NE (Waiver Request to support RMR for the Mystics)
- ISO-NE (Day Ahead Market Scheduling Change)
- Pan Alberta Gas (Pacific Gas Transmission)
- Con Edison Co. (Decertification)
- Con Edison and Central Hudson Gas & Electric (Information Disclosure)
- Arizona Directs (El Paso Natural Gas Co., multiple dockets)
- Northern Municipal Distributors Group (Northern Natural Gas Co.)
- New England Cogeneration Association (Northeast Utilities)
- Northern Nevada Industrial Gas Users (Paiute Pipeline Co.)
- East-of-California Customer Group (Mojave Pipeline Co., El Paso)
- Dome Petroleum Ltd. (Cochin Pipeline Co.)
- Endicott Pipeline Co. (British Petroleum, Exxon, UNOCAL, Amoco)

Connecticut Public Utilities Regulatory Authority

- United Illuminating Company (multiple rounds)
- Connecticut Light & Power Company (multiple rounds)
- Peaking Docket (Prosecutorial Arm)
- Office of Consumer Counsel (IRP docket)
- Northeast Utilities / NSTAR merger

New York Public Service Commission

- PSEG-LI
- Consolidated Edison Co. (nine dockets)
- Orange & Rockland (three dockets)

New Jersey Board of Public Utilities

- Orange & Rockland (three dockets)
- GPU Energy
- LCAPP Selection Process

Hawaii Public Utility Commission

- Gas Company of Hawaii

Maryland Public Service Commission

- MD PSC (multiple dockets)
- Eastalco Aluminum Company

Massachusetts Department of Public Utilities

- NStar (Carver to Cape Cod Transmission Line)
- Enron Capital & Trade

New Hampshire Department of Public Utilities

- Public Service Company of New Hampshire (Newington CUO)
- Enron Energy Services

Rhode Island Public Utilities Commission

- Enron Energy Services

Public Service Commission of Ohio

- West Ohio Gas Co.

Bonneville Power Administration

- Intalco Aluminum Co.

California Public Utilities Commission

- Pacific Gas and Electric Co. (Contracts)

Indiana Public Service commission

- Southern Indiana Gas and Electric Co. (multiple dockets)

Nova Scotia Utility and Review Board

- Consumer Advocate / Small Business Advocate (Maritime Link)

Régie De L'Énergie du Québec

- L'Association des Industries Forestières du Québec (Industry Restructuring)

EDUCATION

Cornell University

B.A., Arts & Sciences, 1975 (Phi Beta Kappa).

Harvard University

Masters, specialization in Energy Economics, 1978.

Stanford University

Post-graduate Industrial Organizational Management Program, Department of Electrical Engineering, 1979.

INDUSTRY PRESENTATIONS & PUBLICATIONS

Law Seminars International Conference; Transmission and Clean Energy in the Northeast “Offshore Energy Policy Issues, Where Are We Headed, How & When?,” March 2019

“Renewable Initiatives in the Greater Northeast and Mid-Atlantic: A Rorschach Test on What’s Beautiful and Believable,” Cornell Energy Connection, October 2017

“Infrastructure Update in New England,” New England – Canada Business Council Energy Trade and Technology Conference, November 2016

“Eastern Interconnection Interdependency Report,” Electric System Natural Gas Infrastructure Risk, Joint Meeting of Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Board, October 2016

“Natural Gas – What you Need to Know,” Organization of MISO States, Annual Meeting, October 2016

“System Reliability Analysis: Infrastructure Disruptions, Delays and Potential Market Impacts,” Northeast Gas Association, September 2016

“Chronology of Technical Assessments Affecting Pipeline Deliverability to New England,” New England Roundtable, November 2015.

“Natural Gas / Electric Nexus in PJM,” PJM Roundtable, October 2015

“Pipeline to Reliability,” IEEE Power & Energy, Volume 12, Number 6, December 2014.

“EIPC Gas-Electric System Interface Study” Northeast Power Coordinating Council 2014 General Meeting, December 2014

“Finding Practical Solutions to Fuel Supply and Generation Capacity Problems” Infocast Northeast Energy Summit, September 2014

“Update on Gas-Electric Coordination in the Northeast” Infocast Northeast Energy Summit, September 2014

Regional Market Trends Forum “Ten Years After” Gas & Power in Perspective,” May 2014.

“Infrastructure and Reliability Challenges for the Northeast Fuels Market,” New England Energy Conference and Exposition, May 2014.

“BuildingEnergy14 Understanding Our Energy Distribution Systems” Northeast Sustainable Energy Association, March 2014.

“Understanding Our Energy Distribution Systems: Gas Infrastructure and Deliverability in New England,” Northeast Sustainable Energy Association, March 2014.

“Polar Vortex Forensics: Initial Review of Key Drivers Affecting Power Prices in NYISO” Northeast Sustainable Energy Association, February 2014.

“Gas/Electric Interdependence: Challenges & Opportunities,” New England Consumer Liaison Group Meeting, June 2013.

“How Coal Plant Retirements Will Drive Midstream Investment in the Midwest and Northeast,” Infocast b2bwebinars, June 2013.

“Maine Energy & Environment Policy: Priorities for the 126th Legislature” March 2013.

“Market Dynamics Affecting Deliverability, Pricing and Strategic Opportunities in New England,” September 2012

“Natural Gas / Electric Dependencies in a Clean Tech Economy,” Harvard University School of Engineering and Applied Sciences Industry Presentation, Cambridge, Massachusetts, September 2012.

“Viewpoints on Current Events,” NECA Fuels Conference Panel, Newton, Massachusetts, September 2012.

“A New Englander’s Perspective: Shale Gas-Quantities, Price and What’s to be Done?” NECPUC Symposium, Samoset, Maine, May 2012.

“Leaning on Line Pack,” Public Utilities Fortnightly,” January 2011.

“Growth Prospects for Appalachian Gas: Good Access Trumps Market Fundamentals,” Platts 3rd Appalachian Gas Conference, October 2010.

“Future of Natural Gas in New England and Interaction with Electricity Markets,” New England Roundtable, April 2010.

“Managing Inter-Dependencies Across Gas and Electricity,” Carnegie Mellon University, Department of Electrical Engineering, December 2008.

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“Functionality of Northeast Capacity Markets Under RPM, the Demand Curve and LICAP,” Northeastern Power Supply Forum, Infocast, Philadelphia, June 2006.

“How Much Gas is Enough? Finding Incentives to Lessen the Gas Overbuild,” Platts Northeast Power Markets Forum, Washington, D.C., March 2006.

“How LNG fits into the Regional Market,” New England Roundtable, Boston, February 2006.

“Outlook on Natural Gas and LNG in New England,” New England Roundtable, November 2004.

“Market Dynamics Driving LNG Growth Prospects,” INFOCAST, Boston, October 2004.

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“Value Drivers Affecting Pipeline & Storage Entitlements,” INFOCAST, Houston, September 2002.

“The Big Picture on Power Market Dynamics and Storage,” INFOCAST, Houston, June 2002.

“2002 Outlook on Gas Supply and Deliverability,” INFOCAST, Boston, January 2002.

“Build vs Buy: An Assessment of Meeting End-User Electricity Requirements, Power Economics,” July/August 2001.

“Technical Assessment of New England’s Natural Gas Pipeline Adequacy,” on behalf of ISO-NE, before New England Association of Energy Engineers, April, 2001; U.S. Department of Energy, Wye Workshop on Strategic Initiatives for Coal and Power, March, 2001; Northeast Energy and Commerce Association, March, 2001; Boston Bar Association, February, 2001; Massachusetts Roundtable, February, 2001; NEPOOL

Reliability Committee, January, 2001; and, NEPOOL Participants Committee, January, 2001.

“Forecasting Equity Returns for Merchant Power,” INFOCAST, Atlanta, GA, September 2000.

“Maximizing the Value of QFs and IPPs in a Restructured Environment,” INFOCAST, Santa Monica, CA, July 2000.

“Valuing Transmission and Distribution Assets,” INFOCAST, Orlando, FL, January 2000.

“Build v. Buy: New Commercial Benchmarks,” International District Energy Association, Boston, MA, June 1999

“Monetizing Key Value Drivers,” INFOCAST, Buying & Selling Utilities’ Generation Assets, Boston, MA, November 1998.

“A Business Perspective on the Competitive Transition of the Electric Utility Industry,” American Bankruptcy Institute’s Fifth Annual Northeast Bankruptcy Conference, Falmouth, MA, July 1998.

“Uncertain ESCO Margins in New England’s Transitional Energy Markets,” Con Edison Energy conference on Supplying New Retail Markets, New York City, June 1998.

“PPA Buyouts and Restructurings: War Stories from the Trenches,” Exnet conference on Industry Restructuring, Washington, D.C. 1997.

“Monetizing NUG Opportunity Costs,” Sloan School of Management, Massachusetts Institute of Technology, August 1996.

“Natural Gas Procurement Options for Power Generators in New England,” presented to New England Cogeneration Association’s New England Gas Markets Conference, May 1995.

“The Emerging Secondary Market for Idled Transportation Capacity in the Northeast,” presented to Executive Enterprise’s Northeast Gas Markets Industry Conference, April 1994.

“Outlook for Gas-Fired Electric Power Generation in the Northeast through 2000,” presented to Executive Enterprise’s Northeast Gas Markets in the Post 636 Environment, November 1993.

“Gas Supply and Transportation Contract Issues: Implications for Cogeneration Project Financing,” presented to annual symposium on Energy Planning sponsored by Niagara Mohawk Power Corporation, May 1993.

“A Post-Merger Outlook on Wheeling in New England: FERC Precedent Cloaked in a Merger,” presented to Executive Enterprise's Second Annual Northeast Power Market Conference, May 1992.

“Transmission of Non-Utility Generation in New England,” presented to Executive Enterprise's Third Annual Industrial & Utilities Conference, Chicago, IL, October 1990.

“Capital Structure and Rate of Return for Regulated Entities: the State Perspective v. FERC's View, Accounting Association of Oil Pipelines,” Houston, Texas, February 1986.

“Demand-Side Management (DSM) Technologies for Island Utilities,” St. Lucia West Indies, September 1985.

“Alternative Marginal Cost Methodologies since PURPA,” Center for Professional Advancement, New Brunswick, NJ, May 1983.

“Utility Resource Selection-Decisions and New Challenges,” Department of Electrical Engineering, Tufts University, April 1982.

Participated in biannual Stone & Webster Utility Management Development Program on gas price and Federal regulatory developments, cogeneration and marginal costs, 1982-1989.

ASSOCIATIONS (CURRENT AND PAST)

American Gas Association

International District Energy Association

Northeast Gas Association

Northeast Energy and Commerce Association (prior Board Member)

Testimony Experience of Richard L. Levitan (Partial)

Federal Energy Regulatory Commission

ISO-NE Exelon Mystic 8&9
Docket Nos. ER18-1509-000, ER19-1639-000
Gas Harmonization Quadrant

New York City Generators (New York Independent System Operator)
Docket No. ER11-2224-000

Southwest Gas Co. (El Paso Natural Gas)
Docket No. RP05-422-000
Docket No. RP08-426-000

Pan Alberta Gas
Docket Nos. RP94-149-000, RP94-145-000

Con Edison Co.
Case No. 94-E0334

Con Edison and Central Hudson Gas & Electric (Information Disclosure)
Docket No. EL94-45-001

Arizona Directs (El Paso Natural Gas)
Docket Nos. RP88-44-000, RP95-363-000, RS92-60-000, et al

Northern Municipal Distributors Group (Northern Natural Gas Co.)
Docket No. RS92-8-000

New England Cogeneration Association (Northeast Utilities)
Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000, EL90-9-000

Northern Nevada Industrial Gas Users (Paiute Pipeline Co.)
Docket Nos. RP88-227-000, PL89-2-000

East-of-California Customer Group (Mojave Pipeline Co.)
Docket Nos. CP85-437-000, CP86-197-000

Dome Petroleum Ltd. (Cochin Pipeline Co.)
Docket No. IS85-13-000

Endicott Pipeline Co. (British Petroleum, Exxon, UNOCAL, Amoco)
Docket No. IS87-36-000

American Arbitration Association

Pio Pico Power Co.
Case No. 01-18-0000-0900

**Connecticut Public Utilities Regulatory Authority
(formerly Department of Public Utility Control)**

Wholesale Procurement of Standard Service and Last Resort Service
United Illuminating Company (multiple rounds)
Connecticut Light & Power Company (multiple rounds)
Docket No. 06-01-08PH02

Long Term Contracts for Standard Service
Docket Nos. 06-01-08RE01, 06-01-08RE03

Peaker Generation
Docket Nos. 07-08-24, 08-01-01

Integrated Resource Planning
Docket No. 10-02-07

New York Public Service Commission

Consolidated Edison Co. (nine dockets)
Docket No. 94-E0334

Orange & Rockland (three dockets)

New Jersey Board of Public Utilities

Orange & Rockland (three dockets)

GPU Energy

Long-Term Capacity Agreement Pilot Program
Docket No. EO11010026

Hawaii Public Utility Commission

The Gas Company of Hawaii
Docket No. 6617

Maryland Public Service Commission

Eastalco Aluminum Company
Case No. 7878

Massachusetts Department of Public Utilities

Enron Capital & Trade
Docket No. D.P.U. 97-94

Michigan Public Service Commission

Wisconsin Electric Power Company, d/b/a We Energies
Case No. U-16366

New Hampshire Public Utilities Commission

Public Service Company of New Hampshire
Case DE 10-261

Enron Energy Services
Docket No. D.T.E. 97-251

Rhode Island Public Utilities Commission

Enron Energy Services
Docket No. 2637

Public Service Commission of Ohio

West Ohio Gas Co.
Docket No. 85-0020-GA-GCR

Bonneville Power Administration

Intalco Aluminum Co.
Docket No. 95-420-C

California Public Utilities Commission

Pacific Gas & Electric Co.
Case No. 85-20-Ga-GCR

Southern California Edison Co. (multiple rounds)

Indiana Public Service Commission

Southern Indiana Gas & Electric Co.
Case Nos. 35780-S4, 35780-S8

Régie De L'Énergie du Québec

L'Association des Industries Forestières du Québec
Docket No. D.P.U. 96-25

United States District Court Western District of Washington at Seattle

Puget Sound Energy
Docket No. C95-1833R

2018 Firm Generating Capability for NS Power and IPPs¹

Facility	Fuel Type	Winter Net Capacity (MW)
<u>Hydro</u>		
Avon	Hydro	6.8
Black River	Hydro	22.5
Lequille System	Hydro	24.2
Bear River System	Hydro	37.4
Roseway ²	Hydro	0.0
Tusket	Hydro	2.4
Mersey System	Hydro	42.5
St. Margaret's Bay	Hydro	10.8
Sheet Harbour	Hydro	10.8
Dickie Brook	Hydro	3.8
Wreck Cove	Hydro	212.0
Annapolis Tidal ³	Hydro	3.5
Fall River	Hydro	0.5
Total Hydro		377.2
<u>Steam</u>		
Tufts Cove (1, 2, 3)	Heavy Fuel Oil/Natural Gas	318.0
Trenton	Coal/Pet Coke/Heavy Fuel Oil	304.0
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	150.0
Lingan	Coal/Pet Coke/Heavy Fuel Oil	612.0
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	168.0
Total Steam		1,552.0
<u>Combined Cycle</u>		
Tufts Cove (4, 5, 6)	Natural Gas	144.0
Total Combined Cycle		144.0
<u>Combustion Turbine</u>		
Burnside (1, 2, 3) ⁴	Light Fuel Oil	99.0
Tusket	Light Fuel Oil	33.0
Victoria Junction (1, 2)	Light Fuel Oil	66.0
Total Combustion Turbine		198.0

¹ Data sourced from NS Power 10 Year System Outlook - 2017 Report Revised on July 12, 2018.

² This asset is not used and useful in accordance with recent direction of the UARB. NS Power is assessing the requirements for decommissioning of these assets.

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

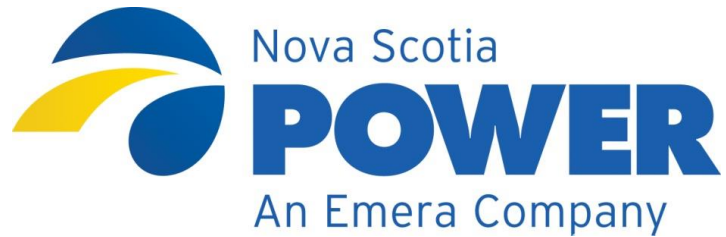
⁴ Burnside Unit #4 (winter capacity of 33 MW) was unavailable at the time but was planned to be returned to service by the end of Q2 2018.

<u>IPPs & Renewables</u>		
Pre-2001 Renewables	Biomass/Hydro	25.8
Post-2001 Renewables (firm) ⁵	Biogas/Wind	64.0
NS Power wind (firm) ⁶	Wind	13.7
Community-Feed-in-Tariff (firm) ⁷	Wind/Hydro	30.5
Total IPPs & Renewables		134.0
Total Capacity		2,405.2

⁵ Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) wind projects are assumed to have a firm capacity contribution of 17%.

⁶ Ibid.

⁷ Ibid.



OCTOBER 24, 2018

Revisions to Rate and Bill Impact Analysis

Confidential for Discussion Purposes

A large, solid blue shape that starts as a thin wedge on the left and expands into a wide, flat rectangle on the right, spanning the width of the slide at the bottom.

Agenda

- UARB Directive
- Proposed revisions to RBIA methodology
- Updated avoided costs
- Data Requirements from NS Power
 - Avoided costs of Fuel, Generation Transmission and Distribution
 - Energy and demand cost escalation rate
- Recommendations

2019 DSM Resource Plan (M08604)

- UARB Order (July 18, 2018)

[...]6. NSPI is also directed to provide E1, and the DSM Advisory Group, its suggested revisions to the rate and bill impact analysis (RBIA) by September 30, 2018.

RBIA Observations

- The apportionment of DSM costs and benefits to rate classes in the current RBIA methodology uses a static allocator factor based on class shares in one historic year (2014 test year) throughout the RBIA period of 2011-2033
 - It does not distinguish between differences in class responsibilities for energy versus demand related costs in areas of generation, transmission and distribution consistent with the UARB-approved Cost of Service Study methodology
 - It incorporates customer-related costs (e.g. billing) which distorts the allocation of benefits and costs associated DSM load reductions, especially for the residential and general customers.
 - It does not recognize year over year dynamics in class usage in response to long-term load forecast and DSM effects
 - It does not account for line losses in the determination of reduced usage for behind the customer meter
- The use of levelized fuel costs from 2011-2040 exceeds the time horizon of the RBIA (2011-2033) and overstates the rate reduction and bill savings in the early years and understates them in the outer years. In addition it overstates the benefits on the average due to inclusion of higher costs from years 2034-2040 which extend beyond the time horizon of the RBIA.

Proposed Revisions to RBIA Methodology

- To the extent practical, the RBIA should reflect the Cost of Service Study methodology in the allocation of forgone recovery of fixed system costs and benefits of DSM programs.
 - Annual fuel costs reduced by avoided fuel cost of DSM programs should be allocated to rate classes based on their shares in annual GWh requirement in each year.
 - Annual fixed generation and transmission costs, reduced by avoided marginal capacity costs, should be classified to energy and demand and reallocated to rate classes based on their shares in GWh Energy and MW coincident demands in each year.
 - Annual fixed demand-related distribution costs should be reduced by avoided marginal distribution costs and apportioned to rate classes based on their changing shares in annual sum of non-coincident class demands each year
 - Customer-related costs should be excluded from the allocation of costs and benefits.
- The rate and customer bill impact to be determined through application of a top-down approach similar to revenue determination process used in GRAs.
 - Changing annual class costs of fuel, energy-related fixed costs and demand-related costs are used to develop annual indices of changes in rate components of energy and demand charges which are in turn applied to class usage determinants to calculate revenues under DSM vs no DSM scenarios for participants and non-participants.
 - Average customer bills under With_DSM and Without_DSM scenarios for both participating and non-participating customer groups are determined by dividing their revenues by customer counts in each year.
- Further enhancements:
 - Appropriately reflects class line losses in determination of modified class usage.
 - In calculation of average bill impacts of participating customers, aligns number of participating customers with energy savings in each year.

Illustration of Differences in Annual Rate Changes as a Result of Proposed Changes in RBIA Methodology

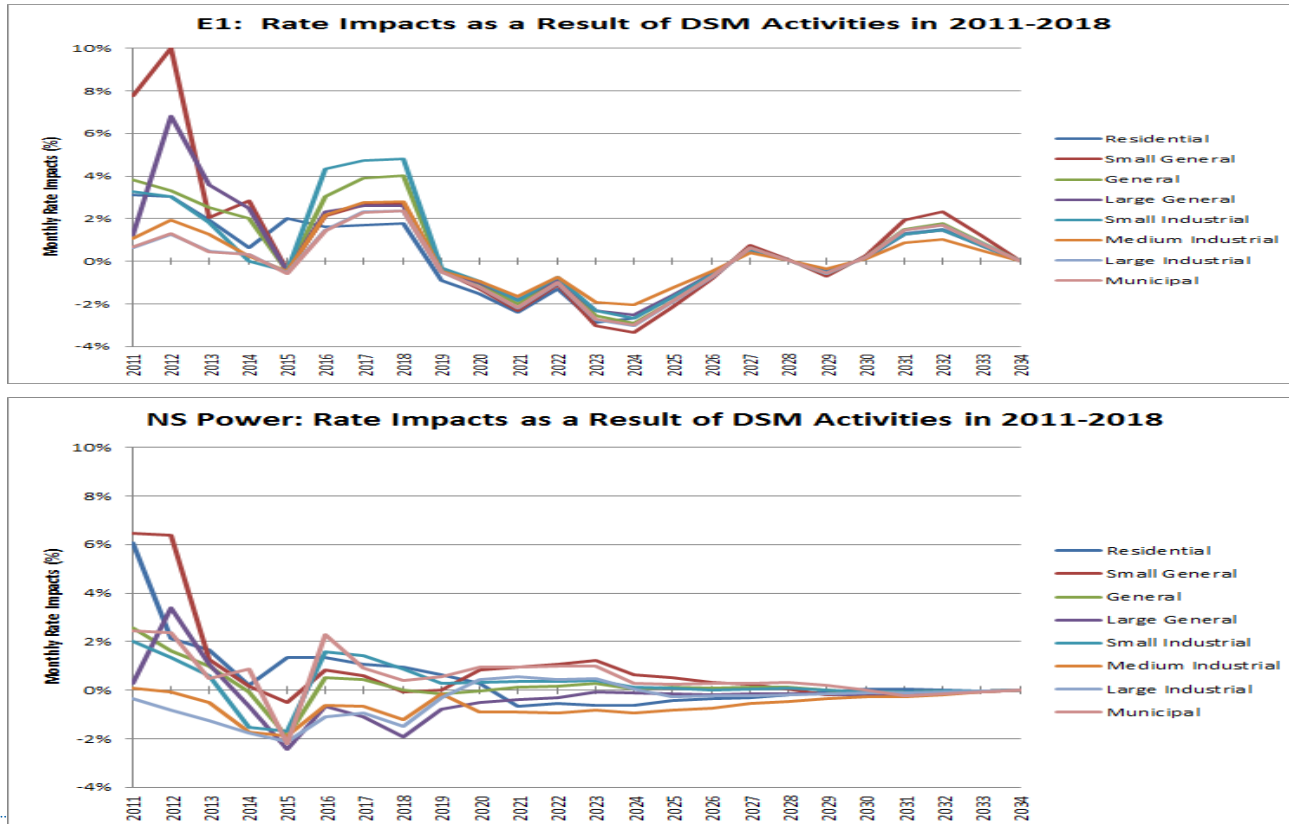


Illustration of Differences in Average Rate Changes as a Result of Proposed Changes in RBIA Methodology

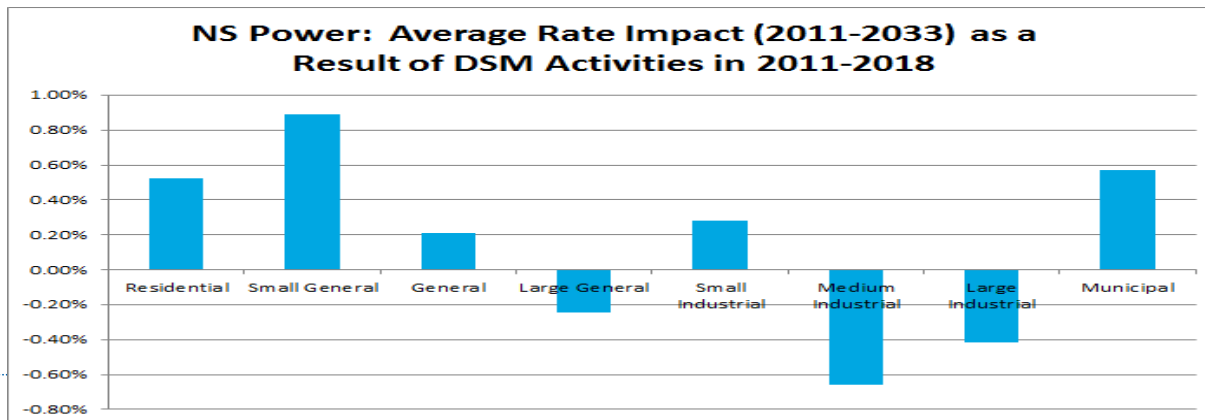
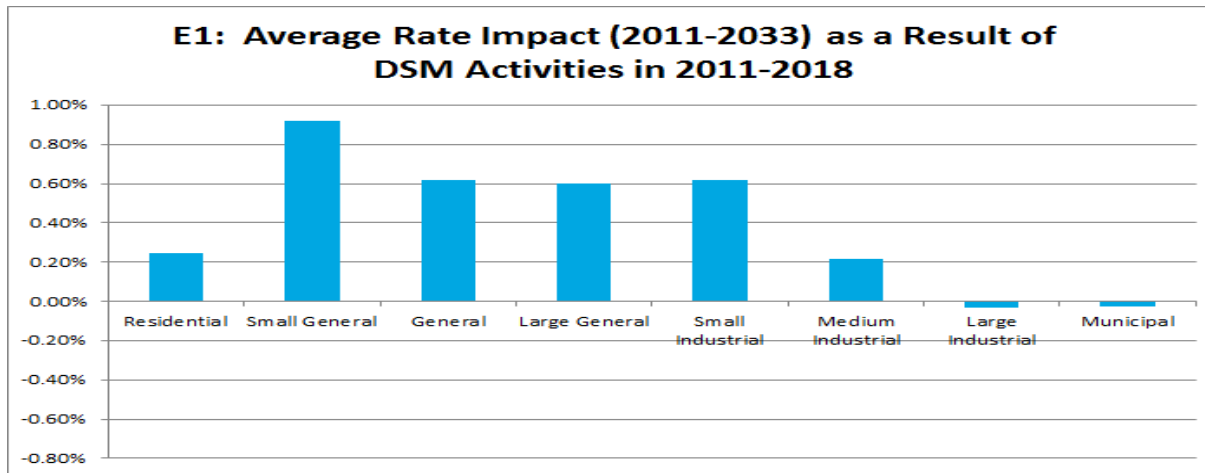


Illustration of Cumulative Differences in Rate Changes as a Result of Proposed Changes in RBIA Methodology

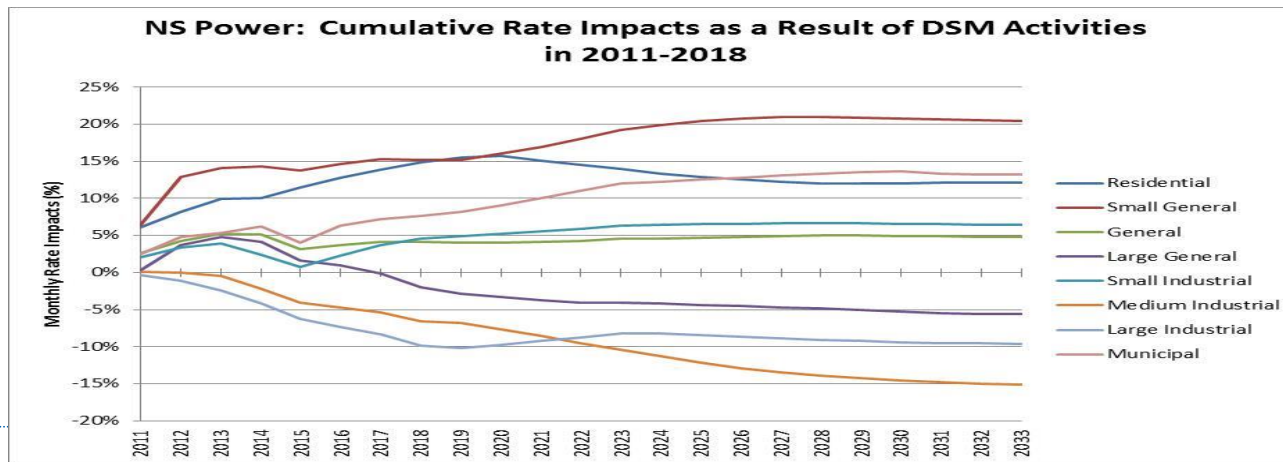
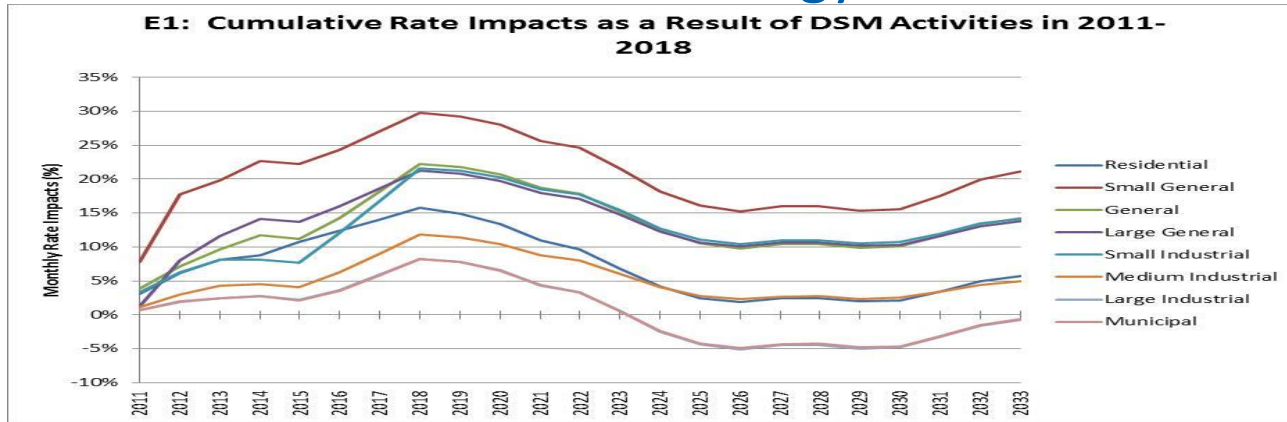
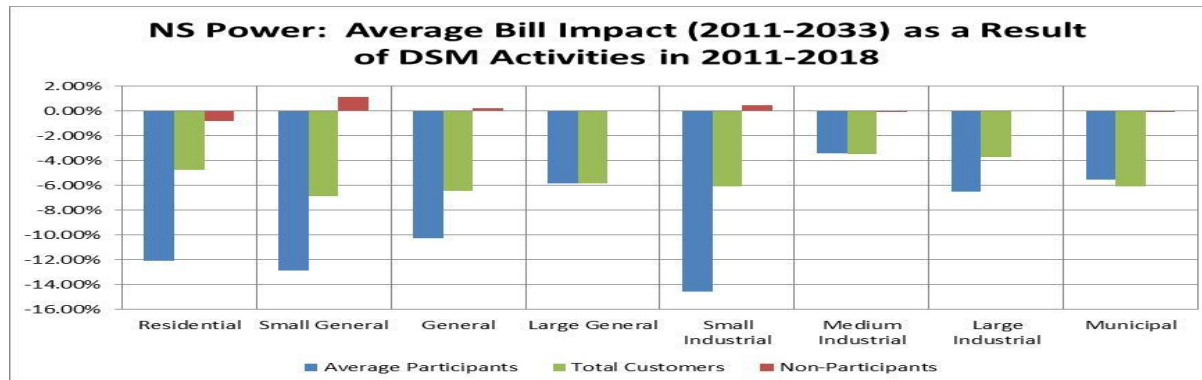
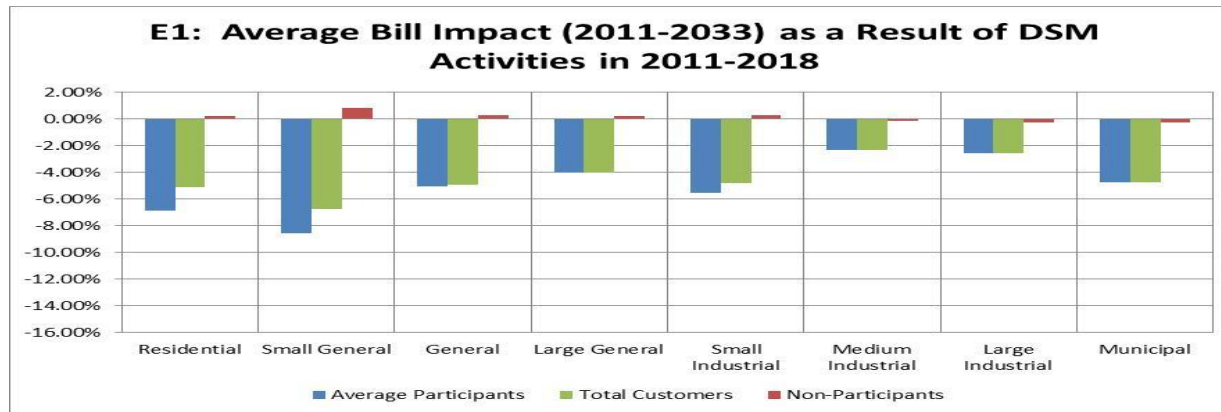


Illustration of Differences in Average Bill Impacts as a Result of Proposed Changes in RBIA Methodology



Under NS Power's approach:

- 1) Non-participants show slightly more diversified bill effects not visible due to scale of the graph.
- 2) Participants show higher bill savings due to reflection of changing number of participating customers in each year. More recent DSM programs target fewer customers but have higher bill effects.
- 3) Customer classes have an average decrease over the period but will experience increases in the early years due to higher rates

Approach to Updated Avoided Costs

- NS Power proposes to use annual avoided fuel costs rather than levelized avoided fuel costs, using the annual values from the last two IRPs. For avoided capacity, NS Power has proposes to use the 2014 IRP avoided capacity cost.
- A new IRP has been directed by the UARB. The next IRP is anticipated to be completed in time for its output to be used for the calculation of avoided costs for the next DSM Planning Cycle (2023-2026).
- The new IRP will reflect the current system outlook information and will provide NS Power's updated optimized evaluation of its long term planning needs. During this interim period, the 2014 IRP is being used, but there are a number of considerations when relying upon these values:
 - System marginal costs are lower than the IRP fuel forecast information (on both a levelized and annual basis)
 - Current long term fuel forecasts are lower than those used at the time of the 2014 IRP
 - NS Power's generation mix includes a growing portion of must take renewable energy
 - New levels of self-generation are being adopted and considered by customers which affects long term load assumptions and related capacity requirements

Updated Avoided Fuel Costs

- Recommend use of annual avoided fuel costs from IRP studies
 - 2011-2014 from the 2009 IRP.
 - 2015-2033 from the 2014 IRP.
- The IRP calculates the difference in Partial Revenue Requirements (PRR) using Strategist with and without the effects of DSM.
 - PRR include only the generation related costs which change under these requirements: fuel, purchased power, thermal and hydro O&M, renewable generation in compliance with RES, capital costs for new resources added in the plan
- Note that the March 6, 2017 letter from the UARB requested NSPI confirm that the costs of the new resources are amortized over the lifetime of the resource. It is confirmed that this is the case in the calculation of avoided costs of capacity and energy.

Annual Avoided Fuel Costs

Year	Avoided Energy Cost (\$/MWh)		Avoided Energy Costs used in RBIA (\$/MWh)			Actual Marginal Cost (\$/MWh)
	2009 IRP	2014 IRP	Current	Proposed	Variance	
2010	133.73					59.11
2011	108.44		166.00	108.44	-35%	59.42
2012	110.81		166.00	110.81	-33%	45.39
2013	97.20		166.00	97.20	-41%	63.56
2014	102.96		166.00	102.96	-38%	46.58
2015	107.41	63.63	107.00	63.63	-41%	47.07
2016	112.34	59.67	107.00	59.67	-44%	43.80
2017	119.29	58.38	107.00	58.38	-45%	54.03
2018	132.56	54.92	107.00	54.92	-49%	
2019	159.35	57.14	107.00	57.14	-47%	
2020	170.64	59.62	107.00	59.62	-44%	
2021	167.17	62.11	107.00	62.11	-42%	
2022	165.27	83.76	107.00	83.76	-22%	
2023	171.26	84.51	107.00	84.51	-21%	
2024	177.41	85.78	107.00	85.78	-20%	
2025	176.46	86.76	107.00	86.76	-19%	
2026	183.81	88.76	107.00	88.76	-17%	
2027	195.57	92.66	107.00	92.66	-13%	
2028	192.07	98.46	107.00	98.46	-8%	
2029	204.83	102.21	107.00	102.21	-4%	
2030	201.96	108.13	107.00	108.13	1%	
2031	210.60	112.94	107.00	112.94	6%	
2032	217.08	119.74	107.00	119.74	12%	
2033		112.58	107.00	112.58	5%	
2034		130.18				
2035		142.73				
2036		149.65				
2037		155.42				
2038		163.39				
2039		168.69				
Levelized	166.07	106.93				
Average 2011 - 2033	158.39	83.78	117.26	87.44	-25%	

Annual Avoided Generation Fuel Costs

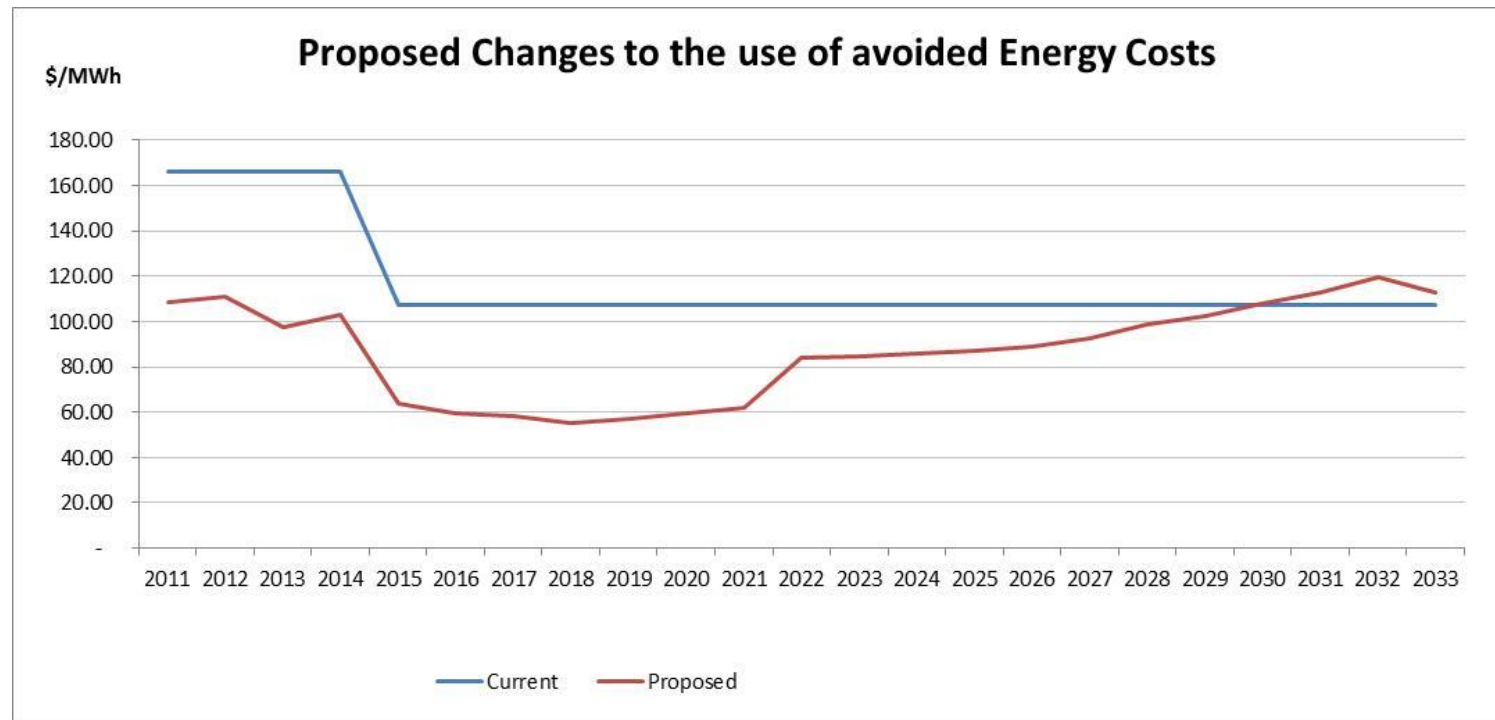


Illustration of differences in Rate Changes as a Result of Changes in Treatment of Avoided Generation Costs

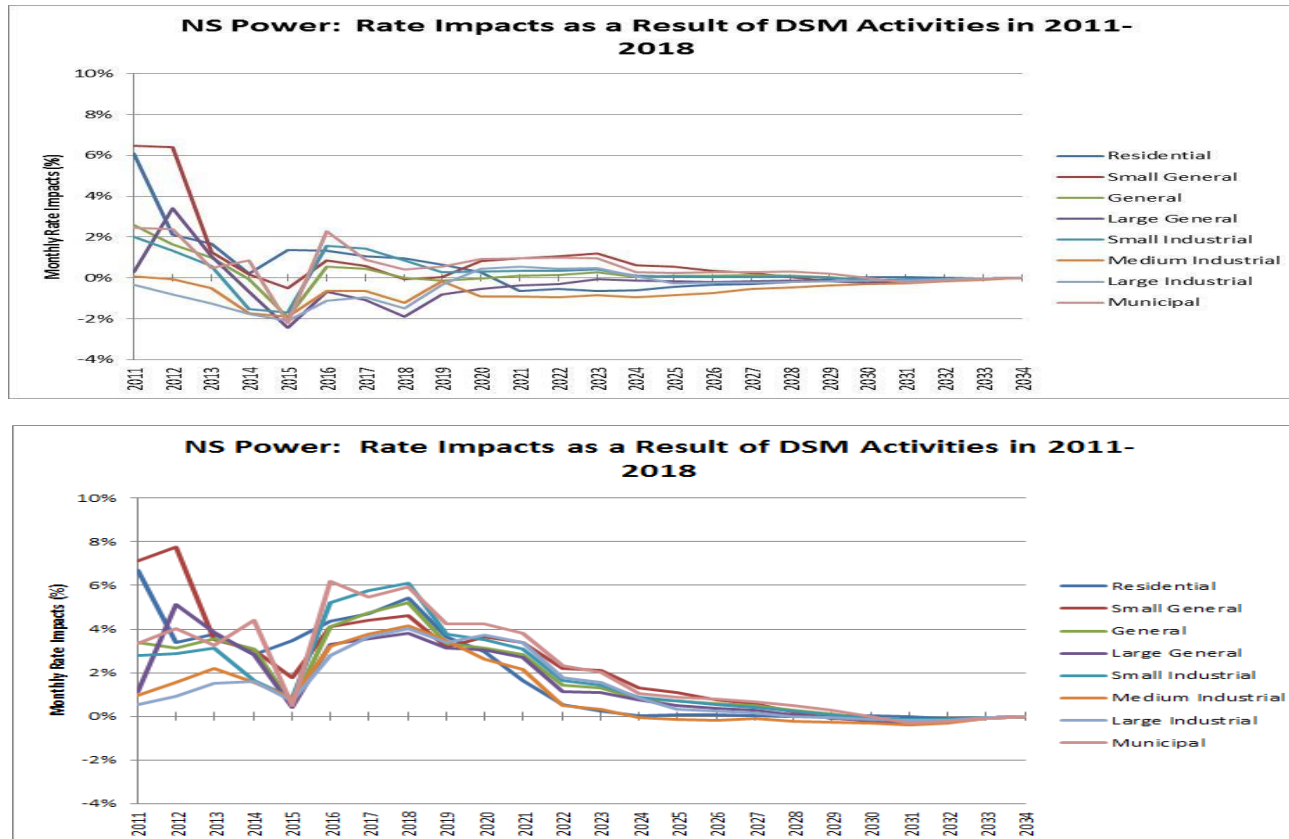
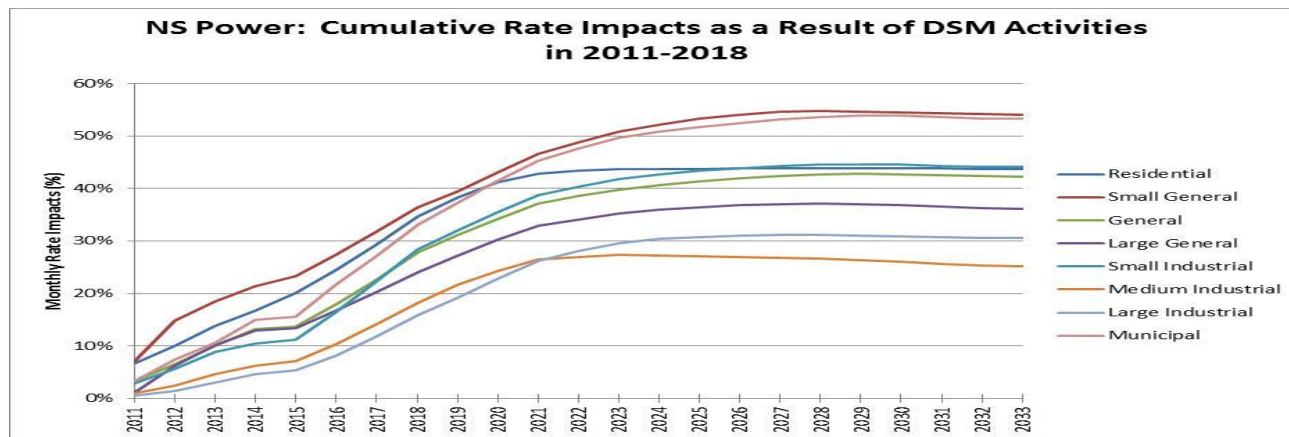
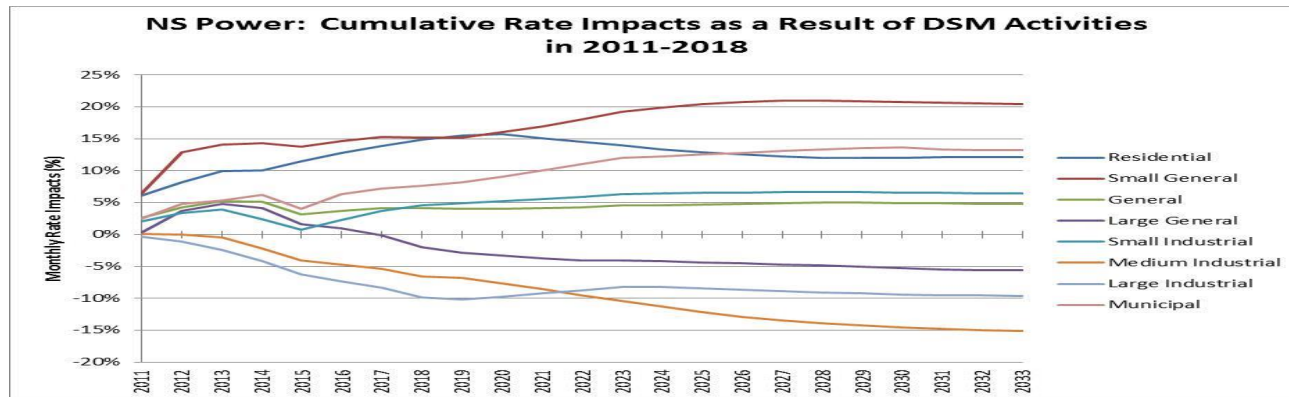


Illustration of Cumulative Differences in Rate Changes as a Result of Changes in Treatment of Avoided Generation Costs

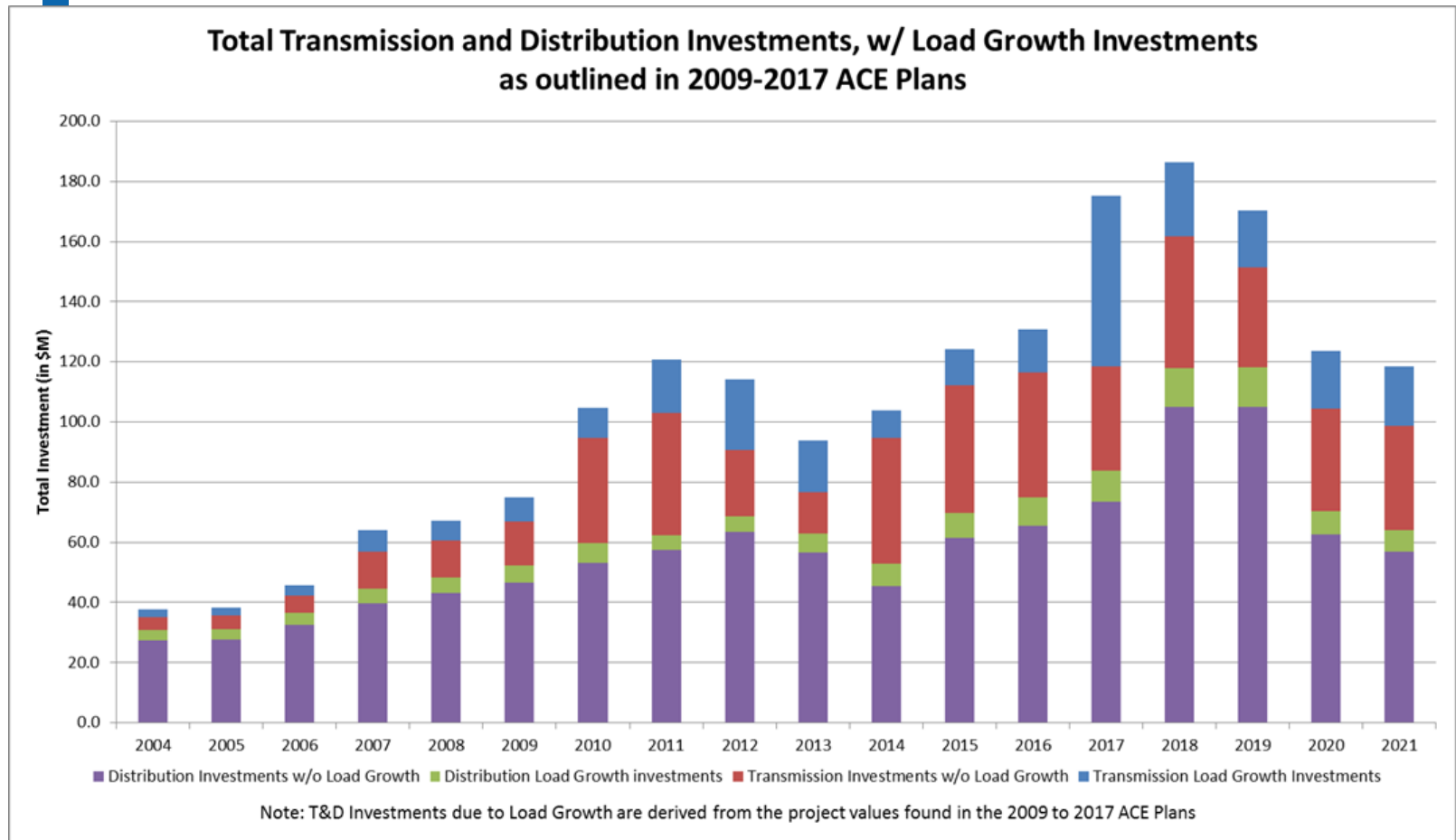


Annual Avoided T&D Costs

Year	Transmission (per MW)	Distribution (per MW)	Note:
2014	\$3,135.63	\$2,787.83	Based on 2014 ACE Data
2016	\$8,365.06	\$3,524.35	Based on 2016 ACE Data
2017	\$10,521.31	\$4,358.27	Based on 2017 ACE Data
2018	Not available yet	Not available yet	Based on 2018 ACE Data

- 2017's transmission value includes Maritime Link investments
- An item's carry-over is deducted from the previous year's item, to reflect actual spend in the given capital year.
- Ratios have been developed to forecast the percentage of T&D load growth related spend (2004-2009 & 2018-2021)
- The detail of the ACE Plan has increased over the last several years, detailing routine spend. This has enabled an increase in the refinement of the analysis performed.
- The data contained within the analysis is sourced from the ACE Plans (2009-2017) and associated Decisions.
- Only load growth related items are included within the calculation.
- Removal of the 2017 Subsequent Submittals, reduces the transmission and distribution values to \$9,586.30 & \$4,306.98.

T&D Investment



Escalation Rate

- DSMAG to “Review the current energy and demand escalation rate (2.7% per year) and select a new escalation rate if appropriate.”
- NS Power proposes simulated increases at the rate of inflation for 2020 – 2030.

Recommendations

- NS Power recommends COSS-based DSM cost and benefit apportionment methodology for the purposes of 2020-2022 DSM Plan and RBIA methodology going forward.
- Annual Avoided Fuel costs to be used in lieu of levelized fuel costs.
 - Consider using actual and currently forecast avoided costs in future RBIA calculations rather than IRP values
- NS Power recommends the use of the following Avoided Fixed Costs for the current calculation
 - Generation - \$195.00/kW (source: 2014 IRP)
 - Transmission - \$10.521/kW (2017 ACE Plan-based)
 - Distribution - \$4.358/kW (2017 ACE Plan-based)
- Average Bill Impact graphs should reflect weighed average as opposed to arithmetic average effects.
- Escalation Rate
 - A rate of inflation should be used in years 2021 – 2033