Enbridge Gas Integrated Resource Planning Proposal

OEB Staff Compendium

Panels 2 – 5

Examination

EB-2020-0091

March 2-4, 2021

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TAB 1

How will Enbridge Gas proceed with an IRP/IRPA?

73. Enbridge Gas will apply to the OEB for approval to recover the costs associated with investment in any IRPA. Enbridge Gas presumes that such an application would, similar to applications for LTC facility alternatives, include an explanation of the system constraint/need, a summary of stakeholder engagement input, rationale for investment in the IRPA, the estimated individual and overall costs of investment, proposed cost allocation and recovery methodologies, proposed ownership and operationalization arrangements and a commitment to ongoing annual monitoring and reporting on the relative effectiveness of the IRPA to relieve the identified constraint. To provide some certainty of the effectiveness of IRPAs as early as possible, Enbridge Gas will build off its existing evaluation, measurement and verification ("EM&V") expertise to determine how the IRPA or IRPA portfolio is progressing in relation to targets. Enbridge Gas will identify and, where possible, resolve unanticipated operational challenges or flaws in the design or delivery of IRPAs that could impede its ability to reliably serve the needs of customers. If no such resolution is reasonably possible, then Enbridge Gas will evaluate the potential of new/incremental/replacement IRPAs and may consider ceasing investment in existing IRPAs that are not achieving the peak period demand reductions originally forecast.

Cost Recovery – Like Treatment for Like Results

74. Enbridge Gas proposes that the costs associated with an IRPA be included in its revenue requirement. The nature of the benefits associated with investments in IRPAs is like the facility expansion/reinforcement projects that they serve to defer, avoid or reduce in that they resolve forecast system constraints/needs. Accordingly, Enbridge Gas maintains that its proposal to treat the costs (either or both capital and O&M) associated with planning, implementing, administering, measuring and verifying the effectiveness of its investments in IRPAs in the same manner as the

costs for facility expansion/reinforcement projects (capitalized to rate base) that IRP will defer, avoid or reduce, is reasonable and appropriate. Similarly, and assuming that Enbridge Gas is approved to capitalize the costs of investments in IRPAs to its rate base, allocating the costs of IRPA investments in the same manner as the capital investments they serve to defer, avoid or reduce is also appropriate since the resulting benefits of system efficiency, reliability and resiliency will be shared amongst ratepayers. Allocating costs in this manner will also ensure that ratepayers avoid rate volatility that could otherwise be caused by significant investment in geo-targeted IRPAs.

75. Certain intervenors have previously made submissions acknowledging that it may be appropriate for Enbridge Gas to be incented to pursue the assessment of and investment in IRPAs.[41] Consistent with its response to those submissions, Enbridge Gas reiterates that the goal of such incentives is to broaden the interests of the Company from solely earning on infrastructure to also and equitably earning from its successes in deferring, avoiding or reducing future infrastructure requirements through investment in IRPAs. In Enbridge Gas's view, the simplest and most effective means of creating a level playing field from which to prioritize IRPAs and new facility infrastructure is by ensuring that Enbridge Gas is equally incented between the two types of investments. Should the Board wish to encourage Enbridge Gas to prioritize investments in IRPAs, then it could consider adding an incentive for such successful investments, over-and-above the regulated rate of return earned (e.g., an incentive based on the net benefits achieved, similar to the

[41] EB-2020-0091, Environmental Defence Submission on OEB Draft Issues List, June 4, 2020, p. 3; EB-2020-0091, Green Energy Coalition Submission on OEB Draft Issues List, June 4, 2020, p. 1; and EB-2020-0091, Pollution Probe Submission on OEB Draft Issues List, June 3, 2020, p. 5.

TAB 2

one Enbridge prefers.

The IRP framework for Enbridge should stress the procedural fairness is a principle to which the Board will adhere when dealing with disputes pertaining to alternatives. Considerations of fairness call for procedures that will allow disputes about alternatives to be raised, considered, and determined in a timely manner. Such disputes should be considered when they first arise and not years later, when Enbridge has already committed to another option.

The phasing of a proceeding in which the material alternatives dispute arises should be adopted in specific cases where the OEB considers such a process to be warranted. Matters related to need and alternatives can be decided in advance of matters related to implementation.

The terms of the IRP framework for Enbridge should discourage Enbridge from frustrating a proper investigation by the OEB and those opposite in interest to Enbridge of an alternative other than Enbridge's preference.

As described above, opportunities exist for innovative IRPs such as LTFP or PDO delivery service. However, the reasonable pursuit of these solutions may require the Board's oversight. We understand the utility is seeking incentives, including the potential to capitalize O&M costs. Given the flow-through nature of our proposals, we do not believe the capitalization of flow-through costs would be appropriate. We believe that the utility may warrant a nominal incentive for facilitating the displacement construct to harness the capability of flows that are occurring in any event as a result of Enbridge shipments from Dawn to Parkway.

We recommend that the monitoring and reporting would be done through the rate-case filings for supply-side alternatives and not as part of a stakeholder day that Enbridge is advancing.

In conclusion, we believe that the time for IRP has come, and it needs to be supported by a sound regulatory framework. This evolution will require informed leadership and objective fact-based decision-making.

The foregoing is FRPO's perspective on how IRP should work for Enbridge, having regard to the issues list in this proceeding. FRPO thanks the Board for the opportunity to present our views and would be pleased to answer any questions that you may have about the contents of this presentation.

MS. ANDERSON: Thank you, Mr. Quinn. We will start with you, again, Ms. Frank.

MS. FRANK: I noticed that your presentation was very focussed on the supply side and opportunities on the supply side as part of an IRP. My question is, is the focus on the supply side driven by your feeling that that's the priority, that they should consider that first? Why is supply side getting so much attention from you?

MR. QUINN: Thank you for the question. In our view, supply side is under-represented in the evidence that is before the Board to this point in this proceeding. We had

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number of questions about different kinds of IRPAs. And if you could turn to Staff 17, I am just trying to understand your response to this.

You seem to suggest that you can only include electric heat pumps as an IRPA if Enbridge would own them. Is that Enbridge's position?

MS. SIGURDSON: No, that is not our position. What we're trying to say -- this is in section B of sub 17 specifically -- is it is would be market-dependent. So we see that in the case of air-source heat pumps, if there is a competitive market, then we would work with third parties within that instance.

But again, I think what we say here is we look at the facilities option, weigh that against the varying IRPAs, and then determine from a cost point of view, benefit to the ratepayers, which one would make the most sense for the ratepayer. And as Sarah talked earlier, and I think Adam yesterday as well, our thought there is in discussion of the IRPAs and the options that we have we would have that as part of the stakeholder discussion to flush out what the possible benefits would be.

MR. ELSON: And so Enbridge could include electric heat pumps as an IRPA where the customers own the equipment and Enbridge is only rate-basing the incentives?

MS. SIGURDSON: Well, the proposal here is again back to that like-for-like treatment, right? So we need to make sure -- and I think Adam spoke to that yesterday, and it's in Exhibit B, so the full cost, we have to do a full cost comparison, and so the modelling and the economics of what that entails, that needs to be done, and that would be part of the second base. We're looking for the direction from the Board on the framework to begin, and that will allow us to understand what is in scope and not in scope, and then that will determine which IRPAs to put forward. And then that would be subject to an IRPA application.

MR. ELSON: Yeah, so part of what I am getting at is in Staff 17 you said ownership of these assets could have a moderating impact on rate base if the result is a more cost-effective IRPA than otherwise. And I was worried that that was suggesting that your proposal is that you'll only include electric heat pumps if you own them, and you corrected that's not the case, and that's helpful.

MS. SIGURDSON: Correct.

MR. ELSON: And my next question, I think the answer is straightforward, and I have seen Adam nodding to this, which is that, assuming that it's cost-effective, Enbridge could include electric heat humps as an IRPA where customers own the equipment and Enbridge only rate-bases the incentives. At least that's the proposal.

MR. STEIRS: Yeah, I think, Kent, that Ravi represented this well, but I will reiterate that the intent here is to leave the door open broadly, in terms of configuration of IRPAs. So we're certainly not restricting ourselves or are intentionally not -- attempting not to restrict ourselves in terms of what arrangements, what combinations, permutations of ownership, and/or the nature

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on some of those IRPAs of that nature, and I certainly think we expect to earn a return on any IRPAs, or deserve to.

MR. PARKES: Yeah, yeah, absolutely, yeah, that's clear. So the question is -- yeah?

MR. KITCHEN: It is Mark Kitchen. You are correct. It is the 10 million that would be capitalized.

MR. PARKES: Okay. SO you can confirm that now then. Okay. Thank you. So in that event where you are earning the same rate of return on IRPA versus a facility project but the actual quantum of costs or the quantum you'd be earning that return on is quite different or could be quite different depending on which specific IRPAs come forward, is it fair to say that Enbridge is sort of accurately indifferent from a financial perspective as to which of those two solutions it's pursuing? And if it's not indifferent, then how does the Board sort of have the assurance that Enbridge is doing all it can to bring forward the lower-cost --

MR. STEIRS: Sorry, I guess I lost you at the tail end there, Mike, but I think you're asking, are we incented to pursue the solution, whether it be a facility or non-facility solution that's in the best interest of ratepayers, are we adequately incented to do so.

I think as long as we have like treatment per like results and we can rate base these alternatives and there's an OEB review of the alternative that we put forward as being the preferred one, and the Board supports that and ultimately agrees that it is in the best interest of the ratepayers, then I think everything's been squared. I think we are satisfied with the rate base treatment and satisfied and the Board and ratepayers are satisfied that they are being served with the optimal alternative.

MR. PARKES: So even if the dollar amount that you are looking to capitalize is quite different in those two, in the two projects you'd be comparing?

MR. STEIRS: Yeah, I think we'd have to look at the specific difference between those two. But I would expect that's the whole point of this proceeding is that we ensure that we are moving forward with the project that's in the best interest of ratepayers.

We have also signalled that going forward once we have a better sense of what the individual IRPAs are, we would be amenable to working with the Board or with a consultant to provide the Board with different scenarios of how we might square any further perceived imbalance in that regard to set up a proposed -- an additional incentive structure to avoid any situations where there may be, you know, a large discrepancy between a facility, the capital associated with a facility based on facility in comparison to a lower capital cost associated with an IRPA project.

MR. PARKES: Okay. Another follow-up in that area, and maybe we could turn to I-Staff 22. Yeah, if you can scroll down, I think just to the first part of the response here. Yeah.

So here you kind of break down the different types of

TAB 5

Stakeholdering

86. Enbridge Gas acknowledges the importance of stakeholder engagement in effective planning processes. Currently, various departments across Enbridge Gas gather information from external sources and stakeholders to inform regional growth projections, including: building permit information received from municipalities, new construction growth informed by housing starts forecasts, unemployment rates, natural gas commodity prices, vacancy rates, GDP, customer interests etc. Enbridge Gas's DSM team conducts stakeholder engagement directly with end use customers, customer associations and through research tactics to inform its multi-year DSM planning efforts. The DSM team also engages with municipalities in their municipal energy planning efforts, providing aggregated consumption data for the various municipal regions, and allowing these municipalities to benchmark natural gas consumption to inform their Community Energy Planning ("CEP") process. Further, formal customer engagement surveys are used to inform asset management planning and during certain rates applications (e.g., as part of Rate Rebasing).

87. Despite these extensive engagement activities, Enbridge Gas accepts that there may be room to enhance its stakeholder engagement in order to glean IRP-specific insights. These additional insights could be geographically-specific and include information on customer types (e.g., residential, commercial, industrial), socio-economic customer attributes, housing stock, saturation of current DSM programming, and an understanding of the status of electricity CDM programs as well as transmission and distribution capacity.

88. Accordingly, the objectives of the IRP Stakeholder Engagement process will be to: (i) ensure planned resources will meet Enbridge Gas's obligation to safely and reliably deliver firm contracted demands; (ii) gather ample geographically-specific

information such that IRPAs can be adequately reviewed and monitored; (iii) help inform the development of new or enhanced energy efficiency programming; and (iv) broadly inform Enbridge Gas's long-term strategic planning.

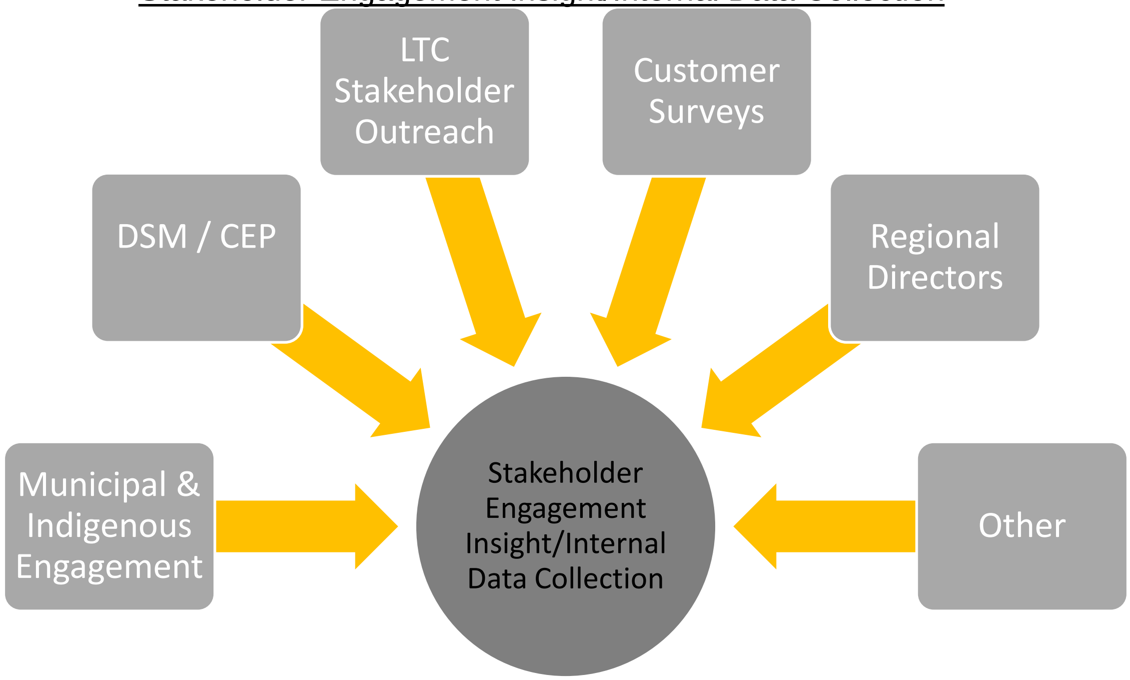
89. Stakeholder engagement for IRP will include three engagement components:

- Component 1: Gather and analyze data and insight from ongoing stakeholder engagement initiatives. These ongoing stakeholder engagement initiatives may be modified to elicit any new information required to enable IRPA analysis;
- Component 2: Discussion on IRP during Stakeholder Days;
- Component 3: IRPA project geographically-specific stakeholder engagement completed prior to filing a proposed IRPA with the OEB.

Component 1: Gathering of Stakeholder Engagement Data and Insight

90. As outlined in Figure 3.1, Enbridge Gas will seek insights from stakeholders and various market participants by working within existing stakeholder engagement channels to mitigate incremental expenses and leverage existing relationships. These existing channels to stakeholders include: municipal, First Nations and Indigenous engagement, DSM, market surveys, LTC stakeholder outreach, utility regional directors, outreach to customer associations and formal/informal dialogue with customers of all types (e.g., through sales representatives). Gathering of stakeholder data and insight will ideally occur on an ongoing basis.

Figure 3.1:
Stakeholder Engagement Insight/Internal Data Collection



Component 2: Enbridge Gas Stakeholder Days:

91. IRP will be included for discussion during regulatory stakeholder days (conducted as required by the OEB or as deemed appropriate by Enbridge Gas), allowing interested parties to ask questions and provide input on IRP-related matters and providing a regular opportunity to gain insights into Enbridge Gas's IRP planning and implementation activities.

Component 3: IRPA Project Geographically-Specific Stakeholder Engagement:

92. The final component of stakeholder engagement related to the IRP planning process will involve consultation dealing with specific IRPAs (identified for a specific need in a specific geographic region). The purpose of this component of stakeholder engagement is to share information about an identified IRPA with stakeholders from the specific geographic area relevant to the IRPA. Feedback from this consultation

work will inform and help shape any IRPA implementation proposal that might ultimately be filed with the OEB for approval.

93. Enbridge Gas proposes that this geographically-targeted stakeholder engagement should, at a minimum, mimic stakeholder outreach implemented as part of new infrastructure expansion/reinforcement projects and the resulting feedback should form part of Enbridge Gas's IRPA application in the same manner that such activities are included in LTC applications. For clarity, this consultation would certainly include municipalities in the area of impact for the IRPA, local Indigenous groups, local customers, builders and developers and other relevant stakeholders in that geographic area. Enbridge Gas notes that each geographic area being consulted regarding a particular IRPA(s) will have different attributes and may have unique stakeholders not previously referenced.

4.0 IRP Enabling Infrastructure

94. Enbridge Gas's current lack of actual measured peak hourly data makes it difficult to understand the actual potential of IRPAs with precision and will make it difficult to measure, verify and report on actual load profiles in the area as a baseline and subsequently, the effectiveness of IRPAs in reducing peak period demand. This knowledge gap increases the risk and, potentially, the cost to ratepayers of investments in IRP (e.g., if Enbridge Gas determines at some future point in time, through limited existing measurement data, that an approved IRPA has not performed as anticipated and that there is insufficient time to adjust the IRPA or to seek incremental IRPA investment). In its IRP Study, ICF recognized this gap and the limitations/risks inherent in proceeding with investment in IRPAs without this data. ICF found that "…until the gas industry invests in advanced metering

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32. Enbridge Gas does not support EFG's recommendation that the OEB establish a planning committee, modeled on Vermont's System Planning Committee ("VSPC"), to secure input throughout the planning process from key stakeholders.[28] The VSPC is comprised of representatives of stakeholder groups with an interest in electric system reliability. While a formal consultative structure has been used by the OEB in the past for natural gas DSM processes (e.g., the Stakeholder Input and Consultation Process established as part of Board's DSM Guidelines for Natural Gas Utilities (EB-2008-0346)), when dealing with natural gas facilities planning where decisions to advance or delay projects are based on regularly updated growth projections, such a formal consultative structure may prove overly cumbersome to navigate given the complexities of system design and planning. Further, facilities planning process risks are not just financial, there is also potential for gas system outages if there are insufficient facilities in place. This is a risk that is not present for standard DSM programs, where the associated risks are financial. Having a consultative model in a process where the risks are much lower may have been appropriate for natural gas DSM in Ontario at one time, but it no longer reflects the norm for natural gas DSM in Ontario and is not appropriate for a process where the utility is ultimately responsible for ensuring it can meet the firm contracted needs of its customers on a design day. However, to be clear, Enbridge Gas strongly supports consultation, as evidenced by its Stakeholder Engagement plan.

33. Enbridge Gas's multi-component approach to Stakeholder Engagement is similar to the stakeholder engagements seen in the IESO Integrated Regional Resource Planning Process ("IRRP") in the sense that it seeks to be informed by public input, making it somewhat more familiar to Ontario stakeholders, and offering a balance of utility planning knowledge and external stakeholder input to inform natural gas IRPA

[28] EFG Report, Section 4.2.4.

adoption in Ontario. However, unlike the IESO stakeholder model, Enbridge Gas proposes that development of natural gas IRPAs will be subject to OEB review and a litigated process following receipt of public input and consideration. This point is important as it offers an official and Board-led review of Enbridge Gas's IRPA projects and investments in a manner similar to facility infrastructure projects and investments in Ontario.

4.0 Cost Recovery and Shareholder Incentives

34. In its Report at page 51, Guidehouse recognizes the benefit of utilities being incentivized to invest in IRPAs above and beyond being allowed to capitalize the costs of and earn a regulated rate of return on investments in IRPAs similar to facility assets. Specifically, Guidehouse states:

> By agreeing to EAMs, the utility is incentivized to achieve higher levels of performance in areas of interest beyond simply meeting baseline performance expectations, and often to achieve greater cost-effectiveness than required. A more traditional rate-recovery strategy does not provide the utility specific areas of focus, such as performance targets, or additional incentive to go beyond minimum savings or cost-efficiency requirements. The incentive theoretically provides more upside earnings potential to the utility to stimulate its efforts in meeting the established target.

35. EFG supports Enbridge Gas's proposal that the costs associated with an IRPA could be capitalized and rate based similar to the facility expansion/reinforcement projects that they serve to defer/reduce/avoid. In its Report, at page 47 EFG states:

> 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-

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there's an analysis done to determine what the optimal solution is, is it a non-pipe solution, a pipe solution, or some combination of the two.

I think Enbridge has suggested that there may be a 3(a) and a 3(b) here, where, you know, 3(a) might be the viability of an IRPA, can we get enough resource to even worth -- make it worth looking at the economics, and then 3(b), you might be looking at the economics.

And then lastly, once you have done that analysis or the company has done that analysis, there is the development of a plan for whether it's an IRPA plan or an infrastructure proposal for how you are going to roll out and acquire the resources needed to address the constraint.

So with that context, I'd like to suggest that I think it's important that the process for consideration of IRPAs or non-pipe solutions really have two components to it, and the first is a robust and what I suggest a formal stakeholder process that would address at some level all four of those decision steps.

And in particular I think this is important because the ability to kind of seek input from parties that might have different perspectives and even in many cases different types of expertise and experience will -- should result in a -- in a more robust look at alternatives and ideally would also minimize disputes and therefore regulatory costs. I specifically suggest in my report that the Board consider adopting a formal committee structure similar to Vermont's system planning committee, which was set up more than a decade ago to kind of create a venue for consideration of non-wires alternatives in the state.

The -- this community in Ontario could be run by OEB Staff, akin to the way Staff currently run the Ontario gas DSM evaluation committee. It would have appointed members to represent a range of stakeholders and expertise. It would probably need to meet quarterly and perhaps have some subcommittees as needed. But it would be transparent and open to the public, so anyone who wanted to attend could do so.

So that's the stakeholder piece of this, the stakeholder engagement piece of this. I also think it's really important to think about the regulatory process and, in particular, that there be timely adjudication of all key decisions during which an IRPA is ruled either in or out, viable or not viable.

Again, in particularly, that would go to the, you know, the second, third and fourth of the key decision points I raised earlier, the binary screening or pre-screening process, the viability/economic screening process and then the plan.

The plan itself would presumably get -- the fourth stage would presumably get put before the Board in a leave-to-construct application, or an infrastructure investment, or in an IRPA plan. But I think it's really important that those two earlier steps, where IRPAs could be ruled in or out, are also approved by the Board in one way or another. And probably the best way to do that would be to require

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BY EMAIL AND WEB POSTING

August 21, 2015

To: **All Natural Gas Distributors**
All Participants in the Consultation Process EB-2014-0134
Other Stakeholders

Re: **2015-2020 Demand Side Management Evaluation Process of Program Results**
EB-2015-0245

This letter establishes the OEB's process to evaluate the results of Natural Gas Demand Side Management (DSM) programs from 2015 to 2020.

Background

As outlined in Section 7 of the OEB's Report on DSM issued December 22, 2014, the OEB will be taking a central role in the evaluation process of DSM program results. DSM programs will be evaluated on an annual basis, with results issued by the OEB to be used by the gas utilities when they file applications for recovery of amounts related to DSM activities.

DSM Evaluation Governance

The OEB will rely on the DSM evaluation governance structure outlined below. The evaluation governance structure describes the general role of the main parties involved in the evaluation process. The evaluation governance structure is expected to be fully implemented following the OEB's selection of an Evaluation Contractor.

OEB's DSM Evaluation Governance Structure	
Party	**Role**
OEB	The OEB is responsible for coordinating and overseeing the evaluation and audit process, including selecting a third party Evaluation Contractor and publishing the final evaluation results on an annual basis.
Evaluation Contractor (EC)	The Evaluation Contractor will carry out the evaluation and audit processes of all DSM programs.
Natural Gas Utilities	The natural gas utilities are responsible for developing an initial evaluation plan that will inform the evaluation of programs, filing an annual draft evaluation report and providing program data and coordination support to the Evaluation Contractor and OEB staff, as requested.
Evaluation Advisory Committee (EAC)	An Evaluation Advisory Committee (EAC) will be formed to provide input and advice to the OEB on the evaluation and audit of DSM results. The EAC will consist of representatives from non-utility stakeholders, independent experts, staff from the Independent Electricity System Operator (IESO), and observers from the Environmental Commissioner of Ontario and the Ministry of Energy, all working with OEB staff.

Evaluation Approach

The OEB will retain a third party Evaluation Contractor to undertake DSM program evaluations and annual audits of program results.

The Evaluation Contractor will draft an Evaluation, Measurement & Verification (EM&V) Plan for the natural gas utilities' DSM programs for approval by the OEB. The EAC will provide advice and input on the development of the plan as required. The EM&V Plan will, at a minimum, address the following:

- Annual Evaluation and Audit of DSM results
- Annual update of input assumptions
- Multi-year DSM program impact assessments and evaluation studies

The OEB-approved EM&V plan is expected to span a period of three-years to coincide with the mid-term review of both the 2015 to 2020 Natural Gas DSM Framework and Electricity CDM Framework.

Annual Evaluation & Audit Process

Consistent with current evaluation practices, the Evaluation Contractor will be responsible for auditing each gas utility's annual DSM results based on the three-year OEB-approved EM&V plan. The detailed annual evaluation and audit process will be developed as part of the EM&V plan.

Updating Input Assumptions

The Evaluation Contractor will review and propose updates to the OEB related to data within the Technical Reference Manual (TRM) on an annual basis. This review of the TRM will include proposed updates to input assumptions to reflect the findings of the annual DSM evaluation and audit. This may require additional research in order to add any new technologies to the TRM and improve the current list of assumptions.

Best efforts will be made to align the natural gas DSM input assumptions list with the electricity CDM input assumption list, where appropriate. The OEB is of the view that having alignment on resource savings amounts related to both natural gas and electricity energy efficiency technologies will help enable a greater level of integrated and collaborative program design and delivery.

Multi-Year DSM Program Impact Assessments and Evaluations

The OEB will engage the Evaluation Contractor to conduct multi-year impact assessments and targeted evaluations of selected natural gas DSM programs on a periodic basis throughout the 2015 to 2020 DSM period.

Within the Evaluation Contractor's multi-year impact assessments, the Evaluation Contractor will be responsible for undertaking various studies which may include estimating natural gas savings, undertaking net-to-gross studies, investigating free ridership rates and spillover effects, examining the level of persisting natural gas savings from various programs and conducting other evaluation studies as required.

Transition Plan

The OEB recognizes that there is a current evaluation process underway, led by the natural gas utilities with support from three committees: the Technical Evaluation Committee (TEC), and two Audit Committees (one for each utility). The committees are comprised of natural gas utility staff, industry stakeholders and independent experts.

The current responsibilities of the TEC include the development of the Technical Reference Manual (TRM), the completion of a Commercial and Industrial Custom Project Net-to-Gross Study, a joint utility Boiler Baseline Study, and the initiation of a Persistence Study. This is important work that should continue at this time. The evaluation and audit of all natural gas DSM program results under the new 2015–2020 DSM Framework will follow the new process outlined in this letter. Once an Evaluation Contractor is retained by the OEB, OEB staff will work with the TEC on an appropriate plan to transition to the new framework on a go-forward basis. With the formation of an Evaluation Advisory Committee (EAC), as described below, an Audit Committee will no longer be required.

Formation of the Evaluation Advisory Committee

The Evaluation Advisory Committee (EAC) will provide input and advice as required throughout the DSM evaluation process. The EAC will be comprised of:

- Experts representing non-utility stakeholders, with demonstrated experience and expertise in the evaluation of DSM technologies and programs, natural gas energy efficiency technologies, multi-year impact assessments, net-to-gross studies, free ridership analysis and natural gas energy efficiency persistence analysis
- Expert(s) retained by the OEB
- Representatives from the IESO
- Representatives from each natural gas utility
- Representatives from the Ministry of Energy (MOE) and the Environmental Commissioner of Ontario (ECO), who will participate as observers

The OEB has recently selected a group of experts representing non-utility stakeholders to provide input and advice as part of the DSM Technical Working Group formed for the natural gas conservation potential study. As the technical expertise and experience required for both the DSM Technical Working Group and EAC are similar, the OEB has appointed the same individuals to represent non-utility stakeholders on the EAC as follows:

- Chris Neme, Energy Futures Group
- Jay Shepherd, Jay Shepherd Professional Corporation
- Marion Fraser, Fraser & Company

Due to a potential conflict, Ian Jarvis, who is a member of the DSM Technical Working Group, has not been included as a member of the EAC.

In reviewing nominations from non-utility stakeholders as part of the formation of the DSM Technical Working Group, the OEB considered the diversity of their expertise, their participation in similar OEB proceedings and working groups and their experience with the Ontario natural gas sector, as well as their ability to represent stakeholders. The selected candidates are expected to provide input and advice based on their experience and technical expertise and not to advocate position of parties they have represented before the OEB in various proceedings.

The OEB will determine the appointment of additional experts following the selection of an Evaluation Contractor.

Cost Awards

Cost awards will be available under Section 30 of the *Ontario Energy Board Act, 1998* to eligible persons in relation to their participation in the Evaluation Advisory Committee or other consultations during the course of the DSM evaluation process. Details will be provided at the appropriate time. Costs awarded will be recovered from all rate-regulated natural gas distributors based on their respective distribution revenues.

If you have any questions regarding this consultation process, please contact Josh Wasylyk at Josh.Wasylyk@OntarioEnergyBoard.ca or at 416-440-7723.

The OEB's toll free number is 1-888-632-6273.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

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b) If Enbridge Gas intends to keep the scope of the Asset Management Plan at 5 years, would it still undertake longer-term demand forecasting and needs identification (e.g. on a 10-year basis), and if so, in what format?

c) Is inclusion within the Asset Management Plan the first stage at which a potential system need (and proposed "baseline" solution) would come to the attention of the OEB and other stakeholders outside of Enbridge Gas? If not, please explain.

d) Does Enbridge Gas have any views on EFG's suggestion regarding providing a public summary of longer-term needs and planning status? If Enbridge Gas supports this idea, does Enbridge Gas believe this information would be best presented as part of its Utility System Plan/Asset Management Plan, its proposed annual IRP monitoring report, or in a separate process?

e) What information does Enbridge Gas propose to provide to the OEB and stakeholders regarding the status of IRPA consideration in response to identified system needs, and when? (e.g. Enbridge Gas's determination based on its binary screening criteria as to whether any form of IRPA should be considered further; Enbridge Gas's plans/actions for further IRPA analysis for system needs that passed the initial screening, etc.)

   Does Enbridge Gas believe this information would be best presented as part of its Utility System Plan/Asset Management Plan, its proposed annual IRP monitoring report, or in a separate process?

f) Does Enbridge Gas believe that its determinations regarding system needs and the potential role of IRPAs should be subject to formal OEB review at any stage prior to Enbridge Gas's application for project-specific approval (IRP Plan/Leave to Construct)? Please explain why or why not.

<u>Response</u>

a) & b)
   Yes, Enbridge Gas intends to increase the scope of the Asset Management Plan ("AMP") back to 10 years in support of longer-term planning initiatives such as IRP.

c) Yes, the first stage at which the OEB and the majority of stakeholders will see identified system constraints/needs and any IRPA(s) and comparable baseline facilities is in the AMP. However, in some instances, Enbridge Gas may work directly with specific stakeholders at an earlier time to review and assess their specific needs on the system and to discuss baseline facility alternatives and potential IRPAs.

d) & e)
Enbridge Gas proposes that the AMP be used to present the long-term needs and IRPA planning status to the Board.

Once the OEB has established an IRP Framework for Enbridge Gas, the Company will begin to reflect IRP details in the AMP, which is filed with the Board to support rate applications. The AMP will identify potential IRPAs within the 10-year time forecast period, including details regarding baseline facility alternatives, IRPAs considered, the rationale for the alternative selected and proposed timing. Enbridge Gas will continue to monitor the underlying constraint/need and update the AMP accordingly if the constraint/need or alternative(s) selected changes until such time that either the baseline facility alternative or IRPA is implemented.

Enbridge Gas will also either file an IRPA application for an IRPA/IRPA portfolio or an application for leave-to-construct ("LTC") facilities which will provide additional details to the OEB and stakeholders as part of the OEB's review of the same

Enbridge Gas also proposes to file an annual IRP Report that documents the progress of any IRPA being planned and implemented.

f) No, Enbridge Gas believes that the only determination required from the Board related to IRP should be for approval of the IRPA applications when filed. As noted in the responses above, details regarding Enbridge Gas's identified system constraints needs, baseline facility alternatives, and potential IRPAs will be filed within the AMP as part of Enbridge Gas's rate setting applications and will be open to discovery and comment by the OEB and intervenors at that time. The OEB and intervenors/stakeholders will also be afforded additional opportunity to further review baseline facility alternatives and potential IRPA(s) at such time that Enbridge Gas files subsequent applications with the Board for approval to invest in IRPA(s)or for LTC facilities and at such time that the Company seeks to recover the costs associated with such investments (the latter being limited to confirming that Enbridge Gas has implemented alternatives in accordance with OEB-approved IRPA/LTC applications prudently). Please see the response at Exhibit I.STAFF.10, for further discussion of the approvals that Enbridge Gas intends to seek from the Board related to future investments in IRPA(s).

TAB 10

NEW YORK STATE
DEPARTMENT OF PUBLIC SERVICE

CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures.

STAFF GAS SYSTEM PLANNING PROCESS PROPOSAL

(Filed February 12, 2021)

Commission has the authority to have an audit conducted by independent auditors to investigate a "…company's construction program planning in relation to the needs of its customers for reliable service…," and reviewing the long-term gas system planning process at each LDC falls under such authority.

Stakeholder Participation

The gas system planning process must include substantial education and stakeholder engagement. Each long-term gas system plan will include the information necessary to clearly explain the planning, design, and implementation development so that the output of the process effectively addresses the reliability needs of natural gas customers and the interests of stakeholders.

Each LDC will host a technical conference three to four weeks following its initial filing. Stakeholders may participate in the technical conference to perform initial due diligence and may follow up with requests for information from the LDC.

The Department will issue a notice seeking comments regarding the LDC's filing shortly after it is received. Stakeholders may then file comments in response to that notice. Comments from stakeholders should include their proposals for alternative solutions to any utility proposed solutions for identified constraints or other projects that would add infrastructure valued in excess of an established cost threshold. Upon completion of the comment period, LDCs will host stakeholder meeting(s) to reconcile different proposed solutions, as necessary. The utilities will then file, at most 30 days after the end of the comment process, a revised long-term plan.

In the event that stakeholders disagree with the revised filing made by the utility, they can file written explanations of their disagreement(s) within 30 days of the filing of the revised plan. The LDC will host a stakeholder meeting to discuss areas of disagreement and any comments received on its filing. Where there are disputed issues, the Commission has the option to decide whether to approve the plan as filed by the utility or direct modifications.

If there are no disputed issues on the long-term plans, the Commission has the option to take action on the plan, i.e., adopting, modifying, or rejecting it, in whole or in part. If the Commission is not expected to take any action on the revised plan, the Director of the Office of Electricity, Gas and Water will issue a letter to the utility stating that no further action on the LDC's plan is anticipated. At that point, the utility's revised long-term plan will be considered to be in effect.

Annual Reports

As explained above, every three years each LDC will file a new long-term gas system plan. In addition, each LDC will file an annual report to help stakeholders continue to develop and maintain their awareness and understanding of the LDC's plan. The annual report is not required in the year a long-term gas system plan is filed. All annual reports much include:

1. An explanation of the LDC's progress on its most recent long-term gas system plan;
2. Detail the LDC's plans for implementing all necessary processes, policies, resources, and changes in standards impacting gas operations and supply;

TAB 11

Problems w/Enbridge Proposal

- 1-day stakeholder meeting per year
  - Enbridge suggests this where most questions can be posed and answered
  - Woefully inadequate to consider all key decisions points for all parts of system
- Conclusions documented in Asset Management Plan, but…
  - No formal interrogatory process on IRPA decisions
  - No adjudication of IRPA decisions
- No adjudication until LTC, IRPA proposal, or rate-basing (for <$10M)
  - Often too late to consider and implement non-pipe solutions…
  - …so Board will often be left with no real choice

TAB 12

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 33-34 of 46; OEB staff evidence (Guidehouse report) / pp. 50-51 of 77

Additional Public Documents: Ontario Energy Board, Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario (EB-2009-0152), January 15, 2010, section 3.2.4; Consolidated Edison Company of New York, Inc, Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure / pp. 26-31 of 33.

Preamble:

Enbridge Gas notes that the simplest and most effective means of creating a level playing field between IRPAs and facility infrastructure is by ensuring that Enbridge Gas is equally incented between the two types of investments (by earning an equal return on investment). Enbridge Gas suggests that the OEB could potentially consider an additional incentive above the regulated rate of return if it wished to prioritize IRPAs, but that the topic of incentives might be appropriately examined in a separate study.

Guidehouse discusses the incentive proposal included as part of Con Ed's Non-Pipeline Alternatives framework filing. The Con Ed proposal itself provides additional detail on this proposed incentive mechanism.

Question:

a) Enbridge Gas notes that ensuring it is equally incented between IRPAs and facility infrastructure would create a level playing field between these two types of investments (i.e. specific IRPA performance incentives may not be necessary). Does Enbridge Gas believe that this position might change if other elements of Enbridge Gas's IRP proposal (risk, approval mechanism, etc.) are modified by the OEB – i.e. would incentives then be necessary to overcome perceived risks associated with spending on IRPAs?

b) Enbridge Gas notes that a performance incentive for IRPAs could potentially be based on the net benefits achieved (in comparison with a facility project), which is the form of incentive proposed by Con Ed. Has Enbridge Gas considered a different form of performance incentive that could provide a (potentially higher)project-specific rate of return to address the perceived higher risk associated with IRPAs, as described in section 3.2.4 of the referenced OEB report, and if so, does it have any views on this type of incentive?
c) Con Ed's incentive proposal includes both a performance incentive (based on net project benefits relative to a traditional infrastructure solution) and a bi-directional cost-containment incentive, that could reward (or penalize) Con Ed for reducing(or increasing) the cost of the non-pipeline alternative during the implementation phase. Does Enbridge Gas believe that a cost-containment incentive could have value in the context of an Ontario IRP Framework, and if so, does Enbridge Gas believe that this type of incentive (as well as performance incentives) could also be examined in a separate study, outside of the initial review of Enbridge's IRP proposal?
d) Does Enbridge Gas believe that the IRP Framework should include any form of penalty if the OEB determines (e.g. in a decision on a Leave to Construct application) that Enbridge Gas failed to give adequate consideration to IRPAs and that Enbridge Gas's actions have had cost consequences for its customers? Why or why not?

Response

a) Enbridge Gas remains of the opinion that ensuring it is equally incented between IRPAs and facility alternatives will create a level playing field between these two types of investments.

   Please also see the responses at Exhibit I.CCC.17 and Exhibit I.EP.6, for discussion of IRP/IRPA related risk and incentives.

b) & c)
   Enbridge Gas notes that in addition to rate base treatment and the net benefits sharing proposal made by Con Ed, Con Ed also has a performance incentive to encourage cost containment around IRPA implementation.

   Enbridge Gas is open to considering incentive mechanisms. If the Board determines that investments in IRP should be prioritized then the Company should be adequately incentivized to undertake IRPA investments and the Board should recognize that as natural gas IRP is a new concept across North America there will necessarily be increased risk associated with such investments. These incentives might be a sharing of net benefits between customers and the utility shareholder, 70/30 as was done by Con Ed. In any case, Enbridge Gas's preference would be to have the opportunity to provide informed recommendations in this regard to the Board.

Enbridge Gas has reviewed the Con Ed cost containment performance incentive and is not convinced it is applicable in the Ontario context at this time. Con Ed's non-pipeline alternatives are being driven in large part by the natural gas pipeline moratoria in New York, which creates a specific urgency for the Con Ed non-pipeline solutions, hence the development of a cost containment incentive that works within the band of net benefits that can be achieved. For clarity, Con Ed's rate base approach plus sharing of net incentives has no penalty. They only penalize Con Ed within the band of the net benefit sharing should they not stay within forecasted costs up to a threshold amount that sees them still retain the rate base incentive. Enbridge Gas notes that at the outset of every new policy framework there is necessarily an adjustment period required where the Board and utilities learn and adjust in order to achieve optimal outcomes. Enbridge Gas is recommending that further exploration of incentives be the topic of a separate study completed outside the initial review of Enbridge's IRP Proposal.

d) As of the date of this submission, Enbridge Gas has complied with all OEB statements encouraging the consideration of IRP (please see section 1.0 of Enbridge Gas's Additional Evidence for a summary of these findings/statements). OEB Staff's expert evidence recognized at page 3, the fact that the Board and Enbridge Gas have taken a proactive approach to establishing a natural gas IRP Framework for Enbridge Gas:

> "Enbridge Gas and the OEB have taken a proactive approach to develop a Gas IRP framework. Enbridge Gas's proposed goal is to develop a framework to guide Enbridge Gas's assessment of IRP alternatives (IRPAs) relative to other facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers. Ontario already has a framework for the deployment of natural gas Demand Side Management (DSM) programs. Enbridge Gas's IRP Proposal includes a definition of eligible IRPAs, screening and selection criteria for IRPA vs. traditional facility projects, monitoring and reporting guidelines and other elements that attempt to solidify the IRP Framework as a standalone construct that is distinct from the DSM and facility project frameworks."

Following the Board's direction to complete and IRP Study and to propose a preliminary Transition Plan as part of its 2015-2020 DSM Framework,[1] EGD and Union worked together with ICF Canada to comply and presented an executive summary of the IRP Study and an IRP Transition Plan to the Board and parties as part of the Board's Mid-Term Review of the 2015-2020 Demand Side Management (DSM) Framework for Natural Gas Distributors (EB-2017-0128/0127). As part of the IRP Study, ICF identified outstanding policy issues and concluded that:[2]

> "Change in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce facility investments."

ICF went on to explain that these changes would include:[3]

> "Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks. Approval to invest in, and recover the costs of the AMI necessary to collect hourly data on the impacts of DSM programs and measures. Changes in the approval process for DSM programs to be consistent with the longer lead time associated with facilities planning. Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facility investments. Guidance on cross-subsidization and customer discriminations inherent in geotargeted DSM programs that do not provide similar opportunities to all customers. Guidance on how to treat conflicts between DSM programs designed primarily to reduce investment in new infrastructure and DSM programs designed to reduce carbon emissions or improve energy efficiency. Guidance on how to treat uncertainty associated with energy-efficiency programs outside the control of the Gas Utilities that impact peak hour and peak day demand."

Accordingly, and consistent with the Board's further encouragement as part of its Report on the Mid-Term Review of the 2015-2020 Demand Side Management (DSM) Framework for Natural Gas Distributors (EB-2017-0128/0127) to advance natural gas IRP Enbridge Gas included its original IRP Proposal as part of its 2021 Dawn Parkway Expansion Project application and evidence in support of establishing an IRP Framework that addresses the changes/gaps identified by ICF in its IRP Study and to guide the Company's assessment of IRPA's relative to other

[1] 2015-2020 DSM Framework, p. 36.
[2] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. 167.
[3] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. 168.

facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers. Enbridge Gas's IRP Proposal and related efforts to date are evidence of its compliance with the Board's encouragement to advance natural gas IRP and reflect the novelty of natural gas IRP across North America.

Further, it should not be lost that Enbridge Gas has long been engaged in passive forms of IRP having successfully conducted natural gas conservation/demand side management programs and having made interruptible services available to its customers for decades.

Overall, Enbridge Gas has shown commitment to the serious consideration and practical implementation of natural gas IRP in Ontario consistent with the Board's previous statements encouraging the same. Considering the above, in the absence of any evidence to the contrary, it is premature and unnecessary for the Board to contemplate the imposition of penalties upon Enbridge Gas for inadequate consideration of IRPA(s) as part of future applications for leave-to-construct ("LTC") facilities. Instead, the Board should focus upon establishing an IRP Framework for Enbridge Gas that provides the guidance necessary to support consideration of IRPA(s) relative to other facility and non-facility alternatives going forward.

As a natural gas distributor with an obligation to prudently serve the firm contractual demands of its customers in Ontario, Enbridge Gas already carries the responsibility to ensure that it considers the optimal and most prudent solutions for ratepayers. In the future, following the establishment of an IRP Framework for Enbridge Gas and as part of its review of future LTC applications, should the Board determine that the Company's consideration of IRPA(s) was deficient and caused undue costs for ratepayers, that would be the appropriate time to consider whether the Company should be subject to penalties based on the best available information and with consideration for the specific circumstances at that time. It is premature to establish punitive penalties at this time.

Please also see the response at Exhibit I.EP.6, for discussion of the risk to ratepayers of investments in natural gas IRP.

TAB 13

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 11 of 24; Exhibit B / pp. 19-20 of 46; OEB staff evidence (Guidehouse report) / pp. 29-31 of 77

Additional Public Documents: Enbridge Gas Inc. 2021-2025 Asset Management Plan (filed October 15, 2020; EB-2020-0181), Exhibit C, Tab 2, Schedule 1, Tables 6.1-3, 6.1-4, pp. 257-259); Consolidated Edison Company of New York, Inc, Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure / p. 5 of 33.

Preamble:

Enbridge Gas proposes criteria for a binary screening that would be used to determine which system needs would require consideration of IRPAs. Guidehouse provides a discussion of Consolidated Edison Company of New York's (Con Ed's) Non-Pipeline Alternatives Framework Proposal as to which types of projects could likely be considered for IRP solutions, which can be compared with Enbridge Gas's proposed criteria.

Question:

a) Has Enbridge Gas reviewed Con Ed's proposed screening criteria? Does Enbridge Gas believe that there are any differences between Enbridge Gas and Con Ed's circumstances that have led to differences in proposed screening criteria? If so, please describe.
b) Enbridge Gas's original IRP proposal included a proposed screening criterion that IRPAs would only be considered in areas with a maximum annual forecasted load growth of 1.4%. Please confirm that Enbridge Gas is no longer proposing that load growth be an element of the binary screening for the relevance of IRPAs, and if so, why Enbridge Gas has proposed removing this criterion.
c) Please provide more clarity as to Enbridge Gas's proposed exemption criterion for safety. Does Enbridge Gas intend this criterion to apply only to projects that need to be addressed immediately, or also to projects where Enbridge Gas intends to

address safety/integrity issues over a longer period of time? For comparison, Con Ed proposes a similar criterion which is limited to "emergent safety risks" that must be resolved as quickly as practicable. Con Ed gives the examples of "replacement of leaking services; replacement of gas mains with active leaks; replacement of main segments due to water intrusion or contractor damage; and replacement of cast iron main due to encroachment activity."

d) Enbridge Gas proposes that projects where system needs must be met in under 3 years would be exempt from IRP consideration. Based on Enbridge Gas's historical experience and its needs identification process, how often do facility expansion/reinforcement system needs arise that would not have been identified more than 3 years in advance? Please describe.
e) Is Enbridge Gas's proposed exemption criterion for "Customer-specific builds" limited to projects that would not impose additional supply or infrastructure costs on Enbridge Gas ratepayers other than the specific customers the projects are intended to connect?
f) Is Enbridge Gas's proposed exemption criterion for "Community expansion &economic development" driven by policy and related funding limited to specific named projects that have been listed as being eligible for rate reduction (e.g. those currently listed in in O. Reg. 24/19 ("Expansion of Natural Gas Distribution Systems")? If additional funding was made available to Enbridge Gas to support community expansion projects, but was not allocated to specific projects, would Enbridge Gas propose that the community expansion projects it chose to pursue with this funding would also be exempt from IRPA consideration? Please clarify what (if any) other factors would exempt a project from IRPA consideration under this criterion.
g) Taking into account both Enbridge Gas's proposal to limit IRP to facility expansion/reinforcement projects, and the additional exemption criteria proposed by Enbridge Gas, please indicate which of the ICM-eligible projects shown in Tables 6.1-3 and 6.1-4 of Enbridge Gas's 2021-2025 Asset Management Plan(pp. 257-259) would have likely been determined to be suitable for further consideration of IRPAs, had these criteria been in place. For projects determined not to be suitable, please indicate which criterion/criteria would have disqualified them from further consideration of IRPAs.

<u>Response</u>

a) – c)

Enbridge Gas evolved its thinking on binary screening related to IRP assessment in the period between filing its original 2019 IRP Policy Proposal and the October 15, 2020 Additional Evidence. Enbridge Gas considered in more depth what factors should constitute a more definitive screening and which items, although insightful, might not absolutely preclude the possible viability of a IRPA such as load growth rate, or project cost, especially when the Company broadened its thinking beyond incremental traditional DSM programming, as had been explored in the May 2018 ICF IRP Study.

Enbridge Gas has reviewed Con Ed's NPA Framework and the screening criteria. Enbridge Gas feels its screening criteria are similar to Con Ed's and remain appropriate. Con Ed in discussing its screening criteria show two things:

i. They outline by way of specific example projects that are a fit for NPA (IRP) are gas distribution infrastructure projects associated with load growth. Indeed, Enbridge Gas sees projects driven by load growth to be the projects best suited to IRP analysis as well especially as the Company is developing practical experience with IRP.
ii. That Con Ed articulates emergent safety risks, which includes gas leaks, being out of scope. This is in line with Enbridge Gas's proposal. Con Ed indicates in their NPA Framework on page 5, that they are looking at reviewing all other safety and resiliency projects for NPA recognizing that it is nascent learning.

> "Instead, under this Framework, the Company [Con Ed] proposes to evaluate planned safety- and reliability-related infrastructure projects (e.g., planned future work under its Main Replacement Program) for replacement using an NPA and attempts to shed light on the many unanswered questions in this uncharted territory."

Enbridge Gas notes that Con Ed is a joint gas and electric utility which may provide it some inherent ability to benefit from a transition to electricity solutions.
Although Enbridge Gas believes that year over year forecasted load growth is an important factor within a Stage 1 analysis on IRPAs, the Company is no longer proposing a specific threshold for load growth after which an IRPA should not be considered. Enbridge Gas feels that the 1.4% was a finding out of ICF's May 2018 IRP Study which may be appropriate for geotargeted DSM as an IRPA but may or may not be appropriate for other IRPA solutions or portfolios of solutions.

At the outset, as Enbridge Gas is gaining comfort with IRPAs and how to effectively plan around them, it is proposing that all safety or integrity related projects are screened out. Enbridge Gas notes that in addition to 'emergent safety risks', Con Ed has also scoped out regulatory requirements that include main replacements for methane reduction. Between the categories under emergent safety and the regulatory requirements, Enbridge Gas believes there may be little difference between what it has proposed with a broader safety screen and what Con Ed has proposed.

d) Most significant investments (those requiring Leave to Construct approval of the OEB) would be identified with more than three years' notice through Enbridge Gas's long-range planning processes. This process identifies projects up to ten years in advance.

The projects that are required more urgently are typically smaller in scope and cost.

Please see the response at Exhibit. I.STAFF.4 a), for discussion of forecasting and need identification processes. In addition to this, Enbridge Gas monitors the gas distribution network for emergent areas of low pressure or capacity constraints. These would typically require immediate remedy.

Projects identified through the long-range planning process would typically be suitable for IRP consideration, if required more than three years in the future. Those identified through the emergent process would not.

e) Yes, the exemption criterion for 'Customer-specific builds' would be limited to projects where no other customers were connecting or deriving value.

f) Yes, Enbridge Gas's proposed exemption criterion for 'Community expansion and economic development' are driven by policy and funding related to projects specific to O. Reg. 24/19 (Expansion of Natural Gas Distribution Systems). If additional funding was made available to Enbridge Gas to support community expansion projects, but was not allocated to specific projects, Enbridge Gas would include consideration of IRPAs.

g) Tables 6.1-3 and 6.1-4 from Enbridge Gas's 2021-2025 Asset Management Plan tables are replicated below for reference.

TAB 14

NEW YORK STATE
DEPARTMENT OF PUBLIC SERVICE

CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures.

STAFF GAS SYSTEM PLANNING PROCESS PROPOSAL

(Filed February 12, 2021)

of those metrics that will establish that a reliability issue exists. Additionally, and in particular, design day standards should be re-examined and re-validated in each LDC's initial long-term plan. The initial long-term plan should also propose a frequency for subsequent re-examination and re-validation of design day standards.

Capital Projects

The long-term plan should identify any infrastructure constraints, both by location and timing. Locational constraints can by localized to a specific municipality, only a part of a given municipality, to a borough or to an area larger than one municipality.

Where an LDC identifies a gap between forecasted supply and demand in the planning process, in addition to traditional supply-side solutions, the LDC should include all reasonable demand management programs, including a no infrastructure alternative, which requires consideration of other approaches to reduce gas demand. LDCs should examine the possibility of expanding demand response, electrification and energy efficiency programs using appropriate incentives. LDCs should also consider utilizing combinations of solutions to close the gap.

Traditional gas capital projects and programs involving the construction of new pipelines or the replacement or expansion of existing pipelines may be potentially suitable for an NPA. Staff proposes that a two-prong screening approach for NPA evaluation should be used for a forward screening of traditional capital projects and programs. Staff would expect projects addressing conditions that pose an immediate threat to system reliability and/or public safety, or where construction is imminent, i.e., within 12 months, such as immediate work related to gas leaks or high priority leak-prone pipe segments, would be exempted from consideration for a NPA.

Opportunities to merge the retirement of leak-prone pipe with an NPA should be explored. Thus, utilities should assess whether a segment of main and associated services can be retired, and an alternative energy approach can supplant renewing the natural gas assets. A process to search for such opportunities should be developed and implemented. For areas experiencing specific economic development demands, LDCs should balance NPA solutions to address both the energy demand needs of the surrounding project service area along with providing the gas supply needs for demand that does not have acceptable alternatives to natural gas from an economic or technological standpoint.

The first track would be a comprehensive review for larger projects (Comprehensive Track), i.e., those with a cost of $2 million or more, requiring a full-scale solicitation of NPA alternatives followed by a benefit cost analysis (BCA) of potential solutions. This should be performed prior to detailed engineering, permitting, and construction, and before more than 5% of the total project cost has been spent.

Smaller projects would utilize an expedited standardized review approach (Expedited Track), including a streamlined economic and technical analysis. The purpose of this is to determine the potential economic and technical feasibility of an NPA that may or may not include a full-scale solicitation for NPA options. This approach should take advantage of existing known alternative solutions with identifiable costs.

Staff recommends that the dollar threshold between the Comprehensive Track and Expedited Track be adjusted accordingly for each LDC to better reflect the existing internal

TAB 15

gas demand how that may vary in reality from what you had forecast at the time investment decisions were made.

So that could be due to climate change policy, or multiple other factors, and how should Enbridge's planning address the risks associated with that possible deviation.

So there are arguments, I think, both for and against addressing this topic within the IRP framework. On the con side, I think it's fair to argue that forecasting methodology, risk of changes in policy market conditions, and treatment of stranded assets are all broad system planning issues that are not new with IRP and, you know, predated any consideration of IRP alternatives and were probably not at the top of the OEB's mind when it initially directed Enbridge to look at alternatives to infrastructure.

But on the pro side, there's an argument to be made that IRPAs can offer some unique value in comparison to facility projects in dealing with risk associated with deviations from natural gas demand forecast, in terms of perhaps being more modular than facility projects and at least with some IRPAs, lower carbon in nature and thus more resilient to future climate change policy implications.

So Enbridge's proposal, as I noted, doesn't really address this topic. But it will be discussed, I know, by Green Energy coalition later. And I did want to flag a that in the New York State proceeding, they have indicated, at least at a high level, that this topic would be dealt with in some fashion, as you can see from the quote there.

TAB 16

40. EFG argues that the Board should monetize various economic risks including environmental regulation uncertainty; peak demand forecast uncertainty; gas market price uncertainty; investment cost forecast uncertainty; and stranded asset risk. Throughout its discussion of economic risk EFG appears to be asking the Board to speculate, in the absence of any detailed evidence to support, based on fluid government policy direction,[32] that Enbridge Gas facilities will experience dramatic de-contracting. EFG has oversimplified this speculation by framing it in three finite scenarios. In fact, there are innumerable potential scenarios and Enbridge Gas believes that, in the absence of quantifiable factors or clear policy direction, its OEB approved forecasting methodologies represent the most reasonable basis from which to develop an IRP Framework for Enbridge Gas. The Board has a long and successful history of assessing the need for proposed projects as part of its review of applications for LTC. As part of those assessments and subsequent OEB decisions the Board considers government policy, market conditions, the load forecasts underpinning requested approvals by utilities, contracted demands, system operations, and stakeholder consultation and makes a determination on the prudence and relative reasonability of such proposals. These processes remain sufficient. If the Board allows for the monetization of economic risk based on the subjective and hypothetical grounds proposed by EFG then it risks supporting the development of an IRP Framework for Enbridge Gas that could make it unreasonably challenging to justify investment in any facility projects in the future, regardless of their economic benefits and without regard for the best interests of ratepayers.

[32] https://news.ontario.ca/en/statement/59395/province-marks-second-anniversary-of-made-in-ontario-environment-plan. By the Ontario Governments own account they consider the Made-in-Ontario Environment Plan a living document that enables the Government to modify their plans as new challenges arise, such as COVID-19, and as new data and innovative technologies emerge, like low-carbon hydrogen.

TAB 17

an emergent safety risk, the utility will have little choice but to proceed with a facility option.

Now, I recognize that not every safety risk would necessarily be emergent in nature, but there's probably a broad expanse of -- or two broad bookends between something that's emergent and something that's not.

So we have set out the binary screening tools to help us to allow us to focus on the IRPAs that are most viable and have the highest likelihood to be successful, and we think we have come up with something that reflects what's done in other jurisdictions, and it's helpful to move forward and helpful to our pursuit of IRP investments going forward.

MR. POCH: I have some questions on that distinction between emergent or non-, but I have got them for the next panel, and I know there's an IR about that, so let's leave that for the moment.

MR. STEIRS: Okay.

MR. POCH: If you can turn up GEC 8. I just wondered if I could get this a little more crisply. We asked you if you're saying that forecasting the effects of future climate policy is difficult and -- and that you forecast gas infrastructure based on current policies, and that you are saying -- you are assuming that it will not change. Is that correct? And you given an answer that those -- is the answer basically, yes, you are only going to forecast based on current policies?

MR. STEIRS: So we forecast based on known and quantifiable policies. And to the extent that that policy sets, for example, carbon pricing into the future, that carbon pricing that has been established and enacted into law would be built into our forecast.

MR. POCH: All right. So let's take that example, the federal announcement that we are going to go up $15 a tonne each year to $173 by '23. If you were doing a forecast today and the forecast today, are you going to capture that or not?

MR. STEIRS: The forecast today would not, because, as I understand it, that is still not fully enacted. But we are aware of it, and when it is enacted we would build it into our forecast.

MR. POCH: All right. And so obviously your cost-effectiveness tests and so on will also not take account of those things; is that correct?

MR. STEIRS: In the future --

MR. POCH: It will only take account of the ones that are, you know, in law and mandatory.

MR. STEIRS: Yes.

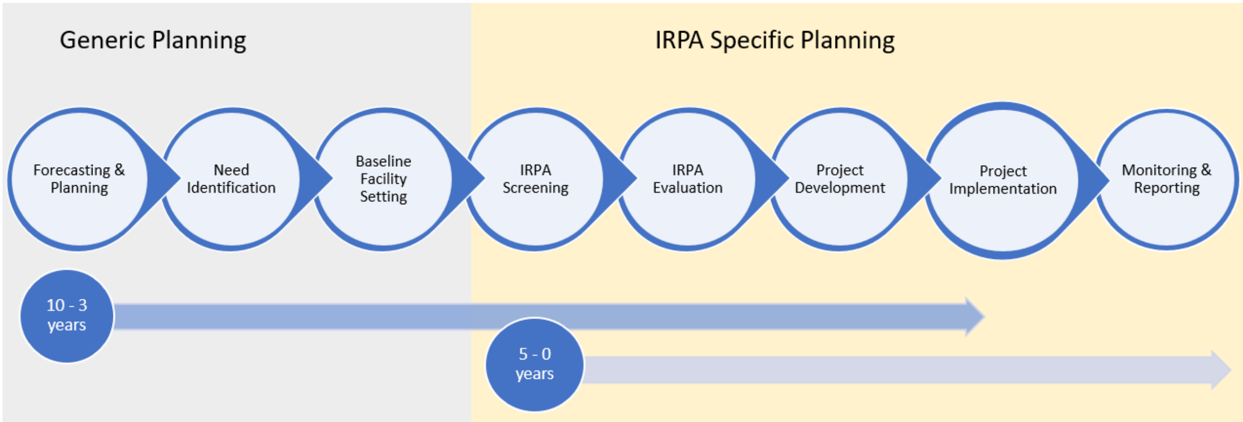
MR. POCH: Okay. Do your load forecasts include currently and will they include adjustments to gas peak day demand for the impact of future federal carbon taxes, for example, if not yet enacted in law?

MR. STEIRS: To my knowledge, no, the methodology we use is consistent. Others may be able to add confirmation or to correct me.

MS. THOMPSON: I can confirm consistency.

TAB 18

Figure 1. IRP Integration at Enbridge Gas



The first step in defining an appropriate process for IRP is to identify what type of system needs / proposed facility projects require any consideration of potential IRP alternatives. Enbridge Gas is proposing a binary screening for IRPAs. The following five characteristics are reasons why the utility may eliminate IRPA from consideration as an alternative to a proposed project:[68]

1. **Safety**: if a facility project to meet an identified need is determined to be essential to offer continued safe, reliable service and meet applicable law, then it will not be a candidate for IRP analysis
2. **Timing**: the threshold of three years before a system need must be met, anything less would preclude an IRPA
3. **Project-specific Considerations**: projects that align with other infrastructure developments may necessitate the installation of physical infrastructure
4. **Customer-specific Builds**: If the project is tied to a specific customer's need, which has either chosen to pay a Contribution in Aid of Construction (CIAC), or to enter into a long-term contract for firm delivery, then the project is not suitable for IRP analysis
5. **Community Expansion and Economic Development**: If a project is driven by policy and funding to explicitly deliver natural gas into communities to bring heating costs down, then it is not reasonable for IRP analysis

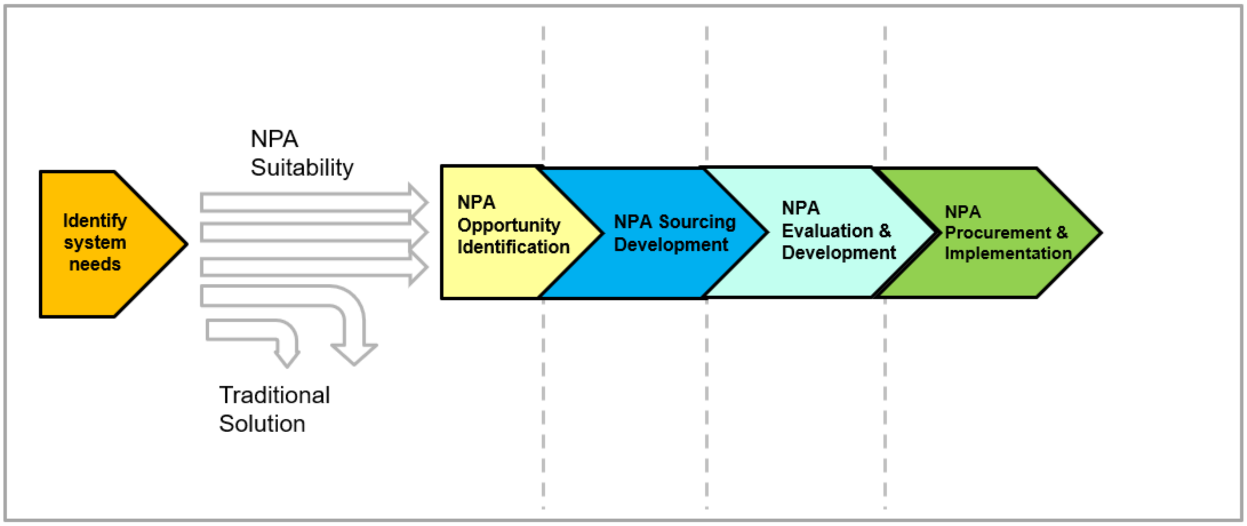
Projects that are eligible for IRP should be defined, and data is required to target the most impactful applications of IRP/ IRPA, which requires peak hourly data that is not currently available. In Enbridge Gas's IRP Proposal, the utility states:

> "The deployment of an AMI system, including ultrasonic meters, will allow for the collection of the hourly data that Enbridge Gas requires to not only target IRPAs effectively but also to monitor and verify their effectiveness to ensure that the IRPAs are

[68] Enbridge Gas. "Integrated Resource Planning Proposal – Additional Evidence". October 15, 2020. https://www.enbridgegas.com/-/media/Extranet-Pages/Regulatory-Filings/RateCases/Other-Regulatory-Proceedings/EB-2020-0091---Integrated-Resource-Planning-Proposal-IRP/Additional-Evidence/EGI_Additional_Evidence_20201015.ashx

- Sourcing, Developing, Assessing, and Implementing NPAs, including evaluation considerations such as benefit-cost-analysis (BCA) and EM&V strategy

Figure 2. NPA Consideration Process from Con Edison NPA Framework



The proposal also highlights how timing is a key consideration for NPA consideration:

> "[Con Edison] proposes to integrate NPA into its natural gas planning process, including by beginning NPA work one or more years earlier than work on a traditional project is scheduled to begin. As infrastructure work is identified and planned, the NPA screening and suitability criteria defined below will determine which projects are a good fit for NPA.
>
> Understanding the timeline of system needs helps to identify the time by when the project needs to be implemented and operational, the lead time available to implement an alternative, and the amount of time [Con Edison] has to implement a traditional solution, if needed. Implementing alternative solutions takes longer than a traditional project because [Con Edison] must engage customers and the market, where applicable, and provide sufficient time for installation, verification and operation of alternative solutions."

Con Edison provides definitions for characterizing potential NPA projects as either large or small sized projects. These categories are not intended to be absolute definitions or restrict the consideration of NPA project. Rather, Con Edison proposes these characterizations to consider the types of NPA sourcing strategies to address the needs. Further discussed in Section 5.1.5, smaller projects can more likely be addressed through extension of existing programs, whereas larger projects can more likely be addressed through market solicitations:

- Large Project: 36-60 month timeline, >$2M cost
- Small Project: >18 month timeline, <$2M cost

Within the Future Gas Planning proceeding, the Joint LDCs made the recommendation to file the long-term Gas System Resource Plans on an approximate three year cycle, with additional

TAB 19

NEW YORK STATE
DEPARTMENT OF PUBLIC SERVICE

CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures.

STAFF GAS SYSTEM PLANNING PROCESS PROPOSAL

(Filed February 12, 2021)

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NEW YORK STATE
DEPARTMENT OF PUBLIC SERVICE

CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures.

STAFF GAS SYSTEM PLANNING PROCESS PROPOSAL

(Filed February 12, 2021)

INTRODUCTION

In the Order Instituting Proceeding in this case, the Commission tasked Department of Public Service Staff (Staff) with issuing "a proposal for a modernized gas planning process that is comprehensive, suited to forward-looking system and policy needs, designed to minimize total lifetime costs, and inclusive of stakeholders."[1] This document sets forth Staff's proposal for a modernized and improved long-term gas system planning process for each gas utility (also called local distribution companies, or LDCs). This proposal envisions a process that will meet the goals set out in the Order Instituting Proceeding and provides for participation by interested stakeholders and periodic review by Staff. Staff's proposal herein would apply to the 11 LDCs identified in the ordering clauses in the Order Instituting Proceeding.[2]

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[1] Case 20-G-0131, Gas Planning Procedures, Order Instituting Proceeding (issued March 19, 2020) (Order Instituting Proceeding), p. 7.

[2] The 11 LDCs are Consolidated Edison Company of New York, Inc. (Con Edison); The Brooklyn Union Gas Company d/b/a National Grid NY (KEDNY); KeySpan Gas East Corporation d/b/a National Grid (KEDLI); Orange and Rockland Utilities, Inc. (O&R); Central Hudson Gas & Electric Corporation (Central Hudson); Niagara Mohawk Power Corporation d/b/a National Grid (NMPC); New York State Electric & Gas Corporation (NYSEG); Rochester Gas and Electric Corporation (RG&E); National Fuel Gas Distribution Corporation (NFG); Liberty Utilities (St. Lawrence Gas) Corp. (SLG); and Corning Natural Gas Corporation (Corning).

PURPOSE OF THE GAS SYSTEM PLANNING PROCESS

In the Order Instituting Proceeding, the Commission stated that circumstances demonstrate that conventional gas planning and operational practices adopted by natural gas utilities have not kept pace with recent developments and demands on energy systems. The Order Instituting Proceeding noted that gas utilities need to learn from recent experience and need to adjust to new energy and climate directions established by the State. Accordingly, gas utilities must adopt improved planning and operational practices that enable them to meet current customer needs and expectations in a transparent and equitable way, while minimizing infrastructure investments and maintaining safe and reliable service. Planning must be conducted in a manner consistent with the recently enacted Climate Leadership and Community Protection Act (CLCPA). In doing this, the gas system planning process needs to continue to provide assurance that customers will have reliable gas service available on the coldest day that can be expected based on actual historical weather data.

Below is a summary of the current gas planning process, followed by a proposal to modernize and improve the process. One goal of this improved natural gas planning process is that LDCs should be able to meet the needs of gas customers without declaring moratoria on the attachment of new customers. While Staff cannot guarantee that no moratoria will be called in the future, this proposal seeks to ensure that any future moratoria will only be called as a last resort, and only after an exhaustive effort to meet customers’ needs through other means. In addition, such moratoria would only occur after ample notice and public discussion. Staff is concurrently issuing guidelines for management of moratoria in a separate document.[3] Importantly, this improved planning process should help guide the LDCs into New York State's low carbon future and limit unnecessary infrastructure investment and the potential for stranded costs that might result. Further, it will allow progress toward an "Integrated Resource Plan" for gas - a continuously updated model linking load, peak demand, costs, and investment opportunities for traditional natural gas solutions and for alternatives.

CURRENT GAS SYSTEM PLANNING AND STAFF REVIEW PROCESS

Ensuring low cost, reliable gas supply to New York State's firm ratepayers continues to be of paramount concern. The LDCs routinely conduct long-term strategic and supply planning, but to varying extents. Geography, access to reliable gas supply, and anticipated future distribution growth can impact the level of detail considered in the LDCs current long-term planning processes. Annually, Staff in the Department's Office of Electric, Gas and Water has the responsibility of reviewing the readiness of the major New York State LDCs for each upcoming winter season and report on that readiness to the Commission. Throughout the winter season, Staff also monitors issues that can potentially impact LDC operations and customers.

Staff incorporates findings from the annual review process into its positions in rate proceedings, supply and capacity contract reviews, and Article VII cases. A utility must provide a review of short-term and long-term load management issues as part of the testimony it files in a rate case.[4]

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[3] Case 20-G-0131, supra, Staff Moratorium Management Proposal (filed February 12, 2021).

[4] Sixteen NYCRR 61.3(d)(6).

Annual Winter Preparedness Review

The availability, reliability, and price of gas supply is a priority concern. Yearly, Staff interacts with the major gas utilities to assess the LDCs' preparations for the upcoming winter season. This winter supply review begins with a Staff data request to the LDCs covering: LDC gas supply portfolios and contract strategies, winter commodity prices and LDC strategies to limit price volatility, marketer and LDC compliance with the Commission's mandatory capacity requirement, and interruptible customers' compliance with the Commission's alternate fuel requirements. Staff then holds meetings with each LDC to discuss the LDC's responses. The utilities then update data on natural gas commodity prices and resulting expected customer bill impacts, as warranted. Staff reports its findings from this review to the Commission in October each year. The Appendix to this proposal contains a thorough review of the annual winter preparedness review process.

JOINT UTILITIES' JULY 17, 2020 FILING

In their July 17, 2020 submission in this proceeding, the Joint Utilities[5] offered the following set of "design principles" to guide the evolution of the long-term gas system planning process:

1. The natural gas system planning process should continue to provide safe and reliable gas delivery service, while supporting New York's environmental, economic development, and other policy goals as cost-effectively as possible.
2. The natural gas system planning process should be designed to meet the anticipated demand for natural gas by customers through all viable supply-side and demand-

[5] The Joint Utilities include Central Hudson; Con Edison; KEDNY, KEDLI, and NMPC (collectively, National Grid); NFG; NYSEG; O&R; and RG&E.

side resources, such as electrification, energy efficiency, and demand response initiatives.

3. The natural gas planning process should balance the need to protect the confidentiality of information for security and procurement purposes with the desire to provide transparency to stakeholders.
4. The natural gas system planning process should enable participation of stakeholders, consistent with the LDC's statutory obligation to provide service at reasonable cost.
5. The LDCs and policy makers should clearly communicate the implications of changes in the gas system planning process to customers and other stakeholders.
6. The natural gas system planning process should guide the LDCs in the development of periodic long-term Gas System Resource Plans that reflect the latest information regarding anticipated demand, the expected contribution of existing and potential supply-side and demand-side resources, market conditions, and policy goals;
7. The plans should include the LDC's proposed long-term actions including demand-side programs, supply-side resources commitments and any investments necessary to address capacity needs, with consideration given to the time that may be required to implement such options;
8. The plans should reflect uncertainty regarding the future through analytical techniques that include sensitivity and scenario analyses where appropriate; and,
9. The plans should include identification of and updates regarding the status of vulnerable locations, including the status of non-pipeline alternatives (NPAs) and other efforts to address supply/demand imbalances.

The Joint Utilities state that they endorse a gas system planning process designed to preserve community economic development opportunities. They also state that they seek a process designed to protect the financial strength and credit quality of the State's natural gas utilities so that they can provide safe, reliable, and affordable service.

The Joint Utilities recommend addressing long-term planning in a Gas System Resource Plan, filed approximately every third year, generally in coordination with rate case filings. Stakeholders will also be invited to propose solutions to address vulnerable locations at sessions that focus on these locations soon after they have been identified. This would include the opportunity to comment at an appropriate time on the framework for design of market solicitations, such as requests for proposals (RFPs) seeking viable alternative solutions to address vulnerable locations, consistent with the potential need to expeditiously implement solutions to resolve system constraints. Developers will be encouraged to respond to these solicitations and propose specific solutions. The Joint Utilities propose to continue to file the winter preparedness plans every year as they address short-term reliability issues.

PROPOSAL FOR A MODERNIZED GAS SYSTEM PLANNING PROCESS

Procedural Proposal

Overview

The need to complete an annual assessment of the utility readiness for each coming winter is indisputable. The exercise is necessary to ensure that the utilities are in fact following established long-term plans, and to assure New Yorkers that the natural gas systems serving them will be safe and reliable, specifically for the upcoming winter heating season.

The long-term gas system planning process, in contrast, must provide analysis of, and visibility into, supply and demand over a longer timeframe than the next winter. This long-term planning must provide the LDCs, Staff, the Commission, and the public with sufficient lead-time to identify potential supply and demand needs and issues, and then evaluate, select and implement resources to address these issues. Resources that generally have long development periods must be planned well in advance of their need, including energy efficiency, electrification, and demand response programs.

The short-term and long-term processes are both necessary and should be consistent with each other. The approach described below will institute a long-term planning process while continuing the annual review of preparedness. The long-term gas system planning process will help the utilities plan where, when, and how to deploy capital to ensure reliability in the future at reasonable cost and in line with State policies. The process will include participation by interested stakeholders, and the LDC's resulting long-term plans will incorporate feedback from those stakeholders.

As outlined in more detail below, Staff envisions a long-term process that would start with a utility filing, similar to the LDCs' proposed Gas System Resource Plan mentioned above. Each LDC will file a long-term plan on a three-year cycle. Staff proposes nine staggered filings over the three-year cycle, with the downstate National Grid companies (KEDNY and KEDLI), Con Edison and SLG filing in year one, NYSEG/RG&E, O&R, and Corning filing in year two, and Central Hudson, NMPC, and NFG filing in year three. The information to be required in this filing is discussed in the "Utility Filing Requirements" section below.

One noteworthy aspect of these requirements is that each utility filing must contain a "no infrastructure option," in addition to any other options that address identified needs in the filing. The no infrastructure option should include a mix of utility-sponsored demand reduction measures that will close any gap between the projected load and available supply. The no infrastructure option should include one or more contingency solutions, such as compressed natural gas or peaking services, which can be called upon if necessary. LDCs should not merely include generalized energy efficiency, demand response, electrification, and pricing strategies. Rather, they should pursue more purposeful development of actual strategies for utilizing these alternatives to meet particular system needs, i.e., "better" alternative solutions to natural gas system planning.

These no infrastructure options will include, but not necessarily be limited to, NPA projects that provide alternative solutions to traditional natural gas infrastructure. The LDCs need to have an NPA Framework within which to consider potential NPAs. An appropriate NPA Framework would have three components: (1) NPA suitability criteria; (2) an NPA cost recovery procedure; and, (3) an NPA incentive mechanism.

Each LDC should include a proposal for the first part of the NPA Framework, the suitability criteria, within their long-term gas system plans. The suitability criteria would be used to identify possible opportunities to defer or eliminate traditional natural gas distribution infrastructure. Each LDC would file the NPA suitability criteria to be applied on a forward going basis as part of its long-term gas system plan. Including the suitability criteria within the long-term gas system plans every three years allows for periodic review of those criteria.[6]

While the suitability criteria may differ by LDC, the NPA cost recovery and incentive mechanisms should be applied consistently for all LDCs. Therefore, the cost recovery and incentive mechanism portions of the NPA Framework should be

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[6] Analogous to this proposal is the treatment of Electric Utility Suitability Criteria for non-wires alternatives (NWAs). The Electric Utility Suitability Criteria are filed as part of electric utilities' DSIP plans, which are similarly updated on a regular basis. See, e.g., Case 16-M-0411, Distributed System Implementation Plans, Con Edison DSIP (filed June 30, 2020), page 180; Also, see the Joint Utilities NWA page for more information https://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities.

addressed separately from the long-term gas system plans and NPA suitability criteria. To enable this, the LDCs should be required to file, jointly if possible, proposed NPA cost recovery procedures and an NPA incentive mechanism within 90 days of the effective date of a Commission order addressing this proposal. This separate track would allow the Commission to establish consistent NPA cost recovery procedures and an NPA incentive mechanism to be applied throughout New York State.

This more generic treatment of NPA cost recovery and incentives is preferable to how NWA cost recovery and incentive frameworks have been handled as part of individual electric utility rate cases. Presently, the existing NWA cost recovery and incentive mechanisms in operation throughout New York State are very consistent.[7] However, the mechanisms were first considered on an iterative basis through individual electric utility proceedings. Indeed, it is this learning experience with NWA cost recovery and incentive frameworks that makes it possible to establish a cost recovery and incentive framework for NPAs on a generic basis.

The Commission should consider having an independent third-party consultant evaluate the utility filings. This consultant could test the assumptions used by the LDCs, check calculations and analyses, provide solutions from best practices in other parts of the country or world, perform a benefit-cost analysis and possibly even act in the capacity of dispute resolution. Compensation for this entity could come from the LDCs themselves, similar to when management audits are conducted by third-party auditors. Under Public Service Law §66(19), the

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[7] See, Cases 17-E-0238 and 17-G-0239, NMPC – Electric and Gas Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 15, 2018), Attachment 1 (Joint Proposal), Appendix 13.

Commission has the authority to have an audit conducted by independent auditors to investigate a "…company's construction program planning in relation to the needs of its customers for reliable service…," and reviewing the long-term gas system planning process at each LDC falls under such authority.

Stakeholder Participation

The gas system planning process must include substantial education and stakeholder engagement. Each long-term gas system plan will include the information necessary to clearly explain the planning, design, and implementation development so that the output of the process effectively addresses the reliability needs of natural gas customers and the interests of stakeholders.

Each LDC will host a technical conference three to four weeks following its initial filing. Stakeholders may participate in the technical conference to perform initial due diligence and may follow up with requests for information from the LDC.

The Department will issue a notice seeking comments regarding the LDC's filing shortly after it is received. Stakeholders may then file comments in response to that notice. Comments from stakeholders should include their proposals for alternative solutions to any utility proposed solutions for identified constraints or other projects that would add infrastructure valued in excess of an established cost threshold. Upon completion of the comment period, LDCs will host stakeholder meeting(s) to reconcile different proposed solutions, as necessary. The utilities will then file, at most 30 days after the end of the comment process, a revised long-term plan.

In the event that stakeholders disagree with the revised filing made by the utility, they can file written explanations of their disagreement(s) within 30 days of the filing of the revised plan. The LDC will host a stakeholder meeting to discuss areas of disagreement and any comments received on its filing. Where there are disputed issues, the Commission has the option to decide whether to approve the plan as filed by the utility or direct modifications.

If there are no disputed issues on the long-term plans, the Commission has the option to take action on the plan, i.e., adopting, modifying, or rejecting it, in whole or in part. If the Commission is not expected to take any action on the revised plan, the Director of the Office of Electricity, Gas and Water will issue a letter to the utility stating that no further action on the LDC’s plan is anticipated. At that point, the utility’s revised long-term plan will be considered to be in effect.

Annual Reports

As explained above, every three years each LDC will file a new long-term gas system plan. In addition, each LDC will file an annual report to help stakeholders continue to develop and maintain their awareness and understanding of the LDC’s plan. The annual report is not required in the year a long-term gas system plan is filed. All annual reports much include:

1. An explanation of the LDC’s progress on its most recent long-term gas system plan;
2. Detail the LDC’s plans for implementing all necessary processes, policies, resources, and changes in standards impacting gas operations and supply;

3. Identify and describe all the information that can be used by stakeholders to help them understand the gas system needs and potential solutions to constraints, an updated gas demand forecast, including any changed circumstances that materially impact gas system planning; and,
4. Describe how the LDC's planning and implementation efforts are organized and managed.

In addition, by May 31 of each year, each LDC should file the following information: actual natural gas throughput for the preceding twelve-month period ended March 31 of that year; actual natural gas load for both firm and interruptible customers, including electric generators' load separately reported, for the period encompassing November 1 through March 31 of the previous winter period; and peak day load for the one day of highest system throughput reported separately for residential, commercial, industrial and electric generation. As each year progresses, this will allow stakeholders to see whether efficiency programs need to be adjusted, and if the utility's efforts to control demand growth have been effective. Further, LDCs should identify and make available to clean heat developers at least the minimally necessary data[8] to enable them to develop demand-side solutions. This should include specific areas where leak-prone pipe segments exist that could be targeted for abandonment and electrification of customer gas load or where infrastructure projects may be needed in the near future to maintain system pressures.

[8] The utilities should identify if they expect they would request confidential treatment of this data. If so, the utilities should propose how particular entities could gain appropriate access to the data, e.g., through non-disclosure agreements between the utility and the third-party.

Utility Filing Requirements

Long-term gas system plans are intended to analyze the anticipated demand and propose means to satisfy that demand. Traditional gas system planning would generally only consider additional natural gas capacity and demand response; modernizing the planning process smartly builds on this traditional process. LDCs must develop an integrated process to satisfy the current external circumstances, including changing policy conditions, the need to engage stakeholders, and consider additional approaches to meet demand. As plans mature over time, they should continuously strive to better integrate all of these factors, including purposeful development of strategies to improve alternatives, such as enhancing energy efficiency, demand response, electrification, and appropriate rate structures.

Stakeholder participation will enhance the planning process by ensuring that differing perspectives are recognized and harnessed to collectively elevate the effort to develop the best possible solutions. In order to provide the necessary tools to build the best product, LDCs must include the information necessary to enable stakeholders to understand the balance of supply and demand. Further, LDCs must provide necessary system data that allows for timely and effective engineering, operations, and business analyses needed to support well informed decisions.

Demand-side management programs have historically been considered on an as-needed basis in rate proceedings. Henceforward, these programs should be integrated into planning processes, both geographically targeted in the context of replacing avoidable projects in a specific area of the distribution system, and system-wide to reduce overall demand and the need for infrastructure investment. The programs should include criteria such as reliability, feasibility, environmental impacts, emissions, avoided need for infrastructure investments, potential use of marketer supplies as delivered services, third-party solutions, system-wide and project-targeted potential, cost effectiveness of options over the appropriate time frame, and local community impacts.

Demand Forecast

The demand forecast must include a 20-year horizon and include a peak day and peak hour consideration, in addition to annual load for all 20 years. The analysis will include a reasonable range of possible error, and cover scenarios (e.g., different sales forecasts based on variance in economic indicators) in the expected adoption and impact of non-traditional alternatives including demand management programs. In addition, the LDC must identify the source(s) of anticipated demand growth. Sources of growth should be identified as: increased demand from existing customers, increased demand from new customers (residential customers, new commercial/industrial customers), and demand growth from conversions by customers (residential, multi-family, and commercial). Utilities should specifically identify growth related to conversions from other fuels to natural gas, especially for residential heating, and how they address such growth or applicable environmental regulations that they believe influence conversion activity.

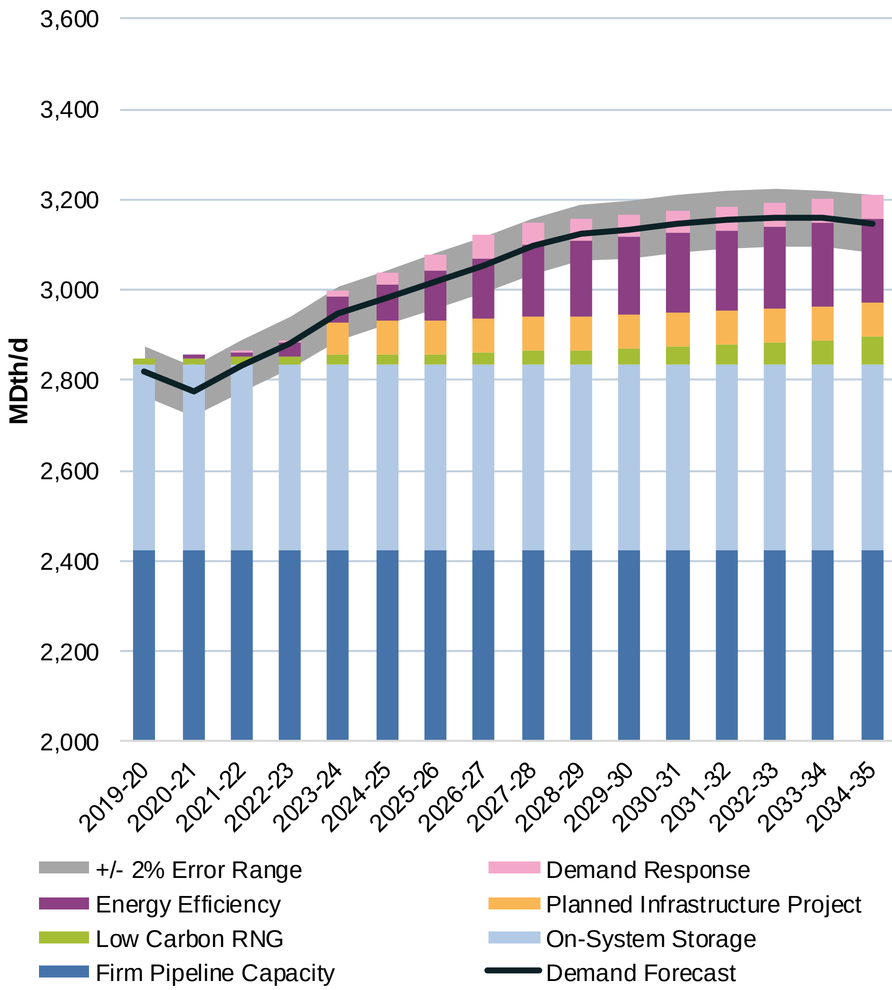
The demand forecast must include a weather-adjusted back cast using actual weather conditions to assess the load that would have been experienced had temperatures dropped to the design day level. Forecasts of future load should be consistent with short term weather and forecasted usage determination techniques and include adjustments for energy efficiency, electrification, demand response, NPAs, and other external impacts (e.g., COVID-19). To enhance transparency in the planning process, the forecast must contain a geographical analysis with enough granularity to clearly identify locations of anticipated localized demand growth to allow for adequate planning. For the LDCs serving the downstate metropolitan area including New York City, Westchester County, and Long Island, the LDCs should separately forecast at least each of the five Boroughs of New York City, and the Counties of Westchester, Nassau, and Suffolk.

Utilities should explicitly state what demand management and energy efficiency programs are included in the baseline demand forecast. This includes, but is not limited to, stating if the forecast maintains the status quo as of a specific date or historical period, adjusts for current Commission-approved spending levels, or assumes some other level of change or trend in outer years.

Supply Forecast

The supply forecast must align with the demand forecast and include a 20-year horizon and contain the planned composition of the supply portfolio. Components must include firm pipeline contracts, gas storage, peaking supplies, demand response, energy efficiency, electrification, and contingency supplies such as trucked compressed or liquefied natural gas. The following graph is a visual representation of the type of portfolio that should be included in the long-term plans.[9]

[9] Visual representation of supply forecast, courtesy PA Consulting



The supply forecast must contain scenarios that cover a reasonable range of future market development, including any specific, identified, developments that are significant enough to reasonably warrant a scenario. The presentation of the supply forecast must contain enough granularity to identify geographical locations of anticipated, localized, supply availability to allow for adequate transparent planning. As demonstrated in the figure above, a margin of error around forecasting would encompass changes in load growth or availability of supply. This discrepancy can be met with contingency supply to avoid possible curtailments of firm customers or the need to declare moratoria. For all planned infrastructure projects, the utilities' analyses need to include whether they are base load, peaking, or contingency solutions. Utilities should also identify critical upstream supply issues, including vulnerabilities due to critical points of existing supply, as well as consequences of delay or cancellation of planned new supply.

Similar to the requirement for the peak demand forecast described above, utilities should explicitly state what levels of demand response, electrification and energy efficiency are reflected in the baseline supply forecast. Utilities should clearly state if the forecast maintains the status quo as of a specific date or historical period, adjusts for current Commission-approved spending levels, or assumes some other level of change or trend in outer years.

The LDCs should propose portfolios of demand response programs that not only include tried and true solutions, but also novel approaches, such as rate design changes. For example, seasonal rates or premium pricing on peak day may be effective at shaping demand. Payments to encourage adoption of electric options that reduce natural gas demand may also be effective. LDCs are encouraged to survey other jurisdictions and even other industries to determine more imaginative solutions to demand-supply gaps. LDCs should also quantify the availability of renewable natural gas in their service territories, either existing or potential, including sources such as landfills, wastewater treatment plants and anaerobic digestion of waste or manure.

Reliability Standards and Anticipated Reliability

The long-term plan should identify the methodology by which reliability will be forecast and measured, including the metrics that will be tracked and used to identify potential future reliability issues as well as trigger or threshold values of those metrics that will establish that a reliability issue exists. Additionally, and in particular, design day standards should be re-examined and re-validated in each LDC's initial long-term plan. The initial long-term plan should also propose a frequency for subsequent re-examination and re-validation of design day standards.

Capital Projects

The long-term plan should identify any infrastructure constraints, both by location and timing. Locational constraints can by localized to a specific municipality, only a part of a given municipality, to a borough or to an area larger than one municipality.

Where an LDC identifies a gap between forecasted supply and demand in the planning process, in addition to traditional supply-side solutions, the LDC should include all reasonable demand management programs, including a no infrastructure alternative, which requires consideration of other approaches to reduce gas demand. LDCs should examine the possibility of expanding demand response, electrification and energy efficiency programs using appropriate incentives. LDCs should also consider utilizing combinations of solutions to close the gap.

Traditional gas capital projects and programs involving the construction of new pipelines or the replacement or expansion of existing pipelines may be potentially suitable for an NPA. Staff proposes that a two-prong screening approach for NPA evaluation should be used for a forward screening of traditional capital projects and programs. Staff would expect projects addressing conditions that pose an immediate threat to system reliability and/or public safety, or where construction is imminent, i.e., within 12 months, such as immediate work related to gas leaks or high priority leak-prone pipe segments, would be exempted from consideration for a NPA.

Opportunities to merge the retirement of leak-prone pipe with an NPA should be explored. Thus, utilities should assess whether a segment of main and associated services can be retired, and an alternative energy approach can supplant renewing the natural gas assets. A process to search for such opportunities should be developed and implemented. For areas experiencing specific economic development demands, LDCs should balance NPA solutions to address both the energy demand needs of the surrounding project service area along with providing the gas supply needs for demand that does not have acceptable alternatives to natural gas from an economic or technological standpoint.

The first track would be a comprehensive review for larger projects (Comprehensive Track), i.e., those with a cost of $2 million or more, requiring a full-scale solicitation of NPA alternatives followed by a benefit cost analysis (BCA) of potential solutions. This should be performed prior to detailed engineering, permitting, and construction, and before more than 5% of the total project cost has been spent.

Smaller projects would utilize an expedited standardized review approach (Expedited Track), including a streamlined economic and technical analysis. The purpose of this is to determine the potential economic and technical feasibility of an NPA that may or may not include a full-scale solicitation for NPA options. This approach should take advantage of existing known alternative solutions with identifiable costs.

Staff recommends that the dollar threshold between the Comprehensive Track and Expedited Track be adjusted accordingly for each LDC to better reflect the existing internal solicitation practices and procedures while continuing to maintain competitive purchasing methods if a full-scale solicitation does not occur. The LDCs should propose the dollar threshold they recommend as appropriate for their operations in their comments on this proposal.

The LDCs should keep Staff informed regarding their application of both the Comprehensive and Expedited Tracks to projects.[10] This should include making a filing in the case in which the LDC's most recent Long-Term Plan is considered, of a decision to implement either the Comprehensive or Expedited Track for a project. The LDC should also offer a meeting during which Staff can obtain more information. Further, stakeholders should have an opportunity to seek any additional information they may need to evaluate how the LDC arrived at the decision of whether to implement an NPA. The LDC would also be required to identify and describe the NPAs it has implemented, is presently implementing, or is presently considering implementing, in its Long-Term Plan and Annual Reports.

Comparison of Alternatives

Utilities should provide a clear quantitative and qualitative explanation for why a particular alternative was chosen. Necessary information to support a choice includes, but is not limited to, the items discussed below.

[10] Safety, reliability and adherence to law cannot be compromised. Therefore, for all gas projects, LDCs will not be restricted from taking measures, including making capital investments, that are necessary to comply with all laws, rules, regulations or orders of the Commission or other applicable agency or to protect the integrity of the pipelines or in the event of an emergency as determined by the Companies.

Benefit Cost Analyses

A BCA is a systematic evaluation of the value of benefits obtained through a potential action or investment against the costs incurred effectuating that action or investment. In 2016, the Commission issued a BCA Framework Order[11] that specified the BCA analysis to be used by the utilities when screening REV-related initiatives and investments, including non-wires alternatives to traditional electric system infrastructure investments. For NPAs to a specific traditional infrastructure project, the avoidable capital expenditures, and any related avoidable Operations and Maintenance (O&M) expense, of the traditional project is the avoided cost benefit used to compare to the cost of any nontraditional alternatives. In the BCA Framework Order, the Commission designated the Societal Cost Test (SCT) as the primary cost-effectiveness screening test and adopted the following foundational principles, stating that a BCA should:

1. Be based on transparent assumptions and methodologies;
2. List all benefits and costs including those that are localized and more granular;
3. Avoid combining or conflating different benefits and costs;
4. Assess portfolios rather than individual measures or investments;
5. Address the full lifetime of the investment while reflecting sensitivities on key assumptions; and,
6. Compare benefits and costs to traditional alternatives rather than valuing them in isolation.

In the BCA Framework Order, the Commission specified that the Utility Cost Test and the Rate Impact Measure Test would also be conducted. However, the Commission stated that

[11] Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

those tests would serve in a subsidiary role to the SCT and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis. Therefore, the role of these additional tests is to provide additional information beyond project or portfolio societal cost-effectiveness. However, the best information in this regard is a full bill impact analysis, which is discussed below.

This BCA Framework has subsequently been adapted by gas utilities in New York to develop BCA Handbooks for NPAs. These BCA Handbooks describe and quantify benefit and cost components and their applications in evaluating NPAs compared to traditional gas infrastructure investments. The utility BCA Handbooks currently include the following primary NPA-related benefit and cost categories:

- Primary Benefit Categories:
  1. Fixed and variable avoided upstream supply;
  2. Avoided distribution capital and O&M expense;
  3. Reliability/resilience improvements; and,
  4. External benefits (including emissions effects).
- Primary Cost Categories:
  1. Program Administration;
  2. Incremental Distribution capital and O&M expense;
  3. Participant NPA Cost;
  4. Alternative Fuel Costs (e.g., Electricity); and,
  5. External Costs (including emissions effects).

The BCA Handbooks also describe the sensitivity analyses that would be applied to key assumptions. The current sensitivity analyses can be improved to make them more robust and better aligned with CLCPA goals and mandates. To that end, future sensitivity analyses comparing NPAs and traditional gas infrastructure solutions should include a scenario that assumes that the full value of any new gas assets will be depreciated by 2050.

To date, BCAs of NPA proposals has been performed using the BCA handbook developed for evaluating energy efficiency programs and non-wires alternatives, with some modifications to represent differences between the electric and natural gas industries. However, there are a few aspects that the utilities, Staff, and stakeholders should continue to work to improve.

First, since wholesale gas capacity markets are not as centralized or transparent as electric wholesale capacity markets, the LDCs should, in the first instance, provide estimates of such avoidable upstream fixed and variable costs. While, at times, these estimates may be based on confidential information, there are procedures available for Staff to review and critique such sources.

Second, while gas utilities have the opportunity to include avoided distribution costs in BCAs for energy efficiency programs, presently no utility includes such avoided costs in those BCAs. This should be corrected. Unlike an NPA for a specific traditional capital project, energy efficiency and other system-wide programs must use a more general estimate of avoided distribution costs. These estimates typically derive from utility Marginal Cost of Service (MCOS) studies. Because different programs, portfolios, and measures may avoid different cost elements, while not avoiding others, these MCOS studies must be calculated and presented in a sufficiently disaggregated manner. Further, Staff believes that the utilities should work toward a more consistent approach to MCOS estimation and reporting, both for avoidable distribution and avoidable upstream costs.

Third, Staff acknowledges the LDCs' interest in pursuing renewable gas alternatives in NPAs. However, more work needs to be done to specify the environmental, and perhaps other, standards that should be applied to nontraditional methane to qualify a source as "renewable gas." Staff invites interested entities to work with Staff, the New York State Energy Research and Development Authority (NYSERDA), and the LDCs to propose such standards for future Commission consideration in this proceeding. Such a proposal, of course, should recognize any ongoing work being conducted by or for the Climate Action Council in this area. Accordingly, in comments on this proposal, interested entities should propose such standards.

To address these issues, Staff proposes to establish an Avoided Cost of Gas (ACG) "best practices" working group. The ACG working group would be open to all interested parties but must, at a minimum, include the LDCs, Staff, and NYSERDA. NYSERDA has engaged a consultant to assist in calculating utility ACG for energy efficiency and other purposes. While this will be very useful, it will still require primary data and other critical inputs from the utilities. Staff requests comments on the three areas for ACG estimation improvements discussed above.

Estimated Bill Impacts and Net Present Value of Costs of Each Alternative

In addition to the BCAs discussed above, the LDC should present an annual bill impact and net present value (NPV) of costs analysis for both a traditional project and any alternatives considered (on either an individual or portfolio basis, as appropriate). The bill impact analysis will allow both the utility and stakeholders to examine the cost impact of projects and alternatives on various customer groups. Costs included in both the bill impact and net present value analyses should include, but not necessarily be limited to: capital expenditures, operations and maintenance expenses (including program administration costs), property taxes, lost revenues (if applicable), cost of removal or retirement (if applicable), and any proposed incentives the costs of which would be recovered from ratepayers. Additional items for consideration in bill impacts include:

1. Projected capacity costs – projects that are intended to avoid the need for capacity may include the impact on projected capacity costs.
2. Cost amortization periods – the LDC should explain its chosen amortization period for the costs of any alternatives (e.g., energy efficiency, NPAs), including identifying any relevant currently authorized amortization periods.
3. Projected throughput – the LDC may hold the throughput constant or modify it depending on the alternative being considered.

Bill impacts should be provided for each customer group (e.g., mass market and larger customers) and should be provided for 20 years or over the useful life of the solution, whichever is shorter. Utilities should ensure that other assumptions and inputs for bill impacts are consistent with uniform accounting practices and existing rate plans, where applicable. If a utility believes it is appropriate to deviate from these practices or rate plan provisions, it should explain why. Utilities should use their discretion for assumptions and inputs where no guidance exists, but should ensure that underlying assumptions are clearly noted and explained for stakeholder review. Similar to the sensitivity analysis required in the BCA, the LDC should provide an alternative bill impact analysis that assumes that the full value of any new gas assets is depreciated by 2050.

The LDC should perform the NPV analysis on an aggregate cost basis and should use the Commission approved pre-tax weighted average cost of capital at the time of the analysis as the discount rate. Consistent with the bill impact analyses, utilities should ensure that other assumptions and inputs for the NPV analysis are consistent with uniform accounting practices and existing rate plans, where applicable, and explain any deviations. Utilities should use their discretion with other assumptions and inputs where no other guidance exists, but should ensure that underlying assumptions are clearly noted and explained for stakeholder review. Similar to the sensitivity analysis required in the BCA and the alternative bill impact analysis, the LDC should provide an additional NPV analysis that assumes that the full value of any new gas assets is depreciated by 2050.

Emissions Impacts

It may be advisable to have a stringent test for new infrastructure given that the construction of new infrastructure, with its accompanying probable long service life, may not be economic in the future and also may not help the State achieve its greenhouse gas reduction goals. Specifically, calculating and reporting the emissions of greenhouse gas associated with all solutions, both supply-side and demand-side, is necessary for transparency when considering choices among alternative solutions.

Utility Incentive Mechanisms

Incentives for achieving targets on alternatives include the following existing and potential mechanisms:

- Existing mechanisms:
    1. Share the net societal benefits incentive mechanism (30%/70% utility/ratepayer benefit sharing);

2. Earnings Adjustment Mechanisms (EAMs):
    a. Share the Savings EAM (for gas energy efficiency cost reduction achievements);
    b. Gas Peak Heating Load Reduction EAM;
    c. Change in gas revenue decoupling mechanism from per-customer to per-class to remove utility incentives to add new customers or remove disincentive to lose customers.

- Potential new mechanisms:
    1. Incentives/EAMs for greenhouse gas reductions that are not covered by existing mechanisms (For example, methane emission reductions in natural gas supply chain -- both downstream and upstream);
    2. Incentives for sourcing renewable natural gas/ biogas.

Issues related to these incentives include whether and how gas-only LDCs can be incentivized to encourage electrification measures.

Additional Issues

Peaking Services

Reliance on peaking services (also called delivered services) to meet peak day load can have certain risks.[12] These services are typically provided by natural gas marketers with firm pipeline capacity bundled with commodity. For interactions of less than one year in duration, the Federal Energy Regulatory Commission (FERC), which has jurisdiction over wholesale natural gas markets, allows market-based pricing. Given that natural gas prices in the metropolitan New York City area are some of the highest in the country, eclipsing $100 per dekatherm at times, these peaking services can be quite costly. However, since utilities only rely on them for a limited number of days

[12] Case 17-G-0606, Con Edison Smart Solutions, Petition of Con Edison for Approval of the Smart Solutions for Natural Gas Customers Program (filed September 29, 2017).

each winter, peaking services have limited impact on customer bills. Generally contracts for peaking services are less than one year in duration. Accordingly, they must be procured every year, with no guarantee that they will remain available to the LDCs in future years. If another entity outbids the LDC, that entity will get the service. Given this information, Staff is uncertain that reliance on peaking services is a reliable strategy. Delivered services are an important part of the peak day portfolio for some LDCs.

In their July 17, 2020 filing, the Joint Utilities stated that developing a simple standard that limits peaking services to a particular percentage of an LDC's portfolio, or limits peaking services to a particular volume level, does not account for different market conditions, demand profiles, and portfolio designs among the LDCs and across time for an individual LDC. The Joint Utilities proposed an approach that purports to address the particular reliability concerns of each peaking resource, while providing each LDC the necessary flexibility to design a balanced portfolio. The Joint Utilities' proposed framework and standards for reliance on peaking services distinguishes between deliverability and recontracting/renewal reliability. The framework effectively "derates" the capacity contribution of resources for planning purposes based on historical data and other relevant information. If a particular resource is judged by the LDC to be 95% reliable — or, stated another way, if a particular resource is expected to have a 5% chance of a forced interruption — then the capacity of that resource would be derated by 5% when included in demand/supply balance analyses. In addition, if that same resource is expected to have a 10% chance of not being available for renewal after contract expiration due to specific market circumstances, that resource would also be derated by another 10% for the period after the current contract expires. The Joint Utilities state that they have developed a common derating range for each category of resources, while maintaining the distinction between deliverability and recontracting/renewal reliability. They have also set forth a common set of guidelines for each resource in a category. The Joint Utilities state that this would provide a common framework and range with LDC-specific and resource-specific circumstances, and go on to state that LDC-specific circumstances include local market conditions, the composition of the overall portfolio, and their customer and demand profile. The resource portfolio will change every year as demand-side resources are added or end-uses are electrified, and it is appropriate for the standards to be able to accommodate these changes. The Joint Utilities state that, for planning purposes, each LDC will propose a derating assumption within the relevant range that reflects their circumstances and the particular attributes of each supply-side and demand-side resource. Each LDC would provide the rationale to support its assumptions.

The proposal made by the LDCs lacks detail on how a derating system will be applied to decision making and is subjective in its application. Staff will gather data on this subject and make recommendations to the Commission in the future. Unless and until the Commission sets generic standards for reliance on delivered services, each LDC should state how much it will rely on delivered services and other peaking assets to meet peak day load and how it justifies that reliance.

Summary Investment Plan

Each long-term plan filing should include the likely and preferred portfolios' of investments, summarizing the cost and bill impacts and the emissions impacts from the preferred option, the no-infrastructure option, and any other options suggested in the long term plan.

Public Availability of Information

Entities, including utilities, that submit information to the Department are entitled to seek confidential treatment for that information pursuant to the Freedom of Information Law (FOIL). Under that law, if a request is made for information submitted with a request for confidential treatment, the Department's Records Access Officer can assess the nature of the information and determine whether it is exempt from disclosure under FOIL. An aggrieved party may appeal the Records Access Officer's determination to the Secretary to the Commission, and may also seek judicial review. The process is highly fact specific and can be quite lengthy.

While the traditional FOIL review process remains available, all stakeholders would benefit from maximizing transparency and minimizing disputes regarding the confidentiality of information provided as part of the gas planning process. Staff notes that KEDNY and KEDLI filed their initial and supplemental long-term plans in Case 19-G-0678[13] without seeking confidential treatment for any portions of them. While the long-term plans envisioned here may differ somewhat from what KEDNY and KEDLI filed in Case 19-G-0678, Staff believes that the utilities can file their long-term plans without the need to seek confidential treatment or make redactions. Should the LDCs anticipate that they may want to seek confidential treatment for information they would need to

[13] Case 19-G-0678, KEDNY & KEDLI – Review of Moratorium, Natural Gas Long-Term Capacity Report (filed February 24, 2020); Case 19-G-0678, supra, Downstate NY Long-Term Natural Gas Capacity Supplemental Report (filed May 8, 2020).

provide as part of their long-term plans, they should identify the types of information in their comments on this proposal.

Affiliate Transactions

In the Order Instituting Proceeding, the Commission stated that Staff should review the transparency of affiliate relationships. Specifically, that Order stated that Staff should examine the practice of procuring pipeline supply[14] from affiliated companies for incentives that are not aligned with state policies.

New York's LDCs have individual affiliate transaction rules approved by the Commission through various proceedings. LDCs have contracted with affiliates for services for many decades. A prime example is NFG, which is an affiliate of both National Fuel Gas Supply and Empire Pipeline. Those two entities are interstate pipelines regulated by the FERC. Before FERC unbundled the wholesale natural gas markets in Orders 436 and 636 in the 1990's, there were many more affiliate relationships.[15] In addition, New York LDCs had previously been part-owners of FERC-regulated pipeline assets, such as the Iroquois Pipeline.[16]

The issue of whether an LDC should contract for capacity with an affiliate in the future is different than whether they have done so in the past. Going forward, such

[14] While the Order Instituting Proceeding directed Staff to examine procuring pipeline supply, Staff has expanded that directive to also examine the practice of procuring pipeline capacity from affiliates.

[15] Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 FR ¶ 42,408 (issued October 9, 1985); Order No. 636, 59 FERC ¶ 61,030 (issued April 8, 1992).

[16] National Grid sold its interest in Iroquois Gas Transmission System to Dominion Resources in 2015.

arrangements should receive more scrutiny given New York's desire to reduce the construction of unnecessary infrastructure and the possible creation of stranded costs that would accompany those assets. Accordingly, as described above in this proposal, LDCs should present alternatives to all infrastructure projects, including those sponsored by interstate pipelines, whether they are affiliated with the LDC or not.

FERC has rules in place that address the potential for affiliate abuse by transmission providers and affiliates. Specifically, FERC Order 717 establishes standards of conduct for transmission providers that ensure that providers do not give affiliates a competitive advantage. Order 717 imposes the following four rules: (1) the Independent Functioning Rule, which requires separation of marketing function employees from transmission function employees; (2) the No Conduit Rule, which expressly prohibits marketing function employees from having access to certain types of information; (3) the Non-Discrimination Rule, which requires that all customers be treated on a non-discriminatory basis; and, (4) the Transparency rule, which requires transmission providers to post affiliate and disclosure information. The FERC rules and codes of conduct in place ensure that incentives for affiliates do not exist and that there is transparency around contracts with affiliates.

In addition, all gas capacity and gas supply contracts entered into by LDCs must be filed with the Secretary to the Commission pursuant to 16 NYCRR Part 720-1.4 "Filing of Contracts."[17] This allows for a prudence review of the contract. If an issue is discovered, a proceeding may be initiated to address it. Redacted versions of these contracts are public.

[17] The Appendix to this proposal contains a further discussion on the filing of supply and capacity contracts.

Although FERC-regulated contracts exist with some utility affiliates, there are no known contracts for gas supply with any affiliates.[18] If any did exist, 16 NYCRR Part 720-6.5 “Gas Cost Adjustment Clauses” defines a standard of review to ensure that the contract would be in the best interest of the ratepayers.

CONCLUSION

Staff proposes that the Commission direct the 11 LDCs identified in the Order Instituting Proceeding to begin filing long term plans every three years as described in this document. These filings will initiate a modernized natural gas planning process, which incorporates the input of all impacted stakeholders and reflects the State’s greenhouse gas emissions reduction goals. Staff looks forward to continued engagement with all interested parties as the Commission considers these recommendations.

[18] An exception would be for the purchase or sale of gas supply with a company’s marketing affiliate for transportation balancing purposes. This is covered by individual company affiliate transaction rules and transparent tariffs without preferential treatment. Only National Fuel Resources, an affiliate of NFG, remains active.

Appendix - Current Gas System Planning Processes

Presently, gas utilities, or local distribution companies (LDCs) gas system planning is reviewed by the Public Service Commission (Commission) and Department of Public Service Staff (Staff) in multiple ways. First, Staff conducts an annual Winter Supply Preparedness Review, the results of which Staff presents to the Commission every autumn. Second, the Commission and Staff also review an LDC's gas system planning during a rate case. Third, gas transmission lines require review and authorization under Public Service Law (PSL) Article VII before a utility can begin construction. Fourth, LDCs are required to file copies of capacity and supply contracts, which are reviewed by staff and can be the subject of a prudence adjustment by the Commission.

Winter Supply Preparedness Review

The annual "Winter Supply Preparedness Review" centers around information provided by utilities with active Staff involvement and no stakeholder involvement. The topics covered include: (1) demand and capacity portfolio; (2) operations and reliability optimization procedures; (3) gas purchasing strategy; (4) forecasted winter bill impacts; (4) forecasted changes to market conditions; (5) transportation customer issues; and, (6) non-firm service management issues. Each of these areas is discussed below.

Demand and Capacity portfolio

Analysis of an LDC's demand and supply balance is a prime determination of how reliably it can provide service to customers for the upcoming winter season. The immediate need is to review demand forecasts for the winter season by customer class for the purpose of identifying what capacity and gas supply will be required to maintain reliable service. This information can then be utilized to analyze the company's winter season and design day supply portfolio.

Staff reviews demand forecasts for both normal and design weather. Normal weather is based on the last 30 years of weather data, whereas design weather is based on the coldest winter day, i.e., the "design day," in at least the last 40 years. Reliability analysis focuses primarily on the design day forecast due to its input into the capacity and supply portfolio. Staff uses the normal weather forecast, compared to forecasts provided in the LDC's most recent rate case to determine if demand is greater or less than what was determined in the rate case. It is essential for this comparison that both the normal sales forecast and the reliability forecast be based on the same data set for both weather and usage.

Each separate demand forecast is broken out into the entire year, a winter season, and specified daily requirements. The most recent forecasted and actual volumes for the past winter are identified and then compared to a new forecast for the upcoming season. Each utility also provides its current estimate for an additional four years, so the review encompasses a total of five years.

Each time period of the forecast is broken down to identify both firm and non-firm service. It is then further delineated to indicate sales versus transportation volumes. While the LDC may not be required to hold capacity for all transportation customers receiving supply from third parties, the utility is responsible for ensuring it has sufficient capacity assets to balance the transportation volumes of customers when deliveries do not match usage of all customers. In a manner similar to how the utility balances supplies for its sales customers, it also provides a firm balancing service regardless of whether the customer's service is firm or non-firm. The level of balancing capacity required is determined by the tariffed service offered by each utility. It is usually set at 2%, 5% or 10% of the transportation customers' average daily volume.

Building a capacity forecast is a multi-step process. The LDC begins with interstate pipeline transportation contracts that serve the basis for year-round supply. Next, the LDC adds winter-only services, starting with interstate pipeline storage and storage transportation contracts. Third, the LDC adds delivered services to the territory's city-gate by third parties, as well as other peaking supplies like cogeneration plant contracts, sources of renewable natural gas and local natural gas production capability that will be utilized for at least a one-day minimum time span. Fourth, the LDC adds hourly gas supplies, such as liquified or compressed natural gas that may only be utilized for specific peak daily periods of time. Finally, the LDC adds in the gas supply requirements for transportation customers not taking supply from the utility itself.

In addition to reviewing the upcoming winter season, the Annual Winter Preparedness Review also includes a review of five-year demand forecasts versus available capacity. These can then be utilized to identify possible shortfalls or excess capacity available for use. Matching anticipated demand with capacity availability can lead to the identification of future issues of concern that need resolution. Historically, five years has been the long-term planning horizon but over the last ten years, increased complexity in utilities' attempts to add capacity has led to longer planning horizons, ten years in most cases.

This portfolio is each LDC's product, though the end result reflects Staff's guidance, questions, and concerns. This can be an iterative process, with the LDC providing follow-up information and data, so that Staff can fully understand the utility's plans for reliability. Further Staff action, including requesting that the Commission direct an action, can occur if warranted, but this is unusual.

Operations and Reliability Optimization Procedures

Demand forecasting is a function primarily analyzed in detail during a utility's rate case proceeding (see Rate Case Review section below). That said, during the Winter Supply Preparedness Review, demand forecasts are provided for reliability planning purposes. These forecasts are updated annually to identify requirements over a five-year time period. The main focus, however, is on the review of the upcoming winter season.

Existing load and load growth forecasts are usually based on econometric/statistical forecast models developed for each residential, commercial/industrial, and multifamily rate class. Two different models are developed for each service class: (1) a model to forecast the number of customers, and (2) a model to forecast use per customer.

In the models calculating number of customers, the independent variables usually include a combination of time trends, population, households, employment, and gas and oil prices. In the models calculating use per customer, the independent variables may be a combination of time trends, heating degree days (HDDs), other weather considerations, population, housing stock, income, employment, unemployment, gross domestic product, and gas and oil prices.

An LDC obtains the historical data and forecasts of the independent variables from its own records as well as using studies from leading economic research and forecasting firms along with consumer data and energy prices from the U.S. Department of Energy, Energy Information Administration. The LDC then utilizes this information to develop the econometric models or other statistical procedures to generate load forecasts.

An LDC's historical sales data includes the impact of actual energy efficiency savings from both the New York State Energy Research and Development Authority (NYSERDA) and LDC-sponsored energy efficiency programs. Forecasted energy efficiency programs may be reflected in the LDC's forecasts as a reduction to the base econometric forecast. This must be done with some caution, however, since an over-estimation may cause a supply shortage for customers, and an under-estimation could result in paying for unneeded capacity. In addition to the energy efficiency programs, each LDC will identify how its forecasts incorporate demand response programs, microgrids, and non-pipeline alternatives conducted by the LDC, contractors, or NYSERDA.

The variable that creates the most difficulty in demand forecasts remains weather and weather volatility. Over many years, despite the warming trends and reduction of actual HDDs on an annual basis, LDC's service territories still experience very cold winter days, as well as unusually warm winter days, creating greater variability in planning processes. A significant difference exists here between gas and electricity planning – natural gas demand peaks when the weather is very cold, and lack of adequate planning can result in property damage to homes from frozen pipes and even life threatening situations such as residents using carbon monoxide emitting appliances to provide space heating if natural gas is not available.

Planning for the impact of weather starts with the identification of HDD data by winter season, month and day, including the specific weather data points used for forecasting purposes. This will lead to a weather forecast for both a design day and design winter weather pattern. All weather data, including actual HDDs and normal HDDs are sourced from the National Oceanic and Atmospheric Administration. Each utility will identify the weather station(s) that it utilizes.

Staff requires a 30-year time period for the determination of normal weather. The design winter may vary from utility to utility, but the most common reflect a 10%-15% colder than normal winter. The design day determination looks at the coldest day experienced over at least 40 years. Additional weather conditions such as wind, humidity, and consecutive cold days may also apply.

The weather forecast and load forecasts are combined to identify deliverability and supply requirements. The LDC calculates usage per HDD by removing any summer load related to non-heating usage, considered base or non-weather gas demand, from any given winter period and dividing by the degree days related to that time period. In this manner a forecast for either a normal weather or a design weather pattern can be estimated and forecast. The forecast is updated once a year for a five-year period, but an LDC’s gas control operations works with an on-going forecast on a continuous basis.

The five-year forecast described above is then used in a short-term forecasting process by the LDC’s gas control operations for gas dispatch purposes. The LDC does this by utilizing different weather services to predict both the day ahead and short term (five - seven day) weather forecasts. This information is then inputted into either a purchased software system for gas dispatching or in a program privately developed by the individual utility. The result is a send out schedule (or curve) for the utility's short-term and day-ahead plan. These estimates use data from the five-year planning process but are forecast independently by adding other known criteria that can impact the day-to-day fluctuations in demand requirements. Typical added considerations are temperature, wind, weekend/weekday, day-to-day temperature volatility, etc.

The LDC combines this information with forecasted third-party supplier nominations to generate a daily dispatch report which provides retail sales (usage), purchase, storage and transportation forecasts for the current day and up to five days into the future. Staff will spot check available daily dispatches, especially those for a peak day, to identify its accuracy and the need for adjustment.

Gas Purchasing Strategy

LDC gas supply portfolios consist of a variety of components. These include contracts for interstate pipeline and storage capacity, as well as purchases of gas supply at the wellhead, at market centers or liquid points and at the city gate (delivered services), and arrangements to purchase the firm gas supplies of large volume customers with alternate fuel capability during peak periods. In addition, LDCs may have peaking supplies such as liquefied natural gas or compressed natural gas plants located within their service territories.

Staff's review of the LDCs' winter supply preparedness focuses on the adequacy of their capacity and supply arrangements to meet expected firm demand in an upcoming winter season. LDCs must provide a complete listing of all interstate and intrastate capacity, gas supply, peaking and delivered services contracts. Additionally, the LDCs must explain how the use of these contracts adheres to the Commission Policy on Gas Purchasing[19] while maintaining reliable service to all customers.

In 2007, in its Mandatory Assignment of Capacity Order[20] the Commission required that LDC's assign capacity to retail marketers, also known as energy services companies or ESCOs. Capacity owned by and brought to a service territory by marketers at that time was grandfathered to allow them to continue to supply their own capacity. Most marketers already received their capacity from the LDCs. For the grandfathered capacity that marketers provide, the LDCs must annually check the documentation provided by the marketers and verify that the marketers have firm, primary delivery point capacity for a minimum of the months of November through March. This verification ensures that marketers have the capability to provide the gas for the utility to deliver to the transportation customers.

There are three primary components that make up the price of the natural gas commodity that is ultimately paid for by sales customers. The first component is the price of gas in storage. This reflects the average price of gas incurred during the injection season, i.e., April through October. The second component is the average winter price, for the months from November through March, determined on either a monthly or daily

[19] Case 97-G-0600 –Gas Cost Volatility and Alternate Gas Purchasing Mechanisms, Statement of Policy Regarding Gas Purchasing Practices (issued April 28, 1998) (Policy on Gas Purchasing).

[20] Case 07-G-0299, Role of Local Gas Distribution Companies – Capacity Planning and Reliability, Order on Capacity Release Programs (issued August 30, 2007) (Mandatory Assignment of Capacity Order).

basis.[21] The third component is the price of any hedged volumes. These hedges can be fixed price gas supplies or financial instruments used to remove uncertainty concerning the winter price of flowing supplies.

LDCs must diversify the pricing of their gas purchases in order to limit price volatility. In its Policy on Gas Purchasing, the Commission outlined what purchasing options a diversified supply portfolio might include. The Policy on Gas Purchasing suggested, but did not limit, considerations of a blend of short- and long-term fixed price purchases, spot acquisitions, use of physical and financial hedges, and contracts that provide flexibility in the amount of gas taken. The Policy on Gas Purchasing seeks to decrease volatility in customers' bills, while still providing the dispatch of gas on a least cost reliable basis. Because changes in market prices are unpredictable, the price of a gas supply portfolio with appropriate volatility reduction may turn out to be lower or higher than the current market price of gas without volatility mitigation. In addition, the locations from which gas is purchased can also be diversified based on a utility's ability to transport the gas to its service territory.

Forecasted Winter Bill Impacts

As part of the Winter Supply Preparedness Review process, the utilities provide estimates of the potential residential customer bills, based on currently projected commodity costs and normal weather for this winter. Customer bills have two primary components: gas costs and delivery

[21] Domestic supply is usually tied to the price of a specific published price index representing actual trading. NYMEX futures contracts priced in the Gulf Coast and Northeast Production Zone supply is generally tied to the domestic price indices for the general location of purchase.

charges. Gas costs are further broken out as firm demand and variable commodity charges.

Firm demand charges are those associated with the interstate pipeline or storage contracts. These are set by the Federal Energy Regulatory Commission (FERC). Commodity prices are variable throughout the winter season and these estimates take into account the quantity and actual price of gas in storage, any fixed-priced gas supply contracts, the amount of financial hedging, and the quantity and market price of unhedged gas used. The unhedged amount will be priced at some published index rate for a specific trading location, either monthly or daily based on the supply contract. For delivery charges, these estimates consider any changes in delivery rates approved by the Commission. It considers the different tiers of charges in the utility’s tariff for increasing volumes based on a normal winter. Included is a comparison of the forecasted residential customer bills, including gas prices, gas adjustment clause refunds or surcharges and any delivery rate changes, with the actual bills from the prior winter.

Forecasted Changes to Market Conditions

Staff reviews how each LDC balances its approach to service reliability with changing market conditions. Historically, this has centered on load growth. More recently the review has centered around the balance between restrained infrastructure additions and the advancement of energy efficiency measures to dampen remaining load growth. This is especially true in areas where capacity is constrained.

Major projects that are normally used to implement a reliability strategy within the next five years are reviewed as well as any alternatives for consideration. Discussions about possible non-pipe alternatives are now the center of these discussions. These projects center around both supply-side and demand-side alternatives. Supply-side alternatives include compressed natural gas, renewable natural gas designed to minimize or eliminate methane emissions, and potentially liquefied natural gas projects. Demand-side alternatives include non-firm service, firm demand response programs, more aggressive energy efficiency programs, and fostering electrification.

Due to the potential for changing dynamics, the interplay between natural gas and electric markets continues to demand review. This includes a comparison of changes in gas for electric generation in summer compared to winter periods. Increased gas use for electric generation during the winter period, when the gas distribution system peaks, is of the utmost importance for reliability. Most of the gas-fired electric generators are not firm customers and must switch to an alternate fuel during periods of extreme cold weather.

Staff reviews typical communication processes between gas-fired generators and a utility’s natural gas control center especially if the need for improvements have been identified. Distributed generation/combined heat and power systems, including any micro-grid applications, are generally firm customers. Their impact on design day forecasting needs to be understood and managed.

Transportation Customer Issues

The Commission unbundled delivery and commodity for gas customers in the 1990s.[22] As discussed above, pursuant to

[22] Case 93-G-0932, Restructuring of the Emerging Competitive Natural Gas Market, Opinion and Order Establishing Regulatory Policies and Guidelines for Natural Gas Distributors (issued December 20, 1994).

the Commission’s Mandatory Assignment of Capacity Order in 2007, marketers who then contracted for their own capacity were allowed to continue to supply their own capacity. Most marketers already took their capacity from the utilities. For the grandfathered capacity that marketers still bring to the LDCs’ city gates, LDCs must show that they have checked the documentation provided by the marketers and verified that they have firm, primary delivery point capacity for at least the months of November through March.

In addition, Staff reviews other processes and procedures that are part of the retail access programs for small residential and commercial customers to identify any issues or problems that may need to be addressed. Management of imbalances between third-party deliveries and actual customer usage is a common theme, as well as allocation of deliveries among the different service territory delivery locations.

Outside of the retail access programs, there are procedures for large firm core and non-core transportation customers. Core market customers lack alternatives. They take either: (a) firm sales service, and lack installed equipment capable of burning fuels other than gas; or (b) firm transportation service. Back-up and standby services provided to firm transportation customers are core market services. Participants in the retail access programs are all core customers and their transportation quantities are balanced monthly by the utilities.

Non-core customers have alternatives. They take sales service under flexible rate schedules. This includes sales services that are labeled as "firm" services in some LDC’s tariffs, but whose prices may be linked to the prices of alternate fuels or services where sales and transportation services are offered in unison. These customers have installed dual-fuel equipment, or take interruptible transportation service. Backup and standby services provided to non-core market customers, if any, are themselves non-core services. Non-core customers are also those that participate in daily-balancing programs. Processes and procedures that are part of larger volume customer transportation must also be reviewed.

Non-Firm Service Management Issues

During the annual Winter Supply Preparedness Review process, Staff verifies the LDCs' processes and procedures for non-firm or interruptible service customers. In the downstate market (New York City, and the Counties of Westchester, Nassau, and Suffolk) there are about 4,000 interruptible customers who rely on alternate fuels when interrupted, while in the upstate market there are less than 100 such customers.

The LDCs' ability to provide reliable service relies on interruptible customers consistently discontinuing gas service when required to do so. Thus, the Commission requires interruptible customers who must switch to an alternative fuel during a gas interruption to have alternate fuel available during the winter heating season,[23] or have the ability to cease operations of gas fired equipment as well as the need for utilities to follow specific protocols during an interruption.[24] Con Edison and both downstate National Grid Companies now also

[23] Case 00-G-0996, Criteria for Interruptible Gas Service, Order Directing Utilities to File Revised Interruptible Gas Service Tariffs (issued August 24, 2000); Case 00-G-0996, supra, Order Adopting Permanent Rule (issued January 31, 2001). Case 00-G-0996 contains additional orders, issued through September 2006.

[24] Case 15-G-0185, Heating Fuel Oil Supply Coordination with Interruptible Gas Service Customers: February 2015 Issues, Order Adopting New Communications Protocols (issued December 16, 2016).

have special rules[25] regarding the handling of interruptible customers who repeatedly violate non-firm tariff requirements. These customers and their remediation efforts need to be tracked and recorded. The LDCs are responsible to ensure compliance.

Rate Case Review of Supply, Capital Projects and O&M Expenses

Sixteen NYCRR 61.3(d)(6) requires that every gas rate case filing include the gas purchasing policies and load management practices. This includes explaining how the LDC ensures that gas costs for both the historic test period and rate year are prudent and from the least-cost reliable sources. Such testimony should discuss both the long- and short-term gas procurement plans as well as a description of existing gas supply contracts. This testimony should include quantities as well as costs for all sources of gas supply.

The key concept in rate cases related to long-term supply planning is "load management." This entails an analysis of both customer demand requirements and the capacity to provide gas supply to meet those requirements.

Assessing demand starts with historic sales data for the number of customers and billed sales per month by service class, sub class, or customer class (i.e., heat, non-heat, commercial, public authority and industrial), as applicable, for the last five calendar years, including the historic test year, and the current year to date. This then is developed into a customer count forecast and normal sales forecast for a defined rate year and subsequent rate years as requested by Staff. Staff reviews the LDC's sales forecasting methodology, with the

[25] Cases 18-G-0565 and 19-G-0191, Con Edison - Tariff Filings, Order Approving Tariff Amendments with Modifications, (issued November 15, 2019); Cases 19-G-0370 and 19-G-0371, KEDNY and KEDLI - Tariff filings, Order Approving Tariff Amendments with Modifications (issued November 15, 2019).

LDC providing a written explanation of the forecasting methodology (e.g., econometric, historical regression or trends, customer provided information) used to derive the first rate year and subsequent rate years forecast sales and customers by service class, sub class, or customer class, as applicable. The LDC includes a description of all inputs, basis of assumptions and any adjustments to results.

Where econometric or regression methodologies are used, an LDC will provide economic variables analyzed, regression results for all forecasting equations, all historical data used to produce those regression results, the projected values of all forecast drivers, and the support for these projections. The sales forecast and reliability forecast are both based on 30 years of weather data and up to 10 years of usage data to establish a proper trend of any program impacts. In addition, the LDCs also provide an explanation of any significant out of model adjustments to either customer changes or volume demand projected to occur in the linking period, i.e., the period between the filing of the rate case and the beginning of the rate year, or the subsequent years forecasted.

The final forecast for demand requirements consists of a description of how the LDC forecasts design day load. This includes how the LDC determines base load and how it calculates load for each HDD, by month at a minimum. This is based on a specified temperature for the design day and why that temperature was chosen.

In rate cases, Staff and the Commission also review gas purchasing policies. These policies include not just how the LDC’s contracts the actual supply of gas, but also how the utility will get the gas supply to the service territory. An LDC will provide details of how total reserved capacity is utilized to meet the demand of all firm customers on a design day and design winter basis. A rate filing will contain details of any plans to make significant changes to pipeline and storage capacity assets. These changes need to be compared to the associated design day or design winter demand requiring the additional capacity. Recently, this discussion has included the use of delivered services of third-party capacity as well as non-pipeline alternatives instead of traditional pipeline projects. The LDC's testimony will also address what the utility has done with regard to FERC intervention, interstate pipeline costs, and to minimize cost impacts on firm customers.

Additionally, rate cases review the ability of the utility's distribution system to deliver natural gas to its customers. Operating constraints as well as projects designed for customers requesting service need to be identified. Rate cases also include discussion of any potential natural gas transmission projects subject to Article VII that may be filed in the next five years. The LDC will also indicate if it has been approached by other entities about connecting pipelines, wells, or storage facilities directly to the LDC's distribution system, including high pressure transmission lines owned by the LDC within the service territory. The LDC will include a description of any such facilities currently attached to its facilities.

Rate cases also include a review of compliance with affiliate rules. Specifically, each LDC must provide documentation pertaining to company procedures, rules and regulations regarding the separation of activities among its affiliates. In addition, each LDC must provide all documentation (<u>e.g.</u>, contracts, delegation of authority, etc.) pertaining to gas supply arrangements that exist or have existed with any affiliated marketing/trading organizations.

Finally, though touched on above, rate cases include the identification of capital investments. This includes what investments are currently used and useful to provide service and what new investments are required to continue and/or improve service. Expenses by a utility for fixed assets, like buildings and equipment (e.g., poles, pipes, meters) are considered capital expenditures. These fixed assets have a useful life of more than one year. In a rate case, the Commission generally sets a budget for capital expenditures and forecasts a net plant balance that is included in the utility's rate base. The utility earns a return on the assets in its rate base.

A utility must provide a detailed explanation of each forecasted gas and common capital expenditure project or blanket grouping including a discussion of the need for the project. The common category includes assets that may be shared among different regulated businesses of the utility, such as between Con Edison's gas, electric, and steam businesses. Depreciation is used to allow a utility to recover the capital expended on an asset over its anticipated useful life.

Article VII Cases

PSL Article VII requires utilities to secure a Certificate of Environmental Compatibility and Public Need from the Commission prior to constructing a natural gas transmission line. Article VII establishes a review process for consideration of any application to construct and operate a major utility transmission facility. The Commission can decide whether to grant, modify or deny applications filed under Article VII. Staff members analyze economic, environmental, engineering, legal and safety issues. In addition, the Commission considers the views of stakeholders and the general public in making a determination.

Under Article VII, a fuel gas transmission line is any line extending a distance of 1,000 feet or more to be used to transport fuel gas at pressures of 125 pounds per square inch or more that is not wholly located underground in a city or wholly within the right of way of a state, county or town highway, or village street, or which replaces an existing transmission line and extends less than one mile.

The length and size of the proposed line determines the length of time in which a decision may be made. For lines less than five miles in length and six inches or less in diameter, a decision will be made within 30 days of receipt of a completed application. For lines between five and 10 miles, and for lines less than 5 miles with a diameter greater than six inches, a decision will be made within 60 days of receipt of a completed application. For lines greater than 10 miles of any diameter there is no time limit for a Commission decision.

Generally, the reviews consider the basis of the need for the facility, whether the plan for the line conforms with applicable state and local laws and ensuring that the facility will not pose an undue hazard to persons or property along the area traversed by the line. The review also considers the nature of the probable environmental impact, the extent to which the facility represents minimum adverse environmental impacts, and whether overall the facility of the line as well as its construction and operation is in the public interest.

Any person may file comments with the Commission regarding these projects. When a line is longer than 10 miles, Individuals can deliver an oral or written statement of concerns or personal views at a public statement hearing. The Commission has the authority to conduct a hearing for any gas transmission project subject to Article VII no matter how long it is.

Contract Filings required in the Commission’s Regulations

Any time an LDC executes a new contract, binding precedent agreement, master contract or other binding agreement, the LDC must file it within 30 days of execution with the Secretary to the Commission. Staff can then review the agreement for prudence.

16 NYCRR Part 720-1.6 (Responsibility for Filing) indicates that each public utility shall file copies of its contracts with the Commission, in a form prescribed by the Department of Public Service, showing all rates and charges made, established, or enforced, or to be charged or enforced, under all forms of contract or agreement. In Part 720-1.4, contracts, which by reference include provisions of tariffs filed with the Federal Energy Regulatory Commission, shall be accompanied by copies of such tariff provisions. Whenever revisions are made to the tariffs filed with the Federal Energy Regulatory Commission that affect the terms of the contract, these revisions shall also be filed with the contracts. The acknowledgment of the receipt of any contract by the Commission, or the fact that any schedule, amendment, supplement, or statement is on file with the Commission does not prejudice a subsequent investigation and determination by the Commission as to its lawfulness. Staff reviews all filings for their appropriateness and has the ability to elevate an issue for review by the Commission.

In addition, under 16 NYCRR Part 720-6.5 Staff reviews all costs associated with contracts resulting in costs that flow through the LDCs’ gas cost adjustment clauses, especially those directly associated with identifiable gas supply purchases. In addition to the actual cost of the gas purchased, to be included in the average cost of gas computation, fees and any additional charges are subject to the following conditions: (i) such fee must provide a net reduction in the delivered cost to the public utility on an avoided cost basis, i.e., the combination of gas costs, delivery costs and fee payments must be less than the cost of the supply that would have been taken but for said purchase; (ii) the payment may not be to an affiliate of the utility, nor may it be for gas ultimately purchased from an affiliate; (iii) no costs attributable to utility personnel, e.g., wages or expenses, may be included in such fee payment. Staff reviews the LDCs' monthly gas cost adjustment clause statements and their associated workpapers. Additionally, Staff conducts an annual reconciliation of all gas costs.