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February 2, 2021

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
M4P 1E4

Attn: Christine E. Long, Registrar and Board Secretary

By electronic filing and e-mail

Dear Ms Long:

Re: EB-2020-0003 – EGI IRP – GEC/ED Responses to Interrogatories

Attached please find responses to interrogatories in regard to the evidence of Energy Futures Group.

The responses are organized as follows:

Party submitting interrogatory	**Exhibit #**
OEB Staff	N2.GEC-ED – tab 1
Enbridge Gas Inc.	N2.GEC-ED – tab 2
Pollution Probe	N2.GEC-ED – tab 3
Energy Probe	N2.GEC-ED – tab 4
Anwaatin	N2.GEC-ED – tab 5
BOMA	N2.GEC-ED – tab 6
LPMA	N2.GEC-ED – tab 7

Sincerely,

David Poch
On behalf of Green Energy Coalition and Environmental Defence

Cc: all parties

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GEC-ED Responses to Staff IRs

IR 2-Staff-1-GECED

Ref: Exhibit M2.GEC-ED / p. 17 of 55

Preamble: Energy Futures Group (EFG) recommends a mechanism that stakeholders and the OEB can utilize to trigger formal OEB review of both forecast needs and proper consideration of alternatives before potentially viable alternatives are precluded due to concerns about inadequate lead times (i.e., to preclude the potential for leave to construct applications to be filed and resolved too late to reasonably consider and cost-effective alternatives).

Questions:

a) Does EFG intend that this review mechanism could be triggered at a stage prior to Enbridge Gas bringing forward an application seeking rates or facilities approval for a project? Can EFG provide any examples of how such a review mechanism works in other jurisdictions that may be of relevance for Ontario?

b) Does EFG believe this review mechanism should trigger review of higher-level plans/forecasts that encompass multiple projects (e.g., the Utility System Plan/Asset Management Plan), or would it be project-specific in nature?

Responses:

a) Yes, the mechanism EFG is recommending, which is akin to Vermont's current electric system planning process, would require review prior a regulatory filing by the utility. For example, as shown in Figure 4 of my report, the Vermont process includes several steps that would each ultimately involve review and discussion between utility and non-utility parties prior to any regulatory filing. Among those steps are:

    1. Utility identification of potential future T&D constraints
    2. "Screening" of those constraints, based on a set of prescribed "rules", to determine whether some level of analysis of non-wires solutions is warranted. Among those "rules" are whether the need is driving by something that cannot be addressed by reducing localized peak demands (e.g., the need to replace an aging piece of equipment or to address a safety issue).
    3. An initial, high-level assessment of maximum peak load reduction that could be cost-effectively achieved in the geographic area of interest to determine whether a more detailed analysis is warranted.
    4. A more detailed analysis of maximum peak load reduction that could be cost-effectively achieved.

5. Development of a non-wires solution plan (what Vermont calls a "reliability plan") if and when the previous step suggest a non-wires solution could be viable and cost-effective.

It is only after those steps are completed – or that a decision in either step 2, 3 or 4 suggests that a non-wires solution is not viable or would not likely be cost-effective – that the utility files a plan for regulatory approval.

Note that these steps, and the "screening" criteria and tools used in them, were developed through the Vermont System Planning Committee (VSCP), involving input from utility and non-utility parties.

Note also that the VSPC meetings are open to any interested party to observe. However, the VSPC has a specific membership which includes appointed representatives for a range of stakeholder types (e.g., utilities; representatives of both residential customers and business customers; representatives of environmental groups; representatives of regional planning organizations; representatives of the renewable energy industry; etc.). Further the VSPC has voting rules. Thus, there can be disagreements. Further, parties that are not members of the VSPC can disagree with the VSPC's conclusions. Thus, there is still an option for any party to contest a utility filing. That said, it is my understanding that the VSPC has succeeded in reaching consensus in all of its discussions and, probably as a result of that process, there has been little if any conflict on utility filings before the Vermont Public Utility Commission.

This process could be largely adopted for Ontario consideration of non-pipe solutions. There would need to be some refinements. For example, the involvement of Vermont Energy Efficiency Utilities (EEUs) in developing and/or providing feedback on estimates of geotargeted energy efficiency potential, is not currently applicable to Ontario because responsibility for gas efficiency program delivery is currently assigned to the gas utility rather than an independent third party (as in Vermont for electric efficiency programs).

b) I have not participated in and am therefore not intimately familiar with the higher level planning processes referenced in the question. As long as those processes are solely about establishing foundational assumptions around load forecasts, energy supply contracts, etc. that might inform assessments of potential need for individual infrastructure projects but would not in any way preclude consideration of alternatives, then the principal focus of the review process I have proposed would be on consideration of options for individual project needs (i.e., project-specific). The various processes should be timed, sequenced, and implemented in a manner that ensures that costs avoidable or benefits achievable by alternatives do not become unavoidable or unachievable respectively.

IR 5-Staff-1-GECED

Ref: Exhibit M2.GEC-ED / pp. 27-29 of 55

Preamble:
EFG recommends that Enbridge Gas develop two IRP pilot projects, noting that most jurisdictions considering IRP have started with pilot projects.

Question:
a) Please provide any perspective as to how advanced an "IRP framework" (or similar policy guidance) was in the other jurisdictions mentioned by EFG that initiated IRP pilots. Does EFG believe that all aspects of an IRP Framework need to be addressed prior to the pilot stage? If not, which elements are most important to receive OEB direction on, in EFG's view?

Response:

I have not systematically studied this question. However, my general sense is that the interplay between the timing of pilots and the timing of the development of IRP frameworks has varied somewhat across jurisdictions.

I do not think that all aspects of a framework need to be in place before pilots are launched. Nor do I think development of all parts of an IRP framework should be put on hold until pilot programs are launched and completed. Key elements of the framework should be put in place as soon as possible. They include guidance or requirements on:

- goals of IRP
- planning horizons – i.e., minimum number of years into the future that T&D needs must be forecast so that potential non-pipe alternatives will not be precluded by inadequate lead times
- range of measures that need to be considered when assessing non-pipe solutions
- pre-screening criteria (if any) – i.e., for what T&D investments must non-pipe solutions be considered
- cost-effectiveness – both the test to be used (types of impacts to include) and any other guidance on key assumptions (e.g., discount rates)
- how uncertainty regarding future climate policy, given its potential to fundamentally change the gas industry as we know it, should be addressed
- cost recovery
- utility shareholder incentives for investments in non-pipe solutions

Note that it would be eminently reasonable to treat the IRP framework as a "living document" that is expected to be updated over time as experience is gained and lessons are learned, including (but not limited to) planning and implementation of the pilot projects. Thus, in addition to adding elements to the framework in the future, elements that are included in an initial framework could be refined.

IR 5-Staff-2-GECED

Ref: Exhibit B, Appendix A / p. 67 of 92; Exhibit M2.GEC-ED / pp. 47-55 of 56

Additional Public Documents: Planning Process Working Group Report to the Board, The Process for Regional Infrastructure Planning in Ontario, May 17, 2013; Independent Electricity System Operator, Regional Planning Process Review Straw Man Design, February 28, 2020

Preamble: ICF discusses electricity system planning in Ontario, including the regional planning process and how it has considered non-wires solutions. EFG discusses the applicability of lessons learned from IRP in the electricity sector to natural gas IRP. The public documents listed provide more information on Ontario's experience considering non-wires alternatives in electricity system planning. The OEB-endorsed Process for Regional Infrastructure Planning in Ontario (2013) details the planning process for addressing regional infrastructure needs, including needs screening, and how non-wires alternatives should be considered as potential solutions, and has informed regional planning since that time. The regional planning process is currently under review. The IESO's Regional Planning Process Review Straw Man Design report summarizes many of the learnings of how this process has worked in practice to date, and recommendations for improving the regional planning process, including discussion of addressing barriers to non-wires alternatives.

Questions:

a) Has EFG reviewed Ontario's experience with non-wires alternatives in the regional planning process, including the documents mentioned above?

b) If so, does EFG have any observations or lessons learned from Ontario's experience with non-wires alternatives (e.g., practices that should or should not be transferred to IRP planning for Enbridge Gas)?

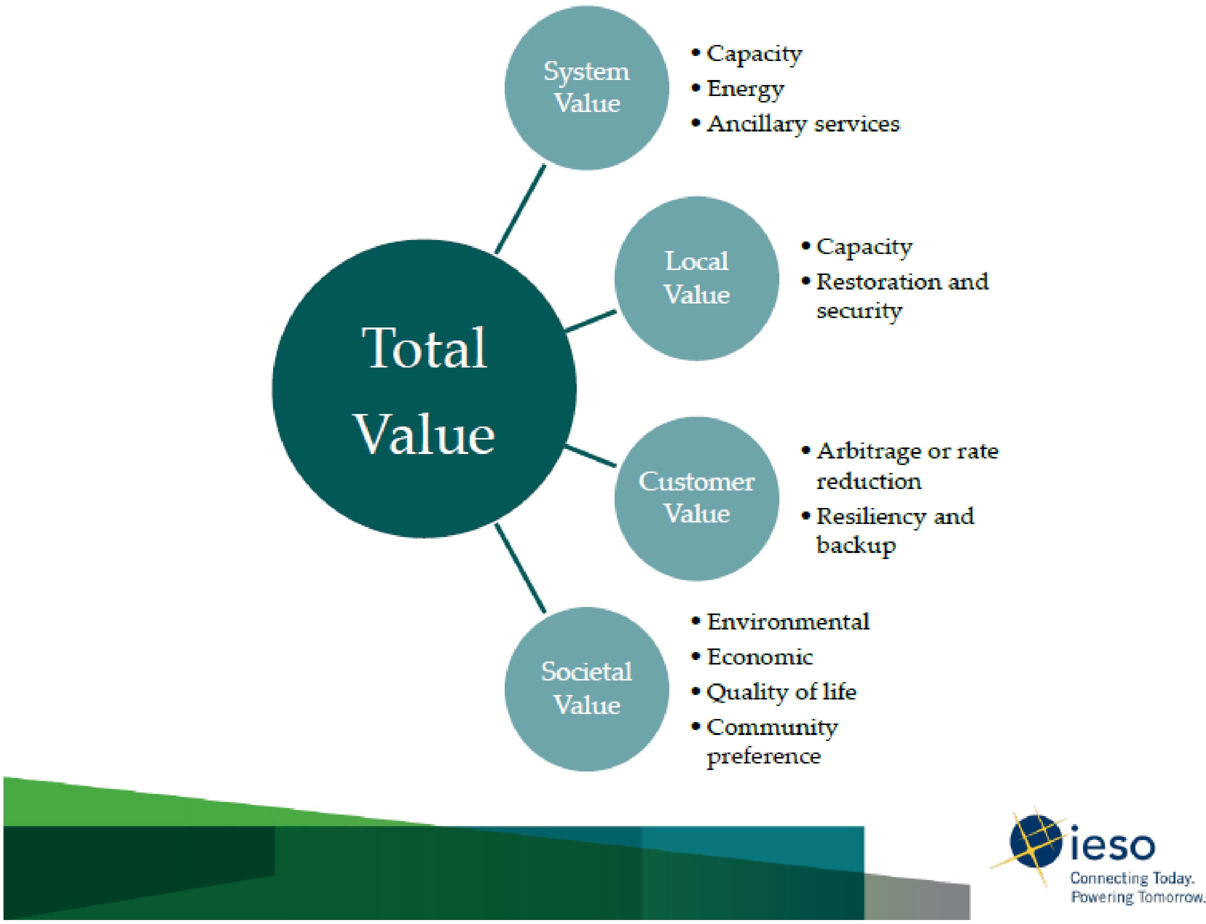
Responses:

a) I have not comprehensively assessed Ontario's experience with non-wires alternatives. I have reviewed the Regional Planning Process Review Straw Man Design document.

b) There are some elements of consideration of non-wires alternatives (NWAs) in Ontario that are not relevant to – and may even make it more difficult than – consideration of non-pipe solutions in the province. In particular, the different role of the IESO in managing the system, including transmission reliability, and the role of dozens of different distribution utilities in managing local reliability concerns, creates complexity and requires collaboration in ways that are not required for Enbridge which manages all of those functions (in one entity) for gas system reliability.

That said, there were some important elements of the Straw Man Design that would appear to have applicability for the gas system. In particular, as the following graphic from the Straw Man Design (slide #94) made clear, there are many different value streams associated with non-wires solutions, most of which are also relevant to non-pipe solutions. Related points include the IESO's conclusion that one of the historic barriers to NWAs is that "broader system capacity, energy, and ancillary services needs are not considered in conjunction with local needs" (slide #91) and that a regional planning objective should be "enabling a fair comparison" between wires and non-wires solutions by "develop(ing) an evaluation framework to capture, to the extent they can be realized, the full range of NWA benefits" (slide #101). All of those "lessons" appear to (1) support the recommendation I have made that cost-effectiveness analyses of non-pipe solutions need capture all gas system benefits (including avoided energy costs and avoided carbon taxes) as well as other benefits related to provincial energy policy goals; and (2) argue strongly against the Enbridge proposed approach to cost-effectiveness assessment based primarily on a discounted cash flow analysis. They also underscore the reason that the same cost-effectiveness test should be used for assessment of the economic merits of all utility system investments. To do otherwise – as Enbridge is proposing (a different test for non-pipe solutions than for DSM, for example) – is to assign different values to the exact same benefit in different investment decisions.

Potential Value Streams



I also found the IESO discussion of the value in developing "tools that help model system needs with more granularity" (slide #108) and "tools and methodologies to develop, evaluate and compare non-wires options" insightful and very applicable to gas non-pipe solutions.

See also the GEC-ED response to Pollution Probe IR #10 on IESO stakeholder engagement principles

IR 5-Staff-3-GECED

Ref: Exhibit M2.GEC-ED / pp. 53 of 55

Preamble: EFG describes Consolidated Edison Company of New York as "arguably the leader in non-wires alternatives" and notes its projects to defer distribution system investments.

Questions:

a) In EFG's view, are there specific elements of the planning approach or regulatory framework which have made Con Ed particularly successful in using non-wires alternatives to defer infrastructure investments in its electricity operations? If so, please describe.

b) In EFG's view, are there other electric utilities that have experienced notable success in using non-wires alternatives to avoid infrastructure investments (particularly with regards to transmission/distribution investments, as opposed to generation investments)? If possible, please identify these utilities, and any elements in the planning approach or regulatory framework that EFG believes are important factors in their success.

Response:

a) and b)

First, all of the jurisdictions and/or utilities that have made significant advancements in considering non-wires solutions, including ConEd, have had a history of focusing on least cost planning, where least cost was defined to encompass all utility system costs and typically other jurisdictional policy objectives as well. That has ensured that all of the streams of benefits that non-wires solutions provide – certainly including the value of deferring a distribution system investment, but also avoided energy and avoided capacity cost savings – are reflected in its assessments of what investments make sense. In ConEd's case, that is evidenced by use initially of the Total Resource Cost (TRC) test and more recently the use of the broader Societal Cost Test to assess cost-effectiveness of non-wires solutions.

Second, there is consistency between analyses of the economics of system-wide investments in distributed energy resources, including energy efficiency, and analyses of the economics of non-wires solutions. This is true for ConEd. It is also a common theme across all the jurisdictions seriously considering non-wires solutions with which I am familiar.

Third, ConEd began seriously considering non-wires solutions in the early 2000s after receiving feedback from regulators that there were concerns about the magnitude of the costs of its proposed distribution infrastructure investments. They ultimately invested in dozens of non-wires solution projects by 2010. To my knowledge, there was not a comprehensive regulatory policy framework on non-wires solutions in place at the time that those projects were being planned. In other words, regulatory pressure to keep T&D costs down may have been at least as important as a structured policy framework. I suspect that the later regulatory approval of shareholder incentives has helped enable the larger and more complex non-wires projects currently being implemented.

Fourth, ConEd has relied heavily on a competitive solicitation process to determine when non-wires solutions would be economically viable, to determine which resources to acquire, and to hedge against risk of non-performance (e.g., through penalty clauses in contracts with winning bidders who do not deliver the level of peak savings contracted). While I do not think that this is the only, and perhaps not even always the best way for every jurisdiction to pursue non-wires or non-pipe solutions, it did seem to play a non-trivial role in giving ConEd management confidence to pursue non-wires solutions.

Finally, I believe that the involvement in Vermont's System Planning Committee process of multiple parties with varying interests, as described in my report as well as in response to IR 2-Staff-1, has resulted in a very thoughtful, systematic and effective approach to consideration of non-wires solutions.

IR 6-Staff-1-GECED

Ref: Exhibit M2.GEC-ED / p.34 of 55; Exhibit C / pp. 8-13 of 46

Preamble:
Energy Futures Group recommends that the Total Resource Cost + (TRC+) test should serve as the foundation for assessing the relative cost-effectiveness of pipe and non-pipe solutions.

Questions:
a) One issue with the use of the TRC+ test is that transfer payments (e.g., incentives to customers) are not considered costs or benefits, meaning that an IRPA could be cost-effective but have a very unequal distribution of costs and benefits. For IRPAs, these transfer payments might potentially accrue to a small number of participants (e.g., a demand response program for large customers). Does EFG have any information on how other jurisdictions have addressed this issue, specifically in the context of infrastructure planning?

Response:

First, it is technically inaccurate to say that the TRC+ test does not treat incentive payments as costs or benefits. The TRC+ test treats the entire cost of a measure as a cost. Incentive payments are typically a subset of the measure cost. In that sense, they are indirectly included in the TRC+ as costs. In fact, the treatment of full measure cost (both the portion covered by a utility rebate and the remaining portion covered by the participating customer) as a cost under the TRC+ typically results in a higher cost estimate (i.e., having a more adverse effect on cost-effectiveness calculations) than just treatment of incentive payments as a cost would (e.g., as under the Utility Cost Test (UCT)).

With that said, it is probably worth noting most of the jurisdictions analyzing the cost-effectiveness of IRPAs with which I am familiar are doing so using either the TRC or the Societal Cost Test (SCT). The only exceptions – e.g., the Michigan utilities – use the Utility Cost Test (UCT).[1] Like the TRC, the SCT treats incentives to customers as transfer payments. As previously noted, while the UCT treats incentive payments to customers as a cost, it does not include any customer contributions to the cost of measures (or any customer non-energy benefits) in cost-effectiveness assessments, and therefore can often result in more favorable cost-effectiveness results than the TRC+ test. Importantly, and in contrast with Enbridge's proposed cost-effectiveness framework, under all three tests – the TRC, SCT and UCT – avoided energy costs, avoided carbon taxes and market price suppression effects should be considered benefits.

[1] Importantly, that is the same test that the Michigan utilities use to assess cost-effectiveness of their system-wide efficiency programs and indirectly (i.e., through their system-wide IRP planning processes) the same test they use to assess cost-effectiveness of demand response and other distributed energy resources.

To my knowledge, the issue of some customers receiving more benefits than others as a result of IRPA programs has not been a major concern (if it has been raised at all). There are probably several reasons for that.

First, it is important to recognize that there are similar inequities inherent in supply-side investments. For example, if the capacity of an existing pipe needs to be increased to address growing peak demand from customers in a specific geographic area, and the cost of that upgrade is recovered from all customers, there is cross-subsidization from customers outside the geographic area (whose demands are not causing the need for the capacity upgrade) to customers within the geographic area (whose demands are causing the need for an upgrade). There is even cross-subsidization within the geographic area because localized peak demand growth is never evenly spread across all existing customers. It is typically driven by the addition of new customers and/or growth from a subset of existing customers. Existing customers whose peak demands are flat or even declining still pay for a portion of the capital investment in new pipe. Put simply, having all customers pay to meet a need driven by a small subset of customers is just as much a cross-subsidy as having all customers pay for some benefits received only by some customers.

A second related reason is that it is problematic to consider a perceived inequity for one particular investment at one point in time in isolation of all other investments made on the utility system over the course of many years. While a small subset of customers may benefit more than others from a non-pipe investment today, different subsets of customers will benefit from future non-pipe solutions programs, as well as from system-wide DSM programs and other initiatives run by utilities.

Finally, with respect to the hypothetical example in the question – large customers receiving payments for participation in a demand response program – such payments would have to be less expensive than investment in new pipe for it to be cost-effective. In that example, all customers would be better off than if the demand response payments were not made and the more traditional infrastructure investment was made instead.

IR 6-Staff-2-GECED

Ref: Exhibit M2.GEC-ED / pp.42-43 of 55; Exhibit C / pp. 8-13 of 46

Preamble: Energy Futures Group recommends that a societal discount rate be used for cost-benefit analysis.

Questions:

Enbridge Gas has proposed that the OEB develop a staged economic evaluation, noting the three potential stages of cost-benefit analysis in the E.B.O. 134 process (economic, customer, and societal). If multiple stages of cost-benefit analysis or multiple cost-benefit tests are used, as proposed by Enbridge Gas, would EFG recommend that the societal discount rate be used in each of these tests? Why or why not?

Response:
Conceptually, as noted in both my report and in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, the choice of discount rate for a primary cost-effectiveness test should principally be a function of provincial policy goals. For example, if there is a policy conclusion that the only economic impacts of interest in Ontario are those affecting the gas system, then a higher discount rate such as the utility's cost of capital would be appropriate. However, if provincial energy policy objectives are more expansive than that, including interest in such societal concerns as alleviating energy burdens on low income customers, reducing environmental impacts, etc., the discount rate should be more akin to a societal discount rate. It is worth emphasizing that the Government has already provided direction to use a societal discount rate for assessing cost-effectiveness of DSM, suggesting the province has a somewhat broad set of energy policy objectives. In that context, I see no basis – at least not until and unless a systematic assessment of policy objectives has been undertaken – for having a different discount rate between a so-called "economic" stage and a "societal" stage. Indeed, as explained in my report, it would be highly problematic to use a different discount rate for two different kinds of utility system investments (i.e., for DSM vs. for non-pipe solutions).

IR 6-Staff-3-GECED

Ref: Exhibit M2.GEC-ED / p. 34 of 55; Exhibit C / pp. 8-13 of 46

Preamble: Energy Futures Group discusses how to address economic risk in cost-effectiveness analysis and recommends that scenario analysis (with different levels of demand) be used to conduct cost-effectiveness analysis.

Question:
In EFG's view, could the differing economic risks associated with IRPAs and facility projects be addressed in cost-effectiveness testing without explicitly reviewing Enbridge Gas's demand forecasting methodology and requiring scenario analysis of multiple demand forecasts? For example, could this be addressed more generally through a risk adder, which EFG mentions specifically in the context of gas price volatility?

Response:

Yes, a risk adder could be used in lieu of scenario analysis to accomplish a similar objective. The challenge would be in establishing the appropriate magnitude of the adder. Some level of scenario analysis that considers potential impacts on future peak demands – even if relatively crude – may be necessary to help inform that decision.

IR 9-Staff-1-GECED

Ref: Exhibit M2.GEC-ED / pp. 44-47 of 55

Preamble: EFG discusses three options for cost recovery/incentivization of IRPAs, and states that capitalizing and ratebasing IRPAs may be the best option.

Questions:

EFG notes that, if capitalizing and ratebasing IRPAs is adopted, "the specific details of this option would need to be designed to ensure that utilities have an incentive to implement the optimal solution (pipe or non-pipe) that it is the best solution for customers". Does EFG have any additional comments as to what specific changes might be needed in order to achieve this objective?

Response:

There may be value in analysis of differences in shareholder profitability when investing in IRPAs in lieu of investing in more traditional "pipe" infrastructure. In that regard, the Board may wish to be cognizant of any upstream impacts that affect the shareholder. To the extent that the returns to shareholders from IRPAs are appreciably lower, it may be worth considering a modestly higher rate of return for IRPAs or another form of adjustment or true-up. The incentives should be sufficient to align the interests of the utility with the interests of the customers.

Another potential consideration would be to tie the magnitude of the rate of return on IRPAs to utility performance in delivering them. For example, a normal rate of return could be earned for achieving IRPA savings at forecast costs with modest bonuses for better results. Alternatively, the normal rate of return on all capitalized investments could be supplemented by a modest "shared savings" as a way to provide additional incentive to maximize benefits to customers.

I have not performed the additional analysis that may be required to make informed decisions on such fine-tuning of the ratebasing option. The results of pilot projects may inform such analyses in the future.

GEC-ED Responses to EGI IRs

Enbridge 2.1

Reference: Section 4.3.2.1

Preamble: The evidence states that "The Board should require Enbridge to begin to deploy two such pilot projects in 2021 with actual deployment of IRPA resources beginning no later than January 2022."

Question:

a) Please comment on how the two pilot projects should be selected, implemented, and evaluated.

b) Should pilot projects be completed and evaluated before the Board finalizes an IRP Framework for Enbridge Gas? If the answer is "no", why not?

Response:

a) The pilot projects should be designed to provide the greatest possible insight and lessons for future potential IRPAs. That should mean projects that offer opportunities to test a range of different geotargeted resources, which in turn would mean – at least in part – geographic areas with a diverse mix of customer types. It may also be appropriate to intentionally test deployment of different resource options, including different types of efficiency programs and demand response programs – even if the options being tested do not necessarily represent the "least cost" mix of options for the given location (since pilots are more about learning how to achieve least cost solutions in the future). This is analogous to the approach taken for the Boothbay pilot NWA project in the state of Maine. There may also be value in testing different implementation strategies in the two pilots. For example, Enbridge could deliver (or use its existing DSM program contractors to deliver) the geotargeted programs in one pilot and use a competitive solicitation to acquire geotargeted resources for the other pilot. The pilot projects should also be large enough to provide meaningful insights, but small enough to ensure that design, implementation and evaluation is not overly complex and can be carefully managed.

   Evaluation should be designed to provide answers to key questions including:

   - How could forecasts of local (geography-specific) peak demand needs be improved?
   - How much localized peak savings can be acquired by different programs or initiatives?
   - Which programs or initiatives are easier to ramp up quickly?
   - What are the advantages and/or disadvantages of Enbridge simply ramping up existing DSM programs vs. using a competitive solicitation to contract with energy service companies to run programs?

- What lessons can be learned about how to manage integration of geotargeted programs with system-wide DSM programs (including customer communications)?
- At what cost can increased geotargeted peak reductions by acquired by program type – both based on actual costs incurred in pilots and lessons learned about how such costs may be able to be reduced in the future?

b) An IRP framework should not await the results of pilots. The Board should adopt an interim framework based on best information available today with the expectation that the framework will be revised periodically as provincial policies evolve and as new lessons are learned – especially after conclusion of the pilots. The pilots may take several years to design, implement and evaluate. Then there will be additional time required for the Board and other parties to consider and debate lessons learned for purposes of integrating such lessons into a policy framework. In other words, if the Board were to wait until pilots are concluded to adopt a framework, it may be 4 or 5 years before a framework is in place (on top of the seven years since the Board first made clear in the GTA Pipeline case that it expects the Company to rigorously assess demand-side alternatives to infrastructure investments). In the meantime, a number of opportunities for cost savings and risk reduction for Enbridge ratepayers could have been missed.

Enbridge 5.1

Reference: Section 1.4.1

Preamble: The evidence states that "Experience in other jurisdictions suggests that more granular forecasting that accounts for such changes can significantly alter estimates of T&D needs."

Question:

Please provide examples of natural gas utilities that have implemented more granular forecasting which has significantly altered the estimates of their transmission and distribution needs, including the detailed explanation of volumetric variances from their original forecasting methodologies to new more granular ones.

Response:

The reference is to an electricity T&D example. It was beyond the scope of my report in this proceeding to conduct an assessment of gas industry practice with regards to granularity of forecasting of T&D peak demands, and I am not aware of such gas utility examples.

Enbridge 5.2

Reference: Section 4.2.1.2

Preamble: The evidence states that "Some jurisdictions have initial "rough cut" criteria – including lead time – for determining whether a detailed IRPA analysis is warranted. In Vermont, the criteria for consideration of non-wires solutions for deferral of electric transmission system investments are structured around the magnitude of the load reduction required as follows:

- 1 to 3 years for load reductions of 15% or less;
- 4 to 6 years for load reductions of 15% to 20%;
- 6 to 10 years for load reductions of 25%."

Question:

Please provide examples of the other jurisdictions where "rough cut" criteria for natural gas lead time and load reductions are similar to the criteria for consideration of non-wires solutions in Vermont. Are the "rough cut" criteria cited in evidence currently used and valid for the assessment of non-wires solutions in Vermont?

Response:

While I am aware of such "rough cut" criteria being used in other jurisdictions for the electric industry, I am not aware of any being used for the gas industry. They may not be – at least not yet – because development of policies for consideration of gas non-pipe solutions has lagged development of policies for consideration of electric non-wires solutions. However, I cannot confirm this one way or another.

To the best of my knowledge, the rough cut criteria referenced are still being used in Vermont. The document referencing them is posted to the Vermont System Planning Committee website (see: https://www.velco.com/uploads/vspc/documents/ntascreeningtool_2012_09_27.pdf).

Enbridge 5.3

Reference: Section 4.2.4.1

Preamble: The evidence states that "The Gas IRP framework should establish a planning committee, modeled on Vermont's System Planning Committee, to secure input throughout the planning process from key stakeholders."

Question:

Does Vermont have a system planning committee for natural gas utilities? If not, why not?

Response:

Vermont currently does not have a system planning committee for natural gas utilities. One reason is undoubtedly because Vermont Gas, the state's sole gas utility, is quite small. It serves less than 15% of the state – with about 53,000 customers and $110 million in annual revenue[1] compared to the roughly 370,000 electric customers and about $830 million in annual electric utility revenue.[2]

It is worth noting that the Vermont System Planning Committee was created following passage of legislation in 2005 that was, in turn, precipitated by regulatory concern over inadequate planning for the Northwest Reliability Project (NRP), an electric transmission investment initially estimated to cost on the order of $130 million. The ultimate cost of the NRP ended up over $300 million. In contrast, in its 2001 IRP Vermont Gas was forecasting total annual capital expenditures – across all projects – of between $4.4 and $7.4 million per year for the years 2002 through 2006.

[1] See U.S. Energy Information Administration gas utility form 176 data (https://www.eia.gov/naturalgas/ngqs/#?report=RPC&year1=2016&year2=2019&company=Name).
[2] See U.S. Energy Information Administration electric utility form 861 data (https://www.eia.gov/electricity/data/eia861/).

Enbridge 5.4

Question:

Please confirm that New York is the only jurisdiction in North America with real/practical experience with natural gas IRP for the purposes of the deferral of natural gas infrastructure, beyond conducting research or pilot initiatives.

Response:

I have not conducted an exhaustive assessment of other jurisdictional policies or gas utility planning processes. However, I am not aware of a jurisdiction or utility outside of New York that has invested in more than research or pilot initiatives to defer a specific identifiable piece of gas infrastructure investment. Accordingly, my evidence seeks to provide learnings from the electricity sector which is farther along in the implementation of IRP. However, a number of jurisdictions aside from New York aim to deter natural gas infrastructure more generally with broad-based DSM through a mandate to implement cost-effective DSM. This is explicitly or implicitly intended to deter or avoid the need for natural gas infrastructure.

Enbridge 5.5

Question:

Is EFG aware of a Benefit-Cost analysis for natural gas IRP that has been thoroughly reviewed and accepted by a regulatory body in North America? If so, please provide the details of this analysis (ideally including all calculations in excel with formulae intact) and the resulting conclusions/decision/direction of the relevant regulatory body.

Response:

As discussed in the OEB Staff report, ConEd has developed and used a benefit-cost analysis (BCA) framework to assess non-pipe solutions in New York.[3] EFG is not aware of a jurisdiction that other than New York that has adopted benefit-cost analysis procedures specifically for consideration of gas non-pipe solutions. That is likely because no other jurisdiction has addressed consideration gas non-pipe solution issues to the degree that New York has. However, many jurisdictions have regulator-approved benefit-cost analyses for integrated resource planning that focus on system-wide considerations as opposed to geographically-specific projects. The ConEd benefit-cost framework is consistent with these whereas Enbridge's is not.

That said, the *principles* of benefit cost analysis of utility system investments – including the question of what categories of benefits and costs to include in benefit-cost tests – are universal. In other words, they should not change based on the kind of investment being considered. Nor is there any conceptual reason for them to differ based on whether the utility is electric or gas. This is made clear in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* cited in my report.

[3] The Guidehouse report states that though the New York Public Service Commission has not specifically issued a ruling on the BCA framework, it has approved programs whose cost-effectiveness was assessed through the framework (Guidehouse report p. 15, footnote 38).

Enbridge 6.1

Reference: Section 1.5.1

Preamble: The evidence states that "Individual customer demands for gas connection can be grounds for providing that connection, as long as the customer is prepared to pay for the full cost of their contribution to system costs and risks. However, if demand from a new customer would require T&D investment at a point in the system that serves many other customers, the utility should be required to consider non-pipe solutions. In addition, Enbridge should also proactively work with potential new customers to consider non-pipe alternatives early on, where that would reduce overall system costs and risks (e.g., heat pumps in new buildings)."

Question:

Is Energy Futures Group ("EFG") advocating for Enbridge Gas to provide incentives through investment in IRPAs (e.g., incremental energy efficiency programming) to individuals/entities which are not contracted customers of Enbridge Gas?

Response:

Not if the customer is not going to become a customer of Enbridge. If a customer is going to become a customer of Enbridge, it may be appropriate to provide incentives to reduce the amount of new load – especially at peak – that will be added to Enbridge's system. Indeed, that is exactly what the Company has historically done through its efforts to promote efficiency improvements in new construction of homes and commercial businesses through some of its DSM programs. Where the optimal solution for the customer end use appears to be electricity, in keeping with the Board's encouragement to coordinate efforts with the electricity sector, Enbridge should have a protocol for alerting the IESO or local electrical utility to work with the customer.

Enbridge 6.2

Reference: Section 4.2.3

Preamble: The evidence states that "There are a range of measures that can be part of non-pipe solutions. That includes energy efficiency; demand response; electrification of gas end uses with air source heat pumps, ground source heat pumps and other technologies; and localized injection of compressed gas."

Question:

If additional electric distribution, or transmission assets need to be built as a result of such investments in natural gas IRP should their associated costs be included in cost-effectiveness tests?

Response:

That should depend on the cost-effectiveness test adopted by the Board for gas investments pursuant to a review of applicable provincial energy policies. If the Board were to determine that provincial energy policies dictate that no impacts other than gas utility system impacts are of interest or concern, and therefore concludes that the Utility Cost Test should be adopted, then such electric T&D investment costs should not be included. However, if the test adopted by the Board includes impacts on other fuels, as the TRC test or a Societal Cost test would, then added costs to the electric system, including any added T&D costs, should be included.

Consistent with the guidance in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources,* my report recommends that the Board initiate a stakeholder engagement process to identify Ontario energy policy goals relevant to cost-effectiveness analysis in order to determine what categories of costs and benefits should be included in cost-effectiveness assessment of all gas utility investments. In the interim, I recommend that the Board adopt the same TRC+ test currently used in the province to assess the cost-effectiveness of DSM. Under that test, impacts of non-pipe solutions on the electric system – whether electric system cost reductions resulting from efficiency measures that reduce both electricity use and costs (as well as reducing gas use and costs) or electrification measures that increase electric use and costs – should be included.

That said, it should be emphasized that most non-pipe alternatives will not add cost to the electric T&D systems. Efficiency programs – e.g., insulation and air sealing of homes – will typically *lower* electric T&D costs. Even fuel switching from gas to electricity will often not increase electric T&D needs because fuel-switching will tend to focus on heating end uses which drive gas peak demands whereas the Ontario electric system and therefore probably much of its T&D system is currently summer peaking. Furthermore, many space heat fuel-switching options, such as advanced heat pumps, are more efficient in cooling mode than standard central air conditioners, so they could actually reduce summer peak demands and therefore reduce peak demands on many parts of the electric T&D system. Put simply, any cost-effectiveness test that quantifies electric T&D impacts should address both potential for additional benefits (i.e., electric T&D cost savings) as well as for additional costs.

Enbridge 6.3

Reference: Section 4.4.2.2

Preamble: The evidence states that "The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM for DERs) is a widely-recognized reference for electric and gas utility industry best practices on cost-effectiveness analysis. Moreover, it is the only such reference that starts with and articulates fundamental principles that must be followed if assessment of the economic merits of distributed energy resources – including, but not limited to applications in non-wires solutions or non-pipe solutions – is to be balanced and accurate."

Question:

Does EFG propose that the standards and assumptions set out in the NSPM for DERs be applied to natural gas IRP without consideration or adjustment for the differences between electricity and natural gas systems and methodologies? If adjustments/refinement are required, please specify what changes EFG proposes and explain why.

Response:

The NSPM for DER principles for benefit cost analysis of utility system investments are universal. That is, they should not change based on the kind of investment being considered. Nor is there any conceptual reason for them to differ based on whether the utility making the investment is electric or gas.

For example, as the NSPM for DERs makes clear, all utility system impacts resulting from a potential (or actual) utility system investment should always be included in benefit-cost analyses. That is, all gas utility system impacts resulting from a gas utility investment should be included in a cost-effectiveness assessment of that gas investment, just like all electric system impacts resulting from an electric utility investment should be included in an assessment of that electric investment. To be sure, there are different *types* of electric utility system impacts and gas utility system impacts and only those types of utility system impacts relevant to each fuel type are relevant to a cost-effectiveness assessment. For example, electric DER investments can avoid new electric generating capacity costs, while there are no analogous "avoided capacity costs" in gas utility systems (though there may be avoided transmission tolls). Also, the magnitude of the value of different impacts – such as the value of avoided energy costs – will be different for gas and electric utilities (i.e., the value of avoiding a kWh of electricity each year for 15 years will be different than the value of avoiding an m^3 of gas consumption each year for 15 years). However, all relevant utility system impacts should always be included in benefit cost analyses of either gas or electric system investments.

Similarly, provincial policies should dictate what other categories of impact (non-utility system impacts) should be included when assessing cost-effectiveness of utility investments. For example, if mitigating climate change or mitigating poverty are articulated energy policy goals in a jurisdiction, impacts of investment options on both greenhouse gas emissions and low-income customers should be included in benefit-cost analyses – for *both* gas utility investments *and* electric utility investments. Again, the magnitude of the impacts may be different for gas and electric utilities, but the principle that they should be included in cost-effectiveness analyses holds equally for both gas and electric investments.

Enbridge 6.4

Reference: Section 4.4.2.3

Preamble: The evidence states that "…all gas utility system impacts must be included when assessing cost-effectiveness of non-pipe solutions or any other type of gas utility investment. That means considering not only the value of avoided or deferred T&D investments, but also the value of avoided energy costs, avoided storage capacity costs, avoided carbon taxes, market price suppression effect and any other gas utility system impacts."

Question:

Is it EFG's view that certain benefits/costs should be excluded from an IRP-related Benefit-Cost Analysis? If so, please specify which benefits/costs should be excluded and provide rationale for their exclusion.

Response:

As stated in my report, my recommendation – consistent with the principles of the NSPM for DERs – is that (1) all gas utility system impacts be included; (2) the Board initiate a stakeholder engagement process to identify policy goals relevant to cost-effectiveness analysis in order to determine what additional (non-utility system) categories of costs and benefits should be included; and (3) in the interim (i.e., until the policy review process is completed), the Board adopt the same TRC+ test currently used in the province to assess the cost-effectiveness of DSM.

Thus, in the longer term, the Board process to identify relevant provincial energy policy goals would guide the determination of what categories of impacts might be excluded. In the interim, the adoption of the TRC+ test would mean that several categories of impacts are either excluded and/or significantly undervalued. For example, the TRC+ test assigns no specific value to public health impacts, job or economic development impacts, or impacts associated with environmental emissions other than greenhouse gas emissions. It also clearly undervalues participant non-energy impacts, as the 15% adder for non-energy benefits that is currently in the TRC+ test results is a conservatively low value for improvements to health and safety, comfort, business productivity, and other participant benefits that gas efficiency programs can provide.

Enbridge 6.5

Question:

Taking into consideration Enbridge Gas's Responding Evidence filed December 11, 2020, please explain fully any remaining concerns EFG has related to Enbridge Gas's proposed use of a staged discounted cash flow methodology to assess IRPAs.

Response:

First, as evidenced by GEC interrogatories to Enbridge on its staged DCF proposal, the specifics of what Enbridge is proposing are not very clear. Thus, it is difficult to answer this question definitively until Enbridge's interrogatory responses have been provided. With that caveat, the concerns I articulated in my report appear to still apply to Enbridge's revised proposal for a staged DCF test.

First, if "Stage 1" of the Company's proposal would not treat avoided energy costs and avoided carbon taxes as benefits (and potentially even effectively treat them as costs because they would reduce revenue), it would be fundamentally flawed. Indeed, it would not even be a test of cost-effectiveness. Cost-effectiveness assessments tell us whether costs are going up or down relative to an alternative being considered. That cannot be assessed if reductions in critical elements of utility system costs are not treated as benefits (or worse, if they are treated as costs). Put simply, it would be inappropriate for the primary "stage" of a cost-effectiveness test to measure something other than cost-effectiveness.

Second, it is also problematic to exclude impacts related to public policy goals – including relevant societal impacts – from the primary stage of a cost-effectiveness test. Doing so is effectively saying that that we do not actually care much about those goals and are willing to make investments that make achievement of those goals more difficult and more expensive.

Third, Enbridge's proposal for a staged approach to cost-effectiveness analysis begs the question of how the stages would be used. For example, if the Company is proposing that an IRPA project would have to "pass" a Stage 1 assessment before being considered for Stages 2 or 3, then Stages 2 and 3 essentially become additional ways to screen out IRPA projects rather than mechanisms for seriously considering other cost savings to ratepayers and/or other benefits to the province. Even if that is not the Company's intent, one can intuit that the Company would not generally support having the results of secondary tests regularly over-riding the results of its first stage test analysis – otherwise there would not be a reason for considering policy-driven societal impacts separately, and at a later stage. At best, it would seem that Enbridge is effectively suggesting that results from its secondary tests should be used to override decisions flowing from its primary test only if the secondary test results are extremely poor. That would be tantamount to saying we should be fine with investments that are more expensive than alternatives (once avoided energy costs, avoided carbon taxes, and any other gas system benefits are considered) and investments that are less effective in addressing policy goals – as long as they are not *dramatically* more expensive or *way out of synch* with provincial policy objectives. That is problematic.

Fourth, as I stated in my report, it is also highly problematic to use different tests for different kinds of utility investment decisions. Put another way, it is economically irrational to use a different test of cost-effectiveness for infrastructure investments than for investments in DSM or renewable gas or any investment the Company may be considering.

To conclude, to the extent that the Company's rationale for proposing its DCF+ test is to focus on rate impacts, it is vital to underscore that cost-effectiveness and rate impacts are two completely different things requiring two very different kinds of analyses. Rates can go up while costs are lowered, and vice versa. Both analyses can have value for informing regulatory decisions on utility investment choices. However, in my experience – including all the analyses of both non-pipe solutions and non-wires solutions with which I am familiar – reductions in total costs typically take precedence, with decisions adjusted if rate impacts are considered too substantial (rather than the other way around).

Enbridge 7.1

Reference: Section 4.4.2.3

Preamble: The evidence states that "…all gas utility system impacts must be included when assessing cost-effectiveness of non-pipe solutions or any other type of gas utility investment. That means considering not only the value of avoided or deferred T&D investments, but also the value of avoided energy costs, avoided storage capacity costs, avoided carbon taxes, market price suppression effect and any other gas utility system impacts."

Question:

a) Please clarify whether the costs contemplated by EFG for IRP-related cost-effectiveness assessments are customer (or geographically) specific, or rather generic utility-wide (broad based) costs.

b) In a hypothetical situation where an IRPA solution or portfolio of solutions only addresses residential customers – providing those residential customers with customer commodity and carbon charge savings - does EFG consider any resulting cross-subsidization between rate classes as a ratemaking concern?

Response:

a) The value of avoided or deferred T&D investments resulting from non-pipe solutions should be specific to the actual investment that is avoided or deferred – i.e., it should be geography-specific. Also, the actual cost of running geotargeted DSM or other non-pipe solution programs should be used rather than the much less relevant average costs of system-wide programs. Other costs (and benefits) should be estimated as accurately as reasonably possible. To the extent that there are reasons for estimates of other impacts to be different in a certain geography than system-wide, then geography-specific values could be used. However, impacts such as avoided carbon taxes and market price suppression effects will never be geography specific.

b) Not necessarily. It is important to recognize that cross-subsidization between customers – and even between rate classes – can also occur when supply-side investments are made. For example, if the capacity of an existing pipe needs to be increased to address growing peak demand from customers in a specific geographic area, and the cost of that upgrade is recovered from all customers, there is cross-subsidization from customers outside the geographic area (whose demands are not causing the need for the capacity upgrade) to customers within the geographic area (whose demands are causing the need for an upgrade). There is even cross-subsidization within the geographic area because localized peak demand growth is never evenly spread across all existing customers. It is typically driven by the addition of new customers and/or growth from a subset of existing customers. Existing customers whose peak demands are flat or even declining still pay for a portion of the capital investment in new pipe. Put simply, having all customers pay to meet a need driven by a small subset of customers is just as much a cross-subsidy as having all customers pay for some benefits received only by some customers. Thus, rules governing acceptance (or not) of cross-subsidization resulting from investment in non-pipe solutions should be consistent with how cross-subsidization is treated with respect to traditional infrastructure investments.

Second, the hypothetical framed in the question appears to presume that costs would be spread equally across all customers. That may be the case if the cost of non-pipe solutions is rate-based. However, if the potential for cross-subsidization between rate classes is concerning enough – and different enough in magnitude from cross-subsidization on supply-side investments (see previous paragraph) – costs of some IRPA components could be expensed, in full or in part, instead of capitalized (perhaps with a different utility performance incentive structure). Put another way, there are undoubtedly options to address any cross-subsidization between rate classes, should that become material.

Since the preamble to the question related to a discussion of cost-effectiveness and the question itself has to do with cross-subsidization associated with cost recovery and resulting rate impacts, it is important to emphasize that concerns about cost-effectiveness, cross-subsidization and rate impacts are different things. They address different questions. For example, cost-effectiveness analysis addresses whether total costs are higher or lower for a given investment relative to another. Concerns about cross-subsidization and/or rate impacts are concerns about equity between or across customers, not about cost. Thus, they should be analyzed separately from analyses of cost-effectiveness. As explained in the NSPM for DERs, this is a fundamental principle.

Finally, as discussed in Appendix A of the NSPM for DERs, when considering concerns about cross-subsidization and rate impacts it is important to both consider them over the long-term – and to consider trade-offs in addressing equity concerns relative to economic impacts.

Enbridge 1

Reference: Section 4.4.2.4.2

Preamble: Climate Policy Risk

Question:

How can the OEB make assumptions about climate policy that go beyond what is currently directed by the Ontario's Ministry of the Environment, Conservation and Parks without supplementary Government direction to the OEB?

Response:

First, as evidenced by the recent increase in carbon taxes, federal climate policy decisions can also affect the merits of gas utility investments.

Second, this is not a choice between making an uncertain assumption about future climate policy regulations and not having to make an uncertain assumption. Rather, it is a choice between two different uncertain assumptions: (1) an explicit assumption that there will be – or at least that there is a decent probability that there will be – new climate policy regulations; (2) an implicit assumption that there will be no new climate policy regulations. Ignoring the potential for future climate policy changes is tantamount to assuming there will not be any. It is foolhardy to completely ignore the possibility that future climate policies will affect the economics of current gas infrastructure investments. That is particularly true when the costs of such infrastructure investments are expected to be recovered over 50 years or some other very long period of time. It is much more reasonable to assign probabilities for potential future policy impacts, based on the best information available, or at the very least to separately conduct analyses of alternatives under different policy futures (e.g., as sensitivity analyses) so that the impacts of potential changes in policy can be understood and trade-offs between different utility investment options can be considered with that understanding.

GEC/ED Responses to Pollution Probe IRs

Pollution Probe #1
[Exhibit M2.GEC-ED]

a) Please rank the following IRP approaches from best to worst from a consumer, policy and cost-effectiveness perspective, and explain the ranking.

- Siloed energy planning by fuel type (e.g. natural gas, electricity, renewables, etc.)
- Planning by fuel type with a mandated consideration of benefits and costs against other fuel options.
- Fully fuel-agnostic energy planning

b) If an energy option other than a new natural gas pipeline is the best IRP alternative resulting from an assessment (e.g. geothermal), please explain the role of the regulator and utility to ensure that the best option is implemented?

Responses:

a) Conceptually, the rank order would be as follows (best being #1):

1. Fully fuel-agnostic energy planning
2. Planning by fuel type with a mandated consideration of benefits and costs against other fuel options
3. Siloed energy planning by fuel type.

The more comprehensive and integrated an analysis of options can be, the more potential for capturing benefits associated with economic and other trade-offs between fuels.

b) If possible within the context of its statutory obligations and other legal requirements, the regulator should require the utility to identify and support the best option. If the context is consideration of an upgrade in pipeline capacity to meet demand growth, the utility should be required to invest instead in the best option. If the context is consideration of a new pipeline to expand the utility's service territory, the utility should simply be prohibited from extending its service to the new area if customers' energy needs could be met at lower cost and lower risk (including the cost of the proposed infrastructure expansion) with other fuels.

Pollution Probe #2

[Exhibit M2.GEC-ED]

Reference: In Section 1.3.2 you recommend that the IRP framework should require utilities to prepare and publish an annual T&D needs summary based on a rolling 10-year forecast of needs, the drivers behind those needs, whether the needs may be candidates for non-pipe solutions (and why or why not), and the status of consideration of non-pipe solutions for each identified need.

Questions:

a) Should the annual assessment be part of the annual rate case or a separate process (e.g., like the Gas Supply Plan Review)? Please explain why.
b) Please confirm that review of the rolling 10 Year IRP Plan does not remove other statutory requirements that Enbridge would need (e.g. Leave to Construct project reviews or approval to place any amounts into rates like done through a Rate Case).

Response:

a) I am not familiar enough Enbridge's annual rates or Gas Supply Plan review cases to offer an informed opinion.
b) Confirmed.

Pollution Probe #3

[Exhibit M2.GEC-ED]

Reference: In Section 1.5.2 it is suggested that the "TRC+" test be used for IRP until a better alternative is available.

Questions:

a) Please indicate why the TRC+ test is better than the Societal Cost Test.
b) Does TRC+ include emissions (e.g. carbon) pricing? If not, should that be added?

Response:

a) In the abstract, neither the TRC+ nor the Societal Cost Test (SCT) is "better" than other. As explained in my report and in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, a jurisdiction's primary cost-effectiveness test should include (1) all utility system impacts; plus (2) all other categories of impacts associated with that jurisdiction's energy policy objectives. That means the correct (or "best") test will be different for different jurisdictions. The best test can essentially range from the Utility Cost Test (UCT) – if there are no energy policy goals beyond minimizing utility costs – to a fully expansive SCT – if policy goals include a very wide range of interest in consumer impacts, other fuel impacts, water impacts, environmental impacts, public health impacts, economic development and job impacts, etc. The TRC+ test is one of many possible tests that include more impacts than the UCT and less than the SCT. The answer to the question of which test is "better" for Ontario should be based on a review of provincial energy policy goals.

   In my report I recommend that the OEB initiative a stakeholder process to identify relevant provincial energy policy goals and determine the categories of impacts that should be included in an Ontario cost-effectiveness test. See my response to EP-GEC/ED-2 for reference to case studies of jurisdictions that have undertaken such reviews. I also suggested that – in the interim (until such a process is completed) – the OEB adopt the TRC+ test. I suggest that the TRC+ test be the interim test because (1) it is already being used for assessing cost-effectiveness of DSM in the province and the same cost-effectiveness test should be used for all utility investment decisions; and (2) the test is being used for DSM at the express direction of the provincial Government.

b) It is my understanding that the TRC+ test includes the cost of the federal carbon tax. That is appropriate – not just for the TRC+ test, but for any cost-effectiveness test – because that tax is a utility system cost of compliance with applicable carbon emission regulations.

Pollution Probe #4

[Exhibit M2.GEC-ED]

Reference: Section 4.1. identifies six Goals for a Gas IRP Framework in Ontario.

Questions:

a) Please explain how the reliability goal would apply to gas expansion projects (e.g. to new customers that may have cleaner or more-cost effective energy options).
b) For 'cost minimization' and 'risk minimization', please confirm this is from the customers perspective. If not, please explain.
c) Do you agree that the following steps are appropriate for natural gas IRP. If not, please explain what should be different.

Scenario 1: Potential Gas Expansion	Scenario 2: Existing Gas Infrastructure/ Customers
Assess Consumer Energy Needs	Assess Future Demand
Assess Fuel / Technology Options	Identify Demand-Side or other IRP Options
Select Preferred IRP Option (or mix)	Assess Options and Apply Beneficial Mix
Assess Demand-Side Mitigation Potential	Identify Infrastructure Options, Cost and Benefits
Identify Infrastructure Options, Cost and Benefits	Assess Options
Assess Options	Select Preferred Infrastructure Option
Select Preferred Infrastructure Option	

d) Community energy and emissions planning is supported by the Province of Ontario and used by municipalities across Ontario to support effective energy planning and reach emission reduction goals. Is this included under one the six goals identified or should it be included as a seventh. Please explain.

Responses:

a) The goal of gas system reliability is not relevant to proposed gas infrastructure investments whose purpose is the expansion of the gas system to new areas or new customers when such expansion is optional (i.e., not required by law).

b) The goals of cost minimization and risk minimization should be from the perspective of customers as a whole, not from the perspective of utility shareholders. The 6th goal I recommend – alignment of utility interests with IRP goals – is the only goal related to the narrow perspective of utility shareholder interests.

c) The general flow of the proposed steps is appropriate. However, I am not entirely clear about what some of the steps, as articulated in Pollution Probe's table, are intended to convey or represent. Also, I would suggest that ideally both supply and demand options (or both traditional infrastructure investments and non-pipe alternatives) be identified and characterized concurrently. Finally, it is important to flag that assessments of cost and benefits should include assessments of risk, particularly of the potential for future climate policies to change the economics of gas supply. My conceptual alternative would be as follows.

Scenario 1: Potential Gas Expansion	**Scenario 2: Existing Gas Infrastructure/ Customers**
1. Assess Consumer Energy Needs	1. Estimate Future Peak Demand
2. Identify and characterize technology and fuel options for meeting consumer energy needs (including different levels of gas end use efficiency as well as different levels of end use efficiency for other fuels)	2. Identify and characterize alternatives – supply and demand – for ensuring reliability of gas system
3. Assess relative cost-effectiveness of different options (including risk)	3. Assess relative cost-effectiveness of different options (including risk)
4. If gas system expansion is least cost option, develop plan for expansion; if not, reject expansion.	4. Develop plan for deploying least cost option.

d) Local community energy planning and/or environmental goals could be reflected in several of the six goals I have proposed. For example, to the extent that municipalities have adopted policies or regulations that affect costs of different fuels and/or could affect them in the future, such costs should be reflected in the "cost minimization" goal as well as in the "risk minimization" goal. Further, to the extent that provincial support for municipalities could reasonably be interpreted as at least indirectly supporting local policies or regulations, such local policies and/or regulations should be considered in the context of the goal of alignment with other governmental policy objectives.

Pollution Probe #5

[Exhibit M2.GEC-ED]

Reference: Section 4.3.2 indicates that two pilot projects in 2021 would be appropriate.

Questions:

a) In a recent Leave to Construct application (EB-2020-0192 London Line Replacement) Enbridge conducted a DSM option assessment, but used only two years of DSM benefits rather than the full measure life (as required in the OEB DSM Framework) to do the cost-benefit comparison against the preferred pipeline option. Please specify what controls the OEB would need to put in place to ensure that proper analysis is conducted for the IRP Framework or any pilots.
b) If two pilots were done, would it make sense to conduct one on an existing pipeline that needs to be replaced and one for a project to feed new customers? If not, why not and what is recommended.
c) Given that Enbridge will file its next generation DSM Plan in 2021, what elements should be included in that plan to enable any pilots (e.g., budget)?

Responses:

a) As I stated in my report, any analysis of non-pipe solutions must include all utility system impacts. That not only means capturing all sub-categories of utility system impacts (e.g., avoided energy costs, avoided carbon taxes, gas price effects, avoided T&D costs, etc.), but also the full life-cycle impacts of each investment option – supply or demand – that is considered. Any analysis that does not do that should be deemed inadequate, with the proposed infrastructure investment rejected on the grounds that it has not been demonstrated to be in the public interest.
b) I would recommend that both pilot projects involve actual geo-targeted deployment of non-pipe alternatives so that field experience can be gained and lessons learned from such deployments. For cases in which a gas infrastructure project is proposed in order to bring gas to new customers, the "non-pipe alternative" is just not making the gas infrastructure investment because other fuel and technology options – which customers in the targeted area would be assumed to access through the market on their own (or perhaps with support of their local electric utility) – are lower cost and/or lower risk. In such cases, there is no field testing of a gas utility funded investment from which the gas utility could gain experience. There is only testing of an analytical approach. To be clear, there would definitely be value to testing such an analytical approach. Also, such an analysis should have a relatively modest cost. Thus, it could be a reasonable addition to my suggestion of two pilots of in-field deployment of non-pipe solutions.

c) I would not suggest that non-pipe alternatives be funded out of DSM plan budgets. First, the determination of how much money should be spend on geotargeted DSM should be based on the number and scale of non-pipe solutions projects that are economically justified. That can vary greatly from year to year and cannot be fully understood or anticipated at the time that multi-year DSM budgets are being adopted. Second, efficiency programs are just one of several categories of potential non-pipe alternatives. It would not make sense to fund other alternatives, such as demand response or electrification or even CNG or localized injection of other fuels, out of the DSM budget. Nor would it make sense to fund geo-targeted DSM to be funded out of a DSM budget while other non-pipe alternatives are funded through a different mechanism. All non-pipe alternatives should be funded in the same way. Third, system-wide DSM programs that are funded through Enbridge's DSM plan are already being significantly under-funded relative to economically optimal levels. It would be potentially problematic to put system-wide programs in competition for scarce budget dollars with geo-targeted programs deployed to defer gas T&D investment. In short, there should be a separate mechanism for funding non-pipe solutions, including all potential options that could be deployed as part of such solutions.

   That said, there are some things that the Company's next DSM plan could do to not only meet appropriate system-wide DSM program objectives but to better prepare the Company to deploy non-pipe solutions. Specifically, there would be value in ensuring that there is a broad enough range of efficiency programs, addressing all significant customers groups. That has value not only for the DSM portfolio – enhancing equitable access to efficiency investment opportunities across all customers – but also for ensuring that there is a broad enough range of program foundations upon which any geo-targeted DSM initiative could build, regardless of the customer mix downstream of the potential supply constraints. Also, it would be important to ensure that system-wide DSM programs are targeting efficiency improvements in key end uses driving peak demands (i.e., space heating).

Pollution Probe #6

[Exhibit M2.GEC-ED]

Reference: Section 4.4. suggests "Focusing initially on projects with at least a 3-year lead time for consideration of non-pipe solutions is reasonable".

Question:

a) The OEB proposed DSM planning and funding cycle is five years. How should DSM alternatives be funded if they fall inside the five-year DSM cycle and were not budgeted for in that cycle?

Response:

See response to Pollution Probe #5.

Pollution Probe #7

[Exhibit M2.GEC-ED]

Reference: Section 4.5 related to Cost Recovery and Financial Incentives.

Question:

a) For incenting non-gas alternatives, what controls would need to be put in place to restrict monopoly power issues (e.g. Enbridge affiliates or picking winners and losers in the competitive market for geothermal)?

Response:

a) Enbridge should be prohibited from “picking winners and losers”. If geothermal investments or home weatherization work or demand response programs are determined to be cost-effective components of a non-pipe solution, the Company should be required to acquire such resources through programs that are vendor neutral (e.g., specifying efficiency and/or other objectively relevant performance criteria and offering financial incentives for any installation that meets those criteria, regardless of vendor) and/or through competitive solicitations that are also vendor-neutral. I am aware that concerns about product and vendor neutrality have arisen in the past in the context of DSM programs. While I am not familiar with the details of how such concerns were addressed, it is possible that specific regulatory requirements the OEB has put in place to address them in the context of DSM programs could also be applicable here.

Pollution Probe #8

References:
[EB-2020-0136, Reply Argument of Enbridge Gas, November 17, 2020, Page 9 of 23] - "For current planning purposes, the Company cannot assume that the emissions and gas consumption reduction targets set out in the Made in Ontario Environment Plan (MOEP) or the City of Toronto's TransformTO initiative will be met."
[PollutionProbe_IR_Appendix A-Toronto Plan_20210112]
[PollutionProbe_IR_Appendix G-Ontario Environment Plan_20210112]

Questions:

a) Based on best practices, what is the best manner to ensure alignment between utility IRP planning assumptions and government energy and emissions planning and policy?
b) Please provide any relevant recommendations on how the OEB could bridge the gaps between long-term utility planning and government planning and policy assumptions.

Responses:

a) and b)

When government emission reduction targets are non-binding, there is some uncertainty about whether they will ultimately be met. On the other hand, it is hard to see how such targets could not be read as signals that there is at least a decent probability that some form of legally binding emission regulations will be enacted in the future. In that context, it would be imprudent to proceed with gas system planning as if there is no chance of future carbon emission regulations. Put simply, as discussed in my report (see Section 4.4.2.4), the cost-effectiveness of different gas system investment options should be analyzed both with and without assumptions about future carbon emission regulations. That way regulators and other parties can consider both sets of results. In essence, they can conduct risk assessments by assigning probabilities to different outcomes – either explicitly (to mathematically compute a probability weighted average cost-effectiveness of different options) or qualitatively.

For example, the six New England states are currently in the middle of work on their every three year Avoided Energy Supply Cost study. That study develops assumptions about the various components of electric avoided costs, gas avoided costs and other fuel avoided costs. Those assumptions are then used in cost-effectiveness analyses of energy efficiency programs, demand response programs, electrification programs, non-wires solutions, and potentially other distributed energy resource investment contexts. The study is currently developing a set of estimates of avoided costs that are based solely on forecasts of energy, capacity and other prices assuming energy markets will be constrained only by laws currently “on the books”. That is its core scenario. Societal values for avoided carbon emissions (i.e., carbon emission externalities) are also developed for pairing with that core set of assumptions. However, because most New England states have adopted ambitious greenhouse gas emission reduction goals, the study team is currently in the process of defining a sensitivity scenario in which it is assumed that such goals are binding and policies necessary to ensure they are reached are enacted. That sensitivity will likely result in significantly different assumptions about future avoided energy costs – for electricity, gas and other fuels. Each state can then use some combination of the core and sensitivity results in cost-effectiveness analyses to inform distributed energy investment decisions.

Pollution Probe #9

References:
[PollutionProbe_IR_Appendix C-BCUC Guidelines_20210112]
[PollutionProbe_IR_Appendix D-ConEd Interim BCA Handbook_20210112]
[ICF IRP Report, Section 2.1] - "Based on a review of the state of the industry, there is no relevant precedent for, or evidence of natural gas utilities consideration of the impact of broad-based DSM, geo-targeted DSM or dedicated DR programs impact on facilities planning. Further, while electric utilities have used DSM and DR programs to reduce the need for new generating capacity and transmission capacity for many years, there is only relatively limited experience deferring distribution system infrastructure."

Questions:

a) Pollution Probe has provided two illustrative examples above of specific natural gas IRP related initiatives. One from BCUC started almost 20 years ago and has been matured through regulatory process and effort of the Canadian gas utility (Fortis). The second example indicates an interim gas utility handbook that was developed in 2017 and updated based on stakeholder feedback. Additional transferable experience is also available from entities such as IESO. Do you agree with the major finding by ICF that there are little to no best practices available to inform gas IRP in Ontario? Please explain your answer.
b) If there are limited precedents to draw from, what is the best approach to ensure that the IRP Framework is robust enough to meet Ontario's energy needs for the future?

Responses:
a) and b)

I disagree with ICF's finding that there are little to no best practices available to inform gas IRP in Ontario. While gas precedents are certainly limited, there are a number of electric non-wires examples from which lessons can be drawn. As I state in my report (see Section 5), "the principles, processes and cost-effectiveness frameworks for considering gas non-pipe solutions are the same as those for considering electric non-wires solutions."

Pollution Probe #10
[Exhibit M2.GEC-ED] [PollutionProbe_IR_Appendix F-IESO Engagement_20210112]

Question:
Do you agree that the IESO Engagement Principles used to coordinate their planning represent best practices? If not, what changes would you recommend?

Response:
I would propose several modifications to the IESO principles:

1. I modify the 5th principle on "effective facilitation". Specifically, I would recommend that the decision-making body – the IESO in this case – not be the facilitator of discussions. In my experience, dialogue with stakeholders is much more effective if a neutral facilitator is hired. To the extent that an engagement process is expected to be of some length or even on-going, even more structure would ideally be put in place to ensure neutrality. For example, a neutral facilitator should ideally be selected, through a consensus process to the extent possible, by all the stakeholders. The neutral facilitator should also develop meeting agendas based on input from all stakeholders. It should also ultimately answer to all stakeholders (this can be accomplished through a steering committee representing all stakeholders). This process has been used for years in state of Illinois for addressing a wide range of policy and technical issues associated with the state's utilities' efficiency programs through what is called the Illinois Stakeholder Advisory Group (SAG). I have been an active participant in the Illinois SAG for a decade.
2. I would amend the 6th principle on "communicating outcomes" to be clear not only about the how input was considered and the rationale for decisions made, but also about why alternative approaches proposed by one or more stakeholders were not taken. That could be the implicit intent in the description of the IESO principle, but it could be made more explicit.
3. Adding a principle on financial support. For engagements that will involve significant time commitments and/or technical expertise, it is important that stakeholders who can demonstrate they have an important perspective to offer are able to financially afford to bring that perspective to discussions.

I would also note that while stakeholder engagement processes governed by the principles put forward by the IESO (and including modifications I have proposed) are important, there also needs to be a regulatory backstop. That is, there needs to be a regulatory process for resolving disagreements that cannot be resolved through stakeholder engagement. That regulatory process needs to be transparent, enable participation by all stakeholders with a legitimate standing – including through funding of experts and legal fees – and be based on a clear set of rules.

GEC-ED Responses to Energy Probe

EP-GEC/ED-1

Ref: GEC/ED/Energy Futures Report, page 6-1.4, Issue #5: Industry Best Practices, 1.4.1 More Granular Load Forecasting.

Question:

a) Please provide more detail what is meant by More Granular Load forecasting.
b) Please provide examples based on geography, rate classes etc.
c) Does more granularity require installation of AMI systems? Please discuss in terms of costs/benefits. How would EGI's Gas Supply Plan differ in context of the current approach and more granular forecasts?

Responses:

a) and b)

See response to 2-BOMA-6

c) No, more granularity would not require installation of AMI systems (though it could potentially be aided by AMI). The reference in my report to granularity is about accounting for differences, by geography (or T&D system element), between (1) future DSM program savings and future government efficiency codes and standards; and (2) historic DSM program savings and historic government efficiency codes and standards. Adjustments for such differences should be based on the best available information about the peak impacts of different efficiency measures and programs. That could include estimated ratios of peak demand savings to annual energy savings by measure and/or program similar to those estimated by ICF for Enbridge.

   I do not know enough about EGI's Gas Supply Plan – or about the likely differences in past and future DSM programs – to comment on how it would differ.

EP-GEC/ED-2

Ref: GEC/ED/Energy Futures Report, page 8

Preamble:

"The Ontario Energy Board should consider establishing a stakeholder workshop process to identify policy goals relevant to cost-effectiveness analysis in Ontario and to ensure that all relevant costs, benefits, and risks are included in the benefit-cost analysis. This could be led by an external expert that would prepare a draft report for the Board's consideration."

Questions:

a) Please clarify what is Stakeholder Workshop to achieve for example whether this is a Task force to review/amend E.B.O.134 and E.B.O.188 Guidelines (or not) and what are the specific outputs expected?

b) What is the composition of the proposed Workshop/Task Force.

Response:

a) As stated in my report, the primary test for assessing cost-effectiveness test of non-pipe solutions should be (1) include all gas utility system impacts (including avoided energy costs, avoided carbon taxes, market price suppression effects (if any), etc.); and (2) other categories of impacts consistent with provincial policy goals. The latter may include impacts on low income customers, impacts on public health, a range of environmental impacts, etc. The purpose of the proposed workshop process would be to address the question of which such additional categories of impacts (beyond utility system impacts) should be included. For a further conceptual discussion of this idea, see the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs)*, particularly Chapter 3. For examples of how other jurisdictions have used stakeholder engagement processes to considered the NSPM principles and develop a primary cost-effectiveness test reflective of their policy goals, see the case studies at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/case-studies/.

   As explained in my response to Enbridge 6.5, The Company's proposed approach to basing cost- effectiveness assessments of non-pipe solutions on EBO 134 is fundamentally flawed because at least Stage 1 of the Company's proposed cost-effectiveness test would not actually measure whether total gas utility system costs (let alone total costs relevant to provincial policy goals) are higher or lower for non-pipe solutions. Thus, my proposal for a workshop process is focused on identifying the categories of impacts related to provincial policy goals that should be included in a primary cost-effectiveness test rather than on identifying ways that EBO 134 or EBO 188 should be revised. There may be other legitimate purposes for which EBO 134 and/or EBO 188 could be used. There may even be reasons to assess whether refinements to EBO 134 and/or EBO 188 would be appropriate for such other purposes or applications. I have not attempted to address the merits of such refinements.

b) The workshop should be open to participation by all interested stakeholders.

EP-GEC/ED-3

Ref: GEC/ED/Energy Futures Report, page 8

Preamble:

"The discount rate used for cost-effectiveness analysis of utility investment decisions should be a function of Ontario's policy objectives. Until an assessment of such objectives has been performed, the Board should require that the same discount rate used to assess cost-effectiveness of system-wide DSM programs (currently 4%) also be used when comparing the costs and benefits of pipe and non-pipe solutions."

Questions:

a) Is Energy Futures proposing a social discount rate? If so, please provide specifics.
b) For gas infrastructure projects why should not the utility's Weighted Average Cost of Capital be used? Please Discuss.
c) What discount rates are used in other jurisdictions? Please provide examples.

Responses:

a) As stated in the preamble, like the question of what categories of impacts beyond gas utility system impacts should be included in the primary cost-effectiveness test, the discount rate used in the test should be primarily a function of Ontario's energy policy objectives. See the NSPM for DERs, section 5.11 for discussion of the rationale for that concept. Absent or until an assessment of provincial policy objectives, the current 4% real discount rate used to assess cost-effectiveness of DSM should be used – both because it represents direct government input on discount rates and because it is economically irrational to use different discount rates to assess different investment decisions (often for some of the very same measures) on the same utility system. I do not consider a real 4% discount rate to be a "societal" rate. It is more like a blend between a societal rate and the utility's cost of capital. In my experience, real societal discount rates are typically estimated to be between 0% and 3%. One common reference is long-term U.S. Treasury Bond yields which currently suggest a real discount rate on the order of 1% or less.[1]
b) The utility's weighted average cost of capital represents the time value of money for utility shareholders. It is not at all clear why that time preference is appropriate for

[1] The electric and gas utilities in Illinois assess cost-effectiveness of energy efficiency programs using a societal discount rate. They use a ten-year average of 10-year Treasury bond yield rates as the proxy for the societal discount rate. For 2021 they will be using a real rate of 0.42% based on Treasury yields between 2010 and 2019. (https://ilsag.s3.amazonaws.com/IL-TRM_Effective_010121_v9.0_Vol_1_Overview_09252020_Final.pdf).

investments that both affect many other parties and may need to be considered in the context of a variety of public policy objectives.

c) I have not conducted a survey of discount rates used in other jurisdictions.

EP-GEC/ED-4

Ref: GED/ED/Energy Futures Report, page 8

Preamble:
"Conceptually, there are three ways in which utility shareholder incentives for investment in non-pipe solutions could be expressed: (1) incentive payments structured as a percent of the cost of non-pipe solution; (2) capitalizing and earning a return on non-pipe solution costs; and (3) incentive payments based on a percent of net economic benefits (cost savings) resulting from deploying a non-pipe solution instead of a more expensive T&D option."

Question:
How does the option of capitalizing and earning a rate of return on non-pipe solution costs reconcile with using a social discount of 4% on DSM solutions (Page 8)? Please discuss.

Response:
There is no economic reason why the discount rate used to assess the net present value of economic impacts needs to be the same as the rate used by the utility to capitalize expenditures. The discount rate is simply a reflection of the time value of money for the entity or group for which a net present value calculation is being computed. An individual or business would not and should not use different discount rates to assess the impact on their economic well-being of paying back one loan with a 5% lending rate and paying back another at a 10% lending rate.

EP-GEC/ED-5
Ref: GEC/ED/Energy Futures report, page 15

Preamble:
"Some jurisdictions have initial "rough cut" criteria – including lead time – for determining whether a detailed IRPA analysis is warranted. In Vermont, the criteria for consideration of non-wires solutions for deferral of electric transmission system investments are structured around the magnitude of the load reduction required as follows:

- 1 to 3 years for load reductions of 15% or less;
- 4 to 6 years for load reductions of 15% to 20%;
- 6 to 10 years for load reductions of 25%."

Questions:

a) Does Energy Futures have examples of lead times for gas infrastructure plans and projects? If so, please provide a summary by jurisdiction?
b) Has Energy Futures asked EGI what its lead times are for Infrastructure Plans/Projects? If so, summarize the result for both T&D Projects.
c) Why is Energy Futures proposing a 3-year horizon rather than some other lead time? Please discuss.

Responses:

a) In its report for OEB Staff, Guidehouse notes that ConEd (New York) considers potential non-pipe solutions in two size categories for which it assigns two different lead times:
    - large projects which are defined as costing more than $2 million and for which it is assumed a lead time of 3 to 5 years is required; and
    - small projects which are defined as costing less than $2 million and for which it is assumed that lead times could be as low as 18 months.[2]
b) In its October 2020 supplemental evidence Enbridge stated that "if a system need must be met in under 3 years, an IRPA cannot be implemented and verified in time…"
c) As explained in my report (p. 30), since Enbridge is just getting started with consideration of non-pipe alternatives, focusing initially on projects with a minimum lead time of three years seems reasonable. I also note that there could be exceptions where a shorter lead time could be considered. I also note that lead time guidelines should be re-evaluated and adjusted – and perhaps tied to project size as in the Vermont non-wires solution guidelines and ConEd's non-pipe solution guidelines – as the Company gains experience with non-pipe solutions.

[2] See Guidehouse report p. 30.

EP-GEC/ED-6

Ref: GEC/ED/Energy Futures report, page 20, 4.2.3 Simultaneous Consideration of All IRPA Resource Options is Required

Preamble:
This section focuses on non-pipe alternatives.
Questions:

a) How do upstream infrastructure and contracting supply solutions (including storage) fit into consideration of IRP Resource Options? Please discuss.
b) Please provide a table/matrix of all IRPA Resource Options Energy Futures believes should be included.

Responses:

a) It is not clear what EP means by "fit into". It is also not clear how upstream infrastructure and/or contracting supply solutions could be used to address a downstream distribution system constraint. Certainly, in specific cases where the location of storage or injection point of supply relative to the location of need allows storage or supply (or transport) contract options to address the need they should be included in IRPA assessments.
b) There are a range of potential demand-side resource options that can be geographically targeted. They include energy efficiency, demand response, fuel-switching (e.g., electrification of some customers' end uses), and district energy systems. While I am not as familiar with them and therefore cannot necessarily provide a comprehensive list, there are also supply-side options such as injection of compressed natural gas into the system downstream of the supply constraint. Further options may emerge as technology evolves and the IRPA process should remain open to any viable alternative going forward.

EP-GEC/ED-7

Ref: GEC/ED/Energy Futures Report, page 27

Preamble:
"Most jurisdictions that are seriously considering gas and electric IRPAs have started with pilot projects to actually field-test and gain experience with planning processes, deploying geo-targeting efficiency and other IRPA resources, evaluating the impact such geo-targeting is producing, and valuing such impacts and other key aspects of non-pipe solutions."

Questions:
a) Please provide the key features/considerations in developing a gas pilot project.
b) Other than the Northwest Natural Gas Oregon Project, please provide other gas pilot project examples.

Responses:
a) See response to Enbridge 2.1
b) I am not familiar with additional gas pilots.

GEC-ED Responses to Anwaatin IR

IR Anwaatin-4

Ref: Exhibit M2.GEC-ED, pp. 6 and 21-24

Preamble: Mr. Neme's evidence is that "IRP analyses are much more robust if they involve stakeholders in the key steps associated with the making of decisions rather than just as potential sources of information or in perfunctory discussions after decisions have largely been made" and that "the [Ontario Energy Board] and stakeholders should be informed and included throughout the IRP process." Mr. Neme suggests that the IRP framework should establish a planning committee, modeled on Vermont's System Planning Committee, to secure input throughout the planning process from key stakeholders.

Questions:

a) Please comment on the value of including indigenous communities among the stakeholders involved in IRP analyses.
b) Please comment on whether indigenous communities should be represented on any planning committee established in respect of the IRP framework.

Responses:

a) Any stakeholder that has a legitimate stake in the economic and/or public policy implications of IRP analyses and any resulting investment decisions – including indigenous communities – should have standing to engage in regulatory processes through which IRP options are considered.
b) Planning committees, such as the Vermont System Planning Committee, need to strike a balance between (1) having sufficient and broad enough representation of consumers and other types of stakeholders; and (2) being modest enough in size to be manageable. I do not know enough about either how the gas utility system serves indigenous communities in Ontario or about those communities' interests in IRP issues to comment on how those communities should be represented on such a committee.

GEC-ED Responses to BOMA

2-BOMA-1

Ref: Exhibit M2.GEC-ED (Neme, 2020), p. 5, Section 1.3.1 Bullet 2

Preamble:
The IRP framework should require utilities to prepare and publish an annual T&D needs summary based on a rolling 10-year forecast of needs, the drivers behind those needs, whether the needs may be candidates for non-pipe solutions (and why or why not), and the status of consideration of non-pipe solutions for each identified need (see Figure 3 below for an example of this information). This kind of longer-term planning is commonly performed in jurisdictions that are seriously considering IRPAs.

Question:

a) How does this compare with the current Gas Supply Planning used by Enbridge given recent OEB changes to this requirement?

Responses:

I do now know enough about the current Gas Supply Planning used by Enbridge to comment in detail. However, as indicated in the GEC response to IR 2-Staff-1-GECED part b, the various planning and approval processes should be timed, sequenced, and implemented in a manner that ensures that costs avoidable or benefits achievable by alternatives do not become unavoidable or unachievable. Optimal coordination of these processes may reduce redundant effort and regulatory costs while improving customer outcomes.

Also, the IRP planning process must involve more than the provision of information. The OEB should have an opportunity to require Enbridge to pursue and/or reconsider IRPAs early in the planning process.

2-BOMA-2

Ref: Exhibit M2.GEC-ED (Neme, 2020), Page 6, Section 1.3.4, 3rd Bullet

Preamble:
The Gas IRP framework should establish a planning committee, modeled on Vermont's System Planning Committee, to secure input throughout the planning process from key stakeholders.

Question:

a) Please provide the terms of reference and membership of the Vermont System Planning Committee (VSPC).

Response:
The VSPC Charter can be found here:
https://www.vermontspc.com/library/document/download/5641/VSPC_Charter_20160720.pdf
.

The VSPC membership can be found here: https://www.vermontspc.com/about/membership.

2-BOMA-3
Ref: Exhibit M2.GEC-ED (Neme, 2020), Page 19, Section 4.2.2.2

Preamble:
In its 2018 analysis of the role efficiency potential could play in deferring gas infrastructure investments, ICF estimated that, based on the most recent provincial Market Potential Study ("MPS"), the maximum achievable potential for peak hour demand savings is "in the range of 1.2% of peak hour demand per year."[17] ICF then noted that only about 17% of Union Gas planned facility investments and 14% of Enbridge planned investments had peak demand growth rates below 1.2% and suggested that meant that "DSM could potentially avoid a little less than 20% of the Gas Utilities' planned investments."

Questions:
a) Please provide your analysis of the differences between electricity IRP and gas IRP.
b) How are they treated differently in a combined utility?

Responses:
a) It is not clear how the question relates to the preamble, so I am not certain about what exactly is being asked. That said, there is no *conceptual* difference between consideration of electric non-wires solutions and consideration of gas non-pipe solutions. As noted in section 5.1 of my report, the principles, processes and cost-effectiveness frameworks should be the same for both gas and electric utilities.

   There will obviously be differences in some of the specifics. For example, the way peak loads are forecast for reliability purposes, the value of deferring T&D infrastructure, the uncertainties associated with future climate policy, the maximum amount of peak load reduction possible, the range of specific measures that can be deployed, and other details may be different for gas utilities than for electric utilities. However, some of those things will be different not only between electric and gas utilities, but also between different gas utilities and even between specific projects for the same gas utility. See Section 5.4 of my report for more information on how the value of gas non-pipe solutions and the value of electric non-pipe solutions may differ (or not).

   Note that for reasons explained on pp. 19-20 of my report, the ICF conclusions reference in the preamble to this question are problematic and misleading.

b) I see no reason why the policy framework for consideration of gas non-pipe alternatives should be any different for a dual-fuel utility than for a gas-only utility. The only possible exception to that statement could be with respect to shareholder incentive mechanisms – to the extent that it is likely that electrification will play a significant role in non-pipe solutions.

2-BOMA-4

Ref: Exhibit M2.GEC-ED (Neme, 2020), Page 21, Section 4.2.3.2

Preamble:
"As noted above, one shortcoming of ICF's analysis of the potential viability of non-pipe solutions is that it focused solely on the peak demand reduction potential from energy efficiency. While increased efficiency savings can sometimes be sufficient to defer a T&D investment, that will not always be the case. However, there are IRPA options other than geotargeted efficiency – including demand response programs; electrification of gas end uses with cold climate air source heat pumps,[21] ground source heat pumps, heat pump water heaters, and other technologies; and local injection of compressed gas – that should also be considered.[22] Any rules governing consideration of non-pipe solutions should require that all IRPA options be considered and that the IRPA plan chosen (if one or more combinations of IRPA options could cost-effectively defer a T&D investment) should represent the least cost mix of such options.[23]"

Question:
Traditionally, electricity demand side management has been based on replacing inefficient equipment with higher efficiency models and as a result, the standard practice is based on related data. Increasingly, there is more and more evidence that greater and longer lasting and less expensive natural gas savings result from overall performance improvement with respect to the integration of systems in buildings, homes, or industrial plants, tracked and measured by metered data rather than engineering estimates and assumptions. What is your opinion on how these advances will affect IRP?

Response:
I agree that there is a growing body of evidence to suggest that better integration of systems, coupled with on-going tracking and management of energy use, can be a significant source of energy savings that is not always reflected in either utility DSM program portfolios or in efficiency potential studies. However, I have not yet seen evidence to suggest that such savings can be captured programmatically in ways that are greater in magnitude, longer-lasting and/or less expensive than all other savings opportunities. That may well be true or possible for individual buildings or even for certain categories of buildings, but it is not clear it is true for full program portfolios.

That said, to the extent that such savings are cost-effectively achievable in specific geographic areas that would need to be targeted to defer a T&D upgrade – and I would expect that to be the case, at least to some extent – they should be considered to be part of the resource potential that analysis of non-pipe solutions should assess and endeavor to acquire.

2-BOMA-5

Ref: Neme, 2020, Exhibit M2.GEC-ED

Preamble:
Vermont has long demonstrated its commitment to many of the principles and processes contained in Neme, 2020.

Questions:

a) Please provide a brief history exploring the options to replace traditional supply side approaches in Vermont.
b) Please provide the policy and government changes that supported these developments as well as a description of Vermont, its service territory/customer base, energy mix and results on the demand side compared with all forms of delivered energy.

Response:

a) and b)

One could write a book about the Vermont's 30-year history in exploring and pursuing demand-side alternatives to energy supply investments. That is outside the scope of my work in this proceeding. I would need more context for the question to provide an appropriately brief summary of relevant key points in Vermont's history. Note that my report provides numerous references to Vermont IRP requirements and the Vermont System Planning Committee. There is also a great deal of information on Vermont's size, demographics, energy consumption, success with efficiency programs and other related topics which can be found on-line.

2-BOMA-6

Ref: Exhibit M2.GEC-ED (Neme, 2020), Page 6, Section 1.4.1

Preamble:
T&D peak demand forecasts that are based primarily on historical data will not reflect the effects of changes in scope or mix of system-wide efficiency programs or major changes in building codes or government efficiency standards for gas consuming equipment. Experience in other jurisdictions suggests that more granular forecasting that accounts for such changes can significantly alter estimates of T&D needs. The Gas IRP framework should require Enbridge to begin developing more granular forecasting capabilities and, in the interim, to make at least high-level adjustments to forecasts to account for major known changes to efficiency programs and/or codes and standards.

Questions:

a) Please define more granular forecasting.
b) Please discuss the degrees of granularity that are appropriate for electricity forecasts and natural gas forecasts and provide your rationale.

Responses:

a) As the language in the preamble suggests, what I meant by more granular forecasting is to adjust forecasts that might otherwise be based solely on historic peak demand trends for a given T&D system element to reflect expected differences between (1) past utility energy efficiency program impacts and past government efficiency codes and standards; and (2) likely future utility efficiency program impacts and future expected government efficiency codes and standards. For example, if a geographic area had many small businesses that contribute a significant portion of peak demand on a T&D system of interest and which had historically not participated in significant numbers in the utility's efficiency programs, and if the utility was planning on launching a new small business program that could reasonably be expected to achieve significant participation in the geographic area, all other things being equal, that would be a basis for adjusting the local peak load forecast. Of course, all other things are often not equal, so the utility should make those kinds of adjustments across all efficiency programs and customer types – as well as for changes in government codes and standards – to determine how to adjust peak load expectations. See the article on ConEd's forecasting that is referenced in footnote 11 my report for more perspective on this issue.
b) I see no reason that the kind of geography-specific adjustments to peak demand forecasts described in my report would not be equally important to make for both gas and electric utilities.

2-BOMA-7

Ref: Exhibit M2.GEC-ED (Neme, 2020), Page 7, Section 1.5.1, Bullet 4

Preamble:
Individual customer demands for gas connection can be grounds for providing that connection, as long as the customer is prepared to pay for the full cost of their contribution to system costs and risks. However, if demand from a new customer would require T&D investment at a point in the system that serves many other customers, the utility should be required to consider non-pipe solutions. In addition, Enbridge should also proactively work with potential new customers to consider non-pipe alternatives early on, where that would reduce overall system costs and risks (e.g. heat pumps in new buildings).

Question:
Are GEC, ED, and its Expert Witness aware that Enbridge Gas Distribution has raised the issue of heat pumps, solar water heating, and distributed energy to the OEB at least since 2009, but without success? As recently as 2016, in its decision about Community Expansion, (EB-2016-2004), the Board ruled that: "the environmental groups have submitted that the utilities should be required to assess sustainable energy technologies for all community expansion projects. The OEB agrees with the position of OEB staff that utilities are primarily in the business of gas distribution and should not be required to provide detailed assessments of alternative technologies such as solar and geothermal as part of the community expansion applications."

Response:
Fuel switching, which includes switching to heat pumps, has always been an element of DSM, including at the OEB. For example:

- The OEB's 2011 DSM Guidelines included fuel switching (p. 4);
- The OEB's 2014 DSM Filing Guidelines included fuel switching (p. 10);
- The OEB's 2016 Cap and Trade Framework included fuel switching (p. 6);
- The OEB's 2017 Marginal Abatement Cost Curve Report addresses heat pumps in great detail (see appendix A).

The quote from EB-2016-0004 excerpted in the question is missing important context. The Board went on to note that:

> "Parties that wish to address alternative technologies can bring forward relevant evidence in the leave to construct applications. ***<u>Where practical alternative technologies</u>***

are more economically feasible than natural gas, including the impact of cap and trade on gas prices, it is unlikely that gas expansion will proceed." (emphasis added)

In addition, with respect to the decision in EB-2016-0004:

1. 2016 was five years ago;
2. the understanding of what needs to happen to address climate change, including both the magnitude of carbon emission reductions likely to be ultimately needed from the gas industry and the options for dramatically reducing such emissions, continues to evolve;
3. an important point with regard to electrification in this proceeding is that there is a non-trivial possibility that future climate policy will require reductions in carbon emissions from the gas industry at levels that will either require electrification and/or significant conversion to expensive renewable gas – either of which could have dramatic effects on gas demand that should be considered when weighing the merits of proposed gas infrastructure investments (including the potential for creating stranded assets); and
4. Enbridge itself has suggested that heat pumps be considered a measure for non-pipe solutions in this proceeding.

GEC-ED Responses to London Property Management Association IRs

Interrogatory #1

Ref: Exhibit M2, pages 13 – 14

With respect to the goals of a gas IRP framework for Ontario:

a) The evidence states that any starting point for any IRP is that gas customers' energy needs must be safely met. Please explain why the reference is to gas customers rather than energy customers.

b) Is it possible that energy customers' energy needs can be safely met through other energy types and without the use of natural gas?

c) With respect to cost minimization, please explain to whom the relevant cost and benefits are applicable. For example, is it related only to the costs and benefits of the utility or does it include societal costs and benefits and costs and benefits for the customers impacted by the IRP?

d) With respect to alignment with other government policy objectives, should the governments include the federal, provincial and municipal governments? If not, please explain why not and which government policy objectives would be relevant.

e) How should an IRP plan take into account potential conflicts in government policy objectives, such as, for example, expansion of natural gas service to currently unserved areas and the reduction of greenhouse gas emissions?

f) With respect to the equitable consideration of all viable resource options, please define viable.

g) With respect to the equitable consideration of all viable resource options, do these options include electrification, solar electricity generation, solar water heating, hydrogen, propane, air-source heat pumps, geothermal systems, energy storage, etc.? Are there any options that should not be considered a viable resource option at this time?

h) With respect to the alignment of utility interests with IRP goals, does the author agree that the utility does not need any financial incentive over and above the return on rate base if the most cost-effective solution continues to be a capital investment (pipe or non-pipe), even if the capital investment is less than what it would have been in the absence of the IRP?

i) With respect to the alignment of utility interests with IRP goals, should the utility have a financial incentive where the most cost-effective solution includes the provision of a non-pipe alternative by a third-party supplier that may or may not be a regulated entity?

Responses:

a) The reference was to gas customers because a gas IRP framework is about determining whether and when alternatives to investment in gas system infrastructure is warranted. One potential non-pipe solution is electrification of some current gas customers' heating, water heating and/or other energy end uses. In such cases, a current gas customer could be transformed into a non-gas consuming customer. However, they would have started as a gas customer.
b) Yes, it possible that energy customers' energy needs can be safely met through other energy types and without the use of natural gas.
c) As stated in my report, as well as in responses to Enbridge 6.4, any assessment of cost-effectiveness must include all gas utility system benefits and costs – including avoided energy costs, avoided carbon taxes, and gas price effects – that affect customers. It should also include any additional customer and/or societal impacts that are important given the province's public policy interests and goals.
d) The OEB is a provincial regulator. Therefore, the determination of which additional categories of impacts – beyond utility system impacts – should be reflected in cost-effectiveness analyses should be based on Ontario's policy interests and goals. That said, both local and federal policies can affect utility system impacts – again, all of which should be included in a jurisdiction's cost-effectiveness test. The federal carbon tax policy is a classic example.
e) Government policy direction is sometimes very clear and in other cases may not be. Where it is not, some informed judgment must ultimately be employed by regulators. As discussed in Section 3.5 of the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, where there is uncertainty about which non-utility system impacts to include because of uncertainty associated with or even conflicts between government policies, secondary tests can also be used. For example, if there is uncertainty about whether to include program participant impacts (i.e., the additional cost that

efficiency program participants pay for an efficiency measure – beyond a utility rebate – as well as any non-energy benefits they receive), regulators can require that cost-effectiveness analyses be performed both with and without such impacts and make decisions while weighing both sets of results. For the specific example provided in the question, the solution may be to support expansion of the gas system into specific areas only where it is either explicitly mandated by government and/or where it can be demonstrated to be cost-effective, including consideration of the expansion cost, relative to alternatives.

f) Viable means technically capable of meeting an energy need. That is the starting point. Cost-effectiveness analysis will then show whether technically viable options are economic or not.
g) Yes, all such options – and any others that could technically meet energy system needs – should be considered and evaluated for cost-effectiveness.
h) One should not necessarily expect the absolute dollar value of return to shareholders from investment in a non-pipe alternative to be as large as the dollar value of return from a gas infrastructure investment. That said, it may be appropriate to offer a modest “bonus”, over and above the utility’s normal rate of return, for investment in non-pipe alternatives. Overall, the return needs to be sufficient to align the interests of the utility with consumer interests. See response to IR9-Staff-1.
i) Yes, the utility should have a financial incentive where the most cost-effective solution includes the provision of a non-pipe alternative by a third-party supplier that may or may not be a regulated entity.

<u>Interrogatory #2</u>

Ref: Exhibit M2, page 14

a) Is the reference to “a single integrated resource planning process” limited to gas IRP, or is it a broader concept that would include electricity transmission and distribution planning and unregulated energy providers (for example, propane distributors, CNG providers, geothermal providers, solar providers)? If not, please explain why not.

b) Would the “single integrated resource planning process” also include planning and other relevant departments and/or ministries from municipal, provincial and federal governments? If not, please explain why not.

c) In addition to the parties noted in parts (a) and (b) noted above, are there other groups/organizations that should be involved in the “single integrated resource planning process”?

Responses:

a) The reference was to a single IRP process for all gas utility system investments. Provincial energy planning and related policies should ideally consider the inter-relationship between all elements of the provincial energy system, with regulatory decisions on gas system IRP made in the context of such a province-wide energy plan. Such province-wide energy planning may be the purview of the provincial government rather than the OEB, unless the government has given direction to the OEB to develop such a province-wide plan.
b) See response to part “a”.
c) All interested stakeholders should have the opportunity to provide input on the development of IRPs – regardless of the scale of their focus.

Interrogatory #3

Ref: Exhibit M2, page 15

With respect to the lead time needed, is the reference to load reduction, current annual sales and gas consumption related only to annual gas consumption or does it also encompass peak day and/or hour requirements?

Response:
The use of the term “forecast gas consumption” in my report may have been misleading or confusing. Since gas infrastructure investments are driven by peak day and/or peak hour requirements, lead times should be tied to how quickly peak day and/or peak hour demands could be reduced. Any related reductions in annual gas consumption should simply be reflected in calculations of the benefits of geotargeted investments in peak demand reductions.

Interrogatory #4

Ref: Exhibit M2, pages 15 – 16

How should the utility ensure that third-party providers of non-pipe alternatives are included in the integrated resource planning process to ensure that these providers are afforded the lead time they need to become a viable option within the planning horizon?

Response:
To the extent that the OEB adopts the stakeholder engagement process recommended in my report (akin to the Vermont System Planning Committee), any third party provider could track planning and the resulting decisions with significant lead time.

Interrogatory #5

Ref: Exhibit M2, page 44
The evidence states that it would be reasonable for the utility and its shareholders to expect to be able to make money in the acquisition of a combination of resources that balances cost-minimization, risk minimization, carbon emissions reductions and other policy objectives.

a) Please explain if it is reasonable for the utility and its shareholders to make money on assets and/or services that are used as a part of the combination of the resources used that are owned and provided by non-regulated third-party providers.

b) If non-regulated third-party providers are able to provide some or all of the assets and/or services needed to satisfy an IRP, are they entitled to the same expectation as the utility and its shareholders to make money on their assets and/or services?

Response:

a) Yes, it would be reasonable for the utility to profit because the utility would be undertaking the planning that led to the deployment of those third-party resources and may ultimately be providing some or all of the capital required for an investment to the third parties. The utility would also presumably be ultimately responsible for achieving the promised objectives. The extent of profit would vary based upon the utility investment of resources.
b) My presumption is that the gas utility will be responsible for procuring the resources that are part of a non-pipe solution. Such procurement would necessarily require payments to third parties that would need to be sufficient for them to be profitable (or they wouldn't be provided).

Interrogatory #6

Ref: Exhibit M2, page 46

For each of the shareholder incentive mechanisms described, please explain the potential impact on competitive third-party non-pipe solution providers. Are incentives available to third-party non-pipe solution providers either through the utility or through some other mechanism?

Response:
All other things being equal, Enbridge should always endeavor to utilize the lowest cost option for providing a non-pipe solution. The utility, OEB and customers should be indifferent as to who is actually providing the non-pipe solution. Any third-party provider would either (1) be incented through the structure of its contract with the utility to provide the non-pipe solution; and/or (2) be able to be sufficiently profitable by selling peak demand reducing products or services to Enbridge's customers (with whatever financial incentives or support Enbridge would provide to the market to help produce the investment in peak demand reducing measures).