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November 15, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
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Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598946

2017 Long Term Gas Resource Plan (LTGRP) (the Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 3

On December 14, 2017, FEI filed the Application referenced above. In accordance with Commission Order G-132-18 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 3.

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

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A. ICF EVIDENCE

74.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, pp. 6-7

Best Practice Review

On page 6 of the Expert Witness Report of Michael Sloan and John Dikeos, ICF (ICF Report), in Exhibit B 11, ICF states:

> 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.

On page 7, ICF states:

> 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.

74.1 Please provide a list of the gas utilities reviewed by ICF, including those that have begun to consider the impact of Demand Side Management (DSM) programs on peak hour/peak day demand forecasts.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

ICF reviewed the IRP reports and/or IRP report-style documents of the following gas utilities as part of its jurisdictional review for the Enbridge/Union Gas IRP study:

Avista Utilities, California Utilities (Joint), Cascade Natural Gas, Colorado Springs Utilities, Con Edison, FortisBC, Intermountain Gas, New Mexico Gas Company, Northern Utilities, Northwestern Energy, Northwest Natural Gas, Oklahoma G&E, Puget Sound Energy, Questar Gas, and Vermont Gas Systems.

For most of these utilities' IRP plans, DSM was treated as a reduction of the total annual demand forecast based on the results of an achievable potential study and cost-effectiveness framework.

74.2 Please discuss whether, based upon FEI's current understanding of its load profile, FEI expects that any potential targeted DSM programs would need to achieve demand reductions in the peak hour only, or multiple hours that "shoulder" the peak hour.

Response:

FEI consulted with ICF to provide the following response.

The need to target either peak hour only, or multiple hours that "shoulder" the peak hour in order to realize the potential benefits of investing in a targeted DSM program depends on the avoided infrastructure investment that is being targeted by the program. Natural gas distribution facility planning time horizons differ based on the type of load served. Local, "small diameter" distribution mains which are fed from distribution pressure (DP) stations are designed to meet peak hour, or even peak 15-minute load requirements.

The required duration of the demand reductions for smaller distribution mains also depends on the overall demand profile; if periods surrounding the peak period exhibit only a slightly lower demand, it may be necessary for DSM programs to achieve demand reductions for an extended period.

For larger mains within the distribution service territory, such as those supplied by FEI's intermediate pressure (IP) stations, the peak period for planning purposes often stretches beyond the peak hour. These systems serve a variety of different loads, and rely to a greater degree on line pack to meet peak period demand. For these facilities, shifting load by an hour or two away from peak load would have little or no impact on the system requirements.

For larger transmission mains which feed transmission pressure (TP) stations, and for contracted capacity on transmission pipelines, capacity requirements are determined by a 24-hour peak day load, and shifting load by a few hours either way would have little or no impact on infrastructure requirements.

FEI's service territory includes infrastructure requirements that fall into each of these categories.

74.2.1 Please discuss how this impacts the viability of demand reduction programs.

Response:

FEI consulted with ICF to provide the following response.

FEI interprets a "demand reduction" to be a general term for any program intended to reduce natural gas demand during peak period use (either the peak hour, peak day or a number of days over a peak period event) based on improvements in efficiency or the implementation of an improved control strategy, or 'demand response' (i.e. wherein the utility is in some way able to control the use by participating customers of certain energy equipment during peak demand periods). For further clarity, this response assumes that 'demand response', 'geo-targeted DSM' and general DSM programs that either target peak demand or due to the nature of the measures implemented tend to reduce peak demand, are all considered "demand reduction" programs.

The viability of demand reduction programs depends on the specifics of the demand reduction program, and the specifics of the facilities that might be impacted by the demand reduction program. Most DSM measures currently available for natural gas utilities result in natural gas demand reductions that stretch beyond the peak period. In fact, the implementation of most gas DSM measures lead to reductions in gas demand throughout the entire year.

74.2.2 Please briefly discuss any risks associated with shifting the peak hour as a result of demand response programs.

Response:

FEI consulted with ICF to provide the following response.

FEI interprets a "demand response" (DR) program to be either a program that shifts load away from the peak period, by moving demand forward or backward in time in order to reduce peak period demand, or a dispatchable load program that curtails load during peak periods.

For a DR program that is based solely on changing customers' energy use behaviors during a peak event, the first risk is that not enough customers actually change their behavior at the time the change is required. The factors that impact customer behavior are many, dynamic and complex and cannot be expected to be consistent from one peak event to another. The remainder of this response considers the potential for load shifting programs other than strictly behavioral programs, or assumes that somehow this initial risk is overcome.

For smaller mains and services that are designed based on peak hour criteria, DR programs capable of shifting demand by an hour or two may be effective. For these facilities, the ability to shift peak load to the period either before or after the peak hour could reduce the need for incremental capacity, or allow the load to be served by a smaller capacity system. However, since DR programs typically shift loads to hours shouldering the peak period, there is a risk that it may simply shift the peak to a new time period rather than reducing the peak.

For larger infrastructure projects that are designed around the peak day or extended periods within the peak day, an effective DR program would need to have the capability to shift demand over a longer period. Hence, the viability of a demand reduction program depends on the specifics of the demand reduction program and the specifics of the facilities that might be impacted by the demand reduction program.

Demand response programs are not widely used in the gas industry due, in part, to the nature of peak system planning requirements for natural gas utilities. There would be significant risk in relying on a demand response program to avoid infrastructure investments in areas where the shift in demand may not be sufficient to move the demand out of the critical planning period.

The types of demand response programs discussed for natural gas utilities are also likely to reduce the efficiency of the natural gas use. This would include increased heat losses if water heating is shifted to periods prior to the peak demand periods, and additional losses of efficiency associated with cycling of natural gas appliances.

75.0 Reference: ICF EVIDENCE

Enbridge DSM Mid-Term Review, Submission to Ontario Energy Board,

January 15, 2018, Appendix D, p. 19

Review of Ontario Gas Utilities

On page 7 of the ICF Report in Exhibit B-11, ICF states:

> 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.

On page 8, ICF states:

> 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 midterm review, as per the OEB's requirements
>
> …
>
> 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.

On page 6, ICF references the Enbridge DSM Mid-Term Review, Submission to OEB, January 15, 2018 (Enbridge Review). On page 19 of Appendix D of the Enbridge Review, ICF states:

> While DSM programs do broadly impact facilities requirements, and the cost savings associated with a broad based reduction in distribution costs are generally included in the DSM planning process, the linkages between DSM planning and facilities planning are currently passive rather than active, and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process.

75.1 Please discuss if any of FEI's current DSM programs could be considered "geo-targeted"

Response:

No, FEI does not consider that any of its current programs are geo-targeted programs.

75.2 Please explain if geo-targeted DSM programs would likely be more or less expensive on a per-unit basis than "broad-based" programs.

Response:

FEI consulted with ICF to provide the following response.

FEI interprets "per-unit basis" to mean expenditures per saved GJ of energy. While there is little direct experience with the costs associated with geo-targeted programs, ICF anticipates that geo-targeted DSM programs would be more expensive on a per-unit basis than "broad-based" programs. Geo-targeted programs are likely to be smaller than broad-based programs, leading to higher administrative costs per unit. Also, geo-targeted programs are likely to require additional metering, monitoring, and evaluation efforts to ensure that they are accomplishing their objectives.

75.3 Please summarize the details of any additional research/analysis proposed in the ICF study or the Integrated Resource Planning (IRP) Transition Plan.

Response:

FEI consulted with ICF to provide the following response.

The details of the proposed next steps in the Enbridge/Union IRP Transition Plan are summarized in the table below.

Additional Research Proposed in EGD/UG IRP
Collection of hourly demand data: • The collection and evaluation of measured hourly demand data at a customer level to more accurately assess the impact of DSM measures and programs on peak period demand is needed to determine the cost and implementation potential of DSM measures and programs. This will require AMI and automated meter reading (AMR) capability. Until actual hourly data is available, the Gas Utilities will not be in a position to accurately determine the potential cost-effectiveness of using DSM as an alternative to facility investments.
Assessment of the reliability of using geo-targeted DSM to reduce peak hour demand growth: • The risk associated with relying on DSM to reduce peak hour demand is one of the major difficulties in using DSM to reduce facility investments. ICF expects that development of specific in-field pilot studies that test the ability of the utility to offset peak hour demand growth using DSM pilot programs will be the best approach to resolving these issues.
Assessment of the cost of geo-targeted DSM implementation: • The cost per participant of implementing geo-targeted DSM programs is expected to be higher than the costs of implementing system-wide DSM programs. The additional costs are based on the smaller program scale associated with geo-targeted DSM programs, the tailored nature of these programs, and the need for additional monitoring and evaluation. Based on available information, and on ICF's experience with DSM program implementation, these costs are estimated to be 1.5 to 2 times higher than typical DSM program costs. However, until actual data from in-field pilot studies is available, the actual increase in costs will be unknown. The magnitude of these costs may determine whether or not geo-targeted DSM programs can be cost-effective.

FEI's considerations in relation to these research activities are summarized as follows.

FEI Consideration of Research Activity
Advanced Metering Infrastructure (AMI) project: • FEI is implementing a small scale AMI pilot project in a pre-defined area that comprises several different customer types. The initial phase of the pilot project aims to generate data that FEI could use to understand the advanced metering capabilities and logistical issues related to deployment and data collection requirements. • Subject to success in the initial phase, the AMI pilot could also open up a channel for quantifying the effectiveness of various types of peak demand DSM programs. However, further exploratory research is required to develop appropriate measurement and verification protocols and data handling capabilities for this activity. • Additionally, FEI would need to weigh the results of this AMI research against potential future research into the opportunity for deploying advanced metering capabilities at its gate stations and service mains in order to determine which approach delivers most value per unit of cost.

FEI Consideration of Research Activity

Assessment of geo-targeted DSM pilot programs:

- If research conducted in relation to the AMI pilot suggests that advanced metering data could successfully be used for peak demand DSM measurement and verification and if FEI's ongoing assessment of exploratory research in other jurisdictions indicates that suitable candidate infrastructure projects may exist in FEI's service territory, FEI may be able to deploy peak demand DSM pilot programs to assess the reliability of geo-targeted DSM to reduce peak demand growth. In order to do so, FEI would also need to conduct further research into suitable pilot project design characteristics.

Assessment of the cost of geo-targeted DSM for infrastructure deferral:

- If FEI's exploratory research into advanced metering and the reliability of geo-targeted DSM programs suggests that FEI might be able to successfully use DSM to defer infrastructure projects in its service territory, FEI would need to review the cost of geo-targeted DSM programs in relation to the cost of its annual demand DSM programs and would need to examine how such costs might change if geo-targeted DSM programs were deployed at the scale required to defer infrastructure projects.
- Based on the outcomes of this research, FEI would also need to rely on its ongoing assessment of exploratory research in other jurisdictions to determine suitable regulatory, cost assessment, cost allocation and risk allocation models for DSM infrastructure deferral.
- Finally, two other factors need to be assessed for FEI to consider undertaking a geo-targeted DSM pilot study: 1. Alignment of such a study with FEI's DSM guiding principles and 2. The availability and identification of a suitable area within FEI's service territory.

75.3.1 Please provide comment on whether FEI is considering undertaking any of these research activities.

<u>Response:</u>

Please refer to the response to BCUC IR 3.75.3.

75.4 Please discuss if FEI considers that DSM programs should be allocated benefits in DSM cost-effectiveness testing as a result of cost savings from "passive deferral"

<u>Response:</u>

FEI consulted with ICF to provide the following response.

FEI agrees that it is appropriate to include some benefit from "passive deferral". FEI understands the term "passive deferral" in this instance to refer to the potential for infrastructure deferral from its current programs which do not specifically target reductions in peak demand for the purpose of infrastructure deferral.

FEI's approach to evaluating DSM programs does currently include an estimate of the benefits associated with the passive deferral of infrastructure investment. FEI refers to this value as the distribution adder. The cost benefit tests used by FEI to evaluate DSM programs are based on an estimate of the avoided costs that includes an estimate of the distribution system peak capacity costs that could be avoided by the DSM program.

75.4.1 If yes, please suggest how an adder for passive deferral could be calculated.

Response:

The current avoided cost estimate used by FEI to assess the value of DSM programs already includes an estimate of the value of the passive deferral of infrastructure investments. Please refer to the response to BCUC IR 3.75.4.

On page 7 of the ICF Report in Exhibit B-11, ICF states:

> 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.

On page 19 of the ICF Report in Exhibit B-11, ICF states:

> 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.

75.5 Assuming a similar level of maximum available peak demand reductions from DSM in BC as in the Ontario examples, would FEI consider that approximately

1.2 percent annual load growth represents the upper limit where multi-year deferral of infrastructure investments as a result of DSM would be feasible?

Response:

FEI consulted with ICF to provide the following response.

Yes, assuming a similar level of maximum available peak demand reductions from DSM in BC, it is likely that FEI would have a similar upper limit for annual peak load growth (i.e., approximately 1.2%), beyond which multi-year deferrals of infrastructure investments would not be feasible. This upper limit for any individual infrastructure investment depends on several factors, including but not limited to the local climate, the distribution of local demand by sector, the types of measures being implemented, and the current penetration of these measures. Therefore, it is difficult to comment on an exact "upper limit" for FEI without a detailed analysis and/or pilot testing results.

75.5.1 Please discuss whether FEI considers that there could be benefit in undertaking a study of potential peak demand reductions from DSM, similar to the assessments completed for Enbridge and Union.

Response:

FEI consulted with ICF to provide the following response.

For the purpose of this response, FEI interprets "peak demand reductions from DSM" to include passive peak demand reductions from DSM programs, peak demand reductions due to targeted demand response interventions, and peak demand reductions from geo-targeted DSM. While there is value associated with good studies into market issues such as a study of the potential peak demand reductions from DSM, the question becomes whether or not the benefits are likely to exceed the costs. The main benefit of undertaking a study of potential peak demand reductions from DSM similar to the assessments completed for Enbridge and Union is that the analysis would account for the local context and realities in FEI's service territory. However, FEI anticipates that a tailored study would yield similar results, and would not add significant value to the process.

There would be greater value in additional research, analysis, and pilot testing that is currently underway in Ontario, New York and other jurisdictions. Since the results of these next steps are uncertain and select jurisdictions are proceeding with additional analysis and pilot testing, it would be prudent for FEI to proceed cautiously and assess the results of work in other jurisdictions to inform next steps.

75.5.2 Please explain any potential reasons that the maximum annual peak demand reductions from DSM may be significantly different in BC compared to Ontario.

Response:

Please refer to the response to BCUC IR 3.75.5.

76.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, pp. 9-10

Review of Con Edison

On page 9 of the ICF Report in Exhibit B-11, ICF states:

> 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 nonpipeline 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.
>
> 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 other efforts, including parallel planning for a traditional pipeline solution to meet demand growth.

On page 10, ICF states:

> 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.

76.1 Please confirm if the energy efficiency programs included in the Con Edison portfolio includes demand response programs.

Response:

FEI consulted with ICF to provide the following response.

The energy efficiency programs included in the Con Edison Non-Pipeline Solution portfolio currently do not include demand response programs. The RFP process undertaken by Con Edison during the development of the Non-Pipeline Solutions portfolio included provisions for companies to submit bids for demand response programs, and Con Edison did receive responses to the RFP that proposed demand response programs. However, the company did not select any of the proposed demand response programs in the final proposed portfolio.

Con Edison is currently studying the potential for demand response programs as a separate element of their Non-Pipeline Solutions effort. On August 9, 2018, Con Edison received approval from the New York Commission to implement a gas demand response pilot program. This demand response pilot program was not part of the Non-Pipeline Solutions portfolio proposed by Con Edison.

76.2 Please briefly explain how, in the Con Edison example, RNG is expected to reduce pipeline capacity requirements.

Response:

FEI consulted with ICF to provide the following response.

In the Con Edison example, the proposed RNG facilities would have been built within the Con Edison service territory, and would have been interconnected with the Con Edison distribution system. As such, to the extent that Con Edison considered the plants to be a reliable source of supply, the facilities would displace the need for incremental pipeline capacity.

76.2.1 Please discuss whether FEI's current or future RNG projects could potentially reduce pipeline capacity requirements.

Response:

FEI does not view its current or near future RNG projects as being able to reduce pipeline capacity requirements. The small size of each individual project within a distribution area and the small amount of RNG being supplied overall, combined with uncertainty as to the reliability of production during peak, cold-weather events mean that existing sources of RNG (i.e. sources that rely on supply technologies and pathways that are currently applied in BC, such as anaerobic digestion and landfill gas collection) cannot be expected to defer the need for transmission capacity infrastructure over the planning horizon.

If new, large sources of RNG such as that produced from cellulosic organic material (wood waste) become available during the planning horizon, it would be likely that these projects would continue to rely upon existing pipeline capacity to move gas from the source to the customers.

FEI is not currently aware of any such projects and would have to examine the potential impacts of any larger scale projects on its infrastructure if and when they are brought forward.

76.3 Please discuss whether FEI has considered the feasibility of truck deliveries of CNG/LNG as a means of reducing peak period supply in targeted locations.

Response:

FEI would like to clarify that the use of truck deliveries of CNG/LNG in itself would not reduce peak period demand or supply in a targeted location, but rather would be an alternative means of meeting that demand/supply. In general, truck deliveries of natural gas require costly infrastructure and incur substantial operating cost. These issues, along with long term safety, reliability and suitability of the system in that location need to be examined on a case by case basis to determine if trucking CNG/LNG is a preferable alternative to pipe and compression solutions.

For example, FEI continues to deliver propane to Revelstoke using truck and rail, but also continues to evaluate other alternatives. In this case connecting the Revelstoke distribution system to FEI's natural gas network via extending a pipeline has so far remained too costly to be a preferred alternative.

FEI has also successfully implemented truck deliveries of natural gas on a temporary basis to overcome supply capacity constraints in a targeted location. For example, over the past three winter seasons (including the current 2018/19 winter season), FEI has implemented a temporary LNG delivery service to reinforce the distribution pipeline system in the Resort Municipality of Whistler (RMW). In this case, however, upgrades to the pipe network in Whistler are seen as a better long term alternative to ongoing truck deliveries, which are considered short term or interim solutions.

76.4 Please clarify whether in the absence of eliminating the need for new pipeline capacity, Con Edison may be able to invest in smaller capacity, less costly pipeline solutions.

Response:

FEI consulted with ICF to provide the following response.

The Con Edison Non-Pipeline Solutions effort was driven by the desire to reduce the need to contract for new pipeline capacity into the utility's service territory. Currently, no existing pipeline capacity is available to be contracted, hence the increase in contracted capacity would require construction of a new pipeline, or expansion of an existing pipeline. Reliance on new pipeline capacity represents two risks to Con Edison. First, it may not be possible to build the capacity. Second, if built, the capacity is expected to be expensive.

In the event that new pipeline capacity to serve the Con Edison service territory cannot be built, the reduction in demand reduces Con Edison's overall supply risk, which also has significant benefits, regardless of whether or not the full amount of new pipeline capacity can be avoided.

In the event that the pipeline can be built, given the economics of new pipeline capacity, ICF would not anticipate that Con Edison would contract for the full amount of incremental pipeline capacity that would be associated with a pipeline expansion project. As a result, by reducing demand growth, Con Edison can reduce the amount of pipeline capacity that it needs to contract for, although doing so likely would not reduce the size of the pipeline expansion project.

Hence, even if the Con Edison NPS program is not able to fully avoid the need for pipeline capacity, the program will have potential value by reducing the amount of pipeline peaking service that otherwise would be required. The initial Non-Pipeline Solution portfolio proposed by Con Edison was not sufficiently large to eliminate the need for new pipeline capacity.

76.5 Please briefly discuss the strengths and weaknesses of developing an integrated supply-side and demand-side portfolio of non-pipeline solutions, as proposed by Con Edison.

Response:

FEI consulted with ICF to provide the following response.

Since, as stated in ICF's evidence (Exhibit B-11, page 6), there are few examples of natural gas utilities integrating supply-side and demand-side portfolios in this way, the strengths and weaknesses of doing so are not well documented. Further, the differing planning environments and regulatory frameworks between jurisdictions may influence the strengths and weaknesses that can be identified. Logically, one of the strengths that can be expected of an integrated supply-side and demand-side portfolio of non-pipeline solutions lies in the integrated nature and increased comprehensiveness of the analysis.

Conversely, among the weaknesses would be the additional resources and level of effort needed to ensure that the analysis is consistent across all of the different options. Weighing the value of the integrated analysis against the additional resources required to complete it would be a fairly subjective task. Other weaknesses of an integrated supply-side and demand-side portfolio of non-pipeline solutions include the challenges in evaluating the different risk profiles of the different options, assigning different values to the different risks, and coordinating the different timelines associated with option development.

76.6 Please confirm that FEI's understanding is that gas infrastructure investments are less costly in BC than in the New York service area.

Response:

FEI consulted with ICF to provide the following response.

Generally, ICF expects comparable gas infrastructure investments in BC to be less costly than into and within the Con Edison service territory in New York. However, the costs of infrastructure projects differ widely based on the specific circumstances around the project, including project size, project length, and the nature of the ground where the project is located (urban versus rural, presence of water crossings, amount of soil cover over stone, etc.).

77.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, p. 11

Review of Northwest Natural

On page 11 of the ICF Report in Exhibit B-11, ICF states:

> 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.

77.1 Please discuss whether FEI has considered engaging large firm customers regarding the feasibility of interruptible agreements.

Response:

FEI has had interruptible rate schedules available to its large customers for many years and these customers are able to select the level of service that best suits their business. FEI continually engages with its large industrial customers for a variety of business reasons including but not limited to topics such as available rate schedules (i.e. firm or interruptible service) and conservation and energy management programs that may be available to them.

77.1.1 Please explain whether FEI views that this could be considered as a viable demand side alternative to infrastructure investments.

Response:

FEI believes that it has implemented this option appropriately (refer to the response to BCUC IR 3.77.1) and does not view further pursuit of interruptible agreements as a viable demand side alternative. First, moving specific customers to interruptible rate classes may or may not free up broad capacity and second, encouraging such moves among customers may lead to higher risk and unintended consequences for the customer.

On the first point, interruptible customers are typically curtailed in large groups based upon capacity needs of a region. Moving customers to interruptible may result in capacity changes to a specific section of pipeline but would not necessarily result in changes to curtailment and overall capacity requirements. On the second point, customers choose firm or interruptible service based upon their business requirements and risk tolerance. As such FEI presents rate options to customers but is careful to not push a customer into a rate class that could increase their risk and lead to unexpected business interruptions and costs. In addition, FEI's largest customers with significant annual consumption already have some amount of interruptibility within their agreements. FEI has used clauses with customers in long term service agreements with significant annual firm contracted capacity, such as the BC Hydro Transportation Service Agreement for Island Generation, whereby FEI gave those customers the opportunity to reduce their contracted firm capacity which as a result may reduce or eliminate potential infrastructure upgrades.

78.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, pp. 14-15

Risk and Reliability Criteria

On pages 14 to 15 of the ICF Report in Exhibit B-11, ICF states:

> 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.
> - 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.
>
> 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.

78.1 In FEI's view, could the application of a "risk adjustment factor" to the DSM cost-effectiveness tests (i.e. a reduction in the calculated benefits of a DSM measure) be an appropriate means of reconciling the differing reliability requirements of DSM and facilities planning?

Response:

FEI consulted with ICF to provide the following response.

A risk adjustment factor, or series of risk adjustment factors, could be an appropriate means of reconciling the differing reliability requirements of DSM and facilities planning, depending on how the risk adjustment factors are structured and implemented. When considering the impact of DSM measures on peak demand, it is appropriate to consider both the reliability of the peak demand impacts and the risk associated with relying on DSM to counterbalance the need for incremental infrastructure investments.

From a reliability standpoint, the peak demand impacts from DSM measures may not be available during a peak demand period for a variety of reasons. From the perspective of risk, program planning requires more certainty that the peak demand impacts from DSM planning will materialize, likely necessitating a larger safety margin.

Reliability and risk must both be considered when assessing whether DSM is a viable option to defer infrastructure investments. Hence, when structuring a risk adjustment factor, several different types of risk must be considered. These include:

- **Program implementation risk:** Will a DSM program reach its implementation targets on time and on budget? How do these risks compare to the risks of facility implementation?
- **Measure performance risk:** Will the DSM measure actually provide the expected degree of peak period demand reduction? Utilities generally have a very high level of confidence in the ability of new infrastructure, but will have less confidence in demand side measures to impact peak demand.
- **Coincidence factor risk:** Will the impacts of the installed measure all affect peak demand at the same time, or will there be a distribution of effects that reduces the overall impact on peak demand.

FEI anticipates that quantifying these risks such that a well supported 'risk adjustment factor' could be added to the cost effectiveness tests would be very difficult. Such assessments, if undertaken, would at best be qualitative given the current knowledge within the industry on the impacts of DSM on peak demand. All of these factors would need to be considered if and when developing a risk adjustment factor.

78.1.1 If yes, please suggest what metrics could be used to calculate the required risk adjustment.

Response:

FEI consulted with ICF to provide the following response.

Since there is limited experience with the use of DSM to defer natural gas infrastructure investments and significant uncertainty regarding the impacts of DSM measures on peak demand, any adjustment factors should be calculated based on pilot testing and/or broader implementation of similar initiatives. The availability of reliable metering to monitor the impacts of DSM measures on an ongoing basis would also have an impact on any adjustment factors.

In addition, the risk adjustment factor would be expected to differ by type of facility and type of DSM measure. Risks will also change over time, and would be expected to decline as experience reduces uncertainty.

78.1.2 Similarly, are there other adjustment factors that could potentially mitigate other concerns identified in ICF's evidence?

Response:

FEI consulted with ICF to provide the following response.

Additional research and analysis would be required to determine whether there are any other appropriate adjustment factors. Over time, FEI can likely expect to take advantage of the research and pilot programs being developed by other utilities in order to reduce the risk factors.

79.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, pp. 7, 16

Planning Timelines

On page 7 of the ICF Report in Exhibit B-11, ICF states:

> 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.

On page 16 of the ICF Report in Exhibit B-11, ICF states:

> 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.

79.1 Does FEI consider that the need for new facilities is always uncertain three to five years before the expected in-service date, or are there instances where there is a relatively strong degree of certainty?

<u>Response:</u>

FEI consulted with ICF to provide the following response.

Yes. There is always some uncertainty associated with the need for new facilities three to five years before the expected in-service date. Please also refer to the response to BCUC IR 1.38.1, which provides a high level view of project time requirements for transmission (excluding regulatory approvals). Three to five years is a typical planning horizon for FEI to examine the requirement for new facilities in order to mitigate system capacity constraints. Similarly for the distribution system, FEI also models potential gas flows five years into the future to confirm whether or not a capacity shortfall is expected due to load growth in each distribution area. Even in cases where there is a relatively strong degree of certainty, such as areas with consistent long-term growth or expected new loads from new industrial customers, economic downturns or other factors can strongly influence the need for new facilities, pushing back or completely eliminating the need in some cases. However, failure to plan for new facilities based on this timeframe increases the likelihood of not having the facilities available when needed.

Based on ICF's best practices review for Enbridge/Union IRP, most of the utilities agreed that a lead time of five years would be required to incorporate DSM as an effective strategy to defer infrastructure investments. With respect to new subdivision and community planning, utilities noted that land use planning guidelines require two to three years for leave to construct, which would mean that the needs of future communities would need to be forecasted at least five years in advance. Some state/provincial commissions may provide utilities with the flexibility to explore multiple options to meet distribution planning but there would need to be a reasonable cut off time after which only one option could be further pursued.

79.2 Please provide FEI's view on how feasible geo-targeted DSM could be:

a) Rapidly scaled up following smaller "proof of concept" program(s).

b) Scaled down if the facility investment was determined to no longer be required.

Response:

FEI consulted with ICF to provide the following response.

There is limited experience with implementing geo-targeted natural gas DSM programs; however, since these programs must be tailored to local realities in order to be as effective as possible, ICF anticipates that such programs will require some additional time and effort to bring to market relative to a traditional DSM program:

- Designing programs to target specific regions or customers will be more complicated than designing broad based DSM programs.
- Gathering market characterization data on the targeted area in question to feed into the program design may be more burdensome than for non-targeted programs. This includes but is not limited to data on the distribution of energy consumption and building types, the penetration of different types of equipment (e.g. different types of space heating equipment), and the relative penetration of energy efficiency measures in the targeted area.
- Setting up any associated metering infrastructure to monitor program impacts would also require additional effort and time.

Nonetheless, FEI believes that geo-targeted DSM programs could be scaled up relatively quickly following smaller "proof of concept" programs that address some of these challenges, assuming such a proof of concept proved successful. The incremental time to scale up programs would likely decline if and as the industry develops appropriate protocols for targeting customer segments and measuring impacts.

The timeline for scaling down geo-targeted programs would likely be similar to the timeline for scaling down typical DSM programs.

79.3 Please provide a list of FEI's expected infrastructure investments as identified in the 2017 LTGRP that could be categorized as "limited" forecasted growth in annual peak hour demand, and relatively high facility project costs.

Response:

FEI interprets "limited" forecasted growth to mean that DSM investments could be considered as alternatives for transmission infrastructure projects if annual peak hour demand growth in the applicable transmission system does not exceed approximately 1.2 percent (as identified by ICF in Exhibit B-11 and subject to several factors, including the local context of any geo-targeted program). The 2017 LTGRP outlines expected infrastructure requirements in Table 6-1 (for the VITS), Table 6-2 (for the CTS), and in section 6.3.3 (for the ITS). However, none of the expected infrastructure investments in FEI's transmission system currently fall within the range of "limited" forecasted growth in annual peak hour demand.

First, for the VITS, the overall average annual peak demand growth rate is about 2.8 percent. However, there are two regions, Victoria and Nanaimo, which have the highest annual growth rate at about 2.5 percent and 3.9 percent, respectively. These annual peak demand growth rates all exceed the 1.2 percent threshold that ICF has identified as the upper limit for considering DSM investments as a potential alternative to infrastructure investment.

Second, for the CTS, the infrastructure investment depicted to be required in the High case with LNG in Figure 6-11 of the 2017 LTGRP is due to potential future demand for LNG transportation fuel (serviced by the Tilbury LNG Plant) and potential large new industrial loads (such as the Woodfibre LNG Project). As a result, if this High case with LNG were to materialize, DSM would not be directly applicable for deferring this infrastructure.

Third, the ITS system expansion alternatives are also driven mainly by annual peak demand growth in the Greater Kelowna region which is about 1.7 percent, which does not meet FEI's understanding of the term "limited" forecast growth.

Additionally, each of the service areas served by these infrastructure projects are large and complex, with many factors potentially having some influence on peak demand. These complexities make these service areas inappropriate for studying and testing the potential impacts of DSM on peak demand. Therefore, for all of the reasons discussed above there are no viable candidates to evaluate targeted demand side alternatives based on FEI's currently identified infrastructure investments as outlined in the 2017 LTGRP.

79.3.1 Please discuss whether, based upon current understanding, FEI considers that any of the infrastructure investments identified could act as viable candidates to evaluate targeted demand side alternatives in future.

Response:

Please refer to the response to BCUC IR 3.79.3.

80.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, pp. 17-18

Other Considerations

On pages 17 to 18 of the ICF Report in Exhibit B-11, ICF states:

> 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?
>
> 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.
>
> 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.

In its response to BCUC IR 1.29.1, FEI states:

> FEI is conducting a pilot project on advanced meters for residential and commercial customers that could provide hourly or more frequent meter readings. As part of that pilot, FEI will be examining the ability of such meters to provide improved data for analyzing end use trends which might lead to a better understanding of the impacts of C&EM activities on peak demand.
>
> …
>
> FEI expects that this pilot will also provide insights into whether or not demand response programs (please also refer to the response to BCUC IR 1.29.1.1), other than industrial curtailment as noted above, would potentially be effective in reducing or shifting peak demand.

In response to BCUC IR 1.64.1.1.1, FEI outlines additional activities that could help in better understanding the impacts of C&EM activities on peak demand.

80.1 Please discuss if FEI has a position on the "public policy questions" posed by ICF with respect to risk allocation.

Response:

FEI consulted with ICF to provide the following response.

FEI agrees that these are issues that need further consideration as part of the ongoing exploration of the potential impacts of DSM on peak demand. For FEI, this ongoing exploration includes monitoring how such issues are being addressed in the few other jurisdictions where consideration of peak demand reductions from natural gas DSM is emerging.

The public policy questions posed by ICF relate largely to the determination and allocation of the risks and benefits associated with using DSM to reduce infrastructure investment. The risks can be divided between reliability risks and cost risks. FEI is of the view that increasing risks to system reliability is not acceptable to its customers, its shareholders, or its regulators. FEI believes that costs should be allocated based on the potential benefits associated with the costs and that the proper allocation of costs requires further consideration based on the potential design of a program that targets infrastructure deferral, should such a program be developed, including the risk of the infrastructure not being deferred.

FEI also views that the continued monitoring of progress on these issues by other jurisdictions prior to incurring additional costs on experimentation and a forced development plan would be a more prudent use of ratepayer funds given the requirement to supply energy during peak period events.

80.2 Please confirm if FEI's position is that it requires additional research as outlined in BCUC IRs 1.29.1 and 1.64.1.1.1, before it would be in a position to trial geo-targeted DSM programs.

Response:

Confirmed. FEI believes that the additional research is required as outlined in the identified IR responses as well as further consideration of and potential research on the issues identified by ICF in the rebuttal evidence report (Exhibit B-11). This research and any outcomes from it also need to be considered within the context of FEI's DSM Guiding Principles as outlined in Section 6.3 of FEI's 2019-2022 DSM Expenditures Plan Application.[1]

80.3 Please explain if FEI expects that the costs of any future geo-targeted DSM programs would be shared across customer classes.

Response:

FEI believes that the allocation of costs for any potential future geo-targeted DSM activities requires further exploration. If in the future, FEI believes that geo-targeted DSM will benefit its customers and determines that a different cost allocation approach is required, it will propose a cost allocation approach for such an initiative at that time.

80.3.1 Please elaborate from FEI's perspective the cross-subsidization risk of geo-targeted DSM compared to traditional infrastructure investments.

Response:

In FEI's view, all customers have access to FEI's service via its infrastructure and the costs of infrastructure are shared across regions and customer classes. In contrast, geo-targeted DSM could raise the risk of cross-subsidization. For example, geo-targeted DSM programs may cause customers in certain locations only to have access to a specific DSM program due to targeted marketing and/or incentive offerings, while other customers who are not targeted will not have access to the program but could pay for a share of costs for such a program. The potential cross-subsidization risk of geo-targeted DSM activities depends on how specific geo-targeted DSM programs are designed. As discussed in FEI's response to BCUC IR 3.80.3, further exploration is still required to determine any potential benefits of and cost-allocation for geo-targeted DSM.

1 FortisBC Energy Inc, 2019-2022 Demand Side Expenditures Plan, June 22, 2018, p 26

81.0 Reference: ICF EVIDENCE

Exhibit B-11, ICF Report, p. 22

Conclusions and Recommendations

On page 22 of the ICF Report, ICF states:

> 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.

81.1 Please elaborate on the suggested scope of the “exploratory research” and the expected costs and timing associated as applicable.

Response:

FEI consulted with ICF to provide the following response.

FEI’s exploratory research approach has been operating in a step-wise fashion, with execution of later steps dependent on the results from previous steps and certain tasks being executed in parallel. The Company has also been incorporating lessons learned on an ongoing basis from relevant activities in other jurisdictions. FEI would prefer to continue operating in this manner since this approach allows for maximum flexibility and risk management. Continued exploration should consider:

- Ongoing monitoring of progress on understanding the impacts of DSM on peak demand in other jurisdictions;
- Developing a deeper understanding of peak consumption patterns in FEI’s service territory – i.e. advancing FEI’s knowledge of daily, hourly and sub-hourly load shapes for various natural gas equipment and new DSM measures as information becomes available;
- Further exploring, and where possible improving on, FEI’s exploratory end-use peak demand forecast method;
- Additional research and pilot testing of options for measuring and monitoring peak demand; and
- Further consideration of pilot testing for geo-targeted DSM programs.

FEI will also examine any additional issues and uncertainties identified by ICF in its rebuttal evidence report to determine if further action by FEI is appropriate. It is challenging to provide the expected costs and timing associated with the majority of these activities since the scope and timing will depend on the preliminary results.

B. NAVIGANT EVIDENCE

82.0 Reference: Navigant Evidence

Exhibit B-11, Navigant Report, pp. 3-4

Conservation Potential Review Model

On page 3 of the Navigant Consulting, Inc. (Navigant) Rebuttal Evidence on DSM Energy Savings Trajectories (Navigant Report) in Exhibit B-11, Navigant states:

> 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…

82.1 Please confirm that the equilibrium market share calculation does not assume that all individuals will necessarily adopt a DSM measure, even if payback periods are relatively favourable.

Response:

FEI consulted with Navigant Consulting Ltd. (Navigant) to provide the following response.

Confirmed; the payback acceptance curves that inform the equilibrium market share calculation indicate the proportion of customers who will accept different payback periods. Even for relatively favourable payback periods, the payback acceptance curves do not necessarily indicate 100 percent adoption. Furthermore, there are other factors within the BC CPR model that influence measure adoption, including the technical suitability for measure adoption and the competition between measures. As discussed in the BC CPR, the surveys used to develop these payback acceptance curves:

> […] presented decision makers with numerous "choices" between technologies with low up-front costs, but high annual energy costs, and measures with higher up-front costs but lower annual energy costs. Navigant conducted statistical analysis to develop the set of curves shown in Figure 5-1, which Navigant used in this CPR. Though FortisBC-specific data were not available to estimate these curves, Navigant considers that the nature of the customer decision-making

process is such that the data developed using North American customers represents the best industry-wide data available at the time of this study.[2]

On page 4 of the Navigant Report in Exhibit B-11, Navigant states:

> 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.

82.2 Please briefly discuss if FEI's experience with DSM programs substantiates the assumption that customer awareness and acceptance of efficient technologies take time to change. Please outline any exceptions.

Response:

FEI consulted with Navigant to provide the following response.

In general, FEI's experience with DSM programs substantiates the assumption that customer awareness and acceptance of efficient technologies take time to change. For example, FEI's C&EM residential program area has provided incentives for tankless water heaters throughout multiple years. Nevertheless, this technology which is relatively new to the Canadian marketplace has shown limited growth in market penetration of FEI customers. FEI's 2012 Residential End-Use Study indicates this penetration to be 2.7 and 4.1 percent in 2008 and 2012, respectively.[3] In theory, instances are possible where new technologies may have very short cycles for increasing customer awareness and acceptance, as anecdotally exemplified by appliances such as smart speakers. However, FEI does not have conclusive data on such cases for efficient technologies whose adoption it supports via its C&EM programs.

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2 FortisBC Energy Inc. (2017). *2017 Long Term Gas Resource Plan*, Appendix C-1, p.496 of the PDF.
3 Sampson Research (2014). 2012 FEU Residential End-Use Study. Table 107. p. 99.

83.0 Reference: Navigant Evidence
Exhibit B-11, Navigant Report, pp. 3-4
FEI DSM Market Potential

On page 5 of the Navigant Report in Exhibit B-11, Navigant states:

> 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.

On page 7, Navigant states:

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

83.1 Please confirm that the FEI market potential analysis did not assume incentive levels of 100 percent of a measure's incremental cost.

Response:

FEI consulted with Navigant to provide the following response.

This response also addresses BCUC IR 3.83.1.1.

Confirmed, the BC CPR market potential analysis itself did not assume incentive levels of 100 percent of a measure's incremental cost. Navigant calibrated the sector-specific incentive levels in the market potential analysis to FEI's historic program experience. This experience is informed by FEI's program teams using market research and considering operational program delivery factors to set suitable incentive levels for specific measures in the short term. However, Section 4.2.3.5 of Exhibit B-1 explores how sensitive forecast C&EM expenditures and energy savings may be to increased incentive levels in the long term and provides the results of this exploration. For this analysis, Navigant used highest incentive levels of 90, 100, and 90 percent of incremental measure cost for the commercial, industrial, and commercial program area, respectively. Navigant selected these levels to simulate aggressive incentives. Navigant's DSMSim model uses the incentive level inputs alongside all other input assumptions and calculates, amongst other results, aggregate program area expenditures by year. The statement that "unrestricted funding streams are already considered" refers to the BC CPR market potential inherently assuming no caps on forecast aggregate C&EM spending overall. In section 2.2.4 of its Exhibit B-11 report, Navigant emphasizes that energy savings higher than the BC CPR market potential are possible if FEI increases incentive levels but that these are subject to a diminishing rate of acquired savings per dollar of incentive spending.

83.1.1 If confirmed, please further explain the statement that "unrestricted funding streams are already considered."

Response:

Please refer to the response to BCUC IR 3.83.1.

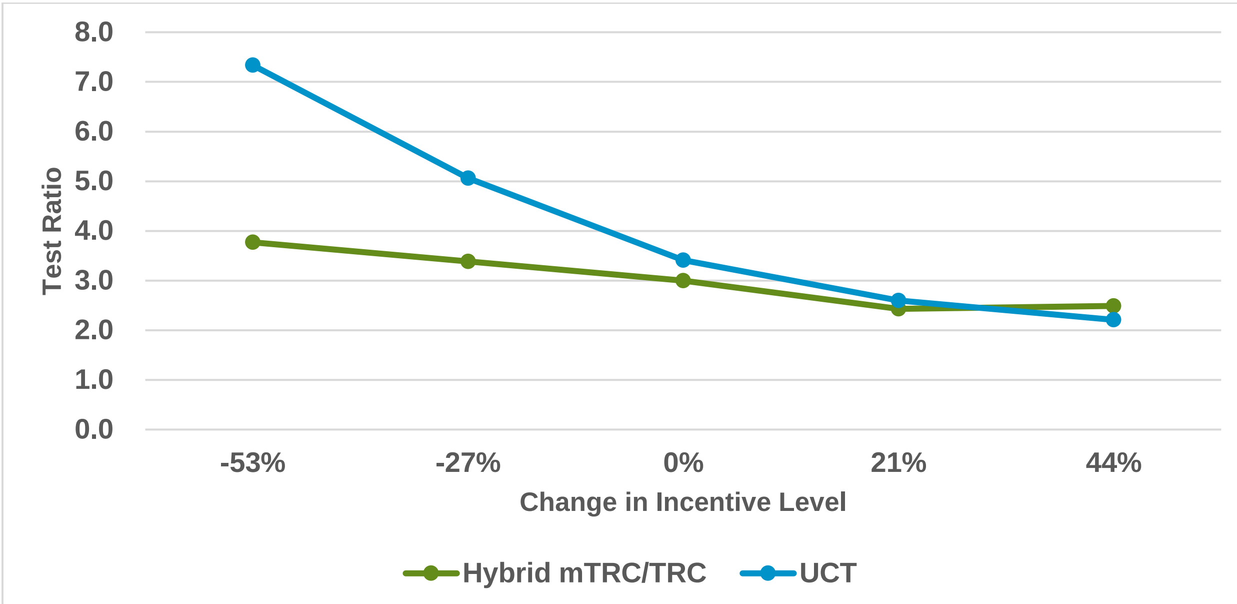
83.2 Please confirm if the incentive sensitivity analysis included cost-effectiveness testing or rate impact calculations, for the higher incentive level assumptions.

Response:

FEI consulted with Navigant to provide the following response.

This response also addresses BCUC IR 3.83.2.1. Confirmed, the incentive sensitivity analysis did include cost-effectiveness testing under the Hybrid mTRC/TRC case (i.e. the benefit-cost effectiveness test perspective that Navigant used for the market potential results in the BC CPR) and under the UCT but did not include rate impact calculations as presented in Section 8 of the 2017 LTGRP. Figure 1 below provides the results of the cost-effectiveness testing for the incentive sensitivity analysis and shows that both UCT and Hybrid mTRC/TRC test ratios decline as incentive levels increase. The slope of this decline is steeper for the UCT than the mTRC/TRC test ratio. UCT results are directly impacted by changes in incentive levels. In contrast, mTRC/TRC results are impacted indirectly only as changing incentive levels impact the proportions at which individual measures are adopted in the market potential. It is important to bear in mind that, as described in Section 4.2.3.2 of the 2017 LTGRP, these results exclude non-incentive expenditures that support or enable C&EM programs at the portfolio level and operational program delivery considerations, such as changes in required staffing levels.

Figure 1: Sensitivity Results Trend-Lines – BC CPR 2035 Incentive Level Cost-Effectiveness, All Program Areas



83.2.1 If confirmed, please provide the results.

<u>Response:</u>

Please refer to the response to BCUC IR 3.83.2.

Navigant states on page 5:

> …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.

83.3 Please briefly summarize the process by which the measure list was developed, prior to being reviewed by stakeholders.

Response:

FEI consulted with Navigant to provide the following response.

The BC CPR describes the process by which the measure list was developed as follows:

> The team reviewed current BC program offerings, previous CPR and other Canadian programs, and potential model measure lists from other jurisdictions to identify which energy efficient measures to include in the study. The team supplemented the measure list using the Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts technical resource manuals (TRMs), and partnered with CLEAResult to inform the list of industrial measures. Navigant worked with the BC Utilities to finalize the measure list and ensure it contained technologies viable for future BC program planning activities.[4]

[4] FortisBC Energy Inc. (2017). *2017 Long Term Gas Resource Plan*, Appendix C-1, p.414 of the PDF.