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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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

[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

[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.

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[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.

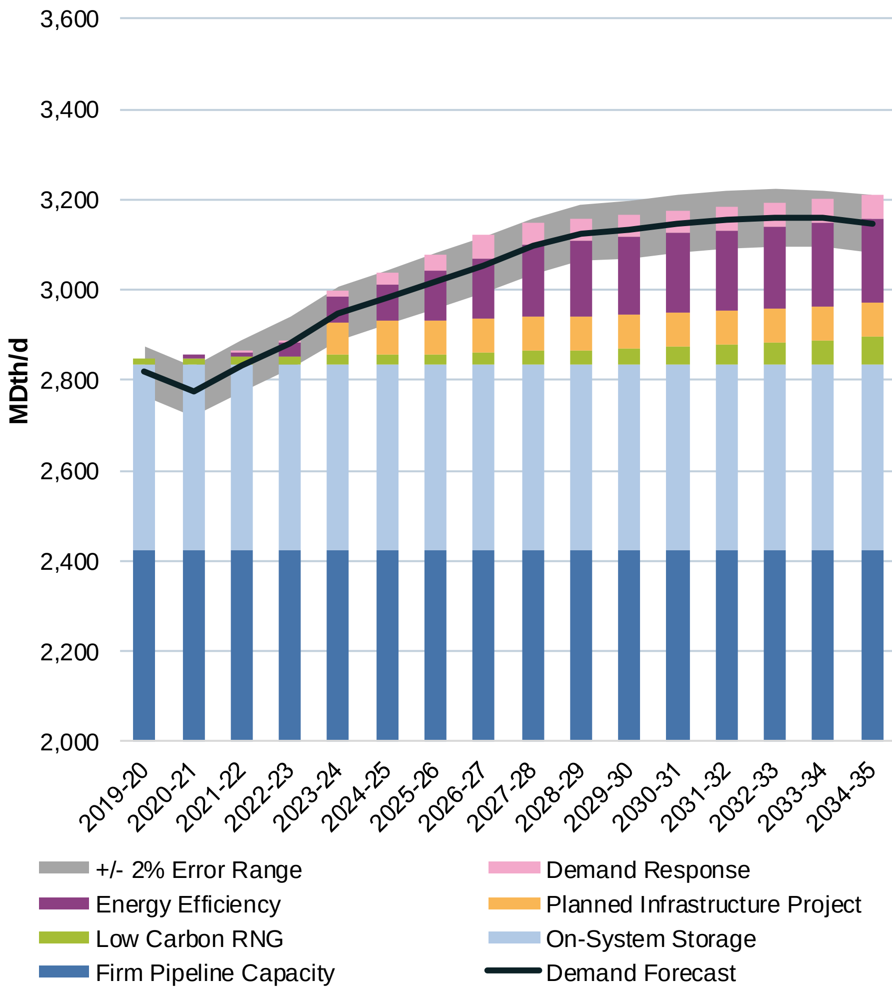
The demand forecast must include a weather-adjusted back cast using actual weather conditions to assess the load that would have been experienced had temperatures dropped to the design day level. Forecasts of future load should be consistent with short term weather and forecasted usage determination 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 (e.g., 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.