Best Practices for Gas IRP and Consideration of "Non-Pipe" Alternatives to Traditional Infrastructure Investments

Chris Neme, Energy Futures Group

Submitted on behalf of:

Green Energy Coalition
Environmental Defence

EB-2020-0091

November 23, 2020

Contents

1. Executive Summary 4
1.1 Introduction 4
1.2 Issue #1: Definition and Goals of IRP 4
1.3 Issue #2: Process to Incorporating IRP into Enbridge's System Planning Processes 5
1.3.1 Planning Horizon 5
1.3.2 Need for Localized Assessment 5
1.3.3 Simultaneous Consideration of All IRPA Resource Options is Required 6
1.3.4 Stakeholder Engagement 6
1.4 Issue #5: Industry Best Practices 6
1.4.1 More Granular Load Forecasting 6
1.4.2 Value of Pilot Projects 7
1.5 Issue #6: Screening Criteria & Methodology for Comparing IRPAs and Facility Projects 7
1.5.1 Pre-Screening Criteria 7
1.5.2 Benefit-Cost Analysis 8
1.6 Issues #7 and #9: Cost Recovery and Financial Incentives 8
1.7 Applicability of Lessons from Electric IRP to Gas IRP 9
2. Introduction 10
3. The Concepts of IRP and Non-Pipe Alternatives 11
3.1 Summary of Key Points 11
3.2 Purpose of IRP 11
3.3 Application of IRP To Transmission and Distribution (T&D) Investment Decisions 13
4. Discussion of Policy Issues 13
4.1 Issue #1: Goals of IRP 13
4.1.1 Goals for a Gas IRP Framework in Ontario 13
4.1.2 Consistency with Other Gas Planning and Investment Frameworks 14
4.2 Issue #2: IRP Process 15
4.2.1 Planning Horizon 15
4.2.2 Need for Localized Assessment 18
4.2.3 Simultaneous Consideration of All IRPA Resource Options is Required 20
4.2.4 Stakeholder Engagement 21
4.3 Issue #5: Industry Best Practices 25
4.3.1 More Granular Forecasting 25

4.3.2 Value of Pilot Projects ... 27
4.4 Issue #6: Screening Criteria and Methodology For Comparing Alternatives ... 29
4.4.1 Pre-Screening Criteria ... 29
4.4.2 Benefit-Cost Analysis ... 31
4.5 Issues #7 and #9: Cost Recovery and Financial Incentives ... 44
4.5.1 Summary of Key Points ... 44
4.5.2 Overview ... 44
4.5.3 Pros and Cons of Incentive Options ... 46
5. Applicability of Lessons from Electric IRP to Gas IRP ... 47
5.1 Summary of Key Points ... 47
5.2 Applicable Lessons from IRP Analyses of Alternatives to T&D Investments ... 48
5.3 Other Transferable Lessons ... 49
5.4 Value of Gas Non-Pipe Solutions Relative to Electric Non-Wires Solutions ... 49
5.4.1 Facilities Planning Requirements ... 49
5.4.2 Cost Structure ... 50
5.4.3 System Outage Risk Tolerance ... 52
5.4.4 Resource Planning ... 52
5.4.5 Peak Hour Data Availability ... 52
5.4.6 The Bottom Line ... 55

1. Executive Summary

1.1 Introduction

The Ontario Energy Board (OEB or "Board") is seeking input on a range of issues related to Gas Integrated Resource Planning ("IRP"), particularly consideration of alternatives to traditional transmission and/or distribution ("T&D") system infrastructure investments – what the industry sometimes calls "non-pipe alternatives" or "non-pipe solutions" and what the Board is calling IRP Alternatives or IRPA in this proceeding.[1]

The Board has identified ten specific issues to be addressed in this proceeding. This report directly addresses six of them:

- Issue #1: Definition and Goals of IRP
- Issue #2: Process to Incorporating IRP into Enbridge's System Planning Processes
- Issue #5: Industry Best Practices
- Issue #6: Screening Criteria and Methodology for Comparing IRPAs and Facility Projects
- Issue #7: Cost Recovery
- Issue #9: Utility Incentives for IRP to Ensure Effective IRP Outcomes

Because some of the report's conclusions and recommendations on these issues are based, at least in part, on lessons from electric utility experience with non-wires solutions, the report includes discussion of when and why electric utility lessons are applicable to gas utilities.

What follows is a brief summary of the conclusions on each of the policy issues addressed by the report, as well as the applicability of lessons from electric non-wires solutions to consideration of gas non-pipe solutions.

1.2 Issue #1: Definition and Goals of IRP

The goals of a gas IRP framework for Ontario should be:

1. **Reliability**: The starting point for any IRP is that gas customers' energy needs must be safely met.
2. **Cost minimization**: A core objective of any IRP framework is that it must enable identification of and require deployment of the least cost mix of resources – based on an assessment of all relevant costs and benefits – for meeting reliability requirements.
3. **Risk minimization**: Another core objective of any IRP framework should be to minimize risk – both reliability risk and economic risk – of meeting reliability requirements. Economic risk is related to and should be reflected in cost-effectiveness assessments.

[1] Ontario Energy Board, Decision on Issues List and Procedural Order No. 2, EB-2020-0091, p. 6.

4. **Alignment with other governmental policy objectives**: IRP rules should lead to investments that are aligned with governmental policy objectives. If they do not, ratepayers will either pay additional costs in the future – and ultimately higher total costs – to re-align system investments with policy and/or incur unnecessary risk. Where possible, impacts on other policy objectives should also be reflected in cost-effectiveness assessments.

5. **Equitable consideration of all viable resource options**. To ensure that costs and risk are minimized, all resource options that could address reliability needs – both demand and supply options – must be considered and evaluated. Moreover, all of the costs and benefits each resource offers (not just those associated with T&D reliability) must be considered and evaluated. Though this might be considered more of a "how" to structure the framework than an outcome "goal", is it so central to successful IRP that it merits calling out.

6. **Alignment of utility interests with IRP goals**: If the utility cannot be sufficiently profitable while pursuing the other framework goals (above), achievement of those other goals will be undermined. Thus, utilities should have a financial incentive to implement the non-pipe solution where it is the most cost-effective option. Again, though this could be considered more of a "how" to structure the framework to meet other "goals", it is so central to achievement of those goals that it merits calling out.

1.3 Issue #2: Process to Incorporating IRP into Enbridge's System Planning Processes

1.3.1 Planning Horizon

- The amount of lead time needed to consider and effectively deploy non-pipe solutions will vary depending on the magnitude of the load reduction required and the size of the geographic area that needs to be addressed.
- 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.
- In addition, there needs to be a mechanism that stakeholders and the Board can utilize to trigger formal Board 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 cost-effective alternatives).

1.3.2 Need for Localized Assessment

- The potential to defer T&D investments can be very project-specific, depending on the size of the load reduction required, the timeline over which it needs to be acquired, the economic value of the T&D deferral, and a variety of factors affecting both the magnitude of the load reduction potential and the cost of acquiring it (e.g. customer mix, local demographics, age and condition of building stock).

- The rules governing consideration of non-pipe solutions should require consideration of all such local factors.
- Any criteria for screening out consideration of non-pipe solutions must be very carefully designed to ensure that they would not rule out potentially viable projects. That means erring on the side of greater latitude when there is uncertainty (e.g. about the size of load reduction that could be achieved), as what is possible in one location may be very different from the "average", particularly when multiple IRPA options are considered together.

1.3.3 Simultaneous Consideration of All IRPA Resource Options is Required

- 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.
- The Gas IRP framework should require that all such measures be considered – individually and in combination with each other – with the least cost mix of such measures selected for investment.

1.3.4 Stakeholder Engagement

- 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.
- The Board and stakeholders should be informed and included throughout the IRP process. If that does not occur, planning assumptions and decisions will only be tested in leave to construct hearings, at which point it may be too late to select a non-pipe solution that might require a longer lead time.
- 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.

1.4 Issue #5: Industry Best Practices

1.4.1 More Granular Load Forecasting

- 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.

1.4.2 Value of Pilot Projects

- There are limits to what can be learned about Gas IRP and non-pipe solutions from just studying what other jurisdictions have done.
- 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 geotargeting efficiency and other IRPA resources, evaluating the impact such geotargeting is producing, and valuing such impacts and other key aspects of non-pipe solutions.
- The Board should require Enbridge to begin planning to deploy two such pilot projects in 2021 with actual deployment of IRPA resources beginning no later than January of 2022.
- The Board may wish to consider establishing a collaborative utility-stakeholder process to design the pilots, select the target areas, establish monitoring and evaluation plans, hold regular check-ins on progress and develop modifications to plans in response to market feedback and other lessons learned.

1.5 Issue #6: Screening Criteria & Methodology for Comparing IRPAs and Facility Projects

1.5.1 Pre-Screening Criteria

- T&D projects required to address safety concerns are generally not candidates for non-pipe alternatives. However, there can be exceptions that merit analysis.
- Focusing initially on projects with at least a 3-year lead time for consideration of non-pipe solutions is reasonable. However, this criterion should not be applied rigidly as there may be exceptions. Moreover, the criterion should be revisited once there is more experience with non-pipe solutions.
- The ability to leverage municipal public road, water or other public works investments is not justification for proceeding with T&D investment projects without consideration of alternatives. Non-pipe solutions can still be lower cost and lower risk.
- 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).
- Absent a government mandate that expressly excludes consideration of alternatives (either individually or under conditions that may apply to specific communities or categories of communities), gas line extensions should not be excluded from consideration. There may be cases where policy goals such as access to low-cost energy could be achieved more cost effectively and with less risk than through gas service expansion.

1.5.2 Benefit-Cost Analysis

- Any cost-effectiveness analysis of any gas utility investment options – including pipe and non-pipe solutions – must include all gas utility system impacts, including avoided gas commodity costs, avoided gas storage costs, avoided carbon taxes, and effects on market clearing prices for gas (e.g. market price suppression effects of efficiency programs).
- Cost-effectiveness analyses of any gas utility investment options – including pipe and non-pipe solutions – should also account for all impacts related to government policy goals.
- 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.
- In the interim, the "TRC+" test – which implicitly assumes participant impacts and environmental impacts are relevant to provincial policy goals – should be the foundation of cost-effectiveness assessments of pipe and non-pipe alternatives. However, consistent with the principle that all utility system impacts should be included, application of the test should include the effects on market clearing prices for gas that have historically not been included in Ontario utilities' use of the test.[2]
- Economic risk should always be quantified – and ideally monetized – as part of IRP analyses. That should be the case regardless of what cost-effectiveness test is used (i.e. regardless of what categories of impacts, costs and benefits are included in cost-effectiveness assessments). It is particularly essential that the risks related to climate change are monetized and included in benefit-cost analyses because these risks could be very important from a financial perspective.
- 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.

1.6 Issues #7 and #9: Cost Recovery and Financial Incentives

- If utilities are to be expected to deploy non-pipe solutions when they are preferable to T&D investments, the utilities and their shareholders should be able to be sufficiently profitable while doing so.
- 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.

[2] This requirement should apply to all uses of the test, including assessments of both DSM and non-pipe solutions.

- A case can be made for each of these options. They all have both advantages and disadvantages.
- The best may be capitalizing and earning a rate of return on non-pipe solution costs. Though perhaps not perfect, this option is most consistent with how utilities profit from traditional T&D solutions, is likely to be the option that will result in the strongest utility management support for non-pipe solution investment, and is simple and well-understood. 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.

1.7 Applicability of Lessons from Electric IRP to Gas IRP

- The principles, processes and cost-effectiveness frameworks for considering gas non-pipe solutions are the same as those for considering electric non-wires solutions.
- There are some differences between gas and electric utilities that could theoretically affect the average economic value and/or frequency of cost-effectiveness of non-pipe solutions relative to non-wires solutions. However, it is not clear whether their combined effect would be to make non-pipe solutions more or less economically attractive – on average – than non-pipe solutions.
- As with non-wires solutions, the economic merits of non-pipe alternatives will likely vary considerably from project to project, underscoring the need for project-specific assessments.

2. Introduction

The Ontario Energy Board (OEB or "Board") is seeking input from Enbridge Gas and other stakeholders on a range of issues related to gas Integrated Resource Planning (IRP), including consideration of alternatives to traditional transmission and/or distribution (T&D) system infrastructure investments – what the industry sometimes calls "non-pipe alternatives" or "non-pipe solutions" and what the Board is calling IRP Alternatives or IRPA in this proceeding.[3]

The Board has identified ten specific issues to be addressed in this proceeding. This report directly addresses six of them:

- Issue #1: Definition and Goals of IRP
- Issue #2: Process to Incorporating IRP into Enbridge's System Planning Processes
- Issue #5: Industry Best Practices
- Issue #6: Screening Criteria and Methodology for Comparing IRPAs and Facility Projects
- Issue #7: Cost Recovery
- Issue #9: Utility Incentives for IRP to Ensure Effective IRP Outcomes

In addressing these issues the report relies on the author's extensive direct personal experience with energy efficiency, utility IRP, cost-effectiveness analysis frameworks for utility investments, and other related topics – both in Ontario and in other jurisdictions – as well as on research he has conducted to explore industry best practices in these areas. Because industry experience with gas non-pipe solutions is still relatively limited outside of New York, and the Board has directed that this report not address Gas IRP experience in New York, the report also relies on experience with electric non-wire solutions, with discussion of the relevance of such experience to consideration of gas non-pipe solutions in Ontario.

Mr. Neme, the author of this report, has more than 25 years of experience with the design, implementation and evaluation of energy efficiency, demand response, strategic electrification and other distributed energy programs and policies. He has worked extensively in the area of alternatives to utility T&D investments. That includes testifying before the OEB in the GTA pipeline case in 2013, providing training on consideration of non-wires alternatives to Ontario Power Authority staff, co-authoring a 2015 report on more than two decades of experience in the United States with deployment of geo-targeted energy efficiency programs to cost-effectively defer electric utility T&D investments, and working for the past several years with the two largest utilities in the state of Michigan on pilot non-wires alternatives projects. Mr. Neme is also a co-author of both the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (published in 2017) and the *National Standard Practice Manual for Benefit-Cost-Analysis of Distributed Energy Resources* (published in August 2020). The latter manual includes a chapter on non-wires alternatives to which Mr. Neme was a key contributor. Mr. Neme is also familiar with Enbridge's current and past

[3] Ontario Energy Board, Decision on Issues List and Procedural Order No. 2, EB-2020-0091, p. 6.

DSM efforts from having regularly reviewed its plan filings, serving on the OEB's Evaluation Committee (since 2015) and previously serving on the Ontario Technical Evaluation Committee (TEC) as well as all but one of Enbridge's annual DSM Audit Committees since they were first formed in 2000.

Mr. Neme has filed testimony on DSM/CDM issues before the Ontario Energy Board on more than twenty occasions over the past 25 years (EBRO 486, EBRO 487, EBRO 493/494, EBRO 497, EBRO 499, RP-1999-0001, RP-1999-0017, RP-2000-0040, RP-2001-0029, RP-2001-0032, RP-2002- 0133, RP-2003-0063, RP-2003-0203, EB-2005-0211, EB-2005-0001, EB-2005-0523, EB-2006-0021, EB-2008-0346, EB-2010-0279; EB-2012-0337; EB-2013-0451; EB-2015-0029; EB-2015-0049; EB-2017-0224; and EB-2017-0255). He has also testified in regulatory proceedings in a dozen other states and provinces including neighboring jurisdictions of Manitoba, Quebec, Michigan, and Ohio.

3. The Concepts of IRP and Non-Pipe Alternatives

3.1 Summary of Key Points

- IRP is a dynamic form of cost-effectiveness analysis whose purpose is to identify which resources – supply and/or demand – merit utility investment given government policy objectives relevant to the utility's service territory.
- The principles, processes for and steps to analyzing the economic merits of alternatives to traditional T&D investments are the same for gas and electric utilities.

3.2 Purpose of IRP

Integrated resource planning (IRP) is a process to evaluate the optimal mix of resources – considering both supply and demand options – to meet utility customers' energy needs while also addressing other policy goals.[4] Put another way, IRP is a dynamic form of cost-effectiveness analysis of utility system investment options. Thus, its purpose is to identify which resources – supply and/or demand – merit utility investment given policy objectives relevant to the utility's service territory.

While ensuring safety and reliability are always core objectives, IRP evolved decades ago to include consideration of economic risk, environmental costs and other relevant social or economic policy objectives.[5] For example, consider the following statutory definition of IRP in the state of Vermont:

---

[4] Body of Knowledge on Infrastructure Regulation (http://regulationbodyofknowledge.org/glossary/i/integrated-resource-planning-irp/).

[5] For example, an article published in 1991 – nearly 30 years ago – noted that the scope of electric utility planning "has expanded to consider energy efficiency and load management as resources, the environmental costs of electricity production, and a variety of resource-selection criteria beyond electricity price" and that "similar changes are beginning to occur at gas utilities." (Hirst, Eric, Charles Goldman and Mary Ellen Hopkins, Integrate Resource Planning: Electric and Gas Utilities in the USA", in Utilities Policy, January 1991; https://eta-publications.lbl.gov/sites/default/files/journal-utilities-policy-01-1991.pdf). Interestingly, the article later makes reference to an Ontario Hydro analysis that included "development of natural and socio-economic criteria (e.g. land and water use, atmospheric emissions, solid waste production and socio-economic effects such as regional employment and local community impacts)." Similarly, a 1992 paper on IRP defined IRP as "the process for integrating supply- and demand-side resources to provide energy services at a cost that balances the interests of all stakeholders" and noted "The goals of IRP have evolved from least cost planning and encouragement of

> "*A 'least-cost-integrated plan' for a regulated electric or gas utility is a plan for meeting the public's needs for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be assessed with due regard to:*
>
> *(A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. §582;*
> *(B) the State's progress in meeting its greenhouse gas reduction goals;*
> *(C) the value of the financial risks associated with greenhouse gas emissions from various power sources; and*
> *(D) consistency with section 8001 (renewable energy goals) of this title.*"[6]

In this example, Vermont has specifically called out, in statute, that reduction in greenhouse gas emissions is a policy objective to be addressed through IRP. However, as discussed extensively in the recently published *National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources* (NSPM for DERs),[7] policy goals can be more general (i.e. not directly specified in IRP rules or procedures, but instead in broader energy policy statements or findings) and articulated either in statute, administrative directives, regulatory orders, and/or other forms. They can also be developed locally or nationally (if affecting the local jurisdiction).

Put simply, in order to ensure that IRP processes will serve the purpose of identifying the optimal mix of resource investments, regulators should identify the policy goals that need to be considered and require that the impacts that different resource options have on those policy goals be quantified. Ideally, all such impacts should be monetized so that the IRP process can identify the least cost resource mix in the context of multiple policy objectives. If they cannot be monetized, an appropriate proxy or qualitative approach to considering them should be employed.[8] If the effects of different energy resource options on relevant policy objectives are not identified and reflected in IRP analyses, the result will be investment in a set of resource options that may be "least cost" relative to a *subset* of objectives but inconsistent with other objectives and, therefore, more expensive than the optimal set of resources for addressing *all* jurisdictional concerns.

---

demand-side management to broader, more complex issues including core competitive business activity, risk management and sharing, accounting for externalities, and fuel switching between gas and electricity." [Bauer, Douglas and Joseph Eto, "Future Directions: Integrated Resource Planning", proceedings of the 1992 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 8, pp. 1-16 (https://www.aceee.org/files/proceedings/1992/data/papers/SS92_Panel8_Paper02.pdf)].

[6] Vermont 30 V.S.A. § 218c (https://legislature.vermont.gov/statutes/section/30/005/00218c).

[7] Woolf, Tim (Synapse Energy Economics) et al., *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM for DERs")*, August 2020 (https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/).

[8] See Appendix C of the NSPM for DERs and Woolf et al. (Synapse Energy Economics), Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Account for All Relevant Costs and Benefits, prepared for the Advanced Energy Economy Institute, September 22, 2014 (https://www.synapse-energy.com/sites/default/files/Final%20Report.pdf).

3.3 Application of IRP To Transmission and Distribution (T&D) Investment Decisions

IRP analyses can be performed at either the system level or in more narrowly targeted geographic areas when weighing the relative merits of traditional capital investments in transmission and/or distribution (T&D) systems. Geotargeted deployment of energy efficiency, demand response, electrification measures and other options to address T&D needs are commonly called "non-pipe alternatives" or "non-pipe solutions" for gas utilities; they are often called "non-wires alternatives" or "non-wires solutions" for electric utilities. In this proceeding, the Board uses the term IRP Alternative, or IRPA. While the observations presented in the balance of this report focus on the application of IRP principles to non-pipe alternatives/solutions or gas IRPA, many are equally applicable to system-wide planning.

4. Discussion of Policy Issues

4.1 Issue #1: Goals of IRP

4.1.1 Goals for a Gas IRP Framework in Ontario

As stated in Section 3.1, IRP is a process to evaluate the optimal mix of resources – considering both supply and demand options – to meet utility customers' energy needs while also addressing other relevant policy goals.[9] Put another way, IRP is a dynamic form of cost-effectiveness analysis of utility system investment options whose purpose is to identify which resources – supply and/or demand – merit utility investment given policy objectives relevant to the utility's service territory.

In that context, the goals of a gas IRP framework for Ontario should be:

1. **Reliability**: The starting point for any IRP is that gas customers' energy needs must be safely met.
2. **Cost minimization**: A core objective of any IRP framework is that it must enable identification of and require deployment of the least cost mix of resources – based on an assessment of all relevant costs and benefits – for meeting reliability requirements.
3. **Risk minimization**: Another core objective of any IRP framework should be to minimize risk – both reliability risk and economic risk – of meeting reliability requirements. Economic risk is related to and should be reflected in cost-effectiveness assessments.
4. **Alignment with other governmental policy objectives**: IRP rules should lead to investments that are aligned with governmental policy objectives. If they do not, ratepayers will either pay additional costs in the future – and ultimately higher total costs – to re-align system investments with policy and/or incur unnecessary risk. Where possible, impacts on other policy objectives should also be reflected in cost-effectiveness assessments.
5. **Equitable consideration of all viable resource options**. To ensure that costs and risk are minimized, all resource options that could address reliability needs – both demand and supply options – must be considered and evaluated. Moreover, all of the costs and benefits each resource offers (not just those associated with T&D reliability) must be considered and

[9] Body of Knowledge on Infrastructure Regulation (http://regulationbodyofknowledge.org/glossary/i/integrated-resource-planning-irp/).

evaluated. Though this might be considered more of a "how" to structure the framework than an outcome "goal", is it so central to successful IRP that it merits calling out.

6. **Alignment of utility interests with IRP goals**: If the utility cannot be sufficiently profitable while pursuing the other framework goals (above), achievement of those other goals will be undermined. Thus, utilities should have a financial incentive to implement the non-pipe solution where it is the most cost-effective option. Again, though this could be considered more of a "how" to structure the framework to meet other "goals", it is so central to achievement of those goals that it merits calling out.

4.1.2 Consistency with Other Gas Planning and Investment Frameworks

Conceptually, it would be ideal if all gas utility resource investment decisions – at least at a high level (i.e., details could be addressed elsewhere) – were part of a single integrated resource planning process. That would ensure that all investment decisions are optimized for all of the needs of the system. To the extent that there are separate processes governing different kinds of utility system investment decisions, it is important that the different frameworks used to make those decisions – including T&D reliability investments decisions, system-wide DSM investment decisions, carbon emission reduction investment decisions, the setting of interruptible rates and others – are consistent with each other in key ways. For example, they should all consider the same policy objectives and use the same cost-effectiveness test – including the same categories of costs and benefits, the same approach to estimating values for each category of impacts, and the same discount rate. It makes no sense to care about local economic development impacts in one type of decision and not care about them at all in another. Similarly, it makes no sense to care about the value of helping customers avoid energy costs with efficiency programs in one context and not care about that value in another. It also makes no sense to assign a high value to a tonne of reduced carbon emissions when considering the merits of investing in renewable gas, a lower value when considering the merits of system-wide efficiency programs and no value when considering the merits of investing in a non-pipe solution to defer a T&D investment. Nor does it make sense to use different discount rates to reflect the time value of money when assessing the cost-effectiveness of different kinds of utility investment decisions – the net present value of achieving one m^3 of gas savings or one tonne of greenhouse gas emission reduction per year for the next twenty years cannot be different for different investment decisions.

To be sure, some of the actual cost or benefit *values* used in cost-effectiveness assessments can be different when the nature of the investment causes those values to be different. For example, some geotargeted efficiency measures may cost more to deliver in a geotargeted manner than in a system-wide program (because of differences economies of scale and or delivery strategy). Of course, the value of avoided T&D will be greater in a geotargeting context than for system-wide DSM. However, the cost-effectiveness analysis framework should be the same and the methodologies used to estimate values of costs and benefits should be the same or at least consistent with each other.

4.2 Issue #2: IRP Process

4.2.1 Planning Horizon

4.2.1.1 Summary of Key Points

- The amount of lead time needed to consider and effectively deploy non-pipe solutions will vary depending on the magnitude of the load reduction required and the size of the geographic area that needs to be addressed.
- The potential to defer T&D investments can be very project-specific, depending on the size of the load reduction required, the timeline over which it needs to be acquired, the economic value of the T&D deferral, and a variety of factors affecting both the magnitude of the load reduction potential and the cost of acquiring it (e.g. customer mix, local demographics, age and condition of building stock).
- In addition, there needs to be a mechanism that stakeholders and the Board can utilize to trigger formal Board 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).

4.2.1.2 Lead Time Needed

The amount of lead time needed to consider and effectively deploy a non-pipe solution will vary depending on the magnitude of the load reduction required (as a percent of current annual sales) and the size of the geographic area that needs to be addressed. The larger the load reduction needed, the longer the lead time required. For example, less lead time would be needed to reduce forecast gas consumption by 5% than would be needed to reduce it by 10% in the same geographic area. Similarly, all other things being equal, the larger the geographic area served by the T&D facility being addressed, the longer the lead time required.

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%.[10]

[10] Neme, Chris and Jim Grevatt (Energy Futures Group), *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*, published by Northeast Energy Efficiency Partnerships, January 9, 2015, p. 64.

4.2.1.3 10-Year Needs Forecast

Some non-pipe solutions – particularly those requiring either larger percentage reductions in load in a geographic area or those for which deployment may be for a very large geographic area – may require more than five years for planning and deployment, as well as to allow for adjustment to strategy in response to market feedback. While utilities may not typically forecast needs more than five years into the future, there is no reason they cannot. While longer-term forecasts may be less certain, that uncertainty can be reflected in the planning process. For example, if it is determined that a T&D need forecast to be seven years into the future could be cost-effectively met with a non-pipe solution, the non-pipe solution could be launched and then halted or slowed if changes to the forecast in subsequent years alter the expectation of whether or when a T&D need would occur. In other words, launching a non-pipe solution for a less certain need would be effectively purchasing an "option" for a lower-cost solution should the need become more certain over time. As previously noted, many efficiency measures and possibly other non-pipe resource options will be cost-effective even without consideration of the value of deferred T&D investments. In such cases, the investments in non-pipe solutions should be considered "no regrets" investments. For those non-pipe alternatives that are only cost-effective when the value of T&D investment deferral is considered, the risk of acquiring them unnecessarily can be monetized and compared to the risk of not acquiring them and purchasing the more costly T&D solution if it turns out it is needed.

It should be noted that it is also common for electric utilities to forecast T&D needs only five years into the future. When non-wires solutions were not being considered, there was perhaps less value in forecasting further into the future. However, in jurisdictions which are seriously considering IRPAs, longer-term forecasts are common. For example, ConEd has been forecasting T&D investment needs at least 10 years into the future.[11] Vermont's transmission and distribution utilities are required by statute to forecast needs at least 10 years into the future and have been forecasting them 20 years into the future.[12] It is worth noting that Vermont's statutory requirements were put in place following a proceeding in which regulators approved a large transmission project but expressed frustration that the transmission utility did not consider alternatives early enough in the process to make them truly viable options.[13,14]

As discussed in Section 5.4.5, electric peak loads are comprised of a larger number of end-uses than gas peaks; also, no one electric end-use contributes to electric peak demand nearly as much as space heating contributes to gas peak demand. The need to consider potential changes in demand from a more varied array of end-uses means electric forecasts of future peak demand ought to be more difficult

[11] Gazze, Chris and Madlen Massarlian, "Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions", in *Public Utilities Fortnightly*, August 2011, pp. 36-41.
[12] Neme and Grevatt, p. 53.
[13] Ibid., p. 47
[14] It is worth noting that the Board has expressed similar concerns itself regarding past Enbridge T&D project proposals. For example, in its order on the Bathurst Reinforcement Project, the Board stated that Enbridge's consideration of non-pipe alternatives "was not appropriate", that Consideration of the DSM alternative should have been an ongoing process starting at the early stages of project identification…" and that "assessment of the DSM alternative should have been completed before Enbridge sought internal approval of the Project." (OEB, *Decision and Order*, EB-2018-0097, January 3, 2019)

to develop and less certain than gas forecasts. Put another way, if it is possible to forecast electric peak demands to identify T&D infrastructure needs ten years into the future, it should be possible to do the same for gas.

Figure 3 (on the following page) presents the various distribution constraints identified by Green Mountain Power in a 2014 forecast, several of which were more than ten years into the future. Particularly when made public, this kind of summary – including a list of each forecast T&D need, the estimated year of the need, whether the need is load growth related, and the current status of planning for the need – provides transparency with regard to utilities' assessments of needs, confidence that opportunities to consider and deploy IRPAs are not being missed, and opportunities for non-utility parties to provide timely input into the planning process. It is a model that the Board should consider requiring Enbridge to follow, together with requirements to engage with stakeholders in reviewing the list, its underlying assumptions and various steps in assessing alternatives where appropriate (see discussion in Section 4.2.4). In addition, there needs to be a mechanism that stakeholders and the Board can utilize to trigger formal Board 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).[15]

[15] It is beyond the scope of this report to characterize such a mechanism in the context of current Board practice. Accordingly, the Board may wish to consider whether existing avenues for such timely intervention are adequate to address this concern.

Figure 3: Green Mountain Power 2014 Forecast of Distribution System Needs[16]

Constraint	Load Growth related (Y/N)	MW Need	Year of need	Zonal identified MW available (potential study)	Further screening (Y/N)
Susie Wilson Substation Area	Yes		2037		No Continue to Monitor
Wilder - White River Junction Area	Reliability and Load Growth		2015		No
Waterbury	Reliability		2015		No
Winooski 16Y3 Feeder	No		2015		No
Hinesburg	Yes		2016		No
Dover Haystack	Yes		2015		No
Stratton	Reliability		2015		No
St Albans	Reliability and Load Growth		>10 years		Reliability Plan filed 4/2/14, Continue to Monitor
Miton	Yes		>10 years		No Continue to Monitor
Brattleboro	Yes		>10 years		No Continue to Monitor
Southern Loop	Yes		>10 years		No Continue to Monitor
Danby	Reliability and Load Growth		2016		No
Granite-Whetmore	Asset Management		2016		No
South Brattleboro	Reliability		2016		No
3309 Transmission	Reliability		2014		No Continue to Monitor / Refine the analysis
Rutland Area	Reliability		Existing Constraint		Reliability Plan filed 4/2/14, additional analysis required
Windsor Area	Reliability		2017		No

4.2.2 Need for Localized Assessment

4.2.2.1 Summary of Key Points

- The potential to defer T&D investments can be very project-specific, depending on the size of the load reduction required, the timeline over which it needs to be acquired, the economic value of the T&D deferral, and a variety of factors affecting both the magnitude of the load reduction potential and the cost of acquiring it (e.g. customer mix, local demographics, age and condition of building stock).

- The rules governing consideration of non-pipe solutions should require consideration of all such local factors.

- Any criteria for screening out consideration of non-pipe solutions must be very carefully designed to ensure that they would not rule out potentially viable projects. That means erring on the side of greater latitude when there is uncertainty (e.g. about the size of load reduction that could be achieved), as what is possible in one location may be very different from the "average", particularly when multiple IRPA options are considered together.

[16] *Ibid*, p. 53.

4.2.2.2 Discussion

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."

There are several problems with this conclusion:[18]

- **The maximum peak demand savings potential per year does not have to be equal to or greater than current peak demand growth rates for non-pipe solutions to merit investment**. If peak demand savings potential is lower than annual peak demand growth rates, the non-pipe solution may not be able to *eliminate* the need for the T&D investment, but it may be able to defer it. Consider a geographic area with peak demand growth rates of 2.4% per year and a T&D capacity investment need that is five years out. If efficiency savings of 1.2% per year is achieved, it will push the need out another five years by cutting load growth in half. The question is simply whether that amount of deferral is cost-effective. Furthermore, pushing the need out five extra years allows for forecasts to be revised, particularly in the context of future greenhouse gas emissions regulation.
- **There are resources other than energy efficiency that can be deployed**. ICF's analysis implicitly assumes that only energy efficiency is available to defer T&D investments. It ignores the potential for demand response, electrification, and other resources to play a role (in combination with geotargeted efficiency). See the discussion in Section 4.2.3.
- **The nature of the T&D need can vary by location.** Perhaps most notably, for large transmission projects, peak day consumption may be more important than peak hour consumption. That changes the nature of estimates of savings potential, particularly for heating controls that lower total daily consumption but may not lower the peak hour demand that matters for distribution peaks. Depending on the mix of customers, it is even conceivable that the peak hour of greatest interest would differ from one part of the system to another. For example, an area dominated by residential customers may have peak demands at different times than an area dominated by commercial buildings (potentially also depending on the type of commercial buildings).[19]
- **The magnitude of IRPA opportunities will vary by location.** ICF's estimated maximum achievable peak efficiency potential of 1.2% per year is an *average* value for the entire province.

[17] ICF Canada, Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, submitted to Enbridge Gas Distribution, Inc. & Union Gas Limited, May 18, 2018, p. 137. Note that I have expressed concerns about conservatisms build into the MPS estimates of achievable savings potential. Since the MPS is only tangentially relevant to this proceeding. I am not reiterating them here.
[18] In addition to the points below, it is unclear why ICF calculated percent of facility expansion investment by capacity instead of by capital cost. Expressing potential as a percent of planned capital cost would provide a better insight into the potential value of gas non-pipe solutions.
[19] ICF provides only a combined residential/commercial hourly peak day load shapes (e.g., ICF 2018, p. 66).

> While a province-wide average could be fairly representative for very large transmission-level projects, it may not be for more localized projects. For one thing, the mix of residential, commercial and industrial loads will vary. For another, even within the residential, commercial or industrial sectors, the age of the building stock (older buildings tend to be less efficient and offer more savings opportunities), customer demographics (e.g. income levels, which can affect both savings potential and the cost of acquiring it), industry types, historical levels of efficiency program participation and other factors that affect IRPA potential can vary substantially from one geographic area to another. I learned this first-hand through work with Consumers Energy (Michigan) on its first pilot electric non-wires solution project. The project was designed to defer a potential upgrade to the Swartz Creek substation. 63% of the electricity consumption downstream of the substation was residential and much of that was low or lower income. Of the 37% of consumption by businesses, half was to two customers: the school district (which had comparatively low summer peak demand) and a large new grocery store that likely had limited savings opportunities. Put simply, though the pilot had some notable success with increasing participation in efficiency programs through targeted marketing efforts, the customer base had lower than average peak savings potential which made achieving large peak demand savings more challenging than it would be in other areas. By design, Consumers Energy's next pilot is focusing on a substation that has a much more diverse set of customers, income levels and peak loads.[20]

Put simply, the potential to defer T&D investments can be very project-specific, depending on a range of factors. The size of the load reduction required, the timeline over which it needs to be acquired, and the economic value of the T&D deferral are obviously all important. However, some other factors may be less obvious but equally important. In particular, the magnitude of the load reduction potential, the cost of acquiring it and the timeline over which it can be acquired can vary significantly from one geographic area to another based on whether peak day or peak hour needs are paramount, the mix of customers, and other local factors. Thus, it is important that rules governing consideration of non-pipe solutions require consideration of such factors.

4.2.3 Simultaneous Consideration of All IRPA Resource Options is Required

4.2.3.1 Summary of Key Points

- 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.
- The Gas IRP framework should require that all such measures be considered – individually and in combination with each other – with the least cost mix of such measures selected for investment.

[20] Neme, Chris (Energy Futures Group) and Mark Luoma (Consumers Energy), "Consumers Energy Non-Wires Solution Pilots: Results from Consumers Energy/NRDC Collaboration", presented at 2019 ACEEE Efficiency as a Resource Conference, Minneapolis, MN, October 16, 2019 (https://drive.google.com/drive/folders/1xGMk0-kzOVP1OxIqrlyDHuARFBHFvgHy)

4.2.3.2 Discussion

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]

4.2.4 Stakeholder Engagement

4.2.4.1 Summary of Key Points

- 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.
- The Board and stakeholders should be informed and included throughout the IRP process. If that does not occur, planning assumptions and decisions will only be tested in leave to construct hearings, at which point it may be too late to select a non-pipe solution that might require a longer lead time.
- 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.

[21] Air source heat pump technology has advanced dramatically in recent years, particularly in the ability to efficiently provide heat at very low temperatures. In fact, there are currently thousands of air source heat pump models that meet cold climate specifications established by the Northeast Energy Efficiency Partnerships (https://ashp.neep.org/#!/product_list/). Those specifications require heat pumps to be able to produce their full nameplate heating capacity at a coefficient of performance (COP) of 1.75 or better when it is 5° F (-15°C) outside. Moreover, the cold climate performance is improving, with one of the major manufacturers about to release a new line that can produce heat at nameplate capacity at -5° F (-21°C) (personal communication with Kevin DeMaster, Manager of Utility and Efficiency Programs for Mitsubishi Electric Trane HVAC, October 2020). For the relatively few hours of winter when such cold climate heat pumps cannot fully meet heating loads, back-up systems – including electric resistance heating coils in the air handler of a centrally ducted heat pump – can be automatically deployed.

[22] One of the lessons learned from a 2015 report on the use of efficiency as an electric T&D resource was that the integration of efficiency with other distributed resources will be "increasingly common and important" (Neme and Grevatt, p. 58). While the peak demand reduction potential of non-efficiency IRPAs may be different for gas and electric utilities, there is no reason to not consider that potential for either fuel.

[23] This assumes impacts relevant to all policy objectives are monetized and included in the IRP economic analysis.

4.2.4.2 Discussion

In its evidence in this proceeding, Enbridge presents a proposal for "stakeholdering". That proposal has three components:

1. **Gathering of Stakeholder Engagement Data and Insight**. Though it is not entirely clear, this component appears to largely be about outreach from the Company to collect market and other data for its service territory that may be relevant to its planning.
2. **"Stakeholder Days"**. Again, though not much detail is provided, this component appears to be a mechanism through which the Company presents what it is doing on IRP and participating stakeholders may ask questions and provide input.
3. **IRPA project geographically-specific engagement**. This appears to be a mechanism through which Enbridge can collect information relevant to specific non-pipe solutions projects that it is analyzing and considering.

While all of these forms of stakeholder engagement may make sense, they collectively fall short of what should be considered industry best practices. Enbridge's proposal appears to be mostly about either (A) collecting data to inform its planning; and (B) periodically presenting what it is doing with IRP and answering questions. In my experience, 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. Such involvement should be at all key points in the analytical process – including forecasting of needs, identification of which needs are driven by peak demand-growth, scoping of alternatives to be considered (where appropriate), reviewing draft cost-effectiveness analyses, developing deployment plans, developing monitoring and evaluation plans, tracking progress and discussing strategy adjustments where needed. The utility needs to both develop initial draft assumptions and ultimately "own" final decisions on each of these steps of the process, as it is the entity on the hook for both costs and reliability of service. However, the utility also has a vested financial interest in investing in new capital projects, so a more structured stakeholder process that requires consideration of other perspectives can help to ensure that investment decisions are truly optimized relative to reliability, cost minimization, and other policy objectives. Other parties can have expertise and insights into key planning assumptions and analytical practices from which the Company and ratepayers could benefit. In addition, this greater depth of engagement brings transparency to the process and should reduce litigation costs.

One model that is worth considering is Vermont's System Planning Committee (VSPC). Though set up to address electric system needs, the process is equally applicable to gas. The VSPC includes representatives from all the electric utilities in the state as well as representatives from suppliers of IRPAs (e.g. efficiency organizations and renewable energy companies) and representatives of the public (representing residential and business ratepayers, environmental groups and regional planning organizations).[24] The state's regulator, analogous to the OEB, appoints the IRPA suppliers and public representatives. A Chair is elected at the beginning of each year from among the voting members. The VSPC meets at least quarterly to identify potential for and consider non-wires solutions. The VSPC charter states that the Committee is a "collaborative body" whose purpose is to "ensure full, fair, and

[24] https://www.vermontspc.com/about/membership

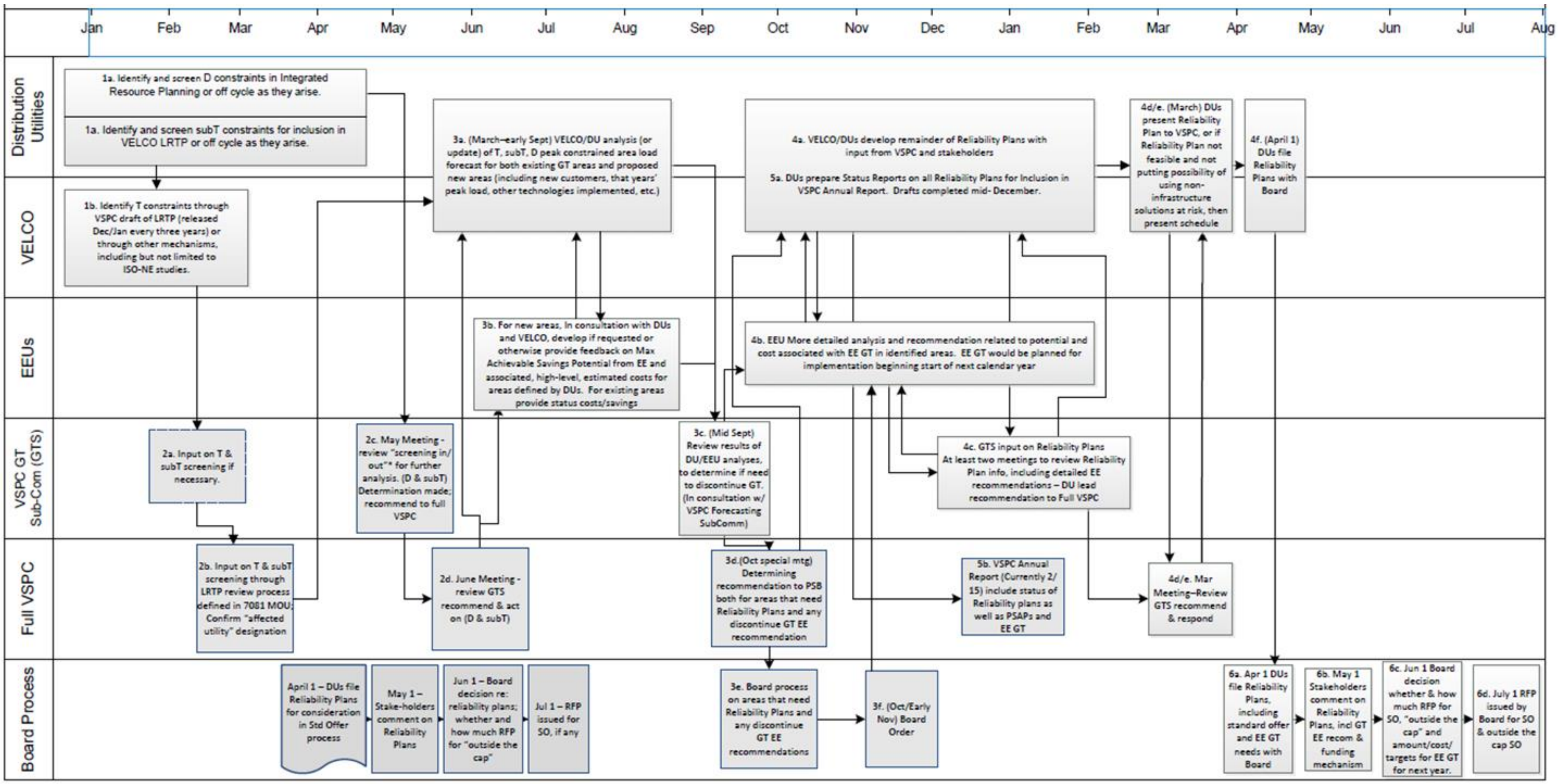
timely consideration of all societally cost-effective solutions to resolve electric grid reliability issues" and which has the following nine objectives:[25]

1. *"Collaborate with and provide formal input to VELCO[26] in the development and review of the Vermont Long-Range Transmission Plan (LRTP) as established in the Docket 7081 Memorandum of Understanding (MOU) and such other processes as may be adopted.*
2. *Jointly review known reliability issues (transmission, sub-transmission and distribution) at least once annually to encourage shared insight and facilitate collaboration among electric grid stakeholders.*
3. *Carry out the functions assigned to the VSPC for screening and analysis of Non-Wires Alternative potential as established in the MOU and the Docket 7874 Screening Framework.*
4. *Enhance transparency and public engagement in electric system planning.*
5. *Provide a forum for the discussion and analysis of the impacts of emerging trends on the behavior of Vermont's electric energy load, including electrification of different end-uses, the installation of storage capacity, demand response measures, distributed generators, merchant projects, and others.*
6. *Seek consensus on the Vermont load forecast to support LRTP development.*
7. *Monitor the installation and impacts of Distributed Energy Resources (DER) to provide broadly shared insight about DER integration and support the development of tools and processes needed to plan for and maintain reliability in an increasingly modernized and intelligent electric grid.*
8. *Provide a forum for utilities and partners to share plans for managing load and infrastructure, and allow for peer-to-peer learning through discussion of shared experiences.*
9. *Maintain regular communication with ISO New England to increase Vermont stakeholder and ISO New England understanding of mutually relevant issues, such as forecasting and grid management."*

A detailed process map of the VPSC consideration of non-wires solutions – including roles of the different parties – is presented in Figure 4.

[25] https://www.vermontspc.com/library/document/download/5641/VSPC_Charter_20160720.pdf
[26] VELCO is Vermont's statewide electric transmission utility. It is jointly owned by all of the state's distribution utilities.

Figure 4: Vermont System Planning Committee Geotargeting Process Map



*"Screening" refers to the use of the Docket 7081 screening tool for bulk and predominantly bulk transmission and the Docket 6290 screening tool for subtransmission and distribution issues to determine their potential to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). An issue is "screened in" if it has potential for a non-wires solution and therefore requires a Reliability Plan, and "screened out" if no potential is found and, therefore, no Reliability Plan is required.

Key to abbreviations

D	distribution	LRTP	VELCO Long-Range Transmission Plan
DU	distribution utility	PSAP	project-specific action plan
EE	energy efficiency	RFP	request for proposal
EEU	energy efficiency utility	SO	standard offer
GT	geographic targeting	subT	subtransmission (subsystem)
GTS	VSPC Geotargeting Subcommittee	T	transmission (bulk/predominantly bulk)
		VSPC	Vermont System Planning Committee

4.3 Issue #5: Industry Best Practices

There are numerous lessons that can and should be applied from industry experience with deployment of both gas and electric distributed energy resources, including – but not limited to – lessons from analysis and deployment of gas and electric IRPAs in other jurisdictions. Many of these lessons are relevant to other specific policy issues flagged by the Board for input in this proceeding. Such lessons are addressed in those other sections of this report. This section addresses only two topics that do not fit as naturally under the other issue headings: (1) the value of more granular forecasting of system-wide efficiency program as well as efficiency code and standards impacts on specific components of the gas T&D system; and (2) the value of "learning by doing" through pilot IRPA projects.

4.3.1 More Granular Forecasting

4.3.1.1 Summary of Key Points

- 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.

4.3.1.2 Discussion

In its January 2018 Transition Plan, Enbridge stated that infrastructure planning is based on long-term forecasts in which "historical gas throughput is used as a basis to predict future consumption…"[27] The Company suggests that such forecasts implicitly account for naturally-occurring conservation (including savings from equipment turnover), future DSM program savings and future savings from new building codes and product efficiency standards. The rationale for that conclusion appears to be that historic levels of naturally-occurring conservation, previous years' DSM savings and savings from past codes and standards are equal to what each of those effects will be in the future. While that may be true – or close to true – it is also possible that it will not be the case.

First, changes in codes and standards can be "lumpy", with much bigger or more impactful changes in some years than in others. For example, the recent federal standard requiring that all gas furnaces have a minimum AFUE efficiency rating of 95% (up from the previous 90%) could have a significantly bigger impact on peak gas consumption than changes in other product efficiency standards in recent years.[28] Indeed, that standard change could, by itself, lead to a decrease in peak demand from existing single family homes by on the order of 0.2% per year.[29] That impact would be felt disproportionately in

[27] ICF 2018, Appendix A.
[28] The previous 90% efficiency standards for furnaces had been in place since 2010.
[29] This is a crude estimate based on the assumption that the average new furnace (absent utility efficiency programs) will be 5% more efficient than the average new furnace purchased prior to the new standard, that

geographic regions or parts of the distribution system where residential customers play a larger role in driving peak demands.

Similarly, utility efficiency programs evolve – both in terms of total savings being achieved and in terms of what programs and measures are providing those savings. For example, if Enbridge was expecting to get the same amount of total savings in the future as in the past, but was expecting more of the savings to come from residential customers through building envelop improvements and less from industrial customers, the net effect will be greater peak demand reductions in the future than in the past because residential building envelop savings are "peakier" – i.e. they provide more peak savings per annual m^3 of gas saved than industrial customers. The obverse would also be true. Just as importantly, the geographic locations where the peak savings were occurring would be different – e.g., more (or less) in residential areas and less (or more) in regions where industrial activity is more concentrated.

Best practice in forecasting would adjust for at least major changes in codes and standards that are materially different than in the past. It would also adjust for future expectations regarding how DSM programs will evolve. It is important to note that such evolution is not just relative to the year before the forecast. Because the forecast is (presumably) based on peak demand changes over a number of historic years, what is relevant is how future DSM programs will be different from past programs over the entire historic period being referenced in the forecast.

Con Ed is perhaps the most notable example of a utility adjusting localized forecasts for its expected mix of future DSM programs and measures. In the early 2000s – long before it began rolling out smart meters – Con Ed developed a methodology for forecasting the geographic distribution of energy savings and the related impacts on peak demands in each of its more than 90 distribution networks. The Company explained this process in a 2011 Public Utilities Fortnightly article:

> *"Our approach uses historical energy consumption patterns and demographic data, by service class and network, to allocate the energy savings expected from various efficiency programs operating in our service area to individual networks. Then, composite load curves for each efficiency program are applied to calculate the coincident peak demand reductions at each network's local peak."*[30]

In the same article the Company reported that this approach to forecasting efficiency program impacts separately for each distribution network area reduced its projected capital expenditure for load relief projects by more than $1 billion over ten years.[31]

To be sure, this kind of capability for refining forecasts for many different sub-components of the distribution system requires a financial investment and takes time to develop. It would not be reasonable to expect Enbridge to be able to instantaneously apply Con Ed's level of sophistication to forecasting localized impacts of its efficiency programs. However, it would be reasonable to expect the Company to begin to develop such capability with the expectation that it would be able to use it in the

---

approximately 5% of furnaces are replaced each year (i.e. an average life of twenty years), that the vast majority of single family homes heating with gas have a furnace and that 90% of gas peak demand from such homes is from space heating (0.05 * 0.05 * 0.90 = 0.00225 or 0.225%)

[30] Gazze and Massarlian 2011, p. 36.

[31] *Ibid*.

future. Also, in the interim, Enbridge should be able to at least make some high-level adjustments to localized peak demand forecasts for substantial changes to efficiency programs and/or major new codes or product efficiency standards. For example, because its future system-wide efficiency programs are expected to achieve significantly greater savings in the near future than were realized in the past several years, Consumers Energy (Michigan) has recently made adjustments to its forecast of peak demands on a substation that is the subject of a pilot electric non-wires solution project on which I am working with the utility.[32]

4.3.2 Value of Pilot Projects

4.3.2.1 Summary of Key Points

- There are limits to what can be learned about gas IRP and non-pipe solutions from just studying what other jurisdictions have done.
- 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 geotargeting efficiency and other IRPA resources, evaluating the impact such geotargeting is producing, and valuing such impacts and other key aspects of non-pipe solutions.
- The Board should require Enbridge to begin planning to deploy two such pilot projects in 2021 with actual deployment of IRPA resources beginning no later than January 2022.
- the Board may wish to consider establishing a collaborative utility-stakeholder process to design the pilots, select the target areas, establish monitoring and evaluation plans, hold regular check-ins on progress and develop modifications to plans in response to market feedback and other lessons learned.

4.3.2.2 Discussion

One of the key lessons from jurisdictions with little or no experience with IRP and/or consideration of alternatives to traditional T&D investments has been to launch pilot programs to field test IRP planning, geotargeted deployment of efficiency and demand response programs, monitoring and evaluation plans, etc. Indeed, most (if not all) jurisdictions that are pursuing IRPAs started with pilot projects.[33]

Pilots serve a couple of functions. First, they will illuminate issues to consider in ways that review of efforts in other jurisdictions cannot. It is just not possible to ascertain all one would benefit from knowing from reviewing reports on or even interviewing of individuals directly involved with the planning and deployment of projects in other jurisdictions. Reports cannot document every experience of potential interest. Interviews cannot be long enough or ask all the right questions necessary to extract all potentially useful information. There is just no substitute for “learning by doing”. Second, pilot projects will give utility staff, particularly system planners, the kind of “real world” experience they need to gain confidence in the role IRPAs can play in meeting system reliability needs. Third, pilots can be set up to learn multiple lessons at once. For example, for Maine’s Boothbay Harbor pilot non-wires project, a decision was made to intentionally deploy multiple distributed resource types – energy

[32] Knowledge from personal involvement in the project.
[33] Neme and Grevatt.

efficiency, demand response, distributed generation, storage – even if a “least cost” approach would have been much narrower in scope.[34] The idea was that broader experience gained would have value in the future.

In its order in the GTA pipeline case (EB-2012-0451), the Board stated that it “accepts that targeted DSM programs and/or rate design options might in some circumstances mitigate the need” for one part of Enbridge’s infrastructure investment proposal, but that uncertainties about such alternatives, coupled with the timing of the need, led it to conclude that the Company’s infrastructure project should be approved.[35] The order went on to state that “further examination of integrated resource planning for gas utilities is warranted”, that a range of related issues – including the potential for targeted DSM and rate designs to reduce peak demand – should be examined, and that in the future utilities would be expected “to provide a more rigorous examination of demand-side alternatives…in all gas leave to construct applications.” It has been nearly seven years since that order was issued. In the intervening period, the province’s gas utilities have commissioned several studies of gas IRP. In 2017, they also launched what they called “in-field case studies”. Specifics on the scope of work for those case studies and their results are not currently available.[36] However, the Companies’ brief description of their purpose - to improve the utilities’ “understanding of the impacts of broad-based DSM programs and technologies on peak hour demand”[37] – suggests that they are not pilot tests of an non-pipe alternatives project designed to defer an infrastructure investment (though they may help inform design of future projects).

Given all the study that has already been done and the questions that the utilities continue to raise regarding the uncertainties that need to be addressed with regard to non-pipe solutions, there would be significant value to launching a couple of pilot non-pipe solution projects. To ensure that the pilots address all key issues of concern to the satisfaction not only of the utilities, but also the Board and other stakeholders, the Board may wish to consider establishing a collaborative utility-stakeholder process to design the pilots, select the target areas, establish monitoring and evaluation plans, hold regular check-ins on progress and develop modifications to plans in response to market feedback and other lessons learned.

Such discussions could begin with consideration of approaches taken to pilot gas non-pipe solution pilot projects in other jurisdictions. For example, Northwest Natural Gas has partnered with the Energy Trust of Oregon to launch a pilot non-pipe solutions project in Creswell and Cottage Grove, Oregon this year. That project is designed to test different strategies for increasing efficiency program savings in geotargeted areas, develop options for management issues that can arise when layering geotargeted

[34] Neme and Grevatt, pp. 35-42.
[35] EB-2012-0451 Order, January 30, 2014.
[36] GEC and ED requested that Enbridge provide this information prior to the drafting of this report. However, the information has not yet been provided.
[37] Enbridge and Union “Transition Plan”, January 2018 (Appendix A to ICF 2018)

efficiency programs on top of system-wide ones, and develop cost and timing estimates of gas peak hour demand reductions.[38]

4.4 Issue #6: Screening Criteria and Methodology For Comparing Alternatives

4.4.1 Pre-Screening Criteria

4.4.1.1 Summary of Key Points

- T&D projects required to address safety concerns are generally not candidates for non-pipe alternatives. However, there can be exceptions that merit analysis.
- Focusing initially on projects with at least a 3-year lead time for consideration of non-pipe solutions is reasonable. However, this criterion should not be applied rigidly as there may be exceptions. Moreover, the criterion should be revisited once there is more experience with non-pipe solutions.
- The ability to leverage municipal public road, water or other public works investments is not justification for proceeding with T&D investment projects without consideration of alternatives. Non-pipe solutions can still be lower cost and lower risk.
- 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 the connection. 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).
- Absent a government mandate for them (either individually or under conditions that may apply to specific communities or categories of communities), gas line extensions should not be excluded from consideration. There may be cases where policy goals such as access to low-cost energy could be achieved more cost effectively and with less risk than through gas service expansion.

4.4.1.2 Enbridge's Proposal

In its October filing, Enbridge suggests that non-pipe alternatives should not be considered if any of the following five criteria were applicable:

1. **Safety**. The Company suggests non-pipe alternatives are not applicable and should not be considered if a T&D investment is required in order to address customer safety.
2. **3-Year Lead Time**. The Company suggests that any T&D needs that must be met in less than three years are not viable candidates for non-pipe solutions, presumably because of the lead

[38] Energy Trust of Oregon, "NW Natural and Energy Trust of Oregon GeoTEE Targeted Load Management Project Implementation Plan: Creswell and Cottage Grove", 4/3/2020. Also, personal communication with Fred Gordon, Oregon Energy Trust, 11/17/20.

time assumed to be required to plan, launch and acquire enough savings from non-pipe solutions.

3. **Ability to Leverage Non-Utility Investments**. The Company calls this "project-specific considerations". It suggests that it should be able to proceed with T&D investments when it is possible to leverage municipal infrastructure development. Presumably, the rationale behind this criterion is that the T&D investment will be lower cost if it can leverage other investments such as road works or water mains replacements.
4. **Individual Customer Demands for Gas**. Enbridge suggests that when a customer wants access to gas and is willing to either pay a "Contribution in Aid of Construction" or to contract for long-term firm services, then the Company should be able to make the T&D investment and not consider non-pipe solutions.
5. **Community Expansion and Economic Development**. The Company suggests that projects that are "driven by policy" with the desire to access gas as a way of bringing heating costs down can be pursued without consideration of non-pipe alternatives.

4.4.1.3 Discussion

While some of Enbridge's proposed criteria are generally reasonable, all require some caveats and some are not at all reasonable. Each is addressed below.

1. **Safety**. Enbridge's safety criterion is generally reasonable. Non-pipe solutions typically cannot be viable alternatives to T&D investments made to address safety concerns. However, there can be exceptions. For example, if the Company were to determine that it needs to embark on an expensive plan to replace large amounts of old pipe for safety reasons, there could be cases in which it is possible to eliminate portions of such costs by completely electrifying buildings in a given neighborhood. Downsizing a pipe via DSM could also be cost-effective in some cases, such as for large projects close to the threshold between pipe sizes. The Company should be required to consider such cases.
2. **3-Year Lead Time**. As discussed in Section 4.2.1.2, the lead time required for successful planning and deployment of non-pipe solutions will vary depending on the size of the geography, how many customers are involved and the magnitude of the load reduction required. As the Company is really just getting started with consideration of non-pipe solutions, initially focusing on projects with a lead time of at least 3 years is reasonable. However, this screening criterion should not be applied rigidly as there may be exceptions.[39] However, as the Company gains more experience with non-pipe solutions, that criterion should be revisited and perhaps married to the size of the load reduction required as has been done with non-wires pre-screening criteria in other jurisdictions.[40]
3. **Ability to leverage non-utility investments**. This proposed criterion is problematic. The ability to leverage municipal road work and/or water main replacement can have two effects: (1) it

[39] For example, the Company may propose projects for which the "need" – or at least the portion of the need that is driving a less than three-year lead time – is economic (e.g., enabling access to lower cost sources of gas) rather than reliability-driven. In such cases, there is no reason to pre-screen out consideration of non-pipe alternatives because. The economic trade-offs between pipe and non-pipe solutions – however quickly they can be planned and ramped up – can be considered as part of cost-effectiveness analysis.

[40] Neme and Grevatt, 2015.

can lower the cost of the traditional T&D investment; and (2) it can accelerate the timing of the traditional T&D investment (i.e. before it is needed). Such changes cannot be assumed to preclude the possibility that a non-pipe solution would be economically preferable. In fact, if the timing of the T&D investment is accelerated enough (relative to its actual need), the net present value of the cost of the T&D solution could be even higher as a result of leveraging municipal public works projects. Moreover, as discussed in Section 4.4.2.4.2, climate policy goals create a very real risk that gas T&D investments could become stranded assets. The bottom line is that cost-effectiveness analysis of pipe and non-pipe solutions should still be performed.

4. **Individual Customer Demands for Gas**. This proposed criterion is too vague. If Enbridge means that it should be able to simply extend a gas line to connect a new customer, that is reasonable provided that the customer would effectively be paying for the entire cost of the connection. However, if supplying gas to a new large customer requires upgrading the capacity of elements of the T&D system that serve many other customers, then the utility should be required to consider non-pipe alternatives. 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).
5. **Community Expansion and Economic Development**. This criterion is problematic. Given Canadian climate policy goals, the related need to essentially eliminate fossil gas consumption by 2050 (and be on a path to that goal now), and the 50-year period over which gas T&D investments may be depreciated, extending gas lines to new communities is highly problematic and risky. At a minimum, such expansions should not be permitted unless either (1) mandated by government; or (2) Enbridge can demonstrate that (A) they would lower total long-term (e.g., over 30 years) energy costs for customers in the Community, relative to alternatives (including electrification), and including consideration of at least a significant probability of having to replace increasing amounts of fossil gas with much more expensive renewable gas; (B) the Community is prepared to pay for the entire cost of the gas line extension; and (C) existing ratepayers will never have to pay for the capital costs of the line extension, even if demand for gas drops dramatically in response to future climate policy regulations (i.e. with the risk born by either utility shareholders and/or the Community receiving the line extension).

4.4.2 Benefit-Cost Analysis

4.4.2.1 Summary of Key Points

- Any cost-effectiveness analysis of any gas utility investment options – including pipe and non-pipe solutions – must include all gas utility system impacts, including avoided gas commodity costs, avoided gas storage costs, avoided carbon taxes and effects on market clearing prices for gas (e.g., market price suppression effects of efficiency programs).

- Cost-effectiveness analyses of any gas utility investment options – including pipe and non-pipe solutions – should also account for all impacts related to government policy goals.

- 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.

- In the interim, the "TRC+" test – which implicitly assumes participant impacts and environmental impacts are relevant to provincial policy goals – should be the foundation of cost-effectiveness assessments of pipe and non-pipe alternatives. However, consistent with the principle that all utility system impacts should be included, application of the test should include the effects on market clearing prices for gas that have historically not been included in Ontario utilities' use of the test.[41]
- Economic risk should always be quantified – and ideally monetized – as part of IRP analyses. That should be the case regardless of what cost-effectiveness test is used (i.e., regardless of what categories of impacts, costs and benefits, are included in cost-effectiveness assessments). It is particularly essential that the risks related to climate change are monetized and included in benefit-cost analyses because these risks could be very important from a financial perspective.
- 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.

4.4.2.2 Core Principles

When considering how to compare the cost-effectiveness of pipe and non-pipe solutions, it is important to start with core principles. 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.[42] 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[43] – is to be balanced and accurate. Table 1 lists and describes those principles.

[41] This requirement should apply to all uses of the test, including assessments of both DSM and non-pipe solutions.
[42] The Manual states that its principles and concepts are relevant to "any jurisdiction where DERs are funded, acquired, or otherwise supported by electric or gas utilities or others on behalf of their customers." It further states that it guidance is applicable regardless of the type of utility – whether investor-owned or publicly owned and whether vertically integrated, T&D or distribution-only).
[43] The Manual includes a chapter on non-wires solutions. In that chapter it states that "the concepts apply equally to non-pipe solutions for gas utilities." (NSPM for DERs, p. 12-2). Enbridge's consultant, ICF, concurs, stating that many of the benefit-cost principles articulated in the NSPM for DERs are applicable to consideration of non-pipe solutions. (ICF Canada, IRP Jurisdictional Review Report, October 14, 2020, filed as Exhibit B, Appendix A in EB-2020-0091, p.3, footnote 6)

Table 1: NSPM for DER Fundamental Benefit-Cost Analysis Principles

Principle 1	**Treat DERs as a Utility System Resource** DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	**Align with Policy Goals** Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	**Ensure Symmetry** Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	**Account for Relevant, Material Impacts** Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	**Conduct Forward-Looking, Long-term, Incremental Analyses** Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	**Avoid Double-Counting Impacts** Cost-effectiveness analyses present a risk of double-counting of benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.
Principle 7	**Ensure Transparency** Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	**Conduct BCAs Separately from Rate Impact Analyses** Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses. Cost-effectiveness analyses should therefore be conducted separately from rate impact analyses.

4.4.2.3 The Appropriate Cost-Effectiveness Test for Non-Pipe Solutions in Ontario

As the NSPM for DERs makes clear, the first principle that DERs be treated as utility system resources means 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.[44] 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. Those impacts must be the core of any cost-effectiveness test.

The question then becomes what other non-utility impacts should be included. The second principle of the NSPM for DERs suggests that the answer to that question is tied to a jurisdiction's policy goals. A comprehensive effort to identify all policy objectives relevant to Ontario IRP analyses is beyond the scope of this report. Moreover, any such endeavor should ideally involve a public process, such as a series of working group meetings, in which a range of stakeholders are invited to provide input and in which such input is discussed and debated. Several jurisdictions have recently used such processes –

[44] NSPM for DERs, p. 2-4.

with designated working groups meeting regularly over the course of a number of months, typically with expert consultants providing technical support – to catalog potentially relevant policies and inform regulatory decisions on which policy objectives should be reflected in the cost-effectiveness tests that will be used to assess the economic merits of investments in energy efficiency and other distributed energy resource options.[45] There could be value in Ontario initiating a similar process.

In the interim, one useful reference may be the Board's prior adoption for cost-effectiveness analysis of system-wide energy efficiency programs of the Total Resource Cost Test plus an adder for non-energy benefits – sometimes known in Ontario as the "TRC+" test. Adoption of the TRC+ test implicitly means that impacts on program participants and the environment are policy concerns and should therefore be included in utility cost-effectiveness analyses.[46] That existing precedent, coupled with the fact that it is problematic to use different cost-effectiveness tests for different kinds of resource investment decisions (e.g., for system-wide DSM programs versus for analysis of non-pipe solutions), suggests that the TRC+ test should serve as the foundation for assessing the relative cost-effectiveness of pipe and non-pipe solutions.

The term "foundation" is used here because there are some gas utility system benefits that have historically not been included in Ontario applications of the TRC+ test, particularly the benefit that efficiency programs provide in reducing market clearing prices for gas (as demand goes down, market clearing prices go down). Accounting for such market price suppression effects is very much consistent with the conceptual construct of the TRC+ test, they just haven't been included in Ontario's application of the test to date. They should be going forward. Of course, that should be the case not only for cost-effectiveness analysis of non-pipe solutions, but for analysis of system-wide DSM programs as well.

In addition, as discussed in detail in the next sub-section, economic risk should be quantified – and ideally monetized – in IRP analyses. That should be the case regardless of what cost-effectiveness test is used (i.e., regardless of what categories of impacts, costs and benefits, are included in cost-effectiveness assessments).

4.4.2.4 Addressing Risk

4.4.2.4.1 The Nature of IRP Risk

There are many elements of risk associated with consideration of T&D investments and non-pipe alternatives. Broadly speaking, there is both reliability risk and economic risk. Each of those categories can be further subdivided as follows:

---

[45] Examples include New Hampshire (https://www.nationalenergyscreeningproject.org/wp-content/uploads/2019/10/Synapse-Report_NH-NSPM_Final_2019.10.14.pdf), Arkansas (see https://www.nationalenergyscreeningproject.org/wp-content/uploads/2019/06/Arkansas_NSPM_Case-Study_5.19-Update.pdf for a summary description of the process and https://www.nationalenergyscreeningproject.org/wp-content/uploads/2018/11/Arkansas_Appendix-A_EE-Policies.pdf for the catalog of policies considered), and Rhode Island (https://www.nationalenergyscreeningproject.org/wp-content/uploads/2018/12/Rhode-Island_NSPM_Case-Study-12-3-18.pdf).

[46] The initial impetus for the adder – or the "plus" part of the TRC+ - was a directive from the Ontario Energy Minister to begin accounting for participant non-energy benefits and environmental benefits in cost-effectiveness analyses of efficiency programs.

- Reliability risk:
  - **Peak demand forecast uncertainty**: if peak demand forecasts are understated, such that either T&D upgrades are not made soon enough or that non-pipe solutions are not of adequate magnitude to meet the need, reliability can be compromised.
  - **Non-pipe alternatives performance uncertainty**: if peak savings from non-pipe solutions are not as large as expected, and there is not enough time to adjust the investment strategy, reliability can be compromised.

- Economic risk:
  - **Environmental regulation uncertainty**: more stringent environmental regulations, particularly with respect to greenhouse gas emissions from gas combustion, could (A) drive up the cost of gas relative to what was assumed when IRP analysis was completed and resource choices were made; and/or (B) reduce demand for gas relative to IRP forecasts (e.g. because of increased electrification and/or increased cost of gas resulting from higher carbon taxes, renewable gas requirements, etc.).
  - **Peak demand forecast uncertainty**: if peak demand forecasts are overstated, consumers will pay for an investment that was not needed.
  - **Gas market price uncertainty**: the actual cost of gas can be greater or lower than forecast when analysis of options was performed and an investment decision was made.
  - **Investment cost forecast uncertainty**: the actual cost of either T&D investments or non-pipe alternatives can be greater or lower than forecast when analysis of options was performed and an investment decision was made.[47]
  - **Stranded asset risk**: if the least cost path to achieving substantial levels of decarbonization of buildings required to meet long-term climate goals is (or is even in significant part) electrification, and gas T&D investments made in the 2020s are amortized over a period of 50 years,[48] there could be significant challenges with cost recovery as fixed costs get recovered over increasingly smaller volumes of sales.

In its evidence in this case Enbridge has flagged the importance of addressing reliability risk. Indeed, the Company and its consulting, ICF, either already use or have proposed new solutions to addressing such risk. To begin with, the potential for the Company to understate future peak demand is addressed – at least in significant part – by basing the forecast on an extremely low winter temperature. For example, the low temperature on the "representative design day" used by ICF to model peak hour demand for Enbridge's Central Service territory was -28^{o} C.[49] However, the City of Toronto has not experienced a

[47] For example, several years ago Enbridge reported that its actual construction costs for the GTA project were $847.4 million (excluding Buttonville and Ashtonbee Stations), or 27% more than the $667.4 million originally forecast (Enbridge, GTA Project Post Construction Financial Report, June 30, 2017). Enbridge also recently reported that the actual cost of the Ashtonbee Station - $22.4 million – was more than double its original cost estimate of $10.9 million. (Enbridge, Ashtonbee Station Post-Construction Report on Costs and Variances, September 13, 2018).

[48] It appears as Ontario T&D capital investments are depreciated over 50 years. See: EB-2020-0181, Exh. B, Tab 2, Schedule 1, Appendix E, and Union Gas, cover letter for Application and pre-filed evidence in Docket EB-2016-0186, June 10, 2016.

[49] ICF 2018, p. 66.

temperature that low since 1943; indeed, it has not experienced a temperature below -25° C in the last 25 years.[50] To address uncertainty regarding the performance of geotargeted efficiency programs as IRPAs, ICF has proposed that non-pipe alternative projects either (A) "plan to install more DSM than may be necessary"; (B) "implement the geo-targeted DSM programs at an accelerated schedule"; and/or (C) "ensure that the progress of the geo-targeted DSM programs…are sufficiently monitored on an on-going basis."[51]

While Enbridge has addressed reliability risk, it has not addressed economic risk. It is important to recognize that geo-targeting of DSM programs can have a number of risk mitigating benefits. These can include:

- **Reducing future environmental compliance costs**. By reducing gas consumption, efficiency programs reduce exposure that participating customers would otherwise have to future costs of compliance with environmental regulations (beyond those already reflected in IRP cost estimates).
- **Insulating customers from future fuel price volatility**. By reducing total gas consumption, efficiency programs reduce the exposure that participating customers would otherwise have to future gas price increases.
- **Option value**. Load forecasts are, by definition, uncertain. Because they are much more modular than capital investments in T&D infrastructure, investments in geo-targeted efficiency programs designed to defer the need for new T&D capacity investment can buy time to observe whether peak demands are growing as expected (adjusted for the geo-targeted program impacts) and to recalibrate forecasts based on new and better information. Because T&D planners, and utilities more generally, have a strong incentive to err on the side of over-estimating peak demand (both in order to ensure reliability and to create new revenue for shareholders), such recalibrations can often lead to reductions in estimated levels of peak demand reductions required to defer T&D investments or even elimination of need for the T&D investment altogether. As a representative from Con Edison (perhaps the electric utility with the greatest depth of experience in implementing non-wires alternatives) put it:

  > *"…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."*[52]

- **Reducing risk of stranded assets**. By eliminating capitalization and cost-recovery of new T&D assets, geo-targeted DSM programs eliminate the risk customers or society or utility shareholder

[50] https://www.currentresults.com/Yearly-Weather/Canada/ON/Toronto/extreme-annual-toronto-low-temperature.php
[51] ICF 2018, p. 161.
[52] Gazze, Chris et al., "ConEd's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

(depending on who bears the risk of cost-recovery) would face if such new investments become "stranded" as a result of carbon emission regulations that effectively require most natural gas use to be electrified. Even if the geo-targeted DSM programs were capitalized, the capitalization would likely be over a much shorter life (e.g., 15 years, which is a typical gas efficiency measure life) than for the alternative T&D investment (e.g., 50 years).

Put simply, it is problematic to account only for reliability risk (through forecasting and DSM program requirements) but not for economic risk. Economic risk can and should also be reflected in IRP analyses.

4.4.2.4.2 Addressing Risk in Cost-Effectiveness Analysis

Overview

Risk should always be quantified – and ideally monetized – as part of IRP analyses. That should be the case regardless of what cost-effectiveness test is used (i.e., regardless of what categories of impacts, costs and benefits, are included in cost-effectiveness assessments).

Economic risk can be addressed included in cost-effectiveness analyses in a couple of different ways. Perhaps the most common is to identify several different futures and separately analyze cost-effectiveness under each of those futures. This has been a fairly common practice in electric utility IRPs for decades. At least some gas utilities are currently doing the same. For example, a year ago Vermont Gas announced plans to "transform the company" to address climate change, with a strategy to "eliminate greenhouse gas (GHG) emissions by 2050" and to reduce them by 30% by 2030. The 2030 goal would be achieved through a three-pronged strategy of doubling its energy efficiency program savings, making renewable gas 20% of its supply, and advancing innovative projects such as district energy and net zero new home construction.[53] The Company is currently in the process of developing its next IRP (expected January 2021) whose focus will be on strategies to achieve these climate policy objectives. Vermont Gas is currently analyzing and plans to base its IRP on assessment of three different futures with three different levels of future demand driven by different assumptions regarding weather, economic growth, the cost of renewable gas and the amount of electrification of gas end uses that will occur.[54]

Climate Policy Risk

In many respects, the most important aspect of risk for gas infrastructure investments today is the potential for climate policy to (1) render such investments unnecessary, at least in the medium to long run, if gas demands are going to decline because of either increased electrification and/or much higher gas prices associated with renewable gas; and (2) adding value to efficiency resources because of both avoided future carbon emission compliance costs (beyond those currently reflected in carbon taxes) and/or higher avoided costs of gas associated with renewable gas. Conceptually, one can conceive of three potential futures related to climate policy:

---

[53] https://www.vermontgas.com/vgs-targets-elimination-of-greenhouse-gas-emissions-by-2050/

[54] Personal communication with Tiana Smith (Vermont Gas Director of Climate Strategy and project manager for the IRP) and Jill Pfenning (Vermont Gas Vice President of Regulatory Affairs and General Counsel), November 16, 2020.

1. Canada does not follow through on its commitment to achieve net zero greenhouse gas emissions, or at least lowers its ambition and imposes no new requirements on fossil gas;
2. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met largely with renewable gas; and
3. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met largely with electrification of gas end uses (served by an increasingly decarbonized grid).

Enbridge could be required to estimate how both the need for an infrastructure capacity upgrade would be affected under each of these scenarios, how gas prices would likely change under each of them, and how the resulting net present value of net benefits from investing in non-pipe solutions would change under each. Of course, there could be hybrids of the three scenarios as well. And there could be variations on the second and third scenarios in terms of the timing of requirements. Such hybrids and variations could also be considered.

A hypothetical example can help to conceptually illustrate the importance of multiple scenario analyses. Consider the three scenario assumptions in Table 2, along with the related graphic depictions of demand growth without non-pipe solutions in Figure 5 and with non-pipe solutions in Figure 6. As Figure 5 shows, under the electrification scenario the duration and the magnitude of the need for additional capacity is very different than under the other two scenarios. As Figure 6 shows, because the maximum load without a non-pipe solution never gets to be more than 6.5% higher than the existing capacity, it is possible to completely eliminate the need with seven years of a non-pipe solution.

Table 2: Hypothetical Characterization of Three Scenarios for a Gas Infrastructure Need

				Annual Demand Growth						
Scenario		**2020 Peak Demand**	**Max Capacity w/o Upgrade**	**2021 to 2025**	**2026 to 2030**	**2031 to 2035**	**2036 to 2040**	**Max Annual EE IRPA Savings**	**Year Upgrade Needed w/o IRPA**	**Upgrade Deferral Year w/Max EE**
1	Business as Usual	94	100	2.0	2.0	2.0	1.0	1.0	2023	2026
2	GHG Regs - Renewable Gas	94	100	2.0	1.5	-0.5	-2.0	1.0	2023	2027
3	GHG Regs - Electrification	94	100	2.0	0.5	-3.5	-6.0	1.0	2023	indefinitely

Figure 5: Peak Loads Relative to Maximum Capacity without Non-Pipe Solution

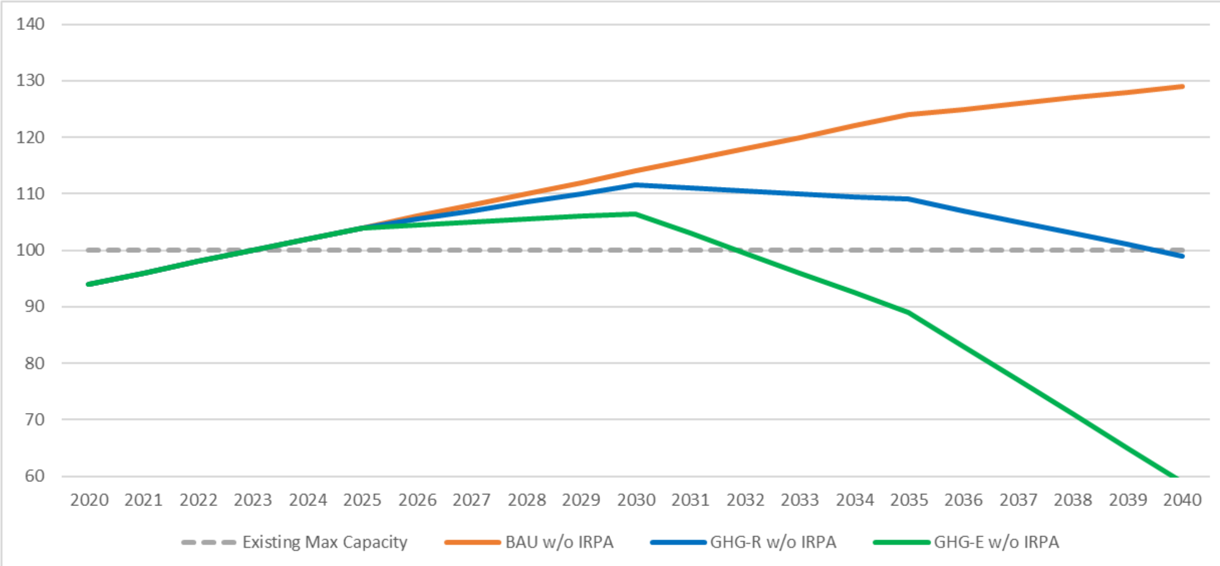
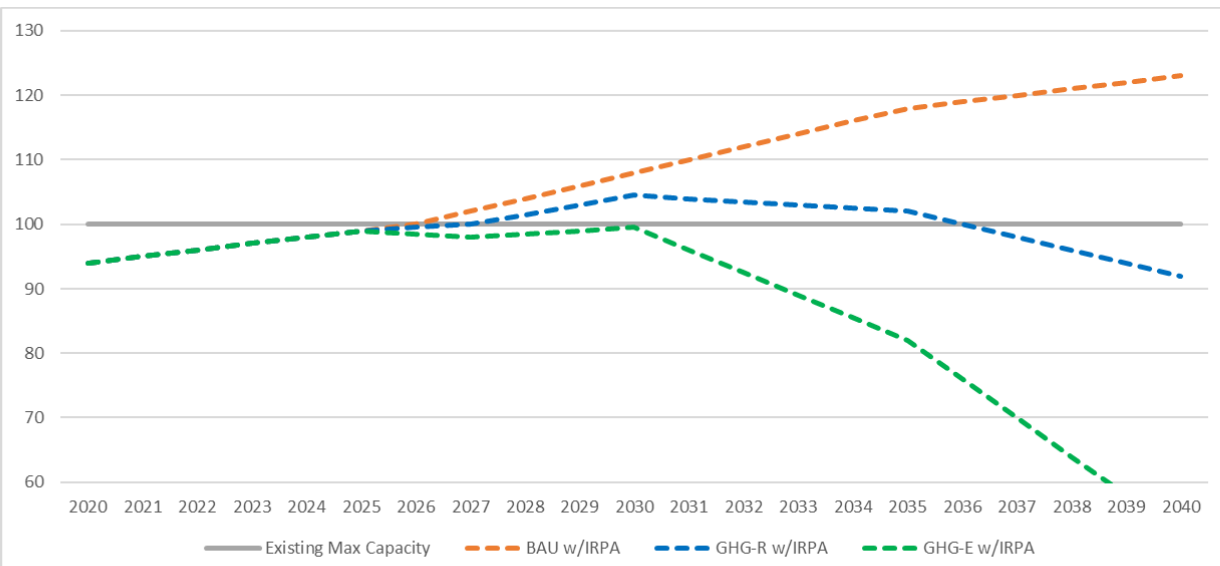


Figure 6: Peak Loads Relative to Maximum Capacity with Non-Pipe Solution[55]



Importantly, different scenarios could not only affect the viability a non-pipe solution for addressing reliability needs; they could also affect the economics of non-pipe solutions. Consider the hypothetical economics of the non-pipe solution scenarios example presented in Table 3. In this simplified example, the cost of the infrastructure upgrade is $100 in today's dollars (column a), which translates to a net present value (NPV) of $89 (column g) if installed in 2023 – assuming a 4% real discount rate. The cost of the energy efficiency IRPA is $20. However, energy efficiency has non-T&D deferral benefits such as

[55] Non-pipe solutions are assumed to run only for as many years as they can defer the infrastructure investment or – for the electrification scenario – for as long as needed before naturally-occurring (including policy driven) demand reductions without non-pipe solutions are enough to eliminate the need for continued IRPA investment.

avoided energy costs. The hypothetical value of those additional benefits is $16 in the Business as Usual (BAU) scenario. Put other way, the value of the T&D deferral benefit would need to be greater than $4 per year of non-pipe solution deployment in order for the non-pipe solution to be cost effective.

Under the BAU scenario, six years of the non-pipe solution – from 2021 to 2026 – would be required to defer the T&D upgrade by three years from 2023 to 2026. If the upgrade is deferred to 2026, the NPV of the project cost would decline to $79 (column h), or a $10 savings (column i). That T&D deferral benefit is not enough to cover the $21 NPV difference (column f) between six years of the non-pipe solution cost and the other non-T&D benefits provided by the efficiency programs, so the non-pipe solution would not be cost-effective. However, the non-pipe solution would be cost-effective under either of the Greenhouse Gas (GHG) regulation scenarios. In the renewable gas scenario, the reason is that the value of avoided energy costs (column c) is assumed to be twice as great as under the Business as Usual scenario, making the efficiency investments cost-effective even without any T&D deferral benefit ($12 in savings per year). In the electrification scenario, though avoided energy costs are the same as in the BAU scenario, the fact that electrification lowers load relative to the BAU scenario means that the non-pipe solution completely eliminates the need for the infrastructure project. That has much greater value (column i) than just deferring it (as in the other two scenarios).

Table 3: Hypothetical Scenarios of Non-Pipe Solution Cost-Effectiveness[56]

Scenario		Cost of Infra-Structure Upgrade (2020 $) (a)	EE IRPA Annual Cost (b)	Cost Savings (Excl T&D) from 1 Year of IRPA (c)	Net Cost (Excl T&D) from 1 Year of IRPA (d)	Years of EE IRPA Required (e)	Net Cost (Excl T&D) from Multiple Years of IRPA (f)	NPV of 2023 T&D Upgrade w/o IRPA (g)	NPV of Deferred T&D Upgrade w/IRPA (h)	NPV of IRPA Deferral Benefit (i)	NPV of Total Net Benefits of IRPA (j)
1	Business as Usual	$100	$20	$16	$4	6	$21	$89	$79	$10	($11)
2	GHG Regs - Renewable Gas	$100	$20	$32	($12)	7	($72)	$89	$76	$13	$85
3	GHG Regs - Electrification	$100	$20	$16	$4	7	$24	$89	$0	$89	$65

Again, this is just a set of hypothetical scenarios presented for illustrative purposes. However, they clearly illustrate how cost-effectiveness could be very sensitive to assumptions about the future, particularly with respect to climate policy. In fact, even if one assumed that there was an 80% likelihood that the BAU scenario would become reality, and that there was only a 10% chance of each of the other two scenarios becoming reality, the probability weighted average result would be that the non-pipe solution was very cost-effective (i.e. a different conclusion than if one only looked at a BAU scenario).

[56] Note that the net benefits shown in the last column of this table is only illustrative of the cost-effectiveness of a non-pipe alternative in the context the hypothetical futures characterized. It does not suggest that a renewable gas approach to addressing climate policy goals would be lower cost than an electrification approach. Economic trade-offs between renewable gas and electrification would need to be assessed under an IRP analysis applied to the entire energy system, including gas commodity costs and the costs of electric alternatives, rather than to just non-wires alternatives to traditional T&D investments. In fact, it is possible, if not likely, that non-pipe solutions would look better under a renewable gas scenario than under an electrification scenario precisely because a switch to renewable gas would be more expensive (leading the avoided costs of gas, a potentially key benefit in deploying non-wires solutions, to be dramatically higher) than electrification.

Addressing Risk of Future Gas Price Volatility

One important benefit of energy efficiency resources is that they insulate customers from uncertainty regarding future energy prices. In essence, efficiency investments are – in part – a hedge against future gas price increases.

The benefit of that hedge can be reflected in cost-effectiveness analyses in a couple of different ways. One is through characterization of multiple potential future gas prices from which a probability weighted average of gas costs can be derived. Another is through analysis of markets for fixed price contracts. For example, a 2018 avoided cost study for the New England states estimate a wholesale electric energy risk premium of 8% based on analyses of long-term contracts.[57] Finally, a risk adder can be used. For example, since 1992 Vermont's regulators have required that energy efficiency measure costs be reduced by 10% when performing cost-effectiveness analysis "to reflect efficiency's 'comparative risk and flexibility advantages' relative to supply resources."[58] That is analogous to assuming an 11.1% risk premium be added to avoided energy costs and other benefits included in cost-effectiveness analyses.

Addressing Risk Associated with Project Cost Estimation

To address risk associated with the potential for system infrastructure costs being higher than forecast, probabilities could be assigned to cost multipliers applied to Enbridge's best estimate of costs. That might first require a study of the difference between historic cost estimates for infrastructure investments and actual costs. To be balanced, adjustments could also be made to estimated costs of non-pipe solutions.

Addressing Risk of Stranded Assets

To deal with the risk of stranded assets, the Company could also be required to consider how cost-effectiveness of non-pipe solutions would change if the costs of the system infrastructure investment had to be amortized over a shorter period such that all costs were recovered by, for example, 2035 or 2040. That could either be a requirement for quantifying the net present value of costs of T&D investments, or a requirement for a sensitivity analysis. For example, in its 2016 application for investment in the Panhandle Reinforcement Project, Union Gas stated that because of uncertainty regarding climate policy and its associated risks it "has calculated the revenue requirement and resulting rate impacts of the Project based on a 20-year estimated useful life of the assets rather than the weighted average useful life of approximately 50 years based on Board-approved depreciation rates."[59]

---

[57] Synapse Energy Economics et al., *Avoided Energy Supply Components in New England: 2018 Report*, prepared for the AESC 2018 Study Group, Amended October 24, 2018.
[58] Woolf, Tim et al., National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, prepared for the National Efficiency Screening Project, May 18, 2017 (https://www.nationalenergyscreeningproject.org/the-national-standard-practice-manual-for-energy-efficiency/).
[59] Union Gas, cover letter for Application and pre-filed evidence in Docket EB-2016-0186, June 10, 2016.

4.4.2.5 Choice of Discount Rate

Discount rates are a reflection of "time preference". When discount rates are high, more weight is assigned to short-term costs and benefits. When they are low, short-term impacts and long-term impacts are weighted more equally.

The discount rates in use today for assessing cost-effectiveness of utility system investments vary considerably from jurisdiction to jurisdiction. That variation is generally a function of whether the jurisdiction has adopted what is commonly called a societal discount rate – typically between 0% and 3% - or uses its utilities' weighted average cost of capital (WACC), which is commonly on the order of 5% to 8%.[60] Note that these values are expressed in "real" terms, meaning that they are net of inflationary impacts.[61]

When regulators make decisions regarding the relative economic merits of different utility system investments, they do not make them with just the needs of utility shareholders in mind. They must also consider the utility's customers, currently and in the future, as well as other government policy objectives. That is relevant to the question of which discount rate to use because a utility's (WACC) is simply a reflection of the time value of money held by *utility shareholders*. It is not a reflection of time preference of current customers or future customers; nor is it a reflection of time preferences implicit in different government policy objectives.

Industry best practice is to base the discount rate used in economic analyses of utility investment options on a jurisdiction's policy objectives.[62] There is no mathematical formula for translating policy objectives to specific discount rate values. However, generally-speaking, the more a jurisdiction's energy policies suggest concern for the long-term implications of investment decisions, for future utility customers as well as current customers and/or for jurisdiction-wide or even broader concerns (e.g., for reducing energy burdens for low income customers or reducing environmental damage), the stronger the case for a societal discount rate.

As discussed in Section 4.4.2.3, a thorough assessment of energy policy objectives relevant to Ontario utility system investments is beyond the scope of this report and should ideally be undertaken through a Board-initiated process involving utilities and other stakeholders. In the interim, the Board should require that cost-effectiveness analyses of non-pipe solutions be performed using the same real discount rate as is used to assess cost-effectiveness of system-wide DSM. That is currently 4%. However, the DSM framework is currently under review and there are reasons to think that a lower rate, more in line with typical societal rates (i.e., 0% to 3%) may be more appropriate. Any change in discount rates for DSM should also apply to consideration of non-pipe alternatives. .[63] As discussed in Section

---

[60] NSPM for DERs, Appendix G and personal experience.

[61] Real discount rates should be used when computing the net present value of future costs and benefits expressed in constant dollars (e.g. 2020 dollars or 2021 dollars). Nominal discount rates should be used when computing the net present value of future costs expressed in future years dollars, including inflationary effects. A nominal discount rate is equal to: (A) 1.00 plus the real discount rate, multiplied by (B) 1.00 plus the inflation rate, minus (C) 1.00.

[62] NSPM for DERs, Appendix G.

[63] Ontario Energy Board, *Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020)*, EB-2014-0134, December 22, 2014.

4.1.2, it would be problematic to use different discount rates to assess the same streams of costs or benefits (e.g., avoided gas commodity costs, avoided carbon taxes, etc.) produced by the same kind of distributed resource (e.g., energy efficiency) in two different investment applications (system-wide DSM programs versus non-pipe solutions). Put simply, the economic value of reducing gas consumption by 1 million m^3 in 2030 is not affected by whether that reduction was produced through a system-wide DSM program or a geotargeted one.

4.4.2.6 Failings of Enbridge's Proposed Approach to Cost-Effectiveness Assessments

In its filing in this case, Enbridge has proposed that the economic feasibility of non-pipe solutions be assessed "using a Discounted Cash Flow (DCF) methodology consistent with principles underpinning the Board's E.B.O. 134 and E.B.O. 188."[64] The Company provides little in the way of additional detail on how it would perform DCF analyses. However, its proposal appears to be both fundamentally flawed and completely inconsistent with industry best practices with IRP.

First, it is not clear whether Enbridge would assign any benefit to energy cost, carbon tax or other non-T&D cost savings realized by Enbridge's customers as a result of geotargeted efficiency programs. That is certainly how the Company has assessed the economics of non-pipe solutions in the past.[65] If that is its proposal going forward, the Company would be saying that the cost of geotargeted efficiency programs would have to be justified entirely on the value of the supply-side infrastructure costs they deferred or avoided. For example, Enbridge's cost-effectiveness test would compare *the entire cost* of geotargeted efficiency programs with *only a portion of the benefits* that the programs would provide. That violates two of the most basic principles of cost-effectiveness analyses: (1) that all utility system impacts should be included; and (2) that there must be symmetry in the treatment of costs and benefits.[66] I am not aware of a jurisdiction that is seriously considering IRPAs (gas or electric) and is using something akin to Enbridge's proposed Discounted Cast Flow analysis as its primary cost-effectiveness test.[67]

Second, Enbridge's proposal for economic analysis does not address any policy objectives other than cost and reliability. Enbridge has identified some other "guiding principles", including alignment with public policy, that it says must be met for a non-pipe solution to proceed. However, such alignment is only considered an *additional* requirement – over and above cost-effectiveness. Policy goals are not considered in the assessment of cost-effectiveness itself. In addition, the requirement for consistency with other guiding principles, including alignment with policy objectives, appears to apply only to non-pipe solutions. Enbridge does not propose to make it a requirement for investment in infrastructure

[64] Exh. B, p. 31.
[65] For example, in an application filed just two months ago, Enbridge appears to simply compare the cost of supplemental DSM programs that would defer a project by two years to the project cost savings (See EB-2020-0192, Exhibit B, Tab 2, Schedule 4).
[66] NSPM for DERs
[67] Several years ago, DTE, one of the two large investor-owned utilities in Michigan, performed a conceptual analysis of the cost-effectiveness of non-wires alternatives without considering other system (electric energy and capacity) benefits that geotargeted efficiency programs would produce. However, that approach was criticized and the Company is now including all relevant benefits from non-wires alternatives in the cost-effectiveness framework is has developed as part of work on actual pilot non-wires projects (personal knowledge from direct involvement in the pilot).

solutions. In other words, the criteria for investing in non-pipe solutions is, by design, more challenging than the criteria for investing in supply-side infrastructure. That too violates basic principles of resource optimization.

Third, Enbridge has not proposed to address economic risk in its assessment of the relative cost-effectiveness of pipe and non-pipe solutions. As discussed in Section 4.4.2.4, economic risk should be monetized, regardless of the cost-effectiveness test being used.

Finally, Enbridge has proposed that cost-effectiveness calculations be performed using its after tax weighted average cost of capital. For the reasons stated in Section 4.4.2.5, a 4% real discount rate should be used instead.

4.5 Issues #7 and #9: Cost Recovery and Financial Incentives

4.5.1 Summary of Key Points

- If utilities are to be expected to deploy non-pipe solutions when they are preferable to T&D investments, the utilities and their shareholders should be able to be sufficiently profitable while doing so.
- 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.
- A case can be made for each of these options. They all have both advantages and disadvantages.
- The best may be capitalizing and earning a rate of return on non-pipe solution costs. Though perhaps not perfect, this option is most consistent with how utilities profit from traditional T&D solutions, is likely to be the option that will result in the strongest utility management support for non-pipe solution investment, and is simple and well-understood. 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.

4.5.2 Overview

From a public policy perspective, if regulators and customers are to expect utilities to acquire the combination of resources that balances cost-minimization, risk minimization, carbon emission reductions and other policy objectives, then it is reasonable for the utility and its shareholders to expect to be able to make money while doing so.

Conceptually, there are at least three ways in which utility shareholder incentives for investment in non-pipe solutions could be structured:

1. **Incentive payments expressed as a percent of the cost of non-pipe solutions**. The incentives could be paid each year that a non-pipe solution is deployed, as long as the non-pipe solution is on track to meet peak demand reduction goals.

2. **Capitalizing and earning a rate of return on non-pipe solution costs**. The rate of return could be the same as for traditional supply-side investments, a little higher to encourage non-pipe solution investment (if needed) and/or tied to performance on non-pipe solution deployment. Amortization should be over the average life of the non-pipe solution investments (typically shorter than lives than supply-side infrastructure).
3. **Payments equal to a share of the economic net benefits associated with non-pipe solution investment – or "shared savings"**. Under this construct, the economic net benefits of the non-pipe solutions are estimated and the utility is allocated a percentage of those benefits, with the balance effectively being allocated to ratepayers.

All of these mechanisms are currently in place in several jurisdictions for various policies supporting investment in distributed energy resources. For example, utilities in Massachusetts, Rhode Island and Connecticut have the ability to earn incentives expressed as a percent of program spending for system-wide efficiency programs; Consumers Energy (Michigan) can currently earn an incentive equal to 13% of non-capitalized spending on electric demand response programs for achieving projected growth in enrollment in its DR programs and 2% of non-capitalized spending for demonstrating progress in consideration and deployment of DR in the context of non-wires alternatives;[68] Illinois electric utilities ratebase efficiency program spending with their rate of return a function of savings relative to goals;[69] Vermont Gas also recently received approval to ratebase the added cost associated with doubling of their energy efficiency program savings by 2025;[70] and Ohio electric utilities have a shared savings mechanism for system-wide efficiency programs.[71] Though all of these incentive structures may not yet be being used in the context of gas non-pipe solutions, there is no reason they could not be.

Of course, there can also be hybrids of these options. For example, the Michigan utilities are allowed to earn shareholder incentives of up to 20% of system-wide efficiency program spending (for achieving first year savings equal to at least 1.50% of electric system sales or 1.00% of gas system sales, plus other performance metrics around lifetime savings and low income program performance), but those incentives are capped at 30% of calculated economic net benefits (a "shared savings" cap).[72] The New York electric utilities are permitted to ratebase investments in non-wires solutions and also receive a

---

[68] Michigan Public Service Commission Order in Case No. U-20164, July 18, 2019.

[69] The utilities get their normal rate of return earned if 100% of savings goals are realized, up to a 200 basis point bonus for achieving 125 of the savings goals, and up to a 200 basis point penalty for falling short of goals (where the penalty starts to kick in varies by utility). Costs are capitalized over the weighted average life of the efficiency measures installed. That has typically been in the range of 10 to 12 years. [Neme, Chris, "Summary of New IL EE Legislation", presentation to the Illinois Stakeholder Advisory Group (SAG), January 24, 2017 (https://s3.amazonaws.com/ilsag/IL_Legislation_Overview_SAG_Planning_01242017.pdf)].

[70] Vermont Public Utility Commission, Order in Case No. 19-3272-PET, 10/22/2020. The order instructs Vermont Gas to "propose a performance incentive mechanism that links its level of return on its energy efficiency investments to its achievement of performance metrics."

[71] For example, First Energy currently has a performance incentive structure in which earns 5.0% of Utility Cost Test (UCT) net benefits for achieving between 100% and 105% of its savings goal, 7.5% of UCT net benefits for achieving 105% to 110% of its goal, 10.0% of UCT net benefits for achieving 110% to 115% of its goal, and 13.0% of UCT net benefits for achieving 115% or more of its goal (First Energy Ohio, 2019 Portfolio Status Report, 5/15/2020, Appendix D (Shared Savings).

[72] Act No. 342, Section 75(2)

portion of estimated economic net benefits from investment in non-pipe solutions that are lower cost than supply infrastructure alternatives.[73]

4.5.3 Pros and Cons of Incentive Options

Each form of shareholder incentive mechanism has advantages and disadvantages. What follows is a quick summary of those tradeoffs.

4.5.3.1 Incentive Payments as a Percent of Non-Pipe Solution Costs

One advantage of expressing incentive payments as a percent of IRPA costs is that it is very straight-forward and easy to understand and compute. Also, because payments are made annually as non-pipe solution costs are incurred, the absolute magnitude of payments is lower than if costs are amortized using the utility's normal rate of return. The net present value of the payments is also lower from a societal perspective because the societal discount rate is lower than utilities' normal rate of return.

One disadvantage is that ratepayers pay the incentives entirely up front and receive the benefits in the ensuing years. If the non-pipe solution is cost-effective, ratepayers will still be collectively better off over the life of the non-pipe solution, but it will typically take several years before the accumulated cost savings are greater than the up-front costs. Another disadvantage is that the incentive is tied to spending levels, which can create a perverse incentive to spend more than is necessary. While that incentive can be addressed through careful regulatory oversight of proposed non-pipe solutions projects, there may still be some risk there. However, it should be noted that such risk also exists for traditional T&D capital investments.

4.5.3.2 Capitalizing Non-Pipe Solution Costs

One advantage to capitalizing non-pipe solution costs is that it better aligns the timing of the costs with the timing of benefits – or cost reductions. If non-pipe solutions are cost-effective, ratepayers will be economically better off from year 1. Another potential advantage may be that this approach is more consistent with how utilities traditionally make money for shareholders. If utility management prefers this approach, it will reduce institutional barriers to investment in cost-effective non-pipe solutions.

One disadvantage is the "flip side" of the advantage of one-time payments as a percent of non-pipe solution costs. Namely, total payment to shareholders will be a little higher, even in discounted terms if using the societal discount rate. As with one-time incentive payments, another disadvantage is that the incentive is tied to spending levels, which can create a perverse incentive to spend more than is necessary. While that incentive can be addressed through careful regulatory oversight of proposed non-pipe solutions projects, there may still be some risk there. Again, it should be noted that such risk also exists for traditional T&D capital investments.

4.5.3.3 Shared Savings

One advantage to shared savings is that it is expressed in a way that clearly articulates how the net economic benefits of cost-effective non-pipe solutions are being allocated between utility shareholders and ratepayers. A related advantage is that it provides a direct incentive to utilities to maximize the

[73] ICF 2020, p. 7.

magnitude of net benefits, which indirectly encourages minimization of the cost of the non-pipe solution.

A disadvantage of shared savings is that the calculation of net benefits is necessarily based on a number different benefits and a variety of assumptions related to those benefits. Thus, there will need to be careful scrutiny of all net benefit assumptions and calculations. While that is necessary at some level to ensure that IRPAs are cost-effective, the stakes are higher when shareholder incentives are tied to them because it is no longer just a question of whether the non-pipe solution is cost-effective; instead, the amount by which non-pipe solutions are cost-effective is vitally important. In addition, the magnitude of some of the assumptions underpinning net benefits calculations – e.g. avoided energy costs for gas – can fluctuate from year to year, raising and lowering utility shareholder incentives, for reasons entirely or at least largely out of the utility's control. Finally, utility incentives to invest in non-pipe solutions that are only marginally cost-effective may not be large enough for management to support the non-pipe solution investment – even if it is still providing value to ratepayers.

4.5.3.4 The Preferred Solution

A case could be made for adopting any of the three options discussed above. However, the best incentive mechanism might be capitalizing and ratebasing non-pipe solution costs – or at least the costs associated with distributed energy resources, such as energy efficiency, demand response, and electrification.[74] That conclusion is based on three factors: (1) consistency with how utilities profit from traditional T&D investments; (2) experience with utilities that suggests this approach is most likely to result in senior management support for pursuing non-pipe alternatives (when appropriate); and (3) simplicity – there is no need to perform calculations based on assumptions (e.g. changing avoided costs, savings lives, etc.) that can be debated, can fluctuate from year to year, and are often outside of the utility's control. 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.

5. Applicability of Lessons from Electric IRP to Gas IRP

5.1 Summary of Key Points

- The principles, processes and cost-effectiveness frameworks for considering gas non-pipe solutions are the same as those for considering electric non-wires solutions.
- There are some differences between gas and electric utilities that could theoretically affect the average economic value and/or frequency of cost-effectiveness of non-pipe solutions relative to non-wires solutions. However, it is not clear whether their combined effect would be to make non-pipe solutions more or less economically attractive – on average – than non-pipe solutions.
- As with non-wires solutions, the economic merits of non-pipe alternatives will likely vary considerably from project to project, underscoring the need for project-specific assessments.

[74] There may be reasons not to treat deployment of compressed natural gas (CNG) or liquified natural gas (LNG) deployment as part of non-pipe solutions in the same way (see ICF 2020, p. 7).

5.2 Applicable Lessons from IRP Analyses of Alternatives to T&D Investments

At a high level, IRP analyses of alternatives to traditional T&D investments should include each of the following steps:

1. Forecast near and longer-term peak demand for all elements of the T&D utility system.
2. Timely identification of capital investments in T&D that will be required given forecast peak demand growth (absent geotargeted deployment of additional IRPAs).
3. Identify the subset of capital investments in T&D that could potentially be candidates for consideration of IRPAs.
4. Characterize the magnitude and timing of the need for T&D investments:
    a. In what year would the T&D capacity increase be needed?
    b. During which hours of the day do peak demands occur?
    c. How much peak load reduction would be necessary during those hours to defer the T&D investment?
5. Characterize the cost of the T&D investments.
6. Assess whether geographically targeted energy efficiency, demand response and/or other IRPAs could be acquired in sufficient volume and over a short enough period of time to either (1) defer or eliminate the need for each T&D capital investment; or (2) allow for a lower cost T&D investment. This will require:
    a. Characterizing the peak demand reduction that individual efficiency, demand response and/or other IRPA measures can provide;
    b. Characterizing the total potential for each measure – i.e., the number of each measure that could be applied or installed – in the geographic area of interest; and
    c. Characterizing how much of the potential could be realized each year (i.e. participation rates).
7. Where there is sufficient efficiency, demand response and/or other IRPA potential to (individually or in combination) defer or allow for lowering of the cost of a T&D investment, estimating the costs of acquiring the IRPAs.
8. Perform cost-effectiveness analysis of the IRPAs – comparing their costs to the cost savings they would provide. The cost savings of IRPAs includes not only the value of deferring or lowering the cost of the alternative T&D investment, but also the value of other relevant benefits that they may provide, including avoided energy costs.

Each of these steps is necessary for assessment of *both* electric *and* gas IRPAs. Thus, many of the lessons learned from decades of experience with analyses of non-wires alternatives are transferable to analysis of non-pipe alternatives. That includes insights into planning horizons, forecasting future T&D needs, analysis of multiple IRPA resource options for a given geography, and the principles and mechanics of cost-effectiveness analysis.

To be sure, there are some differences between gas and electric systems that will need to be addressed in analyses of gas non-pipe solutions. For example, peak periods of interest may be different, the level of reliability may be different and there are some differences in the range of distributed resource options to consider (e.g., electrification and local injection of compressed gas are only options for non-pipe solutions and distributed photovoltaics and/or diesel generators are only options for non-wires solutions). However, that just means that each of the planning steps outlined above needs to account for those differences. The steps themselves do not change. Nor do any of the fundamental principles underlying IRP analyses.

5.3 Other Transferable Lessons

Geotargeting of energy efficiency and demand response programs can be key components of both electric non-wires alternatives and gas non-pipe alternatives. They are also delivered to the same kinds of customers. Conceptually the barriers of customer adoption of efficiency and demand response measures is the same. Indeed, some of the actual measures – e.g., building insulation upgrades – are the same because they produce both gas heating and electric cooling savings. Thus, many of the lessons learned from electric utility about how to geotarget efficiency and demand response programs – including how to layer geotargeting onto existing system-wide program offerings – are applicable to gas non-pipe solutions.

Electric industry experience with stakeholder engagement in consideration of non-wires solutions is also eminently transferable to gas utility consideration of non-pipe solutions. The underlying public policy objectives, utility interests, range of stakeholder interests to consider, and regulatory contexts are all very similar if not the same. As discussed in Section 4.2.4, IRP analyses are much more robust if key inputs to and outputs from each of the analytical steps itemized above are made public and stakeholders are provided opportunities to provide input on them as the analysis is proceeding (rather than just at the end of the process). There is no reason that should be any different for the gas utility industry than for the electric utility industry.

5.4 Value of Gas Non-Pipe Solutions Relative to Electric Non-Wires Solutions

Enbridge's consultant, ICF, has suggested that there may be less *value* to be obtained from non-pipe solutions than there is from non-wire solutions. ICF makes some legitimate conceptual points that could affect differences in value. However, it is not clear how material the differences that they identify are to the relative value of gas non-pipe solutions. In addition, in some cases, ICF appears to have over-stated its case. Moreover, there is one important difference between gas and electricity that cuts in the other direction. Specifically, meeting long-term greenhouse gas emission reduction goals will require either widespread electrification of gas end uses and/or widespread conversion from fossil gas to much more expensive renewable gas. Serious consideration of the *probability* of such outcomes could, by itself, make gas non-pipe solutions cost-effective more often than electric non-wires solutions.

What follows is a brief discussion of the conceptual ways in which ICF suggested that differences between gas and electric utilities would affect the value of non-pipe solutions relative to non-wires alternatives.[75]

5.4.1 Facilities Planning Requirements

ICF observes that electric utilities must plan to meet the highest instantaneous peak demand whereas gas utilities plan to meet only hourly or daily maximum demands. That is certainly true. ICF suggests that these differences "tend to increase the value of reductions in peak demand for the electric industry relative to the gas industry, which makes targeted DSM and DR programs more valuable for the electric

[75] ICF 2018, pp. ES-8 to ES-9.

industry than for the natural gas industry." Even if that is true – and ICF has provided no data or analysis to support its assertion – the fact that electric utility systems are designed with a lower degree of reliability (see Section 5.4.3 below) has a countervailing effect. It is not clear what the net result of those two factors is likely to be.

5.4.2 Cost Structure

ICF states that "gas facilities are typically less expensive than electric facilities per equivalent amount of energy delivered (GJ of delivered energy) for a given level of peak energy demand (peak GJ of delivered energy)." ICF suggests that this means that the economic value of deferring investments in gas infrastructure will be lower than the value of deferring electric infrastructure investments. Again, no empirical data or analyses are provided to support this assertion. Even if it is true, it simply means that either the economic net benefits of deferring gas T&D investments and/or the percentage of gas T&D investments that can be cost-effectively deferred *may* be smaller.[76] Neither of those conclusions – again, if true – would be grounds for not assessing non-pipe alternatives or for not pursuing non-pipe alternatives when they are cost-effective.

Moreover, there is an important element to cost structure that ICF has not addressed: the potential impacts – both cost and risk – of climate policies. As discussed further below, the vast majority of independent analyses of pathways for achieving the level of greenhouse gas emission reductions required to meet 2050 climate stabilization goals – goals which the Canadian government's pledge to achieve net zero greenhouse gas emissions by 2050 is designed to support[77] – suggest that (1) combustion of fossil gas will need to be largely eliminated; and (2) eliminating fossil gas will likely require substantial amounts of electrification of heating, water heating and other gas uses in buildings.[78] Such electrification will lower gas peak demand in ways that current gas utility forecasts have historically not addressed. The only question is when such effects will start to be felt in a significant way. A precise answer to that question requires clarity, which is not currently apparent, regarding how policies and markets will evolve. However, it is clear from the magnitude of the effort and investment that will be required to largely electrify buildings and industry by 2050 that it is going to have to begin relatively soon if 2050 greenhouse gas emission reduction commitments are going to be met – i.e., well before the costs of any new T&D investments, if depreciated over 50 years (or other similarly long period), are fully

---

[76] The value of T&D investment deferral is only one component of the calculus of the cost-effectiveness of non-pipe alternatives. The other is the cost of the non-pipe solutions. Neither ICF's report nor any other analysis with which I am familiar addresses differences in costs of non-pipe versus non wires solutions.

[77] https://www.canada.ca/en/privy-council/campaigns/speech-throne/2020/stronger-resilient-canada.html

[78] For example, see Green, Tom, *Zeroing in on Emissions: Canada's Clean Power Pathways – A Review*, published by the David Suzuki Foundation, 2019 (https://davidsuzuki.org/wp-content/uploads/2019/05/zeroing-in-on-emissions-canadas-clean-power-pathways-review.pdf); Gowrishankar, Vignesh and Amanda Levin, *America's Clean Energy Frontier: The Pathway to a Safer Climate Future*, published by the Natural Resources Defense Council, September 2017 (https://www.nrdc.org/sites/default/files/americas-clean-energy-frontier-report.pdf); Haley, Ben et al. (Evolved Energy Research), Deep Decarbonization Pathways Analysis for Washington State, December 16, 2016; Mahone, Amber et al., (Energy and Environmental Economics), California PATHWAYS: GHG Scenario Results, updated April 6, 2015 (https://www.ethree.com/wp-content/uploads/2017/02/E3_PATHWAYS_GHG_Scenarios_Updated_April2015.pdf); and European Roadmap 2050 project reports at https://www.roadmap2050.eu/project/roadmap-2050.

recovered. Indeed, ICF itself has concluded that current climate policy would likely lead to reductions in gas consumption even in the 2021-2030 timeframe, let alone to meet 2050 emission reduction targets.[79]

Note that some in the gas industry are suggesting that "renewable gas" is a viable alternative to electrification for meeting climate goals. There a number of questions about that viability related to the magnitude of renewable gas that can actually be produced, the extremely high forecast cost of renewable gas at significant levels of production, and the carbon neutrality of renewable gas. For example, a study recently completed by ICF for the American Gas Foundation found that even under the most optimistic set of assumptions the amount of renewable gas that could be produced for pipeline injection by 2040 in the United States was only 3780 bBtu per year.[80] That is equal to about 13% of total 2019 U.S. consumption and 22% of total U.S. consumption in buildings and industry (i.e. excluding all sales for electric power generation).[81] Moreover, the report estimated that the marginal cost of that level of production was on the order of $55 (CDN) per Gj[82] – or nearly 20 times current Henry Hub spot prices.[83] The cost per tonne of avoided CO2e implicit in such costs is far, far above the current carbon price in Canada.[84]

However, even if concerns about the viability of renewable gas are addressed and it becomes the primary pathway for decarbonizing buildings and industry, there will be significant implications for the cost-effectiveness of non-pipe alternatives. Specifically, any significant displacement of fossil gas with renewable gas will lead to significant commodity cost increases. It is just a question of how large those increases will be. Any such cost increases will inevitably put downward pressure on gas consumption (higher prices will lower demand), potentially affecting forecasts of need for infrastructure upgrades. They will also make some gas non-pipe solutions much more cost-effective because the value of avoided energy costs from geotargeted efficiency programs will be significantly increased.

---

[79] ICF notes that the focus on carbon policy will be on gas energy consumption rather than on peak demand and that any reduction in peak demand would be "serendipitous and not be design." (ICF 2018, p. 56) However, it is hard to imagine how key policies to reduce annual gas consumption, such as increased energy efficiency and electrification of gas end uses, would not also result in peak demand reductions. While there are some efficiency measures, such as smart thermostats, that provide annual gas savings without necessarily providing peak demand savings (or even potentially exacerbating peak demand if not coupled with demand response initiatives), the vast majority of gas efficiency measures have a downward effect on both annual energy consumption and peak demand.

[80] ICF, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, prepared for the American Gas Foundation, December 2019 (https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf).

[81] Based on U.S. Energy Information Administration data on 2019 U.S. natural gas consumption (https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm).

[82] The report estimated cost of $45 USD per MMBtu converted to Canadian dollars using a 1.30 exchange rate.

[83] U.S. Energy Information Administration data indicate the average Henry Hub spot price was $2.56 USD per MMBtu in 2019 and $2.39 USD per MMBtu in October 2020.

[84] For example, in a recent response to an interrogatory from the School Energy Coalition, Enbridge estimated that the effective cost per tonne of avoided carbon through procurement of renewable gas as $338 (EB-2020-0066, Exhibit I.SEC.15)

5.4.3 System Outage Risk Tolerance

ICF states that gas utility systems are designed with higher reliability standards – or lower tolerance for risk of outages – than electric utility systems. ICF suggests that the higher level of reliability required by gas utilities "increases the costs associated with monitoring and evaluating the impacts of Geo-Targeted DSM programs targeted at reducing infrastructure investments, and increases in risk of non-performance associated with the DSM programs…" While that may be true if all other aspects of IRP planning and deployment of geotargeting of DSM programs was the same between electric and gas utilities, they are not the same. For one thing, gas utility forecasts internalize much of the lower tolerance for risk of outages by basing estimates of future peak demands on more extreme weather than assumed by electric utilities in T&D planning. Furthermore, as ICF also observes, risk of non-performance by geotargeted DSM programs can be addressed by starting deployment of such programs a little earlier (or other means). While there may be added costs associated with starting earlier, there are also added benefits in the form of avoided energy costs, avoided carbon emissions and other related reductions in risk. Often efficiency programs will be cost-effective – i.e. pay for themselves – even without consideration of deferred or avoided T&D investments, making them a "no regrets" investment. Finally, even if the solution to the higher reliability standards for gas utilities is greater investment in monitoring and evaluation of geotargeted DSM programs, there is no evidence to suggest such additional costs would be large enough to materially affect the economics of the vast majority of non-pipe solutions.

5.4.4 Resource Planning

ICF states that electric utility IRPs review and assess "trade-offs between various generation and electricity purchase options" whereas gas utilities "only acquire resources from the market." First of all, it is not clear why this distinction is relevant to consideration of demand-side alternatives to T&D infrastructure investments. As discussed in sections 3.1 and 4.1, the purpose of IRP is to identify the mix of resources that meets utility system needs, in the context of relevant policy objectives, at lowest cost. Neither utility system needs (if properly defined to include all aspects of producing and delivering energy to customers) nor policy objectives are materially affected by whether the utility has responsibility for acquiring energy and peak capacity or is simply responsible for delivering energy to its customers. Second, the distinction ICF makes between electric and gas utilities is not applicable in the many jurisdictions in which electric utilities have been deregulated. Many electric utilities provide only distribution services and leave acquisition of energy and system peak capacity to competitive wholesale markets. Moreover, it is worth noting that many of the jurisdictions with the greatest experience with non-wires alternatives (e.g. New York, California and several New England states) have been deregulated.

5.4.5 Peak Hour Data Availability

ICF states that deployment of "smart" electric meters gives electric utilities access to more granular data on peak hour demands from each of their customers than is typically available to gas utilities from their customers. ICF suggests that this allows electric utilities "assurances through data" (which gas utilities do not have in the same way) that DER savings will be realized. Enbridge itself has also said that "to accurately design and verify the effectiveness of investments in non-pipe solutions, it is *necessary* to have access to actual hourly customer consumption data" (emphasis added).[85]

It is certainly true that access to smart meter data can enable more precise estimation of efficiency or demand response savings during peak hours of concern. Though ICF did not make this point (Enbridge may have been alluding to it), smart meter data also allow for target marketing of programs to customers who have the potential to provide the greatest peak savings. That said, it is important to be clear that smart meter data are *not necessary* to effectively run geotargeted DSM to defer T&D investments. Again, they can help, but they are not necessary. Indeed, there are many examples of electric non-wires alternative projects initiated in the 1990s and the first decade of the 2000s[86] – i.e. before electric smart meters were widely deployed. In fact, Con Edison, the New York electric utility that is arguably the leader in non-wires alternatives, initiated projects to defer distribution system investments in more than one-third of its distribution networks between 2003 and 2010.[87] Con Ed did not begin to install smart meters until 2017 and will not finish its smart meter roll-out until 2022.[88]

Moreover, in general, electric peak demands are comprised of a more diverse and more discretionary set of end uses than gas peak demands, which should mean that smart meter data are more valuable for understanding and forecasting DSM impacts for electric IRP than for gas IRP. Though cooling loads tend to be the most important peak demand end use in most North American jurisdictions, even in many northern states and provinces, cooling load contributions to peaks are typically smaller (as a percent of total peak loads) than heating load contribution to gas peaks. For example, as shown in Figure 1, cooling loads represent about two-thirds of the average residential customer's contribution to summer peaks (i.e. around 5 or 6 p.m.) in Massachusetts; on winter peak days, no one end use contributes more than about 40% of peak hour demand (around 7 or 8 p.m.).[89] In contrast, as shown in Figure 2, ICF's analysis for Enbridge suggests that space heating accounts for about 90% of the residential sector's peak hour demand.[90] Note that space heating also accounts for about 90% of Union residential customers' contribution to peak hour demand and both Enbridge and Union commercial sectors' contribution to peak hour demand.[91] This is important because most space heating efficiency measures should have savings that are approximately proportional to the difference between indoor and outdoor temperatures and therefore predictable with reasonable accuracy once estimates of annual savings are available. The one notable exception would be control measures, such as smart thermostats. However, smart thermostats need not be a focus of geographically targeted efficiency programs launched as part

[85] Exh. B, p. 35.
[86] Neme and Grevatt.
[87] *Ibid*., p. 20.
[88] https://www.coned.com/en/our-energy-future/technology-innovation/smart-meters/when-will-i-get-my-smart-meter
[89] Guidehouse, *Massachusetts Residential Baseline Study*, prepared for the electric and gas program administrators of Massachusetts, March 31, 2020.
[90] ICF 2018, Exhibit 46 (p. 100).
[91] Ibid, Exhibits 48, 50 and 52 (pp. 101-104)

of non-pipe solutions, unless they are installed in conjunction with demand response initiatives which would allow direct measurement of reductions in run time during peak hours of interest.[92]

Figure 1: Average Massachusetts Residential Customer Peak Day Loads by End Use

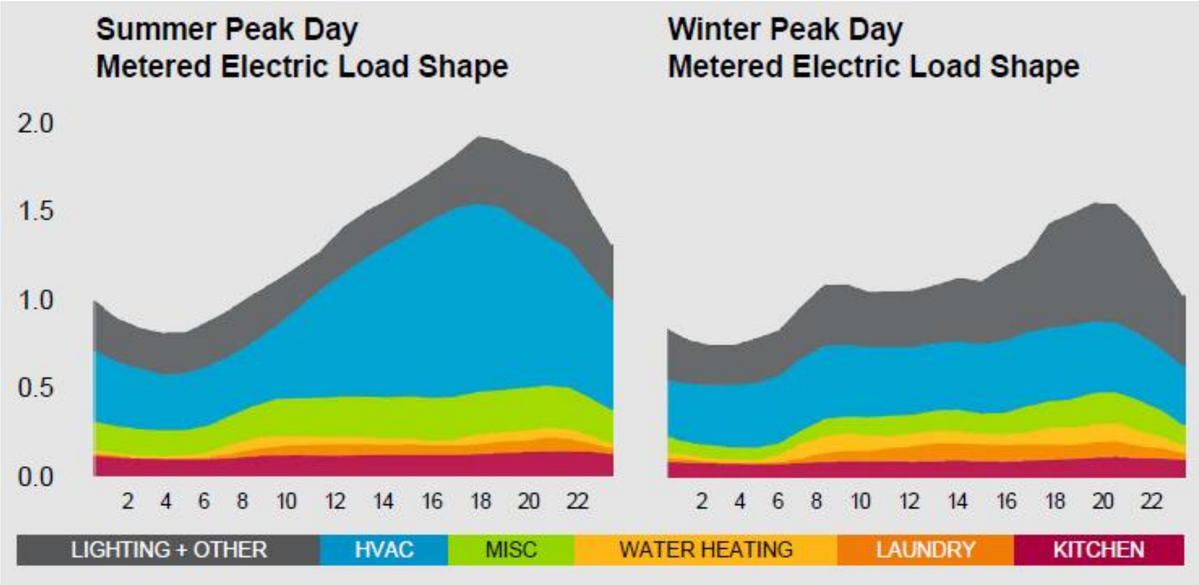
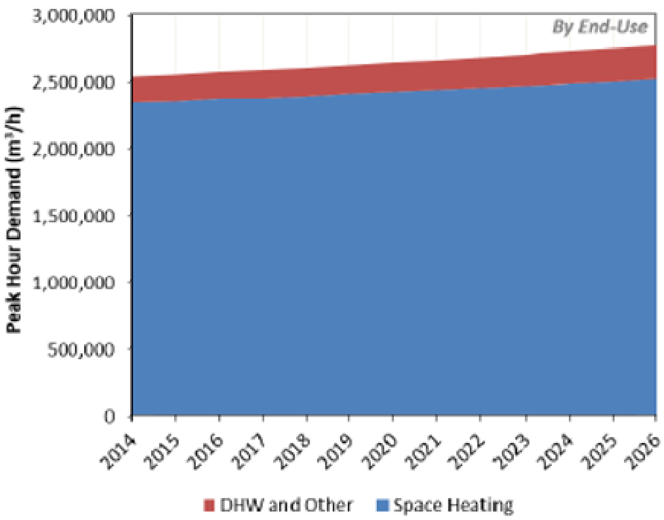


Figure 2: Enbridge Residential Sector Contribution to Winter Peak Hour Demand



[92] A pilot test of such demand response capability in California was promising, with average peak demand savings in the morning of 16% to 25% (Bell, Eric and Stephanie Bieler (Nexant), SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation, August 14, 2018).

5.4.6 The Bottom Line

There are certainly differences between electric and gas utilities that can affect the attractiveness of gas non-pipe solutions relative to electric non-wires solutions. However, it is unclear that the impact on the relative economics of gas non-pipe solutions is material. In fact, the potential for climate policy to significantly alter future demand for gas and/or the price of gas (if it needs to become increasingly renewable) could, by itself, make non-pipe alternatives more economically compelling more often than electric non-wires alternatives.