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November 1, 2018

**VIA ELECTRONIC MAIL**

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

**Attention: Patrick Wruck, Commission Secretary and Manager, Regulatory Support**

Dear Sirs/Mesdames:

**Re: FortisBC Energy Inc. – 2017 Long Term Gas Resource Plan**
**Project Number 1598946**

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's Information Requests on Rebuttal Evidence of FortisBC Energy Inc. with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

**OWEN BIRD LAW CORPORATION**

For Christopher P. Weafer
CPW/jj

cc: CEC
cc: FortisBC Energy Inc.
cc: Registered Interveners

**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (the "CEC")**

**INFORMATION REQUEST ON REBUTTAL EVIDENCE OF FORTISBC ENERGY INC.**

**FortisBC Energy Inc. – 2017 Long Term Gas Resource Plan**
**Project No. 1598946**

**November 1, 2018**

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# I. CEC INFORMATION REQUEST ON THE TESTIMONY OF MICHAEL SLOAN AND JOHN DIKEOS OF ICF

## 1. Reference: Exhibit B-11, ICF page 3

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.

1.1 Please provide a summary of ICF's experience in Canada, and in BC.

1.2 Please identify the Canadian agencies referred to in paragraph 2 above.

1.3 Please provide a brief discussion of ICF's experience representing ratepayer interests, and particularly their experience in Canada and BC.

1.4 Please identify which Canadian jurisdiction(s) can be considered as currently 'leading' in terms of DSM, and identify the leading practices.

1.4.1 Please discuss Mr. Dikeos' and Mr. Sloan's experience in those jurisdictions and their involvement in the 'leading practices', if any.

1.5 Please identify which US jurisdiction(s) can be considered as currently 'leading' in terms of DSM, and identify the leading practices.

1.5.1 Please discuss Mr. Dikeos' and Mr. Sloan's experience in those jurisdictions and their involvement in the 'leading practices', if any.

1.6 Do Mr. Dikeos and Mr. Sloan believe that FEI could be a 'leading' utility in terms of natural gas DSM, including infrastructure deferral related DSM? Please explain why or why not.

**2. Reference: Exhibit B-11, ICF page 5**

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.

2.1 Please discuss the 'current state of the process' in Ontario and highlight the differences between Mr. Grevatt's view with that the authors'.

**3. Reference: Exhibit B-11, ICF page 6**

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.

3.1 The CEC notes that the authors utilize the term 'limited' precedent for the use of geo-targeted DSM or dedicated DR programs. Please identify any experience that the authors are aware of in which natural gas utilities have used or attempted to utilize DSM to directly or indirectly impact facilities planning that is not included in the evidence submitted.

3.2 The CEC notes that the authors utilize the term 'almost no' experience in evaluation. Please identify any experience that the authors are aware of in which natural gas utilities have or have attempted to assess the impact of DSM on specific evidence that is not included in the evidence submitted.

3.3 Please cite any references and/or cases in which it is recognized that DSM programs can impact the need for future facilities and provide the dates of these recognitions.

**4. Reference: Exhibit B-11, ICF pages 6 and 7 and page 18**

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

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.

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.

4.1 The authors state that:

> 'a few gas utilities have begun to consider these impacts. However, these efforts remain in the early stages'.

Please identify all the gas utilities that have begun to consider the impacts, and provide more detail regarding the 'early stage' at which each is currently.

4.2 Please provide more detail as to what the authors would view as constituting an 'emerging' best practice.

4.3 What measurement options are available and/or being developed in order to assess the impacts of DSM on peak hourly demand? Please discuss and provide quantification of any known costs.

4.4 What options are or could be available to produce accurate metered data on natural gas peak demand? Please discuss and provide quantification of any known costs.

4.5 What timeframe is considered to be a 'long lead time'?

4.6 Please confirm that the term 'equity concerns' refers to the concerns of 'cross-subsidization' and 'customer discrimination' on page 18.

4.7 Please discuss why a customer within a boundary being geo-targeted for DSM receiving benefits (incentives) for reducing demand would be a case of discrimination vis-a-vis a customer outside a boundary who could not contribute.

4.8 Please confirm that new facilities can impact rates for all customers regardless of geo-geography, within a 'postage stamp' rate system for customer class rates.

**5. Reference: Exhibit B-11, ICF page 7**

> 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.

5.1 Please provide ICF's 2017 best practice review or indicate where it is provided in the proceeding evidence.

**6. Reference: Exhibit B-11, ICF page 7**

> 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.

6.1 Please provide the study referenced above, if different from the 2017 best practice review, or indicate where it is provided in the proceeding evidence.

6.2 Please elaborate on the differences between implementation of broad-based and geo-targeted DSM programs.

**7. Reference: Exhibit B-11, ICF page 7 and 8**

> 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.

7.1 The authors reference both broad-based DSM and geo-restricted DSM topics for their report, but discuss only the geo-targeted DSM results. Please provide an overview of the results ICF found related to broad-based DSM.

7.2 Under what conditions would a utility likely experience a situation in which annual peak hour demand growth is limited and facility project costs are relatively high? Please discuss.

7.3 In what ways might BC differ from the Ontario natural gas utilities that the authors studied, and how might this impact the results? Please explain.

**8. Reference: Exhibit B-11, ICF page 9 and 10**

> 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.

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.

8.1 What is driving the conversions from fuel oil to natural gas in New York City?

8.2 Please provide Con Edison's rate of natural gas demand growth in New York City.

**9. Reference: Exhibit B-11, ICF page 9 and page 10**

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]

> "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]

9.1 Please provide the relevant metrics to place the evidence cited in context. i.e. what is the total growth which will be reduced by 84,500 Decatherms by 2023?

9.2 Please provide a discussion of the 'gas demand response pilot' including to which rate groups it is targeted.

9.3 Please provide an overview of the 'efforts described in [the] filing' to which the above are additional.

**10. Reference: Exhibit B-11, ICF page 10**

### 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 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]

10.1 Please provide the summary for NW Natural's 2018 IRP and/or the section dealing specifically with DSM, including geo-targeted DSM.

**11. Reference: Exhibit B-11, ICF page 12**

- 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.

11.1 Please elaborate on how the differences in planning time of day increase the value and reduce the cost of reductions in peak demand for the electric industry relative to the gas industry.

**12. Reference: Exhibit B-11, ICF page 12**

- 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.

12.1 Do utility facility costs typically make up a lower percentage of the customer gas bill than for their electric bill in BC as well? Please discuss and provide quantification, with particular treatment for generation as a commodity with multiple period storage.

**13. Reference: Exhibit B-11, ICF page 12**

- 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.

13.1 The CEC interprets the authors' comments as contending that the use of DSM to defer natural gas infrastructure could result in insufficient infrastructure and increased risk to customers. If so, please provide further details as to the percentage of infrastructure or particularly next increment infrastructure that would need to be deferred to result in such an outcome.

13.1.1 If not, please clarify.

**14. Reference: Exhibit B-11, ICF page 12-13**

- 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.

14.1 How often, and/or at what granularity would natural gas metering need to be in order to provide adequate measurement of peak periods and flow for the effective use of DSM?

14.2 Are natural gas meters available that can record at such frequency and/or granularity available?

14.2.1 If so, what is the cost of such a meter, and/or meter reading options? Please explain.

14.2.2 If the cost of metering is deemed to be prohibitively expensive, please provide rough quantification of the value of the savings relative to the cost of the metering.

**15. Reference: Exhibit B-11, ICF page 13**

### 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.

15.1 Please identify the 'most aggressive jurisdictions' to which the authors refer.

15.2 Please comment on the activities of these jurisdictions if not already provided either in the evidence or in response to information requests, and indicate where it is located if already provided.

**16. Reference: Exhibit B-11, ICF page 14**

## 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.

16.1 Please elaborate on the differences between Con Edison's cost structure in installing new infrastructure and that of FEI, and provide quantification of the different costs and how those relate to the cost-effectiveness of geo-targeted DSM.

16.2 What other issues do the authors identify between Con Edison and FEI, besides the expense to install new infrastructure?

**17. Reference: Exhibit B-11, ICF page 17**

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.

17.1 Please discuss the types of business and regulatory construct, cost-benefit analyses, and different evaluation standards that would be appropriate for infrastructure-targeted DSM.

## 18. Reference: Exhibit B-11, ICF page 17-18

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?
   - 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?

18.1 Please confirm that ratepayers typically bear the risk for DSM-related costs.

## 19. Reference: Exhibit B-11, ICF page 21

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.

19.1 Do the authors believe that such a plan would ever be useful to develop?

19.1.1 If no, why not?

19.1.2 If yes, when would the authors recommend such a plan might be undertaken?

# II. CEC INFORMATION REQUESTS TO NAVIGANT CONSULTING INC.

## 20. Reference: Exhibit B-11, Navigant, page 6

### 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' 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.

20.1 How would Navigant expect the results to change given the allowance of 40% as compared to 33% at the time of assessment? Please explain and provide quantification.

## 21. Reference: Exhibit B-11, Navigant page 7

### 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.

21.1 Please discuss the relevance of the statement that '...those incentive levels may be more aggressive than the median incentive levels seen throughout North American utilities'.

21.2 Would it be problematic for FEI to have more 'aggressive' incentive levels than other jurisdictions? Please explain.

21.3 Please provide quantification for the diminishing rate of acquired savings per dollar of incentives, or identify where this is already provided in the evidence.

21.4 Please comment on the potential difference between Greenhouse Gas Emission Reduction seriousness in the BC policy environment and that of other jurisdictions in North America, and particularly contrast the current US administration's GHG policy direction.

21.5 Please confirm, or otherwise explain that the stricter the future for GHG reduction policy the more valuable natural gas DSM will become.