Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

October 11, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598946

FEI 2017 Long Term Gas Resource Plan (the Application) – FEI Rebuttal Evidence

On December 14, 2017, FBC filed the Application noted above. In accordance with the British Columbia Utilities Commission (BCUC) Order G-132-18 establishing the Regulatory Timetable for the proceeding, please find enclosed FEI's Rebuttal Evidence in the matter noted above.

FEI's Rebuttal Evidentiary filing is composed of two parts as follows:

Part 1: Report of Michael Sloan and John Dikeos, ICF. This Report is in response to the Evidence provided by James Grevatt on behalf of the BC Sustainable Energy Association (BCSEA) about the state of the industry regarding the use of non-pipeline solutions, including the use of Demand Side Management to defer or reduce the need for incremental infrastructure investments.

Part 2: Report of Navigant Consulting, Inc. on DSM Energy Savings Trajectories. This report provides comments on the BC Conservation Potential Review (CPR) Section 5, Market Potential, May 2017, in response to the evidence of James Grevatt in his pre-filed testimony submitted by the BCSEA-SCBC.

With respect to the issues raised in Part 1, FEI also submits as rebuttal evidence the following points:

1. ICF's Report identifies numerous activities that are required to enable FEI to determine if it could use Demand Side Management (DSM) to defer infrastructure projects. These activities potentially include further study, metering enhancements, process updates and regulatory adjustments. FEI is already working on these activities by exploring avenues for expanding its peak demand forecast method (as explained in Section 6 of the Application) and examining the technical viability of advanced metering solutions (as explained in FEI's response to BCUC IR 1.29.1).

2. ICF also finds that, among natural gas utilities, exploring the potential for DSM to be used for infrastructure deferral is an emerging practice with an uncertain track record. Any pathway proposed at this early point could change based on the outcomes of the various examination activities. For this reason, FEI is currently uncertain whether and when its ongoing activities and the further activities identified by ICF would lead to a definitive understanding of the pathway for determining if DSM could be used to defer infrastructure projects. As such, FEI currently cannot "submit to the BCUC a proposal and timeline for conducting the analyses that will allow it to fairly consider DSM alternatives to infrastructure investments in the early stages of any project development"[1] as proposed by Mr. Grevatt. However, FEI will report on the progress it has made on its activities when filing the next LTGRP.

If further information is required, please contact Ken Ross at (604) 576-7343.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

[1] Exhibit C2-7, p. 17.

EXPERT WITNESS REPORT OF MICHEAL SLOAN AND JOHN DIKEOS, ICF

Expert Witness Report of Michael Sloan and John Dikeos, ICF:

Rebuttal to Evidence of James Grevatt on 2017 FortisBC LTGRP Testimony

October 11, 2018

Submitted by:
Michael Sloan and John Dikeos

Michael Sloan
ICF
9300 Lee Highway
Fairfax, Virginia 22031

John Dikeos
ICF Canada
300-222 Somerset St West
Ottawa, ON K2P 2G3
1.613.523.0784 | 1.613.523.0717 f
icf.com

Table of Contents

1 Introduction

FortisBC Energy Inc. (FEI) retained ICF to review and provide rebuttal evidence in response to the report that James Grevatt of Energy Futures Group provided on behalf of the BC Sustainable Energy Association (BCSEA) and Sierra Club BC about the state of the industry regarding the use of non-pipeline solutions, including the use of Demand Side Management (DSM) to defer or reduce the need for incremental infrastructure investments.

Specifically, FEI requested that ICF respond to Mr. Grevatt's assessments that:

- The use of DSM to defer or reduce the need for incremental infrastructure investments is an "Emerging Best Practice" for natural gas utilities;[1]
- The idea that DSM demand measures are inherently too risky for planning purposes "is not supported by ConEdison's successful experience in using DSM to defer infrastructure investments";[2] and
- FEI could "develop a plan and timeline" to determine the potential to use DSM savings to defer capital infrastructure "in short order".[3]

We also address the significant challenges associated with the use of natural gas DSM to offset the need for incremental infrastructure investment, none of which are considered by Mr. Grevatt. These challenges include:

- Expected cost effectiveness and applicability of DSM as an alternative to infrastructure investments;
- Lack of good data on DSM program impacts on peak period demand;
- Challenges associated with coordinating timelines between targeted DSM efforts and infrastructure planning;
- Reconciling differences in reliability for infrastructure planning relative to DSM; and
- Addressing cost recovery risks and other structural regulatory issues associated with using DSM to offset the need for infrastructure investments.

[1] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 8.
[2] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 4.
[3] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 8.

2 Qualifications

This expert report is jointly prepared by Michael Sloan and John Dikeos of ICF. Mr. Sloan and Mr. Dikeos have extensive experience in the evaluation of DSM programs, the assessment of non-pipeline solutions to avoid the need for incremental investments in new natural gas infrastructure, and the potential to use geo-targeted DSM to defer or avoid the need for investments in new natural gas distribution and transportation infrastructure.

Introduction to ICF

ICF is one of the largest consultants offering policy, management and technical expertise to the North American gas and oil industry. ICF is also one of the largest DSM support contractors in North America. We help utilities assess DSM potential, design and implement DSM programs, and evaluate DSM program impacts.

In addition to past work with many private sector clients in the gas and oil industry, we have also been consultants to the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the U.S. Environmental Protection Agency (EPA), as well as government agencies in Canada, India, Mozambique, Qatar, and members of the European Union. We also undertake special studies for industry organizations like the American Petroleum Institute (API), Interstate Natural Gas Association of America (INGAA), and America's Natural Gas Alliance (ANGA), among others.

ICF is known for its quantitative, analytical approaches to solving client problems. We have developed models that reflect the present and projected conditions of the oil and natural gas industries, the electric power industry, the coal industry, and of the impact of environmental regulation across all energy industry sectors.

Sloan Professional Qualifications

Mr. Sloan is Managing Director, Natural Gas and Liquids Advisory Services, for ICF. His current professional address is 9300, Lee Highway, Fairfax, Virginia, 22031. Mike Sloan has more than 35 years of consulting experience on natural gas market issues, and has submitted testimony in 32 regulatory and legal proceedings.

Mr. Sloan's areas of expertise include natural gas price volatility and liquidity, natural gas price determination, natural gas storage issues, natural gas avoided costs and evaluation of long-term economic impacts of major transmission pipeline expansion projects, including the value of infrastructure deferral that would result from DSM programs. He has worked extensively on Canadian natural gas market and regulatory issues.

Mr. Sloan also has experience with Non-Pipeline Solutions for natural gas utilities, including the use of DSM to defer or reduce investments in new infrastructure. He is currently leading the ICF team assisting Con Edison in the preparation of Non-Pipe Solution efforts designed to reduce the utility's need for future upstream natural gas pipeline capacity. Prior to this, Mr. Sloan assisted in the development of the Infrastructure Integrated Resource Planning (IRP) planning process for Union Gas and Enbridge Gas in Ontario, including the development of the utility transition plan, and the preparation of the utility assessment of the potential for DSM to defer or reduce future infrastructure investments.

Mr. Sloan's CV is attached to this report as Appendix A.

Dikeos Professional Qualifications

Mr. Dikeos is a Senior Manager for ICF Canada. His current professional address is 222 Somerset Street West, Suite 300, Ottawa, Ontario, K2P 2G3. He has over 10 years of experience with DSM, including deep involvement with the delivery of over 10 conservation potential studies for gas and electric utilities (including FEI's 2010 Conservation Potential Review), support related to the design and implementation of innovative DSM programs in jurisdictions across Canada, the completion of detailed pre-feasibility studies of several DSM technologies, and the delivery of DSM training to utility staff.

Mr. Dikeos assisted in the development of the Infrastructure IRP planning process for Union Gas and Enbridge Gas in Ontario, including the development of the utility transition plan, and the preparation of the utility assessment of the potential for DSM to defer or reduce future infrastructure investments.

Mr. Dikeos' CV is attached to this report as Appendix B.

3 Utility Best Practices

In Exhibit C2-7, Mr. Grevatt states that "it would be consistent with ***emerging best practices*** [emphasis added] for the BCUC to direct FEI to provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development for any anticipated capacity-driven infrastructure investments".[4]

Mr. Grevatt attempts to justify this statement by providing a review of industry practices focused in three utilities/geographic regions. These include recent rulings by the Ontario Energy Board related to Union Gas and Enbridge Gas distribution companies in Ontario, reports by Con Edison in New York, and rulings by the Vermont Public Service Board. The Con Edison and Vermont Public Service Board examples are based on a general study for the Northeast published by the Northeast Energy Efficiency Partnership, of which he is a co-author.[5]

It is important to point out that the examples that Mr. Grevatt cites to support his conclusion that the use of DSM as an alternative to infrastructure investments is an "emerging best practice" primarily relate to electric utility experience, and are generally not recent. The Con Edison example is based on DSM programs targeting electric distribution system infrastructure investments between 2003 and 2008. The Vermont Public Service Board ruling was made in a 2005 power transmission capacity review proceeding.

The 2015 Northeast Energy Efficiency Partnerships report focuses primarily on electric utility efficiency programs. According to the report sponsor:

> "The report focuses primarily on electric T&D deferral, since that is where efforts in this area have focused to date".[6]

While the report sponsor goes on to state that "the concepts should be equally applicable to natural gas delivery infrastructure",[7] it does not address differences between the electric and gas industries that would need to be considered before drawing any conclusions relevant to the natural gas industry from the electric utility experience.

Mr. Grevatt's testimony related to the Ontario Energy Board process for natural gas infrastructure planning is relevant to this discussion, although his conclusions are not up-to-date with the current state of the process in Ontario, and do not reflect an accurate assessment of the state of implementation of these practices in Ontario.

In this section, we will provide a brief overview of other utilities' experiences in assessing the potential for DSM for infrastructure deferral and provide our conclusion regarding the status of gas utility best practices related to the use of DSM and geo-targeted DSM to delay or avoid incremental infrastructure investments.

Our conclusions are based on our direct experience addressing these issues with natural gas utility clients, and based on a recent review of other utilities' experiences prepared for Union Gas and Enbridge Gas in Ontario. This experience includes acting as the lead consultant in the

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[4] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 8.
[5] https://neep.org/energy-efficiency-transmission-and-distribution-resource-using-geotargeting.
[6] Ibid.
[7] Ibid.

preparation of the Ontario Infrastructure IRP process referenced by Mr. Grevatt, including a detailed assessment of the state of the natural gas industry efforts to use geo-targeted DSM to delay or defer infrastructure investments, and assisting Con Edison in the design, evaluation, and implementation of their recent non-pipeline solution effort to avoid the need for new infrastructure.

Based on our experience, we do not believe that the integration of DSM and infrastructure planning should be considered an emerging best practice for natural gas utilities.

3.1 Utility Experience Using DSM to Defer Infrastructure Investment

This section summarizes our knowledge of utility experience with using DSM to defer infrastructure investments. This includes a summary of findings for a 2017 best practice review of North American gas utilities, a status update on Ontario utilities' knowledge and experience in this area, and a review of recent New York non-pipes solutions efforts.

3.1.1 ICF 2017 Best Practice Review

As part of our review of the potential for DSM to reduce the need for infrastructure investment in Ontario, ICF conducted a best practice review of North American gas utilities to assess the state of the industry. This review, which has been filed with the Ontario Energy Board,[8, 9] was completed in early 2017 and focused on experience using DSM and demand response (DR) programs to reduce the need for infrastructure investment. ICF reviewed 15 IRP report and IRP report-style documents, with a focus on gas and combined gas/electric utilities. We also interviewed a cross-section of leading North American natural gas utilities identified as having experience working on integrated resource plans.

ICF's review of the state of the industry indicated that there is limited precedent for, or evidence of, natural gas utilities' use of geo-targeted DSM or dedicated DR programs to directly impact facilities planning. There is a recognition that DSM programs can impact demand, hence impacting the need for future facilities, but almost no experience with evaluating the impact of DSM on the need for specific targeted facilities.

Further, while electric utilities have used DSM and DR programs to reduce the need for new generating capacity and transmission capacity for many years, there is only relatively limited experience deferring distribution system infrastructure.

Overall, our review of existing DSM programs at North American gas utilities in other jurisdictions found that the natural gas industry has extremely limited experience integrating DSM into the facilities planning process and in using targeted DSM to reduce the cost of facility investments. Furthermore, ICF did not identify any natural gas utilities in North America that actively consider the impact of DSM programs on peak hour or peak day demand forecasts

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[8] Enbridge, EB-2017-0127 / EB-2017-0128 – DSM Mid-Term Review, Submission to OEB, Jan. 15, 2018, available at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/596649/File/document.
[9] Union Gas, EB-2017-0127 – DSM Mid-Term Review, Submission to OEB, Jan. 15, 2018, available at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/596652/File/document.

used for facilities planning. Since ICF's study was initiated in October of 2016, a few gas utilities have begun to consider these impacts. However, these efforts remain in the early stages.

We also found that the gas utilities that have contemplated the potential to use DSM programs to avoid or defer specific infrastructure projects have generally expressed concerns about the reliability of the DSM impacts as a facility investment alternative due to the lack of information on the measured impacts of DSM on peak hourly demand. The lack of accurate metered data on natural gas peak period demand, the long lead-time required to incorporate DSM as a potential alternative to infrastructure investments, and equity concerns resulting from geo-targeted DSM programs were also significant concerns.

Furthermore, ICF assessed activity in the electric power industry as part of our 2017 best practice review. Our review indicated that some progress has been made in that industry to defer transmission and distribution costs using targeted energy efficiency. However, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts leads us to conclude that geo-targeted DSM programs are likely to be more cost effective for the electric industry than they are for the natural gas industry, per equivalent amount of energy delivered (GJ of delivered energy), and that the electric industry experience provides only relatively limited value as an example for the gas industry.

More recent efforts by Con Edison, the Ontario natural gas utilities, and Northwest Natural Gas are addressed below.

3.1.2 Review of Ontario Gas Utility Efforts

In Ontario, the Ontario Energy Board (OEB) directed the two major natural gas utilities, Enbridge and Union Gas, to evaluate the potential to use DSM to avoid or defer (reduce) infrastructure costs. The study was designed to assess the implementation of broad-based or geo-targeted DSM programs to meet the forecasted hourly peak energy demand, consistent with the primary goals and principles of facilities planning, to provide reliable natural gas service with reasonable costs. ICF was engaged by the utilities to undertake the study and it was completed in early 2018.

ICF's analysis of the potential for geo-targeted DSM to reduce peak hour demand growth in Ontario suggests that, under certain circumstances, there may be potential to reduce infrastructure investments using geo-targeted DSM programs. The results showed that DSM can cost effectively defer infrastructure investments in certain situations where annual peak hour demand growth is limited and facility project costs are relatively high. However, ICF's research indicated that there are likely to be only a limited number of projects where targeted DSM might make sense. At a high level, the research suggests that it is often expensive and ineffective to assess DSM as an alternative to gas infrastructure projects; especially in cases where demand growth is not the primary driver for the facility investment.

ICF's study also found that there are a number of practical considerations impacting the ability to use geo-targeted DSM. The potential penetration rate for DSM programs can be a limiting factor in the ability to use DSM to offset demand growth, particularly in rapidly growing areas. There is also likely a minimum size for facilities investments where geo-targeted DSM programs could be cost effectively implemented due to program development, implementation, and monitoring costs.

Furthermore, the study found that data limitations on the potential impacts of DSM programs on peak period demand make reliance on DSM to avoid or defer specific infrastructure investments highly problematic at the current time. The main conclusion of this study is that additional research is necessary before the utilities would be able to rely on DSM to avoid or defer new infrastructure investments.

In addition to the IRP study, the Ontario utilities filed an IRP Transition Plan as part of their mid-term review, as per the OEB's requirements. This transition plan lays the pathway for considering IRP over the coming several years, and is currently under review by the OEB. BCSEA's response to BCUC IR 1.2.2 indicates that "the utilities have filed their mid-term reviews, but stakeholder evidence has not yet been solicited by the OEB and no orders have been issued".[10]

Within the Transition Plan, the Ontario utilities have stressed that additional analysis and monitoring of DSM programs and higher energy efficiency equipment, as well as any subsequent impacts of these initiatives on peak period demand should be conducted and factored into infrastructure requirement planning and forecasting processes, prior to relying on these approaches as a targeted alternative to new infrastructure investment.

Although the Ontario utilities proposed an "Integrated Resource Planning Transition Roadmap" as part of their Transition Plan, with suggested activities out to 2019, the regulatory process to review their progress to date and address next steps is only getting started and a definitive timeline and plan do not exist. The Ontario utilities are undertaking case studies to test in field the conclusions of the IRP study and inform the transition to IRP, prior to establishing a formal timeline.

3.1.3 Review of Con Edison Non-Pipes Solutions Efforts

Mr. Grevatt uses a review of Con Edison experience in deferring new investments in electric utility distribution infrastructure between 2003 and 2008 to support his conclusion that the use of targeted DSM to avoid natural gas utility investments in new infrastructure "would be consistent with emerging best practices". He notes that "by relying on firm contracts for demand response, Con Edison was able to save money for its customers by using DSM to defer infrastructure investments that it later concluded might never have been needed".[11] Mr. Grevatt's information is sourced from a White Paper prepared by ICF and Con Edison and presented at the 2010 ACEEE Summer Conference.[12]

While the information provided by Mr. Grevatt regarding the ability of Con Edison to avoid electric distribution system facilities through the use of targeted electric DSM programs is dated and has limited relevance to the natural gas industry or to FEI, Con Edison has more recently been at the forefront of efforts to avoid investments in new natural gas pipeline infrastructure.

[10] Exhibit C2-8, BCSEA and Sierra Club BC Responses to Information Requests from BCUC.
[11] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 5.
[12] Gazze, Chris et al., "Con Ed's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

Con Edison is in a period of rapid natural gas demand growth in the New York City region due to customer conversions from fuel oil to natural gas and to serve new load. The growth in demand is straining the available capacity on the interstate pipeline system serving sections of Con Edison's natural gas distribution system, and Con Edison is evaluating new pipeline contract options to increase capacity into its service territory, as well as non-pipeline solutions to reduce the need for new pipeline capacity. As part of this effort, Con Edison requested proposals from market participants to provide non-pipeline solutions (NPS). The results of this effort were submitted to the New York Public Service Commission on September 28, 2018.

According to this filing: [13]

> "Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") is exploring alternatives to new pipeline capacity to serve its natural gas customers as part of its Gas Smart Solutions Program. As discussed in prior Company filings in this proceeding, the Company issued a request for proposals (the "Non-Pipeline RFP" or the "RFP") in December 2017. The Company has now extensively evaluated the proposals for their customer benefits and ability to meet future natural gas supply needs. As a result of the review process, the Company has determined that there are numerous projects that would provide meaningful benefits to customers, reduce the use of delivered services[14] and advance New York State environmental policy goals. The Company has also determined, however, that the projects to date will not be able to fully meet its expected natural gas supply needs such that it can avoid the need for incremental pipeline capacity."

The non-pipeline solutions portfolio selected by Con Edison is projected to reduce growth in peak period capacity requirements on interstate pipelines into the Con Edison Service territory by 84,500 Decathterms (Dth)/day by 2023 at a cost of $305 million. The proposed non-pipeline solutions portfolio includes energy efficiency programs designed to provide 25,000 Dth/day of peak period gas demand reductions, programs designed to convert 12,400 Dth/day of natural gas space heating load to alternative fuels (electric heat pumps), 7,100 Dth/day of increased peak period natural gas supply from Renewable Natural Gas (RNG), and 40,000 Dth/day of peak period natural gas supply from CNG/LNG delivered by truck to strategic locations on the Con Edison system.[15]

It is important to note that despite committing $305 million to non-pipeline solutions, Con Edison does not expect to eliminate the need for new pipeline capacity, and is undertaking a series of

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[13] Consolidated Edison, Request for Approval of Non-Pipeline Solutions Portfolio in the Smart Solutions for Natural Gas Customers Program, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, p. 1, Case 17-G-0606, Filed September 28, 2018.

[14] "Delivered services are products offered by third parties that have firm contractual rights to pipeline capacity and are willing to sell the capacity bundled with natural gas commodity for a specific period of time or season (e.g., winter)." Ibid. page 1.

[15] Ibid. page 8.

other efforts, including parallel planning for a traditional pipeline solution to meet demand growth. According to the recent Con Edison filing:[16]

> "The Company is pursuing additional measures to address its unprecedented load growth and support reliability. In addition to efforts described in this filing to develop alternatives to traditional pipeline capacity, the Company is taking the following actions to meet customer needs as part of its larger Smart Solutions for Natural Gas Customers effort:
>
> - Doubling its gas energy efficiency targets for 2018, 2019 and 2020;
> - Preparing to launch a gas demand response pilot in Winter 2018/2019;
> - Investigating projects that could increase customer access to renewable thermal resources through business model innovation; and
> - Engaging with pipeline development companies to determine whether a traditional solution to meeting customer heating needs is feasible."

Despite all of these efforts, "Con Edison remains concerned about its ability to supply continued growing customer heating demands for natural gas with currently available resources, and a temporary moratorium on new gas customer connections remains a possibility."[17]

Although natural gas DSM is part of the Con Edison's portfolio of non-pipelines solutions and may help defer the need for new pipeline capacity, Con Edison's situation is somewhat unique and natural gas DSM would be even less cost-effective in most other jurisdictions where the comparative cost of gas infrastructure is much lower than in New York.

3.1.4 Review of Northwest Natural Gas Non-Pipes Solutions Efforts

One natural gas utility that was identified as having looked at the use of geo-targeted DSM for infrastructure deferral as part of our 2017 best practice review is Northwest Natural Gas (NW Natural). NW Natural collaborated with the Energy Trust of Oregon in 2017 to design and implement a geo-targeted load management pilot in Silverton, Oregon.[18, 19] The goal of this geo-targeted pilot was to identify the costs of acquiring peak savings to determine whether projects of this nature can be used as an alternative to physical capacity upgrades. NW Natural noted that there is uncertainty regarding the reliability of peak reductions due to DSM and one of the major challenges the utility faced in the design of this pilot was determining the actual flows for the targeted area due to the number of areas that are served by multiple gate stations.

NW Natural's 2018 IRP, published in August 2018, describes the utility's approach to assessing non-pipe alternatives to infrastructure spending.[20] As part of this process, NW Natural facility planners assess upcoming peak demand shortfalls in their distribution infrastructure and

[16] Ibid. Page 10
[17] Ibid. Page 10
[18] Energy Trust of Oregon (2018). 2017 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors. https://www.energytrust.org/wp-content/uploads/2018/04/2017.Annual.Report.OPUC_.pdf.
[19] Based on recent discussions with NW Natural staff, we understand that the utility is planning to file a report on their targeted DSM pilot project in November 2018.
[20] NW Natural (2018). 2018 Integrated Resource Plan, p. 8.8. https://www.nwnatural.com/uploadedFiles/NW%20Natural%202018%20IRP.pdf.

consider both local peaking assets (e.g. CNG, LNG) and demand side management through additional interruptible customers as potential alternatives to infrastructure spending. As part of the assessment of demand side management alternatives, firm customers with significant annual gas consumption in the targeted areas are engaged to determine if they are willing to pursue interruptible recall agreements. As summarized in the NW Natural's 2018 IRP, the utility recently considered demand side management alternatives, including firm capacity recall agreements, for seven distribution infrastructure projects and was unable to identify sufficient non-pipeline solution options to defer any of the infrastructure projects.[21]

3.2 Differences Between Electric Power and Natural Gas Industries

As previously noted, Mr. Grevatt bases his views on the potential to use DSM to avoid utility infrastructure investments primarily on a review of electric utility industry experience. This experience was documented in the 2015 NEEP report that he co-authored with his colleague Chris Neme on utility experiences with using energy efficiency to defer transmission and distribution (T&D) investments. This report focused primarily on infrastructure deferral in the electric power industry, for which there have been a relatively large number of examples where electric utilities have used passive and geographically targeted efficiency programs to accomplish infrastructure deferral. The successes in the electric power industry were noted by NEEP to be largely due to policy mandates, effective communication between infrastructure planners/engineers and staff responsible for the administration of energy efficiency programs, senior management buy-in, and a focus on smaller load reduction areas where it is easier to plan and execute a DSM opportunity.

The report notes that the conclusions that it draws should be applicable to natural gas infrastructure as well; however, there is no discussion of practical applications in the natural gas industry.[22]

Electric utilities have been using DSM and DR programs to reduce the need for new generating capacity and transmission capacity for many years. Demand Response programs have been used in a number of jurisdictions to reduce peak period demand, and to defer the need for new infrastructure. Where the electric utilities use DSM to offset infrastructure investment, the focus is generally on power generation capacity, or incremental transmission capacity into the company's service territory, rather than the impact on electricity distribution infrastructure.

Some concepts used for electric T&D facilities deferral in the IRP process can be applied to natural gas utilities. However, there are important differences between electric and gas infrastructure planning processes that need to be accounted for when trying to draw parallels

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[21] NW Natural (2018). 2018 Integrated Resource Plan, p. 8.24. https://www.nwnatural.com/uploadedFiles/NW%20Natural%202018%20IRP.pdf.

[22] Neme, Chris, and Grevatt, Jim: Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments. The Northeast Energy Efficiency Partnerships, 2015. https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

between the electric industry approach to IRP and gas utilities' approach. These differences include:

- **Facilities Planning Requirements:** Electricity facilities are designed to meet instantaneous peak requirements, while gas facilities are designed to meet hourly (distribution infrastructure) and hourly and daily (transmission infrastructure), and daily (gas supply) requirements. These differences in planning time of day tend to increase the value and reduce the cost of reductions in peak demand for the electric industry relative to the gas industry, which makes targeted DSM and DR programs more valuable for the electric industry than for the natural gas industry.
- **Cost Structure:** Gas facilities are typically less expensive than electric facilities per equivalent amount of energy delivered (GJ of delivered energy) for a given level of peak energy demand (peak GJ of delivered energy). As a result, utility facility costs typically make up a lower percentage of the typical customer gas bill than for their electric bill. This ultimately leads to the savings associated with a reduction in gas utility infrastructure tending to be lower than the savings available to the electric industry.
- **System Outage Risk:** Electric systems are designed to meet a level of system outage risk that is much higher than the system outage risk that is acceptable to natural gas utilities. While system reliability is a critical planning criterion for the power industry as well as for the gas utility, the costs and time period for recovering from a power system outage are relatively modest compared to the costs of recovering from a gas system outage. Unlike an electric utility where the system typically re-energizes itself almost immediately after the issue causing the loss of power is resolved, a gas system relight may take days, weeks or months to resolve due to the need to manually shut off gas flows to each individual meter prior to re-energizing the system, in order to prevent inadvertent gas leaks during the relight process, followed by a manual relight protocol for each individual meter. Insufficient infrastructure could lead to a system shut down during the coldest part of the winter, leaving residential and commercial customers without heat during extremely cold weather.
- **Resource Planning**: Electric utilities must either acquire power and capacity from the market or produce their own. An electric utility IRP contains a review and assessment of the trade-offs between various generation and electricity purchase options. Gas utilities, in contrast, only acquire resources from the market. A natural gas IRP's purpose is to assess energy delivery infrastructure requirements needed to deliver gas to end-use customers.
- **Peak Hour Data Availability**: For the electric industry, the need to measure peak period electricity demand has resulted in the availability of electric "smart" meters that record data on a substantially more granular flow level than current natural gas meters. As a result, detailed data on peak period electric demand at the individual customer level is available for the electric industry, and subsequently allows for assurances through data that savings will be realized.

  Gas utility infrastructure planning is also based on peak period requirements (peak hour and peak day requirements). However, unlike the electric industry, there is limited customer level data on peak hour and peak day demand, and almost no data on the impact of DSM programs on peak hour or peak day demand. Most gas utilities' customer meters are read no more frequently than once per month, do not record hourly or daily data, and do not measure peak flows.

The differences between the electric system and the natural gas system reduce the cost effectiveness of DSM as an alternative to new infrastructure for natural gas utilities relative to electric utilities. The electric industry can achieve greater infrastructure cost savings from similar DSM and DR measures, due to the higher cost structure of the industry. The difference in risk tolerance between the industries, for capacity shortage, also increases the attractiveness of DSM and DR for infrastructure deferral and avoidance in the electric industry relative to the natural gas industry. In addition, the use of DSM in the electric industry to reduce capacity requirements, and the ability to accurately measure peak demand has resulted in a better understanding of the impact of DSM on peak requirements in the electric industry than in the natural gas industry. This difference reduces the risk to the electric industry associated with the reliance on DSM to displace electricity infrastructure relative to the risk to the gas industry of relying on DSM to reduce the need for natural gas infrastructure.

These differences in planning requirements, system outage risks, peak hour data availability, costs and other factors reduce the value of electric power experience as a proxy for the natural gas industry.

3.3 Conclusions

Despite Mr. Grevatt's claims to the contrary, DSM is not widely accepted as an "emerging best practice" for infrastructure planning. There have been only limited cases where geo-targeted DSM has been implemented for *natural gas* utilities, and no results yet to suggest that this type of effort will ever be considered a utility best practice.

Where DSM has been used, it has been due to special circumstances, including very high cost facilities and challenges in developing new facilities. Furthermore, even in some of the most aggressive jurisdictions, the timeline for implementation of geo-targeted DSM as an alternative to infrastructure investments is not clear.

In the NEEP study authored by Mr. Grevatt and Mr. Neme, the examples presented were focused on infrastructure deferral in the electric power industry. The majority of investments into energy efficiency programs that were discussed in this report were driven by regulatory requirements, or by legislative mandate. The report noted that the electric power experiences are applicable to the natural gas industry; however, as noted in the previous section, there are key differences between the electric power industry and natural gas industry in planning requirements, system outage risks, peak hour data availability, costs and other factors.

There is currently a fundamental disconnect between the limited risk acceptable to natural gas utilities in the facilities planning process and the lack of information on the ability of DSM to reliably reduce peak period demand that will need to be addressed before FEI would be able to rely on DSM to reduce infrastructure investment. These risks are further highlighted in the following section.

4 DSM Infrastructure Deferral Risk Assessment

In his expert evidence, Mr. Grevatt has noted that "FEI's perception that DSM demand measures are inherently too risky for planning purposes is not supported by Con Edison's successful experience in using DSM to defer infrastructure investments".[23] We interpret this conclusion to mean that Con Edison's experience in using DSM to defer infrastructure investments indicates that FEI is incorrect in its perception that DSM demand measures are inherently too risky for planning purposes.

However, there are fundamental differences between Con Edison and FEI that reduce the relevance of the Con Edison experience. The primary difference between FEI and the Con Edison experience is that Con Edison is a combined electric and gas utility throughout the majority of its service territory. As identified in the ACEEE paper referenced by Mr. Grevatt, which was jointly written by authors from Con Edison and from ICF, the Con Edison experience referenced by Mr. Grevatt is based on electric utility experience rather than natural gas experience.

In addition, the Con Edison service territory faces a different set of issues than the FEI service territory. The New York City and surrounding areas served by Con Edison represent one of the most expensive regions in North America to install new infrastructure. As a result, the economics of expansion projects in the Con Edison service territory are expected to be much different from the economics of facilities projects in the FEI service territory.

These differences result in a significantly different planning environment that negates the relevance of the Con Edison electric experience in determining the riskiness of planning to use DSM to defer natural gas infrastructure investments.

Our experience with natural gas utilities supports the perception that the risks of using natural gas DSM to avoid infrastructure investments are not currently well understood and, in most cases, have only begun to be considered by gas utilities and their regulators. Major differences and uncertainty in the planning environments for DSM and infrastructure that impact the risks of using DSM to avoid or defer natural gas infrastructure investments are described in more detail below.

4.1 Differences in Risk and Reliability Criteria

One of the most challenging differences between the current DSM and facilities planning processes is the difference in risk and reliability criteria. DSM and facilities planning have fundamentally different reliability requirements that must be reconciled in order to transition to an integrated DSM and facilities planning process:

- A primary goal of facilities planning is to ensure the utility pipeline system is sufficiently sized to ensure that demand will not exceed the system capacity at design conditions. As a result, the facilities planning process is based on a primary philosophy of risk avoidance.

[23] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 4.

- Some primary goals of DSM program planning are to ensure natural gas is used more efficiently and to influence a culture of conservation.

DSM success is measured using a variety of metrics, including program participation rates and savings. However, the use of deemed savings in DSM program evaluations can lower the precision and confidence behind the actual savings resulting from DSM programs. Risk is inherent in DSM planning and implementation by design. Typically, utilities are encouraged to innovate in their approaches to program delivery in order to increase program uptake.

The use of DSM to reduce the need for facility investments changes the balance of risk for the DSM program. For a DSM program to be relied upon as an alternative to a new facility investment, it needs to satisfy the same risk criteria as the facility investment it is replacing.

The risks associated with facilities planning are not just financial; there is also the potential for gas system outages if facilities are insufficient. This risk is not present for standard DSM programs. If DSM programs fail to meet their objectives, the utility would be expected to identify and resolve the issues with the program, including potentially restructuring, redesigning, or canceling the program. There may be financial implications related to these changes but direct impact on consumers would be limited.

However, a DSM program implemented as an alternative to a new infrastructure project could lead to a shortage of system capacity if the program does not perform as intended, with potentially significant impacts on consumers. As a result, if a geo-targeted DSM program designed to reduce facility investments is non-performing and fails to deliver the expected savings, or if the savings appear to be uncertain during the evaluation phase, the utility will be required to proceed with the facility investment to ensure the same level of overall system reliability. This would lead to an increase in the overall cost of serving the load growth, as both the DSM costs and the facility investment costs would need to be recovered. In addition, the facility investment may need to be accelerated to meet the need, resulting in higher than anticipated or originally budgeted project costs.

The differences in risk and reliability are accentuated by the lack of information on the impact of DSM on peak hourly demand. While, with certain exceptions, there is general agreement that DSM can impact peak hourly demand, there is little to no data available on the actual impact.

4.2 Coordinating Timelines for Geo-Targeted DSM Programs

On an operational basis, DSM planning operates in a relatively short time-frame. For infrastructure deferral/avoidance via DSM, the program planning schedule depends on the type of program, and whether the policy issues described in the subsequent section are settled and an appropriate framework is developed.

The length of time that a DSM program needs to be in place (to reduce peak demand sufficiently to reduce the need for a specific facility investment) depends on the specific customer characteristics, the DSM program, and the specific facility investment. The rate of demand growth in the region served by the new facility is particularly important. For facility investments in areas with rapidly growing demand, the DSM programs may need to be in place earlier in order to offset additional incremental demand growth necessary to reduce the need for incremental infrastructure.

The lack of information on the ability of natural gas DSM programs to impact peak demand currently makes it impossible to know with certainty when a DSM program needs to be implemented, and how long the program needs operate in order to successfully reduce the facility investment. The rate of demand growth that must be offset by the DSM program will also have a significant impact on the length of time that the DSM program will need to be implemented.

For a geo-targeted DSM program to reduce a facility investment, program results need to be in place with sufficient reliability to ensure that the new facility will not be required to meet demand. Generally, this would require a successful evaluation of DSM program results before the leave-to-construct filing. Given the need to evaluate the impacts, the DSM program would need to be completed, or demonstrate measurable results; at least two years prior to when the additional capacity was initially projected to be required.

Hence, a successful geo-targeted DSM program would need to be approved and put into motion approximately three to five years before the expected in-service date of the targeted facility investment. However, the need for new facilities is generally uncertain at this stage. As a result, geo-targeted DSM programs may need to be implemented before gas utilities have a high degree of certainty that the facility investment will actually be required. This is likely to lead to DSM investments in areas where demand growth either accelerates or slows down, changing the amount of DSM necessary to reduce the facility investment, potentially leading to an expenditure on DSM that may not realize its full value as intended.

5 Other Considerations Impacting the Ability to Use DSM to Avoid/Defer Investments in Natural Gas Industry Infrastructure

Mr. Grevatt recommends that:

> "FEI's open-ended proposal to study the potential use of DSM to defer traditional peak capacity-related infrastructure investments is insufficient to ensure that the BCUC won't be "forced" to approve capital investments that could have been avoided. FEI should submit to the BCUC a proposal and time for conducting the analysis that will allow it to fairly consider DSM alternatives to infrastructure investments in the early stages of any project development."[24]

This recommendation fails to consider the complexities associated with implementing a policy to determine how DSM should be considered in the evaluation of infrastructure investments. Based on our experience in Ontario and in New York, and based on discussions with other utilities that have considered these issues, it is our recommendation that a wide range of policy issues need to be addressed prior to setting a specific timeline on this type of process. These policy considerations include:

1. **Changes in the Approval Process for Infrastructure Targeted DSM:** The differences in timeline and risk between DSM achieving annual energy savings and related benefits, and DSM targeted at specific infrastructure investment deferral or avoidance create different planning requirements. Geo-targeted DSM programs designed to reduce peak hour demand will need to be implemented much earlier in the facility planning cycle, often before there is certainty around load growth, and will have limited opportunity for revisions if the programs are not meeting expectations. In addition, the ultimate impacts of the programs – deferral or avoidance of infrastructure investment – will be subject to the general planning uncertainty consistent with the necessary implementation time frame.

   As such, DSM programs and technologies targeted at infrastructure deferral or avoidance may need to be subject to a different business and regulatory construct, cost-benefit analysis and different evaluation standards than standard DSM.

2. **Allocation of Risk:** There is an increase in risk and an increase in cost to the utility of relying on DSM programs as an alternative to infrastructure investment due to the uncertainty regarding the reliability of these programs. This leads to a number of public policy questions:
   - How much risk is appropriate? And how should the risk of underestimating facilities requirements be weighted relative to the risk of overestimating facilities requirements? Is the risk to society of potentially not having the necessary energy services in place an acceptable risk? How would this risk be assessed?

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[24] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 17.

- Who bears the risk if a geo-targeted DSM program does not lead to a deferral of an infrastructure investment?
- Who bears the risk if the benefits of a geo-targeted DSM program do not materialize, and the utility pipeline system is insufficient to meet peak demand?

3. **Additional Research:** The incorporation of DSM to reduce infrastructure investments as part of the normal infrastructure planning process will require additional certainty regarding the costs of geo-targeted DSM programs, and the impact of DSM programs on peak period demand, which will require additional data collection and research.

4. **Cross-Subsidization:** Currently the costs of new infrastructure are shared across customer classes. Geo-targeted DSM programs have the potential to lead to cross-subsidization between customer classes, and between DSM participants and other customers.

5. **Customer Discrimination:** By definition, the use of geo-targeted DSM programs to reduce infrastructure investments will lead to discrimination between customers at the boundary of the geo-targeted region. Customers within the boundary will be eligible for potentially significant incentives, while customers outside of the boundary will not.

6. **Establishment of an Appropriate Leave-to-Construct Budget Threshold for Geo-Targeted DSM Programs:** Developing, implementing, and evaluating geo-targeted DSM programs as an alternative to a specific infrastructure project is expected to be both time consuming and expensive. This will likely only make sense for infrastructure projects with significant savings potential.

7. **Appropriate Cost Effectiveness Testing:** Geo-targeted DSM programs are expected to have benefits that combine the attributes of facilities planning and DSM programs, and should be evaluated considering the benefits of the DSM program on both energy consumption (Traditional DSM) and on their ability to avoid or defer infrastructure investment based on the impact on peak hour/peak day demand (traditional facilities planning).

6 Review of Relevant FEI Experience

In this section, ICF witnesses present a general review of FEI's LTGRP, successes in the work completed to date, and the value of additional research.

FEI focused their 2017 LTGRP planning efforts on assessing delivery infrastructure requirements, and based on forecasted load, the LTGRP examines the potential for demand side resources and options for adding pipe, storage and compression. FEI's 2017 LTGRP indicates that FEI has traditionally built regional peak demand forecasts based on current peak hour use per customer being held constant over the planning horizon. However, in its recent 2017 LTGRP the utility noted that it has explored how the peak hour usage per customer may vary for each end-use alternate future scenario.[25] This new approach allows the utility to explore the potential impacts of broad based DSM programs upon peak hour demand. Although the LTGRP includes high-level assessment of impacts of broad based DSM, it does not include any analysis on targeted DSM.

FEI's 2017 LTGRP notes that the results from their traditional peak demand forecast method remains FEI's base forecast for planning purposes since the exploratory end-use method is not based on metered FEI customer data. However, FEI indicates that it will continue monitoring potential metering solutions that may allow FEI to validate the results of the exploratory end-use forecasting method.

FEI's 2017 LTGRP also provides details on FEI's peak demand forecasts and potential constraints that may need to be addressed throughout facility investments in the coming years. It is important to note that load growth is one of several factors that affect system capacity and influence the need for infrastructure projects. FEI staff indicated that increased urban density close to existing pipeline assets may lead to change in the class designation of the nearby infrastructure, leading to a reduction in the allowable operating pressure for that pipeline. There are also many instances where pipelines need to be replaced due to their age or reinforced to address issues with operating pressures in certain parts of the network.

Peak demand forecasts for FEI's Interior Transmission System (ITS) using FEI's traditional peak demand forecasting method suggest a capacity constraint could occur on this system as early as 2021 and as late as 2022. As such, FEI is currently evaluating facility investment options to address constraints on the ITS. According to FEI staff, the need for this potential investment is based on an annual 2.3-2.6 percent forecast load growth for the demand region most influential on the timing of the project (including the Kelowna, West Kelowna, and Lake Country areas).

ICF's analysis for Enbridge and Union in Ontario in 2017 and early 2018 suggested that, before consideration of costs, DSM could be used to reduce annual peak demand growth by up to 1.0-1.2 percent. While this study was specific to Ontario, the DSM options in Ontario and British Columbia are generally similar and we expect the conclusions for Ontario to be generally valid in British Columbia. As such, the relatively high growth that is forecasted for the ITS region is well above the expected potential for targeted DSM to offset, even before consideration of cost. For this investment, the best possible outcome for targeted DSM would be to defer the investment for a year or two. The timeline of potential facility investments in this area and the

[25] FortisBC, 2017 Long Term Gas Resource Plan, Dec. 14, 2017, p.149.

current uncertainty surrounding the costs and impacts of DSM programs on peak demand make it challenging to consider DSM as an alternative to facility investments for this project.

FEI's 2017 LTGRP also presents the results of an analysis of forecasted peak demand for other areas where future new infrastructure requirements are expected based on demand growth, including FEI's Vancouver Island Transmission System (VITS) and Coastal Transmission System (CTS). The analysis suggests that capacity-driven facility investments on these systems is unlikely to be required until at least 2028 for the VITS and beyond the forecast period for the CTS.

FEI's 2017 LTGRP also addresses the need for investments in distribution system capacity. These investments generally occur more frequently and are smaller in scale than transmission system projects. The results of ICF's research for Enbridge and Union Gas in Ontario showed that DSM can cost effectively defer infrastructure investments in certain situations where annual peak hour demand growth is limited and facility project costs are relatively high. The research was primarily focused on distribution system infrastructure and may be applicable to a subset of FEI's distribution system facility investments once sufficient data collection and verification has been established. However, the overall size of a distribution project is also a limiting factor. The cost of implementing and monitoring a targeted DSM program can make the use of targeted DSM as an alternative to distribution system investments infeasible from a cost perspective.

In summary, our review of FEI's 2017 LTGRP suggests that there are no specific major gas infrastructure projects where DSM could be used as an alternative in FEI's service territory in the next several years. In addition, we understand that FEI has made progress towards expanding its forecasting approach and understanding the capacity impacts of broad-based DSM. FEI has also indicated that it is starting to assess metering solutions that may enable further study into whether DSM can be used as a cost effective alternative to infrastructure spending.

7 Conclusions and Recommendations

Mr. Grevatt noted that in the 2017 LTGRP "FEI fails to provide a concrete plan and timeline for assessing the potential to use DSM as a cost effective alternative to traditional capacity resources".[26] In the BCSEA response to BCUC IR 1.4.2, "Mr. Grevatt recommends that Commission direct FEI to develop a plan that:

> 1) identifies the information that is needed in order to assess the viability of DSM and DR alternatives for deferring infrastructure investments;
>
> 2) describes the approach that FEI will use to obtain the required information;
>
> 3) describes the point in time at which the information will have been obtained; and
>
> 4) describes deliverables and accountabilities associated with the plan."[27]

We do not agree that a specific and detailed Commission directive on this point is needed at this time. Given the lack of certainty surrounding the effectiveness of DSM as an alternative to facility investments and the current lack of any specific major gas infrastructure projects where DSM could be used as an alternative in FEI's service territory in the next several years, the value of directing FEI to develop an accelerated plan is unclear.

In addition, Mr. Grevatt's assessment that FEI could "develop a plan and timeline" to determine the potential to use DSM savings to defer capital infrastructure "in short order"[28] is overly simplistic and does not account for the range of issues that need to be resolved prior to setting a firm schedule for consideration of DSM as an alternative to infrastructure investment. The most significant issues that will need to be addressed can be summarized as follows:

1) DSM has the potential to offset the need for new infrastructure. However, the potential is not well understood.
    - The potential depends on what is driving the infrastructure project (i.e. rate of growth, project cost, ancillary benefits associated with the project, etc.).
    - Integrating DSM into the facilities planning process is complicated. Factors that need to be properly considered and accounted for include project timing and relative reliability.
    - Costs may be higher than expected, especially in advance of more detailed knowledge of the costs and impacts of geo-targeted DSM programs.
    - Targeted DSM raises equity and fairness issues.

2) DSM impacts on natural gas peak period requirements driving new infrastructure investments are not well understood, and very little measured data exists on DSM impacts on peak hour demand or peak day demand for natural gas utilities.

3) There is limited actual experience to draw on to determine the potential for natural gas DSM to offset infrastructure.
    - Use of DSM to reduce facility investments remains relatively untried and untested.

[26] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 3.
[27] Exhibit C2-8, BCSEA and Sierra Club BC Responses to Information Requests from BCUC.
[28] Exhibit C2-7, BCSEA and Sierra Club BC Evidence, p. 8.

- Reliable implementation cost data is lacking.

4) The potential for DSM to offset infrastructure will be limited based on DSM penetration rates, costs, and reliability issues.

5) Additional research and pilot projects would need to be conducted prior to determining a schedule for considering targeted DSM as an alternative to infrastructure.

6) There are numerous regulatory and planning structural issues to be determined before it would be prudent to rely on DSM to offset infrastructure.
   - How does the utility ensure reliability?
   - How will the DSM approval process work?
   - Who bears the risk if the DSM programs are not sufficient?

Finally, based on our discussions with FEI staff, and our review of the FEI 2017 LTGRP filing, FEI has made significant progress to expand its forecasting approach, to understand the capacity impacts of DSM, and to start assessing metering solutions that may enable further study into whether DSM can be used as an alternative to infrastructure spending. Based on the progress to-date and the uncertainty surrounding any pathway for further activities, we recommend that FEI be allowed to continue to conduct exploratory research to determine if and how targeted DSM should be incorporated into the infrastructure planning process, rather than having the approach and timeline determined as part of a regulatory process without any significant assessment of the potential benefits of setting a pre-determined timeline at such an early stage.

Appendix A: Resume (Michael Sloan)

Michael Sloan
Managing Director, Natural Gas and Liquids Advisory Services

ICF
9300 Lee Highway
Fairfax, VA 22031
Tel: 1.703.218.2758
Mobile: 703.403.7569
Michael.Sloan@icf.com

EDUCATION

B.A.., Economics, Policy Studies/Operations Research, Dartmouth College, Hanover, NH, 1983

EXPERIENCE OVERVIEW

Mr. Sloan is Managing Director for ICF's Natural Gas and Liquids Advisory Services Group. He has more than 35 years of experience in the energy field.

Mr. Sloan provides in-depth analytical and regulatory support for natural gas utilities on issues related to natural gas storage, transmission, and distribution. His responsibilities include economic analyses of facility expansion projects, market assessments for corporate acquisitions, estimation of economic damages in litigation cases, and strategic analysis of regulatory issues. Areas of expertise include natural gas price volatility and liquidity, natural gas price determination, natural gas storage issues, natural gas avoided costs and evaluation of long-term economic impacts of major transmission pipeline expansion projects. He has worked extensively on Canadian natural gas market and regulatory issues.

Mr. Sloan is a frequent speaker at natural gas and propane conferences and association board meetings, and has testified on a variety of issues related to natural gas storage market power, natural gas storage economics, natural gas storage land owner issues, pipeline facility expansion economics, and natural gas market liquidity. He has also submitted testimony to the FERC on natural gas liquidity issues in California, and to the Minnesota District Court on propane market economics and pricing practices.

PROJECT EXPERIENCE

Selected Natural Gas Industry Analysis and Regulatory Support

2018 Potential for Infrastructure IRP to Avoid Natural Gas Distribution Facilities Investments. March 2018. For Union Gas and Enbridge Gas in Ontario, Mr. Sloan led a major study to evaluate the potential for an integrated planning process to reduce the need for new distribution company infrastructure by implementing targeted DSM programs.

2018 American Gas Association Study on the Implications of Policy-Driven Residential Electrification. July 2018. For AGA, Mr. Sloan led a study to determine the cost implications of AGA residential electrification scenarios.

2017/2018 Con Edison Non-Pipeline Solutions. Mr. Sloan led a team of ICF consultants assisting in the development of Non-Pipeline Solutions for Con Edison designed to solicit alternatives to new pipeline capacity on interstate pipelines that would require additional pipeline construction in New York.

2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements. January 2016. Mr. Sloan completed a detailed assessment of Ontario natural gas market requirements for Union Gas Limited, and presented the conclusions of the assessment to the Ontario Energy Board ("OEB") during the OEB 2016 Natural Gas Market Review.

Analysis of the Value of Nexus Pipeline Capacity to DTE Gas Customers. December 2015. Mr. Sloan completed a detailed assessment of the value of holding Nexus pipeline capacity on DTE Gas customers for DTE Gas. The assessment concluded that holding Nexus Pipeline capacity would provide long term benefits to DTE Gas customers.

Analysis of the Value of Nexus Pipeline Capacity on Michigan Energy Markets. November 2015. Mr. Sloan completed a detailed assessment of the value of holding Nexus pipeline capacity on Michigan Energy Markets for DTE Electric. The assessment concluded that holding Nexus Pipeline capacity would provide long term benefits to DTE Electric customers.

Analysis of Union Gas Avoided Costs. For Union Gas, Mr. Sloan prepared an assessment of the Union Gas estimates of avoided costs used to evaluate DSM programs. The assessment included recommendations for revisions to the avoided cost estimation methodology.

Analysis of Impact of Changing North American Supply and Demand on Union Gas Pipeline Facilities. September 2014. For Union Gas, Mr. Sloan prepared an assessment of the impact of natural gas market changes on planned Union gas facilities. The assessment concluded that new Union Gas facilities would continue to be used and useful for the foreseeable future.

Analysis of the Impact of Changing Natural Gas Market Conditions on ATCO Pipelines Market Risk. January 2014. On behalf of ATCO Pipelines, Mr. Michael D. Sloan completed an assessment of the impact of recent natural gas market changes on ATCO Pipeline market risk. The assessment reviewed the changes in natural gas supply and transportation on market risks for shippers and customers in Alberta.

Analysis of Natural Gas Market Outlook and Options for Gaz Metro, Quebec, Canada, 2013. Mr. Sloan completed an assessment of natural gas market conditions including expected pipeline flows and constraints impacting the Gaz Metro supply planning.

Analysis of Value of Proposed Natural Gas Storage Facilities 2013: Mr. Sloan used his storage valuation model to evaluate the potential value of contracting for capacity on a proposed storage facility for Heritage Gas, Nova Scotia Canada.

Analysis of Natural Gas Supply Options, Centra Manitoba Gas Company – a Division of Manitoba Hydro, 2010 -2012: Mr. Sloan prepared a detailed assessment of natural gas supply options for Centra Manitoba Natural Gas. The review included detailed assessment of customer demand patterns relative to industry standards, availability and likely costs of alternative supply strategies capable of meeting demand. The assessment also included evaluation of the clients' current facility contracts, and recommendations for future natural gas facility development and contracting practices. The review includes an assessment of likely pipeline flows and tariffs on the TransCanada Pipeline system.

Storage Market Concentration, Union Gas Limited, 2005 – 2006: On behalf of Union Gas, Mr. Sloan evaluated natural gas storage market concentration and natural gas storage market power in Ontario and the Great Lakes Basin. His report included an assessment of the workably competitive market region for Union Gas storage based on an analysis of market liquidity, connectivity, and market concentration. Mr. Sloan also testified before the Ontario Energy Board on behalf of Union Gas Limited on these issues. At the conclusion to this proceeding the Ontario Energy Board deregulated more than 50 Bcf of Union Gas Storage.

Analysis of Natural Gas Commodity Options, Centra Manitoba Gas Company – a Division of Manitoba Hydro, 2006 -2007: Mr. Sloan prepared a detailed assessment of natural gas commodity issues and trends influencing natural gas commodity purchases for Centra Manitoba Natural Gas. The review included detailed assessment of customer demand patterns relative to industry standards, availability and likely costs of alternative supply strategies capable of meeting demand. The assessment also included evaluation of the clients' current commodity purchasing agreements, and recommendations for future natural gas commodity purchasing practices.

Analysis of Optimum Storage Utilization, MichCon Gas, 2006, 2008, 2011: Since 2006, Mr. Sloan has prepared a series of analyses of the optimum storage utilization for the MichCon Gas local distribution company business to support MichCon regulatory proceedings related gas supply costs and storage utilization. The analyses evaluated the value of existing MichCon gas storage to LDC customers based on different weather patterns and usage scenarios.

Analysis of Value of Proposed Natural Gas Storage Facilities to Nova Scotia Power and Light (NSPI) – 2008: Mr. Sloan used his storage valuation model to evaluate the potential value of contracting for capacity on a proposed storage facility to NSPI.

Analysis of the Impact of LNG on Natural Gas Markets in Quebec, Rabaska Limited, 2005 – 2006: Mr. Sloan prepared a detailed analysis and forecast of the likely impacts of an LNG import facility located in Quebec on local, regional, and US and Canadian natural gas markets. The analysis concluded that the facility would substantially reduce natural gas prices in the region, and increase supply options and supply reliability. The report was filed with the Canadian Environmental Assessment Agency by Rabaska Limited as part of the facility approval process.

Analysis of Natural Gas Market Liquidity at Points Affecting New York State LDC's, Northeast Gas Association, 2003: Mr. Sloan co-authored a major study of natural gas market liquidity for the Northeast Gas Association to identify liquid markets for natural gas commodity purchases. The study included development of new approaches to evaluating market liquidity in the Northeastern U.S., and identified market centers that could be considered sufficiently liquid to provide a reliable source of natural gas.

Analysis of Natural Gas and Energy Price Volatility, for the American Gas Foundation and the Oak Ridge National Laboratory, 2003: Mr. Sloan managed a major study and co-authored a report on natural gas and energy price volatility for the American Gas Foundation.

Multi-Client Study, American Gas Association and Interstate Natural Gas Association of America: Mr. Sloan conducted the analysis, and co-authored the report "Short-term Natural Gas Markets" which was widely cited in FERC Order 637. The analysis was used by FERC to provide quantitative support for the removal of price caps in the short-term capacity release market

Propane Market Analysis

Propane Market Metrics Initiative, Propane Education and Research Council, 2003 – 2014: Mr. Sloan has managed a major project to collect and analyze propane market data for the Propane Education and Research Council (PERC). This effort has included consolidation and evaluation of all of the publicly available sources of data on propane demand in the U.S. The effort also includes a continuing assessment of the impact of major market trends on the propane industry, including changes in propane sales per customer over time, impact of price and weather on propane demand, changes in the residential new construction market for propane, analysis of competitive fuel sources, including electricity, fuel oil and natural gas. Mr. Sloan regularly presents results of his analysis to the PERC Board of Directors, and to other propane industry associations and companies.

Propane Market Forecast Model Development: Mr. Sloan managed the development and implementation of two major propane demand forecasting models for the PERC. The models provide the only publicly available forecasting capability at the State and County levels. The Propane Database and Forecasting Model (PDFM) provides State by State assessments of the total odorized propane market by end-use, including residential, commercial, on-road vehicle, industrial, and portable cylinder markets. The County Residential Propane Model (CRPM) provided propane markets with a customizable forecasting tool capable of evaluating residential demand on a county by county basis.

Assessment of Alternative Fueled Vehicle Potential, California Energy Commission, 2010. For this project, Mr. Sloan prepared an assessment of the market potential and market obstacles for propane vehicles in California.

Regulatory and Market Support, National Propane Gas Association, 2008 – 2014. Mr. Sloan provides market and regulatory analysis of issues influencing the propane industry for the National Propane Gas Association.

Assessment of the EIA Regional Residential Propane Model and Regional Residential Distillate Model, U.S. Energy Information Administration, 2006/2007. Mr. Sloan was asked by the EIA to peer review the EIA Residential Short Term Energy Model residential propane and distillate modules. The review included an in-depth review of the two modules, and recommendations to the EIA for model improvements.

Other Energy Supply and Demand Forecasting

Mr. Sloan has also supported and enhanced versions of the oil, natural gas and coal sectors for the MARKAL-MACRO model, the long-term, multi-period optimization model used by the U.S. DOE Policy Office for policy analysis and scenario evaluation of U.S. energy markets. In addition, Mr. Sloan has been responsible for the development and maintenance of a variety of energy forecasting models for the U.S. Department of Energy and the U.S. Environmental Protection Agency, including the World Energy Model (WOIL) and the IDEAS model used by the DOE Policy Office, and the Industrial Combustion Emissions (ICE) Model and the Industrial Fuel Choice Analysis Model (IFCAM) used by the EPA.

EXPERT TESTIMONY

1. Written evidence of Dr. Michael O Lerner and Michael D. Sloan, *Long term natural gas transmission expansion economics,* 1995. Mr. Sloan submitted written evidence and testified on behalf of Union Gas Limited before the Ontario Energy Board in EBRO 486. Mr. Sloan's evidence concerned the long term economics of pipeline expansion on the Union Gas system.
2. Written evidence of Dr. Michael O Lerner and Michael D. Sloan, *Long term natural gas transmission expansion economics,* 1996. Mr. Sloan submitted written evidence and testified on behalf of Union Gas Limited before the Ontario Energy Board in EBLO 251. Mr. Sloan's evidence concerned the long term economics of pipeline expansion on the Union Gas system.
3. "Written Evidence of Bruce B. Henning and Michael D. Sloan", TransCanada PipeLines Limited, Hearing Order RH-1-2002 (dated May 2002). Mr. Sloan submitted written evidence before the National Energy Board on behalf of Enbridge Gas Distribution Inc., Societe En Commandite Gaz Metro, and Union Gas Limited. Mr. Sloan's written evidence concerned the proposed establishment of the Southwest Zone and its impact on market liquidity.
4. "Analysis of FERC Staff Report Investigating California Natural Gas and Electricity Prices", San Diego Gas & Electric Co., Docket Nos. EL00-95-045 and EL00-98-42, prepared by Bruce B. Henning and Michael Sloan, (dated October 15, 2002) and submitted on behalf of Energy and Environmental Analysis, Inc. ("EEA") before the Federal Energy Regulatory Commission ("FERC"). Mr. Sloan's report concerned issues related to FERC's investigation of natural gas and electricity prices.
5. "Written Evidence of Bruce B. Henning and Michael D. Sloan on Behalf of Union Gas Limited", Hearing Order RP-2000-0005 (dated October 29, 2003). Mr. Sloan submitted written evidence on behalf of Union Gas Limited before the Ontario Energy Board. Mr. Sloan's written evidence addressed issues related to the compensation of landowners for the use of natural gas storage pools located on their property.

6. "Written Evidence of Bruce B. Henning and Michael D. Sloan", TransCanada PipeLines Limited, Hearing Order RH-3-2004 (dated June 21, 2004). Mr. Sloan submitted written evidence and testified before the National Energy Board on behalf of Enbridge Gas Distribution Inc., Societe En Commandite Gaz Metro, and Union Gas Limited.
7. Report "The Impact of Rabaska LNG Imports on Quebec and Ontario Natural Gas Markets", authored by Bruce B. Henning and Michael Sloan (dated November 2005) and submitted on behalf of Rabaska Limited Partnership before the Canadian Environmental Assessment Agency.
8. Report "Analysis of Competition in Natural Gas Storage Markets For Union Gas Limited." 2006. Authored by Bruce B. Henning, Michael D. Sloan, and Richard Schwindt and submitted before the Ontario Energy Board Natural Gas Electricity Interface Review EB-2005-0551. 2006. Mr. Sloan testified on behalf of Union Gas Limited before the Ontario Energy Board of Canada.
9. Report "Storage Planning and Optimization for MichCon GCR Customers", December 2007. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of MichCon before the Michigan Public Service Commission U-15451.
10. Report "Assessment of Natural Gas Commodity Options for Centra Gas Manitoba". February 2009. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of Centra Gas Manitoba before the Manitoba Public Utilities Board.
11. Report "Dawn Gateway Pipeline Expansion Project: Market Fundamentals and Market Impact of Project Construction". Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of Union Gas before the Canada National Energy Board.
12. Expert witness report "Opinions and Report on Propane Markets and Prices in Minnesota Related to Minnesota Attorney General Counterclaim and Answer". February 2011. Authored by Mr. Michael D. Sloan and submitted on behalf of Ferrellgas, L.P. before the State of Minnesota District Court, Second Judicial District.
13. Report "ICF 2011 Addendum to the 2007 ICF Report: Storage Planning and Optimization for MichCon GCR Customers", December 2011. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of MichCon before the Michigan Public Service Commission U-16921.
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15. Report "Review of Natural Gas Pipeline Market Activity around the Dawn Hub". May 2013. Authored by Mr. Bruce B. Henning and Mr. Michael D. Sloan and submitted on behalf of Gaz Métro before the Quebec Public Utilities Board.
16. Expert Witness Report and Testimony "Impact of Changing Natural Gas Market Conditions on ATCO Pipelines Market Risk". January 2014. Authored by Mr. Michael D. Sloan and submitted on behalf of ATCO Pipeline before the Alberta Utilities Board. Mr. Sloan testified on behalf of ATCO Pipelines before the Alberta Utilities Board.
17. Expert Witness Report and Testimony "Updated Assessment of Alton Natural Gas Storage", July 2014, Authored by Mr. Leonard Crook and Mr. Michael Sloan and submitted on behalf of Heritage Gas Limited before the Nova Scotia Utility and Review Board. Mr. Sloan testified on behalf of Heritage Gas before the Nova Scotia Utility and Review Board.
18. Expert Witness Report and Testimony "Impact of Changing North American Supply and Demand on Union Gas Pipeline Facilities", September 2014. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board.
19. Expert Witness Report "Evaluation of Union Gas Avoided Costs", December 2014, Authored by Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board in Case No. EB-2015-0029. Mr. Sloan testified on behalf of Union Gas Limited before the Ontario Energy Board.
20. Expert Witness Report and Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2014, Authored by Michael D. Sloan and submitted on behalf of DTE Gas

before the Michigan Public Service Commission in Case No. U-17691. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.

21. Expert Witness Report "Impact of Natural Gas Market Trends on Utilization of the Union Gas Dawn Parkway System", June 30, 2015. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board.
22. Expert Witness Report and Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", November 2015, Authored by Michael D. Sloan and Maria Scheller and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-17920. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
23. Expert Witness Report and Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2015, Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-17941. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
24. Expert Witness Report "2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements", January 2016. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board. Mr. Sloan presented the results of the analysis to the Ontario Energy Board on behalf of Union Gas Limited.
25. Expert Witness Report and Testimony "Propane Market Trends in the Northeastern U.S. and Atlantic Canada", January 2016, Authored by Michael D. Sloan and submitted on behalf of Heritage Gas before the Nova Scotia Utility and Review Board. Mr. Sloan testified on behalf of Heritage Gas before the Nova Scotia Utility and Review Board.
26. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", October 2016, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18143.
27. Expert Witness Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2016. Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-18243.
28. Expert Report "ICF Review of MNP Proposal for Irving Oil Load Retention Service". Authored by Michael D. Sloan and submitted on behalf of Nova Scotia Power before the Canada National Energy Board in Case RHW-001-2017.
29. Expert Report "Assessment of the Impact of the TransCanada Dawn LTFP Service Proposal on Natural Gas Markets", Authored by Michael D. Sloan and submitted on behalf of Union Gas Limited before the Canada National Energy Board in Case RH-003-2017.
30. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", October 2017, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18403.
31. Expert Report "Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment", Authored by Michael D. Sloan and John Dikeos and submitted on behalf of Union Gas Limited and Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2017-0128.
32. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", September 2018, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-20221.

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Bruce Henning, Michael Sloan. "Analysis of Short-Term Natural Gas Markets." *Energy and Environmental Analysis, Inc*., November, 1998.

Michael Sloan, Paul Friley. "Natural Gas Storage Overview in a Changing Market Environment." *Gas Research Institute,* GRI-99/0200, February 2000.

Michael Sloan, Paul Friley, Bruce Henning. "Restructuring Activity of Natural Gas Local Distribution Companies." *Gas Research Institute,* GR00/0018, June 2000.

Bruce Henning, Michael Sloan, Maria deLeon. "Natural Gas and Energy Price Volatility." *Prepared for the Oak Ridge National Laboratory by the American Gas Foundation*, October 2003.

Michael Sloan, Bruce Henning, Sol deLeon, David Clayton. "Propane Industry Issues and Trends." *Propane Education and Research Council*, June 2004.

Michael Sloan, Bruce Henning, Sol deLeon, David Clayton. "Propane Industry Issues and Trends II." *Propane Education and Research Council*, January 2005

Michael Sloan, Bruce Henning. "Propane Industry Issues and Trends III." *Propane Education and Research Council*, August 2005.

Michael Sloan. "Propane Market Growth: A Review of Propane Market Trends and the Role of the PERC Market Metrics Initiative", Prepared for the National Propane Gas Association, January 30, 2006.

Michael Sloan, Bruce Henning. "Propane Industry Issues and Trends IV. " *Propane Education and Research Council*, August 2006.

Michael Sloan. "Natural Gas Supply and Demand in an Uncertain Environment". Canadian Institute Conference on Natural Gas Storage, September 2008.

Michael Sloan, Richard Meyer. "2009 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020." *Propane Education and Research Council*, September 2009.

Michael Sloan. "What Keeps You Up at Night? Natural Gas Market Planning in an Uncertain Environment". Canadian Institute Conference on Natural gas Storage, February 2009.

Michael Sloan. "Back to the Future? Impact of Market Volatility and Uncertainty on Natural Gas Supply and Infrastructure". Canadian Institute Conference on Natural Gas Infrastructure and Supply, November 2009.

Michael Sloan, Richard Meyer. "2010 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020. " *Propane Education and Research Council*, June 2010.

Michael Sloan, Bruce Hedman, et al., "Strategic Market Assessment for Commercial Sector Propane Sales" *Propane Education and Research Council*, February 2011.

Michael Sloan, K.G. Duleep, et al. "Economic Impact of the Propane Green Autogas Solutions Act of 2011 (H.R. 2014)", *National Propane Gas Association*, October 2011.

Michael Sloan. "Industry at a Crossroads", *Propane Education and Research Council*, May 2012.

Michael Sloan, Warren Wilczewski. "2013 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020. " *Propane Education and Research Council*, April 2013.

Michael Sloan. "Implications of U.S. natural gas liquids (NGL) market developments on European petrochemical and NGL markets", Platt's European Petrochemicals Conference, Düsseldorf, Germany. March 2014.

Michael Sloan. “A Detailed Look at the Impact of Cochin Pipeline Reversal on Propane Markets in the Midwest”, presented to the Midwest Governors Association Propane Supply Chain Working Group Meeting June 4, 2014, Madison Wisconsin.

Michael Sloan, Warren Wilczewski. “Impact of the Cochin Pipeline Reversal on Consumer Propane Markets in the Midwest”, *Propane Education and Research Council*, August 2014.

Michael Sloan, “NGL Production Outlook in the Utica and Marcellus”, NGL Gold Rush Executive Briefing, Cleveland, Ohio. September 2014.

Michael Sloan, “NGL Production, Economics, and Pricing in the Utica and Marcellus”, NGL Gold Rush Summit, Cleveland, Ohio. September 2014.

Michael Sloan. “North American Propane and Butane Demand, Markets and Pricing”, Platt’s 4th Annual NGL’s Conference, Houston, Texas, September 2014.

Michael Sloan, Warren Wilczewski. “Impact of the U.S. Consumer Propane Industry on U.S. and State Economies in 2012”, *Propane Education and Research Council*, November 2014.

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Michael Sloan. “Outlook for Natural Gas Demand Growth in the Industrial Sector”, 2015 ARGUS Natural Gas Markets Conference, Houston, Texas, May 2015.

Michael Sloan. “The Market for Global Petrochemical Feedstocks in a Changing Oil Price Environment – Current and Future Trends”, 2015 Platt’s Asian Petrochemical Markets Conference, Shanghai, China, August 2015.

Michael Sloan. “Global LPG Markets: The Outlook for Propane and Butane”, Platt’s 5th Annual NGL’s Conference, Houston, Texas, September 2015.

Michael Sloan. “2016 Propane Market Outlook – Key Market Trends, Opportunities and Threats Facing the Propane Industry Through 2025.” *Propane Education and Research Council*, November 2015.

Michael Sloan. “Evaluating the End Game: The Outlook for the NGL Industry in a Low Oil Price Environment”, *2015 NGL Forum*, San Antonio, Texas, December 2015.

Michael Sloan. “2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements”, January 2016. Submitted on behalf of Union Gas Limited before the Ontario Energy Board, and presented to the Ontario Energy Board Stakeholder Conference, January 2016.

Michael Sloan. “Is Demand Back?? Keeping up with Supply?? Things are not always as they seem – The Big Picture”, 2017 NGL Forum, Atlanta, April 2017.

Michael Sloan. “2017 Propane Market Outlook: Current Market Conditions and the Outlook Through 2025”, NPGA Southeast Convention, Nashville, April 2017.

Michael Sloan. “Business Risk: Implications of a Low Carbon World for Natural Gas LDC’s”, 2017 NGL Forum, Boston, June 2017.

Michael Sloan. "The Impact of Infrastructure Development Trends on Midwest Natural Gas Markets", 2017 NGL Forum, September 2017.

Michael Sloan, Joel Bluestein, Eric Kuhle, "Implications of Policy-Driven Residential Electrification, An American Gas Association Study prepared by ICF", July 2018.

EMPLOYMENT HISTORY

ICF	Managing Director	2016 – Present
ICF International	Principal	2012 – 2016
ICF International	Project Manager	2006 – 2012
Energy and Environmental Analysis, an ICF International Company	RA to Project Manager	1981 - 2006

Appendix B: Resume (John Dikeos)

John Dikeos
Senior Manager

ICF Canada
300-222 Somerset St West
Ottawa, ON K2P 2G3
Tel: 1.613.523.0784
John.Dikeos@icf.com

EDUCATION

M.A.Sc., Mechanical Engineering, University of Victoria, Victoria, BC, 2006

B.Sc., Mechanical Engineering, Queen's University, Kingston, ON, 2003

EXPERIENCE OVERVIEW

John Dikeos is an energy management consultant with over ten years of experience with energy conservation and sustainable energy systems in residential and commercial facilities. His work has focused on assessments of energy efficiency technologies, DSM program design, energy efficiency potential studies, and the implementation of innovative DSM programs.

John's market study and technology characterization experience includes several in-depth studies on a broad array of energy efficiency technologies. For example, this has included separate studies focused on advanced boiler controls, web-enabled communicating thermostats, demand control ventilation, and condensing unit heaters in the commercial and institutional sectors. He has successfully managed several of these projects, ensuring that the work was delivered on time and on budget and that the quality of the deliverables met and exceeded client expectations.

John has also worked on several conservation potential studies for natural gas and electric utilities across Canada, for which he's carried out various types of analyses to determine the economic viability and savings potential of energy efficient technologies. Recently, he has acted as ICF's commercial team lead but he also has significant experience investigating the impacts of residential technologies.

John's program design experience is informed by projects for utilities across Canada and has included the development and analysis of energy efficiency measures, the completion of in-depth analyses of program and portfolio cost effectiveness, and the development of program infrastructure. In addition, he has designed and supported the implementation of innovative energy efficiency programs, including a mid-stream lighting program and a program focused on supporting energy efficiency in hotels.

John is a Professional Engineer (P.Eng.) in the province of Ontario and a Certified Measurement and Verification Professional (CMVP). He also holds Master's and Bachelor's degrees in Mechanical Engineering.

SELECTED PROJECT EXPERIENCE

Technology Assessments and Market Characterization

Pre-Feasibility Studies: Innovative Technologies—FortisBC, BC, 05/2013 – Present. Deep involvement in several in-depth studies focused on characterizing the BC market for innovative natural gas energy efficiency technologies and determining whether they should be incorporated into pilot studies and/or existing DSM programs. In addition to in-depth reviews of the technologies and any available research and pilot studies, each of these studies includes consultations with key market actors, a review of relevant programs in other jurisdictions, a detailed savings analysis on a large number of scenarios, and the development of technical resource manual (TRM) entries. Have served as the primary researcher and project manager on these studies. However, most recently serving as the executive director, which involves training new staff and providing general oversight, technical support related to the research and analysis, and QA/QC of all major deliverables. Have carried out independent studies on the following technologies:

- Manufactured homes (top six measures with the most potential), 2017-Ongoing
- Advanced boiler controls (central boilers in commercial facilities), 2016-2017
- Web-enabled programmable thermostats (RTUs in small and medium commercial facilities), 2016-2017
- Drain water heat recovery (DWHR) systems (residential applications), 2016
- Direct vent wall furnaces (replace lower efficiency space heating systems and lower efficiency fireplaces), 2016
- High-efficiency natural gas fireplaces (replacing existing decorative natural gas fireplaces), 2014
- Condensing unit heaters and IR radiant tube heaters (primarily in warehouses), 2013

DHW Recirculation System Controls—Union Gas, Ontario, 11/2016 – 09/2017. Executive director and technical expert for technology, market and energy savings assessment of domestic hot water (DHW) recirculation system controls in commercial facilities. Provided general oversight, technical support, and QA/QC of all major deliverables.

Smart Thermostats Compatibility Study—FortisBC, BC, 10/2016 – 04/2017. Executive director for a compatibility study of smart learning thermostats for residential buildings. This study examined the Nest, Ecobee3, and Honeywell Lyric thermostats, focusing on aspects related to communication, homeowner interaction, utility and functionality, and equipment and thermostat providers. FortisBC employed this study in its development of a pilot program for residential customers in Kelowna, BC.

Compact Furnaces for MURBs and SFD Homes—Canadian Gas Association, Canada, 05/2015 – 11/2015. Project manager for a pre-feasibility to assess potential energy savings from compact furnaces, a new class of furnaces with rated capacities of up to 30,000 BTU/h. This study focused on applying this technology in homes with space constraints, including multi-unit residential buildings (MURBs) and row/townhomes. Furthermore, ICF investigated market barriers to increased adoption of compact furnaces.

Demand Control Ventilation Market Expansion—Union Gas, Ontario, 09/2014 – 10/2015. Led a pre-feasibility study centered on the market expansion of demand control ventilation (DCV) technology in Ontario. Union Gas used the resulting study to determine the feasibility of expanding their existing program for DCV, which is focused on office and retail facilities with single-zone HVAC systems.

Inventory and Energy Savings Estimates for Residential Self-Programmable/Smart Thermostats—CEATI, Canada, 01/2014 – 07/2014. Led the assessment of the energy savings potential for a North-American scale pre-feasibility study that assessed the market opportunity, technical characteristics and projected energy savings for residential smart, self-programmable thermostats in comparison to the products prevailing in the market. The results of this study helped inform sponsoring utilities on the viability of pilot projects and energy efficiency programs focused on learning thermostats.

Conservation Potential Studies

Integrated Resource Planning Study—Enbridge and Union Gas, Ontario, 09/2016 – 01/2018. Deputy project manager and DSM impact analysis lead for an integrated resource planning study focused on estimating the peak demand impacts of gas energy efficiency measures and the feasibility of using gas DSM to delay or defer infrastructure investments. Study is leveraging the results of ICF's natural gas conservation potential study for the OEB.

Natural Gas Conservation Potential Study—Ontario Energy Board (OEB), Ontario, 11/2015 –06/2016. Commercial team lead for a study to estimate the achievable potential for natural gas efficiency in Ontario from 2015 to 2030, including the franchise areas of Union Gas and Enbridge. Provided general oversight, training, and targeted support to the commercial sector modeling and analysis team, in addition to leading client-facing meetings on behalf of the commercial sector team.

Newfoundland Conservation and Demand Management Potential Study—Newfoundland Power Inc. and Newfoundland and Labrador Hydro, Newfoundland, 12/2014 – 08/2015. Led the commercial sector modeling and analysis for this study, providing general oversight, training, and targeted expert support to the commercial team. My expertise on the assessment of the commercial technologies and the structure of the overall modeling approach was especially critical to the successful execution of this project.

Study on Energy Efficiency and Energy Savings Potential in Industry and on Possible Policy Measures—European Union (EU) Director General for Energy, London, UK, 04/2014 – 02/2015. In collaboration with ICF's London office, led the development of models to characterize the energy efficiency potential in several industrial and commercial sectors in the EU. The model considered hundreds of potential energy efficiency measures and compared achievable potential savings to targets set out by the EU.

Program Design and Implementation

Natural Gas DSM Plan 2019-2022—FortisBC, BC, 08/2017 – Present. Project manager for a study aimed at assisting FortisBC to build their 2019-2022 DSM plan submission to the BC Utility Commission. This includes providing feedback on their draft program offerings, assessing the cost effectiveness of their portfolio, and preparing a detailed report to document the proposed plan and CE results. In addition, led support

Hotel/Motel Pilot Program—Niagara Peninsula Energy Inc., Ontario, 07/2015 – 04/2017. Deputy project manager of an 18-month hotel/motel pilot program in NPEI's service territory. Unique features included a focus on all utility costs, end-to-end support to help participants identify and implement measures, and an emphasis on building recommissioning (RCx) and testing and metering new energy efficiency measures that are specifically tailored to the hotel/motel sector.

Residential Engagement Platform—Toronto Hydro, Ontario, 02/2016 – 01/2017. Led the development of an approved business case for a customer engagement platform to support Toronto Hydro's residential CDM programs. Program is focused on the delivery of home energy reports to a large number of residential customers, which includes social benchmarking approaches, energy efficiency tips, and a comprehensive online platform. Also assisted with certain aspects of the program rollout, including the development of the participant list and the acquisition of floor space data.

Commercial Refrigeration Technical Assistance—SaskPower, Saskatchewan, 04/2014 – 07/2014. Led the delivery of this assignment, which focused on providing recommendations on energy efficient commercial refrigeration measures for use in a prescriptive program design. The project focused on both a review of similar programs being offered by other jurisdictions and a review of cost and performance assumptions for a subset of the measures that could be offered by SaskPower in the future.

Retail Sector Host Initiative—OPA, Ontario, 04/2013 – 06/2013. Completed an assessment of Ontario's retail sector in order to understand the energy efficiency potential that is available through various measures and to set an achievable target for an incremental program targeted at the retail sector. Also collaborated in the design of the initiative and in consultations with various channel partners.

Energy Efficiency Program Design—SaskPower, Saskatchewan, 02/2012 – 09/2013. Carried out analysis related to the design and implementation of several energy efficiency programs, including a prescriptive lighting program, a lighting redesign program, and an industrial energy optimization program. Tasks included the analysis of energy efficiency measures, the development of program process flows, and the production of program documentation, such as application forms and end user guides.

Training Delivery

CDM Program Design and CDM Economics Training—MEARIE Group, Ontario, 10/2014 –02/2016. Led the delivery of a two-day training course related to CDM program design and CDM economics. The course was delivered on four separate occasions to groups of 10-25 staff from LDCs across Ontario. Also involved in the preparation of the training material and with updating the course material on an on-going basis.

HPNC Engineered Worksheets Training—Enbridge, Ontario, 08/2012 – 11/2012. Prepared and delivered a training webinar that was geared towards building owners, contractors and energy service providers and was attended by nearly 100 participants. The training was related to the new engineered worksheets for the IESO's High Performance New Construction (HPNC) program. Material that was covered included lighting and unitary AC basics and how to use the lighting and unitary AC engineered worksheets.

EMPLOYMENT HISTORY

ICF	Senior Manager	03/2017 – Present
ICF	Manager	03/2013 – 03/2017
ICF	Senior Associate	01/2011 – 03/2013
ICF (formerly Marbek Resource Consultants)	Consultant	01/2008 – 12/2010
NRCan Office of Energy R&D	Science and Technology Analyst	06/2007 – 12/2007
Tulmar Safety Systems.	R&D Engineering Assistant	05/2002 – 08/2002

NAVIGANT CONSULTING, INC. REBUTTAL EVIDENCE ON DSM ENERGY SAVINGS TRAJECTORIES

FortisBC Energy Inc., 2017 Long Term Gas Resource Plan: Navigant Consulting, Inc. Rebuttal Evidence on DSM Energy Savings Trajectories

Project No.: 1598946

Prepared for:

FortisBC Energy Inc.

Submitted by:
Robin Maslowski, Associate Director
Stu Slote, Director
Navigant Consulting Inc.
1375 Walnut Street, Suite 100
Boulder, CO 80302
303.728.2518
robin.maslowski@navigant.com

navigant.com

October 2, 2018

Table of Contents

1. Purpose

This report was prepared by Navigant Consulting, Inc. on behalf of FortisBC Energy Inc. (FEI). This report provides comments on the British Columbia (BC) Conservation Potential Review (CPR) Section 5. Market Potential, May 2017, in response to the evidence of James Grevatt in his pre-filed testimony submitted by the BCSEA-SCBC.

In response to Mr. Grevatt's claim: "The Reference Case savings in the LTGRP are based in the BC CPR's Market Potential Forecast, which is very likely to significantly underestimate the savings that FEI could be expected to achieve through programs that are designed to maximize savings"[1], this document:

1. Summarizes Navigant's market potential study in the BC CPR for FEI.
2. Provides an overview of Navigant's potential study process, including steps taken beyond the Market Potential Forecast, as well as the logic which supports our recommendations to FEI; and
3. Responds to the written evidence prepared by Mr. Grevatt that the BCSEA-SCBC has submitted as a part of these proceedings.

In responding to the evidence of Mr. Grevatt, Navigant further explains and supports FEI's DSM Potential Study by discussing the following:

1. The sufficiency of the information provided by FEI to permit the BCUC to make informed decisions with respect to the results of the market potential study;
2. The reasonableness of the market potential savings and level of investment associated with the potential study;
3. The adequacy of the range of programs, savings, and investment levels considered by FEI; and
4. The modelling considerations regarding potential alternate levels of savings and investment by FEI.

[1] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 18.

2. Overview of Navigant's Analysis for FEI

Navigant used its Demand-Side Management Simulator (DSMSim) model to estimate energy efficiency technical, economic, and market potential for FEI in the BC CPR. DSMSim simulates market diffusion of efficient technologies and calculates natural gas savings potentials, in addition to performing benefit/cost effectiveness tests for each measure and the overall portfolio. The model uses an enhanced Bass diffusion model and discrete choice theory to simulate consumer behaviour within the market, with the capabilities to explore different cost effectiveness scenarios and incentive strategies to maximize savings at lowest cost.

2.1 Consideration of Past Performance Does Not Represent the Maximum the Utility Can Achieve

Mr. Grevatt states in his evidence "A detailed analysis of the BC CPR Market Potential Forecast for FEI is beyond the terms of my engagement."[2] However, it is important to understand the underlying dynamics of the BC Conservation Potential Review (BC CPR) market potential forecast to understand that Mr. Grevatt's assertion that calibration to historic performance "implicitly considers past performance to represent the maximum that the utility can achieve"[3] is incorrect. As noted in FEI's response to BCSEA IR 1.18.3:

> "The 2017 LTGRP C&EM analysis is informed by the BC CPR results and by FEI's program experience. As such, the C&EM analysis is informed [emphasis added] by FEI's historical C&EM program achievements, participation economics, as well as the BC CPR consultant's North American DSM benchmark data. Interaction between these sources permitted forecast C&EM adoption rates to change throughout the planning horizon and thus to deviate from historic conditions […] While the C&EM analysis starting point is directly connected to FEI's historical program achievements, the C&EM analysis framework enables future C&EM activity to diverge from historical program designs [emphasis added] […] Beyond the first year of the CPR, the market dynamics (e.g., equipment turnover, new construction and customer willingness to adopt) forecast by the CPR model drove the levels of annual market potential."

As described in the BC CPR, "Market potential is a subset of economic potential that considers the likely rate of DSM acquisition, given factors like the rate of equipment turnover (a function of a measure's lifetime), simulated incentive levels, consumer willingness to adopt efficient technologies, and the likely rate at which marketing activities can facilitate technology adoption. The adoption of DSM measures can be broken down into calculation of the "equilibrium" market share and calculation of the dynamic approach to equilibrium market share [reflecting barriers to market adoption], as discussed in more detail below."[4]

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[2] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 14.

[3] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, Appendix B, page 26.

[4] FortisBC Energy Inc. (2017). *2017 Long Term Gas Resource Plan*, Appendix C-1, page 493.

Specifically, it is important to understand the distinction between the equilibrium market share and the calculation of the dynamic approach to equilibrium market share. Together these two components of the simulation act as the final determinant of market potential. As described in the BC CPR, “The equilibrium market share can be thought of as the percentage of individuals choosing to purchase a technology provided those individuals are fully aware of the technology and its relative merits (e.g., the energy- and cost-saving features of the technology) […] This study calculates an equilibrium market share as a function of the payback time of the efficient technology relative to the inefficient technology. In effect, measures with more favorable customer payback times will have higher equilibrium market share, which reflects consumers’ economically rational decision making. While such approaches have limitations, they are nonetheless directionally reasonable and simple enough to permit estimation of market share for the hundreds of technologies appearing in most potential studies.”[5]

In contrast, the dynamic approach to the equilibrium market share (i.e., the market changes that occur between the current market conditions and the equilibrium market share) employs diffusion modeling,[6,7] to simulate the impacts of well-documented causal influences on market potential adopters, including the effectiveness of marketing and the “word-of-mouth” effect. DSMSim incorporates these influences via parameters for marketing and word-of-mouth in an enhanced version of the classic Bass diffusion model. The possible range of values for these parameters are based upon case studies where these parameters were estimated for dozens of technologies.[8]

Calibration is a critically important step for grounding the analysis in observed market behaviour by informing the customer willingness to adopt. As Mr. Grevatt notes in his evidence and Navigant outlines in the BC CPR, Navigant took a number of steps during the calibration process to meet these objectives and ensure that forecast model results were reasonable, including:

- “Identifying the subset of CPR measures that were included in historic program offerings in order to have a basis for comparison with historic program achievements.”[9] It is important to note here that Navigant did not calibrate to all measures in the CPR—only the subset with historic program results, while the overall CPR potential assesses a significant number of additional measures not included in FEI’s current portfolio.
- “Ensuring similar trends and magnitudes between average historic sector-level savings between 2013-2015 and simulated sector-level savings from the measure subset in 2016.”[10,11] This means that Navigant adjusted the incentive levels and technology (i.e., Bass) diffusion coefficients, such

[5] FortisBC Energy Inc. (2017). *2017 Long Term Gas Resource Plan*, Appendix C-1, page 495.

[6] Bass, Frank (1969). "A new product growth model for consumer durables". Management Science 15 (5): p215–227.

[7] See Sterman, Jracohn D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000. page 332.

[8] See Mahajan, V., Muller, E., and Wind, Y. (2000). New Product Diffusion Models. Springer. Chapter 12 for estimation of the Bass diffusion parameters for dozens of technologies.

[9] FortisBC Energy Inc. (2017). *2017 Long Term Gas Resource Plan*, Appendix C-1, page 502.

[10] *Ibid.*

[11] The team compared simulated savings to 2013-2015 historic averages, rather than a single historic year, because historic savings varied appreciably from one near to the next within each sector.

that, for the subset of CPR measures included in historic program offerings, the growth rate toward the equilibrium market share in 2016 reflected the observed adoption between 2013-2015.

- "Seeking general alignment between 2015 historic sector-level incentives as a percentage of total sector-level spending and simulated 2016 values." [12,13] This alignment is based on the percentage of overall spending towards incentives versus administrative costs (e.g., as opposed to the total amount spent on incentives).

It is important to understand that while the *approach* (i.e., the rate at which the market moves toward the equilibrium) is influenced by historic trends in customer technology adoption as measured by the program, the equilibrium market share is fully independent from the rate of historical program achievements. Ultimately, calibration influences the starting point for the model (i.e., 2016 in the case of the CPR), but does not dictate the equilibrium market share, aside from any influence the calibration process has on simulated incentive levels. (However, it is important to note FEI also investigated sensitivities to determine how the potential might change with changes to the simulated incentive levels, as discussed in more detail below.) Thus, the calibration of Bass diffusion coefficients based on historic program achievements does not affect the equilibrium market share—it affects how quickly the potential savings reach the equilibrium market share as a function of observed market behaviour, as discussed above.

Calibrating the initial starting point for the model to historic program performance also acknowledges that it is more realistic to assume that conditions like customer awareness and acceptance of efficient technologies take time to change, rather than assuming that the market could immediately shift and transform overnight with greater investments in incentives and marketing, as might be assumed in an assessment of (theoretical) maximum achievable potential. As explained in FEI's response to BCSEA IR 2.62.2, (theoretical) maximum achievable potential "generally involves incentives that represent 100 percent of the incremental cost of energy efficient measures above baseline measures, combined with high administrative and marketing costs,[14] and represents a theoretical maximum for program potential. The Market Potential savings included in the 2017 LTGRP C&EM analysis, on the other hand, take into account constraints imposed by market conditions (equipment turnover rates, incentive levels, consumer willingness to adopt, etc.)."

[12] *Ibid.*

[13] The team compared the percentage of simulated spending derived from incentives to the 2015 historic percentages because 2015 was deemed to be most representative of expectations about future spending allocations between incentives and non-incentives.

[14] Rohmund, Ingrid et.al., Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010 – 2030), 2008 ACEEE Summer Study on Energy Efficiency in Buildings, https://aceee.org/files/proceedings/2008/data/papers/5_297.pdf.

2.2 BC CPR Pursued Several Steps to Assess the Full Scale of Realistic Market Potential

Mr. Grevatt states that the DSM savings projection in the BC CPR Reference Case is "overly conservative (low) because the full scale of available savings is not considered."[15] However, Navigant notes that the BC CPR pursued a number of steps, above and beyond a typical achievable potential forecast, to assess the full scale of realistic market potential savings for FEI, as follows:

2.2.1 Assumed an unconstrained budget for FEI's DSM expenditures

FEI's Reference Case inherently assumes no budget restrictions on energy efficiency funding streams. In many jurisdictions, this is one of the underlying assumptions underpinning the difference between a realistic achievable and a (theoretical) maximum achievable scenario, in addition to higher incentive, administrative, and marketing costs. However, unrestricted funding streams are already considered in FEI's market potential forecast.

As noted in the report by the Regulatory Assistance Project (RAP) that Mr. Grevatt cites:

> "Yet even within the realm of achievable savings, there can be a range of projected savings depending on what assumptions are used, especially those regarding possible future budget constraints and related funding streams that may support energy efficiency programs. For example, some achievable potential studies project the amount of savings that could be achieved under a budget allocation scenario constrained by regulatory and policy considerations, whereas others focus on "maximum" achievable scenarios in which there would still be market and program constraints but essentially no budget restrictions [emphasis added]."[16]

2.2.2 Analyzed the potential for new measures not currently within FEI's portfolio

Mr. Grevatt suggests the market potential analysis omits measures by saying: "When a conservation potential study underestimates the amount of cost effective savings that are available, either by failing to appropriately quantify certain measures, i.e., omitting opportunities outright[…]".[17] However, as a crucial step in the development of the CPR, Navigant and FEI prepared a comprehensive measure list, inclusive of measures included within FEI's existing portfolio, as well as measures beyond FEI's existing portfolio. This measure list was reviewed by stakeholders and determined to be comprehensive.

Mr. Grevatt states in his evidence that the "…BC CPR may [emphasis added], like the Colorado potential study, underestimate the savings potential compared to savings potential estimates based on programs that are designed and implemented with the intent of capturing the maximum possible cost effective

[15] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 3.

[16] Chris Kramer and Glenn Reed, "Ten Pitfalls of Potential Studies," Regulatory Assistance Project, November 2012, page 17.

[17] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 13.

savings."[18] However, the testimony ultimately cited in the Commission's decision in the Colorado potential study related to the exclusion of certain emerging technology measures, as opposed to the basis for the potential study calibration and savings forecasts.[19] No such critique in terms of excluding certain measures has been submitted for the BC CPR.

2.2.3 Applied more than one approach to screening measure cost effectiveness, including use of the mTRC, to capture the value of avoiding carbon emissions and non-energy and non-monetary benefits

Mr. Grevatt states in his evidence: "As I noted earlier, RAP suggests that 'policymakers should examine both monetary and non-monetary assumptions' in assessing potential."[20] Application of the mTRC accomplishes this objective of considering the monetary impacts on customer adoption, as well as the value of avoiding carbon emissions and the non-energy and non-monetary benefits that many measures provide customers, but would otherwise not be quantified in the savings estimates.

The regulatory environment for FEI at the time of the analysis allowed the utility to spend up to 33 percent (and currently up to 40 percent) of its entire DSM portfolio on measures or programs that require an mTRC to be cost effective. This approach facilitates the strategic targeting of measures with higher customer acceptance, but less attractive economics, and the incorporation of more DSM into FEI's planning. Thus, the BC CPR analyzed the following three distinct approaches to screening measures for cost effectiveness in recognition of the non-energy benefits that many measures provide customers:

1. **TRC only:** This case uses the TRC cost effectiveness test across all sectors and presents results consistent with the screening method used in the previous CPR report focusing on technical and economic potential.
2. **mTRC only:** This case uses the mTRC cost effectiveness test across all sectors.
3. **Hybrid mTRC/TRC:** This case uses the mTRC cost effectiveness test for the residential sector and the TRC cost effectiveness test for the commercial and industrial (C&I) sectors, which is most analogous to FEI's actual DSM program environment.

The effect of assessing these three approaches was to provide a range of possible savings potential under various cost effectiveness environments, where the 'TRC only' case provides a lower bound and the 'mTRC only' case provides an upper bound for savings potential.

The BC CPR study used the 'hybrid mTRC/TRC' scenario, as specified above, as the foundation for the BC CPR Reference Case. FEI then used the BC CPR Reference Case to inform the 2017 LTGRP Reference Case C&EM analysis. In addition, FEI expanded this potential by using the 'mTRC only'

[18] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 14.

[19] Public Utilities Commission of the State of Colorado, Decision No. C18-0417, Proceeding No. 17A-0462EG, page 22, http://www.swenergy.org/Data/Sites/1/media/documents/news/co-xcel-dsm-puc-decision-6-6-18.pdf.

[20] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, Appendix B, page 28.

scenario as the basis of the C&EM forecast in scenarios subject to the Accelerated outcome of the Non-Price Carbon Policy action critical uncertainty.

2.2.4 Tested a range of incentive sensitivities and determined that the realistic market potential forecast provides a reasonable level of spending

Mr. Grevatt states that the incentive sensitivity analysis "shows that FEI's Reference Case DSM scenario, based on the CPR Market Potential, does not include all cost effective DSM savings."[21] However, Mr. Grevatt does not acknowledge in his evidence that, in the BC CPR, there is a diminishing rate of acquired savings per dollar of incentive spending, for incentive levels above those used in the market potential forecast. By testing a range of incentive sensitivities, Navigant determined that the realistic market potential forecast provides a reasonable level of spending on a $/GJ basis for FEI.

As noted previously in FEI's response to BCSEA IR 2.63.1, the BC CPR has already shown higher savings are possible if FEI increases incentive levels—but at a higher $/GJ cost:

> "Directionally, the BC CPR's long range forecast and sensitivity analysis indicate that higher incentive levels will likely lead to higher customer participation. However, those higher incentive levels may be more aggressive than the median incentive levels seen throughout North American utilities. Additionally, the sensitivity analysis shows there is a diminishing rate of acquired savings per dollar of incentive spending [emphasis added]. Thus, the BC CPR's sensitivity analysis shows that higher savings could be achieved, but those savings levels are not necessarily a suitable target for meeting the FEI's overarching programmatic goals in terms of cost effectively acquiring savings."

RAP acknowledges this effect by stating: "Given that the marginal value of each dollar may vary, the magnitude of the change in savings may not be directly proportional to the magnitude of the change in the portfolio budget."[22]

Ultimately, the impact from a higher level of incentive spending may translate to increased customer rate impacts.

2.2.5 Considered all cost effective measures

Mr. Grevatt states "Even though this framing implies that the Market Potential forecast represents all cost effective savings, it clearly does not."[23] Navigant disagrees with Mr. Grevatt's assessment that the BC CPR did not consider all cost effective measures. As discussed in FEI's response to BCSEA IR 1.9.1, the identification of all cost effective DSM measures is accomplished through the economic potential portion of the BC CPR. As noted in FEI's response to BCSEA IR 1.17.1, the 2017 LTGRP C&EM analysis imports the BC CPR measure assumptions, calibrates the analysis in light of the BC CPR technical potential results, then applies the applicable cost effectiveness tests to produce economic energy savings

[21] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 10.

[22] Chris Kramer and Glenn Reed, "Ten Pitfalls of Potential Studies," Regulatory Assistance Project, November 2012, page 5.

[23] FEI 2017 Long Term Gas Resource Plan, Exhibit C2-7, Testimony of James Grevatt, Energy Futures Group, Inc., for B.C. Sustainable Energy Association and Sierra Club B.C., August 9, 2018, filed by BCSEA-SCBC, page 10.

potential before applying further analysis steps. As such, the 2017 LTGRP considered all cost effective demand-side measure activity.

As stated in FEI's response to BCSEA IR 1.18.3, since the BC CPR evaluated a comprehensive, peer-reviewed collection of C&EM measures, the economic potential provides a reasonable assessment of cost effective savings, given the exclusion of market barriers. To account for market barriers, the BC CPR relied on widely accepted Bass diffusion models and assessments of customer willingness to adopt, as discussed above. Given that all cost effective measures were eligible for market potential and the forecasts of customer willingness to adopt were grounded in observed local market behaviour, the market potential provides a reasonable assessment of cost effective savings potential.

3. Conclusion

In summary, the market potential analysis presents a realistic assessment of savings and spending and thus is more suitable for BCUC consideration in the 2017 LTGRP, than a (theoretical) maximum achievable savings approach.

1. Calibration to historic savings does not imply that savings are inherently conservative:
    a. Calibration is critically important for grounding the analysis to local market conditions that influence factors like word-of-mouth/marketing effectiveness and protecting against overfitting the model in a way that does not effectively predict future market activities;
    b. Calibration influences the starting point for the model (i.e., 2016), but does not dictate the long-run market equilibrium; and
    c. Not anticipating an immediate shift in the market is more realistic than assuming the market would transform drastically (maximum achievable potential is thus more theoretical than practical).
2. The BC CPR pursued a number of steps, above and beyond a typical achievable potential forecast, to assess the full scale of realistic market potential savings for FEI, as follows:
    a. Assumed an unconstrained budget for FEI's DSM expenditures;
    b. Analyzed the potential for new measures not currently within FEI's portfolio;
    c. Applied more than one approach to screening measure cost effectiveness, including use of the mTRC, with the objective of capturing the non-energy and non-monetary benefits that many measures provide customers, which otherwise would not be quantified in the savings estimates; and
    d. Tested a range of incentive sensitivities and determined that the assumed incentive levels in the realistic market potential forecast provide a reasonable level of spending on a $/GJ basis for FEI.
3. The 2017 LTGRP considers all cost effective demand-side measure activity and the market potential provides a reasonable assessment of cost effective savings potential.

Appendix A. Robin Maslowski – Resume

Robin Maslowski

Associate Director

robin.maslowski@navigant.com
Boulder, Colorado
Direct: 303.728.2518

Professional Summary

Robin Maslowski is an Associate Director that leads the Clean Energy Programs Modeling team within Navigant. Robin provides expertise in natural gas and electricity demand-side management (DSM) and distributed energy resources (DER) potential studies, cost-benefit assessment, strategic planning, modeling analytics, and project management. Recent project work includes determining market potential and forecasting for DER, developing cost effectiveness frameworks for electric vehicles (EV) and demand response (DR), identifying implementation strategies and providing procurement support for DR resources, and identifying key areas of opportunity for market growth, such as utility intervention strategies for supporting the adoption of EVs.

Robin served as co-chair of the Peak Load Management Alliance's Women in DR group for three years and president of the Rocky Mountain chapter of the Association of Energy Services Professionals for three years.

Selected Experience

- **EE market potential, DR, EV, and fuel switching potential studies (British Columbia Utilities).** Project manager for the second phase of a conservation potential review for the British Columbia (BC) Utilities. Assessed the market potential (electric and natural gas) for four utilities in Navigant's proprietary DSMSim™ demand-side potential model, which is a bottom-up technology diffusion model grounded in the principles of system dynamics (stock/flow modeling). Analyzed DR potential in Navigant's DRSim™ model, forecast EV potential, characterized the total thermal demand within the territory, provided estimation of fuel switching potential, and delivered model training.
- **Comprehensive forecast of DER technologies (Consolidated Edison).** Project manager for a potential study for distributed energy resources (DER) within Con Edison's territory, including energy efficiency, demand response, customer-sited generation, and storage. This effort includes the review of more than 200 technologies across all customer segments, significant primary data collection, assessment of both natural gas and electric energy efficiency and demand response, and a leading-edge modeling approach for assessing the potential of integrated DER deployments. The results of this project have helped Con Edison with more granular program design and planning.
- **Integrated forecast of system-level and feeder-level DER (Portland General Electric).** Project

manager for the integrated forecasting of DER, including EE, DR, solar, storage, light-duty electric vehicles, medium- and heavy-duty electric vehicles, and charging infrastructure. This study includes forecasting these technologies at both the system-level (i.e., to support integrated resource planning) and at a more granular feeder-level (i.e., to support transmission and distribution planning). Navigant is also estimating the interactive effects between DER and associated load profile for each DER under three different scenarios to inform PGE's company-wide planning efforts.

- **Assessment of non-wires alternatives and DER potential (Orange & Rockland).** Project manager for the assessment of non-wires alternatives (NWA) and DER potential within the service territory of Orange and Rockland Utilities (O&R). As part of this study, Ms. Maslowski and team have conducted a baseline survey of O&R's customers and developed a rigorous database and analysis of the potentials for energy efficiency, DR, customer sited storage, and distributed resources to support O&R's distribution planning efforts and PSC-required assessments of NWAs. Further, Navigant and its partner E3 O&R have developed an NWA toolset to facilitate periodic updates to the potential forecasts, load forecasting, NY-specific benefit-cost approaches, and planning for distribution network upgrade investments.
- **Energy efficiency potential study (Xcel Energy).** Project manager for a potential study for natural gas and electricity energy efficient measures within Xcel Energy's Colorado territory. This effort includes the characterization of 175 energy efficiency measures, use of Navigant's DSMSim™ potential model, and significant primary data collection with onsite validation of data collected through phone and web surveys.
- **Gas DR program design (Con Edison).** Supported Con Edison in the design of a ground-breaking natural gas DR pilot targeting multi-family and commercial customers. Investigated customer curtailment and fuel switching strategies for gas technologies that could provide a net reduction in gas consumption over a 24-hour period through customer and market participant interviews. Helped Con Edison identify the operational requirements for the program; designed and quantified program incentive levels; developed tools to help assess potential customer snapback and support the settlement process; developed program guidelines and materials to support the regulatory filing process and communications to program participants; and supported the stakeholder engagement process. This program is expected to launch in the winter of 2018/2019.
- **Long term forecasting of demand-side resources in the Eastern Interconnection (National Association of Regulatory Utility Commissioners [NARUC]).** Coordinated efforts for a bottom-up analysis of existing and planned energy efficiency and DR in the Eastern Interconnection as part of Navigant's engagement with NARUC to characterize demand-side resource development (including energy efficiency, DR, smart grid, distributed generation, and storage) in the Eastern Interconnection.
- **Regional business case development for smart grid deployment in the Pacific Northwest (Bonneville Power Administration).** Developed a white paper informing regional stakeholders about the costs and benefits of possible smart grid investments and technologies across the Pacific NW. Developed a comprehensive framework for assessing smart grid investment decisions and Navigant's first Grid+™ stochastic model to analyze the relative costs and benefits of each possible smart grid investment. Assessed capabilities including, advanced metering infrastructure, DER, transmission and distribution optimization, grid reliability, and demand management strategies. Coordinated with the Pacific NW Smart Grid Demonstration Project and other regional and national smart grid efforts.

Work History

- Associate Director, Navigant Consulting, Inc.
- Analyst, Summit Blue Consulting
- Research Analyst, Synapse Energy Economics
- Intern, Environmental Protection Agency
- Wind Analyst, Green Energy Ohio
- Applications Engineer (Intern), Lytron, Inc.
- Wind Engineer, Utah Energy Office

Certifications, Memberships, and Awards

- Engineer-in-Training (EIT)
- Peak Load Management Alliance, *Program Design and Implementation* and *Evolution of DR*, Training Instructor, 2017–present
- Peak Load Management Alliance, Women in Demand Management, Founder and Co-Chair, 2013–2017
- Association of Energy Services Professionals, Rocky Mountain Chapter, President and Chair, 2009–2013

Education

- BS, Mechanical Engineering — Franklin W. Olin College of Engineering, 2007

Appendix B. Stu Slote – Resume

Stu Slote

Director

stu.slote@navigant.com
Burlington, Vermont
Direct: 802.526.5113

Professional Summary (natural gas focus)

Stu Slote is a Director with Navigant's Energy Practice, and is based in Burlington, VT. Stu has more than 30 years of experience in the energy efficiency industry and has been with Navigant (formerly with Summit Blue Consulting) since 2007. Areas of expertise include design of, implementation support for, and evaluation of utility demand side programs; and building energy codes development, adoption, implementation and assessment.

- Technical Advisor and QA/QC Reviewer, Ontario Achievable Potential Study (natural gas and electricity), for Independent Energy System Operator and Ontario Energy Board. (2018 to present)
- Project Director for Energy Efficiency Alberta natural gas and electricity energy efficiency potential study, program design, electronic TRM, planning tool, evaluation framework, reporting dashboard and ASHRAE Level 2 Energy Audits of Industrial Facilities. (2017 to present)
- Project Manager for National Grid Massachusetts natural gas and electricity potential study. (2017-2018).
- Led energy efficiency program design enhancements for CenterPoint Gas Minnesota. (2013-2014)
- Project Manager for BGE (Maryland) natural gas and electricity DSM portfolio design and potential study. (2007-2008)
- Project Manager for residential measure characterisations for GasNetworks energy efficiency potential study. (2008-2009)
- Assisted with program design and implementation support for a portfolio of residential and commercial electric and gas energy efficiency programs for Tucson Electric Power. (2007-2012)
- Project manager for a project to characterize residential and commercial gas measures by interviewing equipment installers and distributors, for Vermont Gas Systems. (2008)
- Conducted commercial analysis of New York statewide gas resource assessment, as well as analysis for all gas territories in New York. He assisted in coordinating a large multidisciplinary team to assess residential, commercial, and industrial gas efficiency potential, and design and analyze a portfolio of efficiency programs to be delivered statewide, for NYSERDA (2005-2006)

- Conducted commercial and industrial analysis for a report on gas energy efficiency programs for Consolidated Edison of New York, on behalf of New York City Economic Development Corporation, NRDC, Pace Energy Project, Association for Energy Affordability, and Public Utility Law Project (2004)
- Involved in all aspects of energy codes for the State of Vermont, including development, adoption, implementation and assessment. (1996 to present)

Work History (prior to Navigant / Summit Blue Consulting)

- **Technical Director,** EnSave, Inc., Richmond, VT., 2006 – 2007. Conducted agricultural energy efficiency audits and developed audit reports for utilities and federal programs. Responsible for customizing proprietary audit software tools; developing audit and measure technical savings calculations; screening benefit/costs of program offerings; and managing evaluation, measurement, and verification of energy savings.
- **Senior Analyst**, Optimal Energy, Inc., Bristol, VT, 2002 – 2006. Develop program designs, measure characterizations, cost-benefit analysis and reporting for numerous portfolio plans and potential studies for electric and gas utilities, programs administrators, state agencies and two Chinese provinces. Developed Vermont's first commercial energy code and evaluated Pacific Northwest energy code activities for NEEA.
- **Northeast Regional Building Energy Codes Project Manager**, Northeast Energy Efficiency Partnerships, Inc., Lexington, MA, 1998 – 2002. Managed regional project to develop consistent building energy codes and improve implementation in the New England states, New York, and the Mid-Atlantic region. Supported 11 Northeast states and the District of Columbia in energy code development, adoption, implementation, and evaluation. He managed a project advisory committee comprised of state, utility, and trade allies and facilitated project committee meetings. Participated on state energy code advisory committees in several Northeast states.
- **Energy Engineer**, Vermont Department of Public Service, Montpelier, VT, 1988 – 1997. Conducted technical and economic analyses and evaluations of energy efficiency proposals for all new construction pursuant to the Energy Conservation and Public Utility Services Sub-Criterion under Vermont's Land Use and Development Control Law, Act 250. Developed and implemented policy and program initiatives, with emphasis on Act 250 energy standards and utility demand-side management. Conducted technical analysis in support of Vermont's first Residential Energy Code adopted in 1997.

Select Projects (Project Management)

Efficiency Nova Scotia / Nova Scotia Power – Project Manager (2007 to present)

- Development of DSM portfolio action plans for regulatory approval (annually for 2008 through 2015), 2016-2018, and 2020-2022 (ongoing)
- Development of 25–year potential analysis for regulatory Integrated Resource Plan approval, 2009, 2011, 2013, 2015, 2018
- Residential (2010 and 2013) and commercial (2013) sector baseline studies
- Regulatory and IRP support, including expert witness pre-filed and direct testimony
- Development of technical reference manual
- Development of RFPs for implementation services
- Present results at collaborative stakeholder meetings

AEP Ohio – Project Manager (2008 to Present)

- Development of Energy Efficiency/Peak Demand Reduction portfolio action plans for regulatory approval, for 2009–2011, 2012–2014, 2015–2016, 2017-2019, 2021-2023 (ongoing) and 20-year potential analyses
- DSM portfolio evaluations for regulatory approval, annually for 2009 through 2017, ongoing for 2018
- Residential (2011 and 2013) and commercial/industrial (2011) sector baseline studies, and ongoing for 2017-2018
- Regulatory support; Support DSM demand bid to PJM
- Technical reference manual support; Development of RFPs for implementation services
- Development of initial data tracking system
- Lead bi-weekly client meetings and internal team meetings
- Present results at collaborative stakeholder meetings

Direct Expert Testimony

- Before Nova Scotia Utility and Review Board on behalf of Efficiency Nova Scotia, An Application by EfficiencyOne for Approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties and approval of a 2016-2018 Demand Side Management Resource Plan, NSUARB/M06733 (2015)

- Before Maryland Public Service Commission on behalf of Sothern Maryland Electric Cooperative, In the Matter of SMECO's Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, Case No. 9157 (2008)

- Before Vermont legislative committees on behalf of Vermont Department of Public Service in support of Vermont energy codes adoption (2015, 2010, 2006 and 1996-1997)

- Before more than 100 State of Vermont Act 250 Commissions (and the appellate Environmental Board) regarding permit applications pursuant to Act 250 Sub-criterion 9(F), Energy Conservation and 9(J), Public Utility Services (1998-1997)

- Regarding demand-side management (DSM) program options before the Vermont Public Service Board, specific to Green Mountain Power Corporation Docket 5983 (1997)

- Regarding fuel-switching and other DSM program options before the Vermont Public Service Board Investigation into Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy In Re: Fuel-Switching Issues Specific to Central Vermont Public Service Corporation (CVPS) Docket 5270-CV-1 In Re: CVPS program designs Docket 5270-CV-3 (November 1994-October 1995)

- Regarding DSM program options before the Vermont Public Service Board, specific to CUC Docket 5274-CUC-1 (1993)

Education

- Master of Arts, Public Administration, University of Vermont (1998)

- Bachelor of Science, Energy-Appropriate Technology, University of Massachusetts Amherst (1981)

Appendix C. Navigant Consulting, Inc. – Overview

Navigant's legal name is Navigant Consulting Incorporated and is headquartered out of our central office located at 150 North Riverside Plaza, Suite 2100, Chicago, IL 60606. Navigant maintains 35 principal offices worldwide, including Canadian offices in Toronto, Montreal, Quebec City, and Calgary. Navigant is a public corporation (NYSE: NCI) and specialized independent consulting firm that assists clients in addressing the critical challenges of regulation, risk, business model change, and disputes. Navigant has more than 4,500 professionals and 5,500 employees and generated approximately $700 million in revenue during 2017.

Formed in 1999 by the merger of Metzler Associates and Peterson Consulting, Navigant has expanded through a considerable number of acquisitions over the years. Energy consulting has been a focus of Navigant since inception. In line with this focus, Navigant acquired Summit Blue Consulting, a specialized energy efficiency design and evaluation firm, in early 2010. Navigant's Energy Practice provides consulting services in the areas of energy efficiency and load management program performance measurement and evaluation, program development and implementation; energy systems technology assessment and DSM potential studies; market research and market assessments; utility business management consulting, industry restructuring, and deregulation strategies.

Navigant currently supports DSM program implementation for more than ten energy efficiency portfolios for program administrators in six provinces and states. Navigant evaluates energy efficiency portfolios for more than twelve program administrators in North America. Navigant has supported the assessment of emerging technologies for California and Illinois investor-owned utilities for more than 12 years. Navigant has been a lead contractor for the United States Department of Energy ("U.S. DOE") appliance and equipment efficiency standards program development, adoption, and maintenance for more than 15 years.

Since 1990, Navigant has been involved with the design and implementation of numerous achievable potential studies. As shown in Figure 1, over the past five years alone, Navigant has developed natural gas achievable potential studies for more than a dozen different entities, including investor- and publicly-owned utilities, provincial/state clients as well as regional entities. Our work covers some of the largest natural gas (and electricity) demand-side management (DSM) potential studies in North America.

Figure 1. Natural Gas Potential Studies Conducted by Navigant

Client / Organization	Completion
British Columbia Natural Gas and Electric Utilities \ Province-Wide Conservation Potential Study	2017
Energy Efficiency Alberta \ Province-Wide Natural Gas and Electricity Potential Study	2018
California Energy Commission \ Natural Gas and Electricity Energy Efficiency Target Setting Technical Support	2018
National Grid Massachusetts \ Natural Gas and Electricity Energy Efficiency Potential Study	2018
Orange and Rockland \ Natural Gas and Electricity Distributed Energy Resources Potential and Tool Development Project	2017
Xcel Energy (Colorado) \ Natural Gas and Electricity Energy Efficiency Potential Studies	2016
Arkansas Utilities \ Natural Gas and Electricity DSM Potential Studies	2015
Enbridge Gas Distribution \ Ontario Natural Gas Conservation Potential Study	2014
California Public Utilities Commission \ Natural Gas and Electricity Achievable Potential Analysis	2011 to present