GREENPOINT VAPORIZERS 13&14
LONG TERM CAPACITY PROJECT REPORT
AUGUST 29, 2022

In 2019, National Grid[1] announced that it would stop connecting new gas customers because of a forecast shortfall in the supply of natural gas needed to meet growing demand in downstate New York. The response from residential customers, small businesses, developers, elected officials, customer advocates, and regulators[2] was overwhelmingly negative, as these stakeholders expressed concern about the economic development, affordability, and other impacts of denying customers viable options for satisfying their heating needs. As part of a settlement with the State of New York (the "Settlement"),[3] National Grid agreed to lift the service restrictions and implement various short-term measures to continue serving new customers. Acknowledging both the extent of the supply gap, and that new solutions were necessary to avoid future moratoria, the Settlement provided that National Grid would conduct a public process to identify projects and programs to maintain sufficient gas supplies in downstate New York.

In February 2020, National Grid published the *Natural Gas Long Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island* (the "Long Term Report")[4] that assessed the gas supply constraints in downstate New York and identified potential options for meeting future customer demand. The report analyzed the relative risks and benefits of the identified options (which included interstate pipelines, liquified natural gas and compressed natural gas facilities, on-system transmission projects, and demand-side solutions) in terms of reliability, deliverability, cost, and environmental impacts, among other considerations. After a series of public meetings and information sessions, and thousands of written comments from members of the public and stakeholder groups, in May 2020, National Grid published the *Long Term Capacity Supplemental*

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[1] The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") (KEDNY and KEDLI are collectively referred to as "National Grid" or the "Companies").

[2] The New York State Public Service Commission ("Commission") recently reinforced that local distribution companies ("LDCs") have an obligation to provide safe and reliable service to customers under the regulations, and *moratoria should only be used as a "last step"* to maintain reliability. *See* Case 20-G-0131 *Case Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, "Order Adopting Moratorium Management Procedures" (issued and effective May 12, 2022), at 24 ("Moratorium Management Order").

[3] Case 19-G-0678, *Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid*, "Order Adopting and Approving Settlement" (issued and effective November 26, 2019), dated November 24, 2019.

[4] Case 19-G-0678, *National Grid Natural Gas Long Term Capacity Report* (filed February 25, 2020). The Long Term Reports, summaries, presentations, transcripts, technical information, and other materials are available at https://ngridsolutions.com/.

Report[5] that summarized stakeholder comments and recommended a portfolio of non-infrastructure (*e.g.*, energy efficiency, demand response, weatherization) and targeted infrastructure enhancements, referred to as the "Distributed Infrastructure Solution,"[6] that now serves as the roadmap for addressing supply constraints in downstate New York.

National Grid's Distributed Infrastructure Plan increasingly relies on non-infrastructure, demand-side solutions (*e.g.,* weatherization and demand response) to meet customers' peak energy needs by the second half of this decade, but the Companies' analysis clearly demonstrates that targeted infrastructure investments are also needed in the near-term to maintain the reliability of the gas network in downstate New York. The Greenpoint Vaporizer 13/14 Project is one of two on-system infrastructure enhancements[7] included in the Distributed Infrastructure Solution. The Project consists of two new vaporizer units[8] that will allow for more efficient extraction of liquified natural gas ("LNG") from the existing Greenpoint LNG plant during periods of peak demand. The new vaporizers (i) provide critical safety and reliability benefits for the gas network, (ii) do not add any new gas supply to the system, (iii) will only operate on a handful of the coldest days of the year when they are needed to meet customers demand,[9] (iv) are more efficient[10] than existing vaporization units, (v) are more cost-effective than other options because the project leverages existing assets, (vi) will be located within an existing National Grid facility with minimal construction impacts, and (vii) can be easily decommissioned should customer demand decline in the future.

The need for the Greenpoint Vaporizer 13/14 Project has been presented and vetted in multiple proceedings since the project was first identified and initiated in 2020. In addition to the extensive public engagement and independent analysis undertaken in connection with the Long Term Report process, as well as review conducted by Department of Public Service Staff and other parties in KEDNY/KEDLI's latest rate cases, the Greenpoint Vaporizer 13/14 Project underwent significant public scrutiny in connection with the Air State Facility permit application for the Project that is currently pending before the New York State Department of Environmental Conservation ("NYSDEC"). Securing the air permit is the last step necessary to begin construction. Once

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[5] Case 19-G-0678, *National Grid Natural Gas Long-Term Capacity Supplemental Report* (filed May 8, 2020).

[6] Specifically, for the Distributed Infrastructure Solution, National Grid recommended combining: (1) incremental demand side management ("DSM") programs comprising an aggressive set of incremental energy efficiency ("EE") measures over and above the growth in demand reduction required by previously approved DSM programs as well as new gas DR programs; (2) the LNG Vaporization Option (the Greenpoint Vaporizer 13/14 Project), which adds two additional LNG vaporizers at National Grid's Greenpoint Facility; and (3) the Iroquois Enhancement by Compression option (the "ExC Project"), which involves the construction of additional compression facilities to increase capacity on the Iroquois gas transmission system.

[7] A new compressed natural gas ("CNG") injection site on Long Island is the other on-system project.

[8] As discussed in Section 5(a) infra, the Greenpoint LNG facility currently has six vaporizers, one of which is redundant. When the project is complete, the facility will have a total of eight vaporizers and maintain the same level of redundancy.

[9] The Greenpoint LNG facility liquified gas on 2-14 days per year over the last five winters. Note, the number of operating days does not necessarily correlate to the total send out volume, *i.e.*, there could be several short duration events with a small send out volume (winter 2021-22).

[10] The proposed new vaporizers will operate with an improved energy efficiency of 95.8 percent compared to the existing units with an energy efficiency of 92.4 percent resulting in decreased natural gas usage.

permitted, the Project will take approximately 18 months to construct, just in time to be in-service for the winter 2024/25.

For more than two years, National Grid has delivered on its commitments under the Settlement to serve new customers, initiate customer assistance programs, implement innovative energy efficiency ("EE") and demand response programs, and – importantly – identify new solutions for avoiding moratoria. As discussed more fully below, the exhaustive analysis performed through the Settlement, as well as the work of the independent monitor engaged to review National Grid's gas supply planning, independent engineering assessments, and the considerable work in the recent rate case proceedings, make it abundantly clear that (1) the looming supply gap is real, (2) the Companies' targeted infrastructure projects, including the Greenpoint Vaporizers, are prudent and necessary to avoid future service restrictions, and (3) access to affordable and reliable energy is essential for customers in downstate New York.

Producing the Long-Term Capacity Reports provided National Grid with an unprecedented opportunity to engage with and receive feedback from our stakeholders, including customers of all types, businesses, civic and trade organizations, community groups, environmental organizations, our regulators, and elected officials. We held virtual meetings for customers, created a dedicated website providing access to our reports and other resources to learn more about our solution, and (for the Second Supplemental Report) delivered printed copies to local libraries so that customers could engage with us through their preferred method. We solicited feedback through our website and by emails to our downstate New York customers. We also included messages on bills and sent communications about the reports on social media. It is National Grid's firm belief that no gas utility has ever gone to greater lengths to engage the public for feedback to shape our approach. More importantly, we have relied on that feedback to develop our proposed solution - and no utility has done more to publicly demonstrate the need for targeted infrastructure investments (including the Greenpoint Vaporizer 13/14 Project) and voluntarily subjected its forecast and supply planning to layers of additional independent review. The independent reviews have validated and confirmed that the projects in the Distributed Infrastructure Solution are prudent and necessary for serving customers. Whether one believes the gas network has an enduring role in a low carbon future, there can be no question of the need to maintain reliable and affordable energy options in the near term. These vaporizer units are the final infrastructure component of the Distributed Infrastructure Solution and the only option capable of enhancing near-term system reliability in the event of a pipeline failure or other supply interruption. For all these reasons, the Greenpoint Vaporizer 13/14 Project must move forward as part of a sensible energy policy that addresses the near-term energy needs of New Yorkers – or we risk jeopardizing reliability and revisiting the frustration experienced in 2019 by leaving some customers without practical or affordable heating options.

The Joint Proposal adopted by the New York State Public Service Commission ("Commission") in the recent KEDNY/KEDLI rate settlement[11] provides a mechanism for yet another independent

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[11] Case 19-G-0309 and 19-G-0310, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service*, "Order

assessment of certain on-system projects as a condition of cost recovery over the term of the rate plan,[12] including the Greenpoint Vaporizer 13/14 Project. This report initiates the Companies' request for assessment and cost recovery of the Greenpoint Vaporizer 13/14 Project.

Appendix A provides a list of the regulatory proceedings that have addressed the downstate supply challenges and considered the need for the Greenpoint Vaporizer 13/14 Project. These proceedings have produced thousands of pages of reports, presentations, technical data, independent assessments, public comments, and transcripts. It is not possible to fully incorporate these materials in this report, but the extensive public record and procedural history must be considered in any fair assessment of the need for (and the Companies' decision to proceed with) the vaporizer project.

<u>SECTION 1</u>: EXECUTIVE SUMMARY

In the Joint Proposal, the Companies identified a set of "Long Term Capital Capacity Projects" consisting of on-system infrastructure investments designed to address the supply/demand gap and enhance reliability in the downstate New York service territories. These on-system projects, which leverage existing infrastructure in constrained areas of the service territories, are set forth in Section IV.5.3 of the Joint Proposal and include the Greenpoint Vaporizer 13/14 Project. Prior to cost recovery during the term of the rate plan, the Joint Proposal provides for an assessment of the need for these projects by a qualified, independent consultant to be selected by, and to work at the direction of, Department of Public Service Staff ("DPS Staff").[13] The independent consultant will consider several factors, including the associated safety and reliability benefits, greenhouse gas ("GHG") emissions, and others factors during its review of the project (as described below). The Companies are not permitted to recover the costs of any Long Term Capital Capacity Project during the term of the rate plan if the independent consultant determines that such project is not needed *at the time proposed* by the Companies. Additionally, the ability to recover the costs of any approved Long Term Capital Capacity Project is subject to the achievement of certain performance targets for non-infrastructure solutions (including EE, demand response, non-pipes/third-party solutions, electrification, and leak prone pipe/non-pipe alternative targets). In the Order approving the Joint Proposal, the Commission modified the process to require that the Commission will issue a final decision regarding the surcharge within sixty days of filing of the independent consultant's report.[14]

DPS Staff selected PA Consulting Group, Inc. ("PA Consulting") to perform the independent assessments of the Companies' Long-Term Capacity Projects under the Joint Proposal. On October

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Approving Joint Proposal, as Modified, and Imposing Additional Requirements" (issued and effective August 12, 2021) (the "Order"), adopting with modifications the terms of the Joint Proposal, dated May 14, 2021 ("Joint Proposal").

[12] Joint Proposal, Section IV.5.3.

[13] To initiate the independent assessment, the Companies will file a report identifying the projects for which they are seeking cost recovery, present the Companies' assessment of the need for the project to ensure continued reliable service, and demonstrate the Companies' performance under the Capacity Demand Metrics.

[14] Order, at 122. The Commission subsequently noted that "more than 60 days may be required to complete the review of future Capacity Projects." *See*, Cases 19-G-0309/0310, "Order Authorizing Surcharge Related to the Southeast Suffolk Phase 1 Project" (issued and effective July 14, 2022), at 30.

21, 2021, the Companies, DPS Staff, and PA Consulting executed an agreement governing the terms and conditions of PA Consulting's project review.[15]

The Joint Proposal outlines the factors to be considered in completing the independent engineering assessment for Long Term Capital Capacity Projects, which include: (i) the Companies' need for the project to meet a reasonable forecast of customers' peak demand, based on the Companies' most recent forecast available; (ii) any safety and/or reliability benefits from the project; (iii) viable alternatives to the project that would ensure reliable service; (iv) the All-In Cost of the project and a comparison of the All-In Cost of viable alternatives; (v) the GHG emissions attributable to the project and any viable alternatives; and (vi) any comments and analysis submitted by intervening parties and the public.[16]

National Grid strongly supports New York's goals to reduce GHG emissions economy-wide and reach the goal of net zero emissions. In April 2022, National Grid announced our *Clean Energy Vision*,[17] a plan to decrease reliance on fossil fuels from our U.S. gas and electric systems, enabling the homes and businesses we serve to meet their heating needs without the use of fossil fuels by 2050. This commitment recognizes our critical role in leading the clean energy transition for the future generation of customers. Our plan rests on four pillars: first, aggressively accelerating insulation and energy efficiency improvements to buildings; second, supporting cost-effective, targeted electrification on our gas network, including piloting networked geothermal solutions, to electrify as much as 50% of the heating load by 2050; third, in areas where full electrification may not be practical or cost-effective, providing customers with the tools to pair electric heat pumps with their gas appliances; and, finally, eliminating fossil fuels from our existing gas network no later than 2050 by delivering renewable natural gas ("RNG") and green hydrogen to customers.

At the same time, the Companies' core mission is to provide safe and reliable gas service to New York customers at just and reasonable rates – at a time when access to reliable and affordable energy is more important than ever. With nearly two million customers in our downstate New York service territory, and with a sustained trend over the last 10 years of adding thousands of new customers per year, the Companies must ensure system reliability, plan for our customers' future natural gas demand, and ensure that our gas supply portfolio, gas distribution network infrastructure, and demand-side management programs can meet customers' energy needs. As the Commission recently noted in its order approving the rate settlement for National Grid's upstate New York affiliate, "failure to maintain safe and adequate electric and gas systems throughout the state would undermine the intent of the CLCPA."[18]

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[15] Case No 19-G-0309 and 19-G-0310, Independent Consultant Agreement (filed November 12, 2021).
[16] Joint Proposal, at 45.
[17] https://www.nationalgrid.com/us/fossilfree.
[18] Case 20-G-0381, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, "Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements" (issued and effective January 20, 2022), at 80 ("[The Commission's CLCPA] analysis must be made in consideration of the Commission's statutory obligation to ensure that '[e]very gas corporation, every electric corporation and every municipality . . .

In the Supplemental Long Term Report, National Grid introduced a new component to the Distributed Infrastructure Solution to close the gap between demand and supply. As explained in the Supplemental Report, while planning vaporization upgrades at the Greenpoint LNG facility to increase reliability and reduce maintenance costs (Units 11 and 12), National Grid identified a separate opportunity to enhance throughput at the existing LNG facility and further leverage existing infrastructure with the addition of two vaporizers (Units 13 and 14).[19] The Project is capable of increasing capacity by nearly 60 MDth/day.[20] National Grid provided the following assessment of the relative benefits at the time of the Supplement Report:

<u>Table 1-1</u>: Assessment of Greenpoint Vaporizer 13/14 Project – Excerpt from Supplemental Long Term Report

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Installation of two additional Submerged Combustion Vaporizers (SCVs) at National Grid's Greenpoint LNG facility
Size	60 MDth/day	Designed to meet periods of peak demand
Safety	◕	New York City Fire Department (FDNY) and state entities to review and approve all necessary safety processes and protocols
Reliability	◕	Vaporizers are simple in design and have historically been very reliable – National Grid has extensive experience in this area
Cost	●	Total project cost to install two vaporizers is $65M [updated]
Environmental Impact	◑	The short-term ecological impact from installation will be moderate in the Greenpoint area of New York. While emissions from an LNG system are 10-15% higher than what would be expected for a pipeline solution, impact would be low due to intermittent peak usage.
Community Impact	◕	Low impact to the community – all planned construction and installation is within the existing Greenpoint LNG footprint

furnish[es] and provide[s] such service, instrumentalities and facilities *as shall be safe and adequate* and in all respects just and reasonable.' We note that this statutory obligation long pre-dates enactment of the CLCPA and remains the Commission's core responsibility. Indeed, failure to maintain safe and adequate electric and gas systems throughout the state would undermine the intent of the CLCPA.").

[19] During the public review period (2020), National Grid received comments that there is additional supply capacity of up to 60 MDth/day available through enhancements to LNG vaporization at its Greenpoint location. National Grid agreed that this was an opportunity to close the gap between projected demand and available supply.

[20] The Project will provide 58.8 MDth/day by increasing Greenpoint LNG's total vaporization capability from 291,200 Dth/day to 350,000 Dth/day.

As explained in the Supplemental Report, the process to identify viable solutions to close the supply gap determined that the Greenpoint Vaporizer 13/14 Project (as a component of the Distributed Infrastructure Solution) was the best option for a variety of reasons, including:

- *System Benefits* – The Greenpoint Project will provide almost 60 MDth/day of additional vaporization capacity. Importantly, the Greenpoint Vaporizer 13/14 Project will also provide critical on-system reliability in the event of a supply disruption or excess demand by enabling more efficient extraction of LNG from the existing tanks. Because gas systems operate with effectively zero contingency,[21] and given the challenges to securing additional gas supplies from new sources, projects that can leverage existing infrastructure to support peak operations are critical to ensuring reliability and resiliency going forward. Indeed, the Commission, noting operational issues on interstate pipelines, has found that "National Grid and all gas utilities should consider single points of failure on the interstate gas system and have contingency plans in place to ensure such changes do not negatively impact the reliability of its system."[22] The Greenpoint Vaporizer 13/14 Project provides such contingency.

  The Project is exceptionally well suited to meet the needs of KEDNY's system. It improves the safety and reliability of the system for existing customers, mitigates the risk of curtailments and outages, and enables the Companies to meet customers' near-term energy needs in downstate New York throughout the winter season by enhancing the plant's ability to utilize its existing inventory to address a larger shortfall in supply than the plant can currently address. During peak demand periods, the direct and efficient delivery of vaporized LNG to where most of KEDNY's demand is located (Brooklyn and Queens) allows the Companies to meet our customers' energy needs while minimizing the pressure losses associated with moving that energy. This reduces the unacceptable risk of system pressures dropping below the minimum levels required by federal and state code and the Companies' operating parameters. Without this project, the Companies face unacceptable energy and/or pressure shortfalls in critical areas of the system that would adversely impact system reliability and service to thousands of customers and would potentially need to restrict service connections.

- *Alternatives Considered* – Various alternative projects/programs were (and continue to be) considered for meeting peak demand in downstate New York. Examples include interstate pipeline projects, on-system transmission projects, floating LNG barges, and micro-LNG tanks. These alternatives, which are described and assessed at length in National Grid's series of Long Term Reports, were determined to involve higher costs and greater risks to successful

[21] "Zero contingency" means that the plans for balancing gas demand and supply have no supply contingency or reserve margin. In other words, they are designed to balance supply and demand assuming forecast peak demand is not exceeded and that all available gas capacity resources will be available at 100% with no disruption when needed.

[22] Case 19-G-0678, "Order Instituting Proceeding and to Show Cause," at 5.

and timely implementation than the Greenpoint Vaporizer 13/14 Project and other components of the Distributed Infrastructure Solution. This continues to be the case.

- *Project Costs* – The total capital costs for the Project are currently forecast at approximately $65 million. As described in Section 7 below, the overall Project cost compares favorably to other options (including options that were ultimately rejected based on operational considerations and/or execution risks, or not considered a viable alternative). Among other reasons, the Project leverages existing infrastructure to provide additional peak capacity through targeted on-system investments.

- *Environmental/Community* – Installation will result in temporary environmental impacts related to air quality, storm water, noise, and waste generation. The vaporizers will be installed entirely within the Greenpoint LNG facility existing footprint and housed within a new structure. The installation process does not require significant excavation or drilling, and the new vaporizers will be installed in the vicinity of the existing vaporizers. Therefore, there will be minimal visible impact to the neighboring communities. Recent experience with a similar vaporizer project at the Greenpoint facility demonstrates there will be similarly minimal ecological and community impacts during the construction phase. Once operational, there will be periodic emissions from the vaporizer combustion process on the limited days of operations. However, the Project's emissions will be lower than other LNG alternatives because operation of the vaporizers will be strictly limited to peak days or local operational needs. Moreover, the new vaporizers will displace operation of existing vaporizers, resulting in decreased emissions from the vaporizers due to the increased efficiency of the new units and use of newer vaporizer combustion technology. The new vaporizers do not increase annual output from the facility or frequency of plant operation because vaporization at the facility is limited by operational parameters and the capacity of the existing LNG storage tanks, which are not changing.[23] The new vaporizers will allow the facility to vaporize its current annual capacity at a faster rate to meet demand during short-term, high demand periods, with redundancy in the event of equipment failure. The Greenpoint Vaporizer 13/14 Project compares favorably to other infrastructure solutions regarding community impacts because the vaporizers will be sited within the footprint of the existing Greenpoint LNG facility and do not require truck or barge deliveries (in fact, the new vaporizers will reduce reliance on CNG solutions). In the future, with increased electrification, it is anticipated that the proposed vaporizers will run less frequently. Because of reduced on-site natural gas consumption from the new, more efficient vaporizers, the Greenpoint LNG facility's direct GHG emissions are estimated to decrease by up to 99 metric tons of CO_2e per year as a result

[23] The Commission found similar factors with the SE Suffolk Project supported the conclusion that the project was "not inconsistent with the attainment of the statewide greenhouse gas emissions limits" under the CLCPA. *See e.g.,* Cases 19-G-0309/0310, "Order Authorizing Surcharge Related to the Southeast Suffolk Phase 1 Project" (Issued and Effective July 14, 2022), at 22 ("More importantly, the record shows that the SE Suffolk Project will not allow KEDLI to increase supply on its overall system. Rather it only allows KEDLI to move gas on its system more efficiently to areas with lower pressure. In short, it is a reliability-based project that would not on its own result in increased GHG emissions.")

of the Vaporizer 13/14 Project (see CLCPA GHG Assessment, dated October 20, 2021 (available at https://greenpointenergycenter.com)).

- *Execution/Deliverability* – National Grid has taken all necessary steps to bring the Greenpoint Vaporizer 13/14 Project online but is currently waiting on the Air State Facility permit to commence construction. Detailed engineering, procurement, and delivery of long lead materials have all been completed, environmental reviews and public meetings conducted, and preliminary work that may be performed before issuance of a permit is in progress, pending receipt of the final air permit. The Project already has NYC Department of Buildings ("DOB") permits, and FDNY approvals for construction within New York City. Without the Air State Facility permit, National Grid cannot construct the Greenpoint Vaporizer 13/14 Project. Currently, the primary risk to implementation is not obtaining the necessary permitting for the project, or not obtaining the permits in a timely manner. The Greenpoint Vaporizer 13/14 Project is deemed by the Companies to be the only distributed infrastructure project that can be brought online in time to meet projected demand in the 2024-25 timeframe. Vaporizers have a simple design that allows for easy scheduled and unscheduled maintenance. Additionally, all materials will be made with corrosion resistant and long-lasting materials, such as stainless steel.

- *Capacity Demand Metrics* – As described in Section 9 below, the Companies' efforts related to EE, demand response, non-pipe third party solutions, electrification, and leak-prone pipe NPAs are guided by the Capacity Demand Metrics in the Joint Proposal. The Companies' activities and results under the Capacity Demand Metrics demonstrate the Companies' commitment to increasingly meet customer demand through the unprecedented deployment of non-infrastructure solutions that reduce overall gas consumption.

Following the comprehensive public process effected as part of the Settlement, the Greenpoint Vaporizer 13/14 Project was reasonably determined to be the best option for reliably meeting customers' energy needs and avoiding near-term restrictions on gas connections. For this reason, the costs of the Project are appropriate for recovery through the Demand Capacity Surcharge Mechanism in accordance with the terms of the Joint Proposal.

SECTION 2: BACKGROUND AND CONTEXT

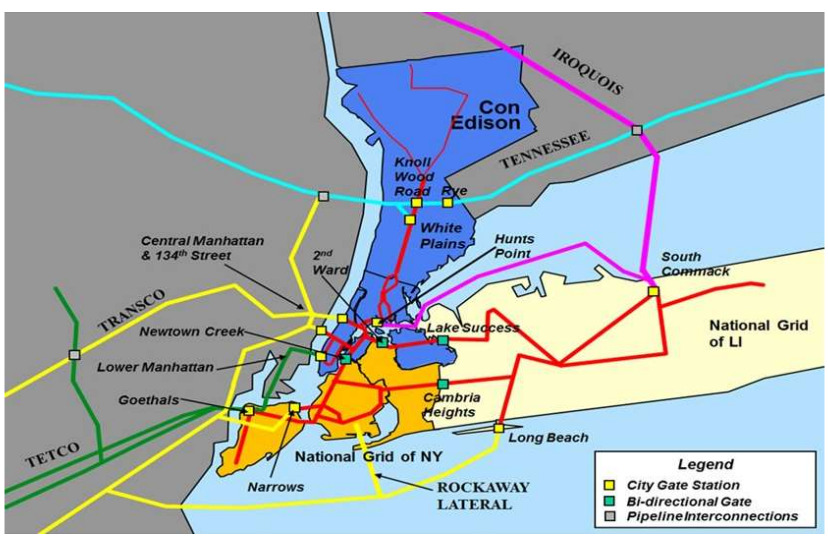
A. *National Grid's Downstate Gas Networks*

National Grid operates two gas distribution companies in downstate New York serving areas of New York City and Long Island. KEDNY's gas distribution system serves customers in Brooklyn, Staten Island, and portions of Queens, all located within New York City. KEDLI's gas distribution system serves Nassau and Suffolk counties on Long Island, as well as the Rockaway Peninsula in Queens. For more than 100 years, National Grid and its predecessors have provided gas service to customers in these areas of downstate New York. Today, the Companies provide natural gas service to more than 1.9 million customers – 1.3 million in KEDNY and 0.6 million in KEDLI. Figure 2-1 is a map of the KEDNY and KEDLI service territories.

<u>Figure 2-1</u>: KEDNY and KEDLI Service Territory

KEDNY and KEDLI have a unique arrangement with Con Edison concerning the operation of the high-pressure gas transmission system serving the three downstate New York distribution companies, known as the New York Facilities System ("NYFS"). Under the terms of the NYFS Agreement, the downstate distribution companies contract for the transportation and receipt of gas from various interstate pipelines that interconnect with the NYFS, including Transcontinental Gas Pipeline Company LLC, Texas Eastern Transmission LP, Iroquois Gas Transmission System LP, and Tennessee Gas Pipeline Company, LLC. KEDNY and KEDLI contract for service from each of these pipelines as well as various other upstream pipelines and storage service providers. The NYFS companies exchange gas across their systems and take delivery of gas on each other's behalf to maximize the benefits of the supply diversity available from access to multiple pipelines and minimize the capital asset base that is needed to move gas to NYFS Companies' combined customer bases. Up to ten gate stations from four pipelines contribute some portion of the gas delivered on any given day. Figure 2-2 below is a map of National Grid's downstate New York interstate gas transmission network.

<u>Figure 2-2</u>: National Grid Downstate NY Transmission Network



B. *Gas Customers*

KEDNY and KEDLI's service territories include residential (customers in individually metered dwellings that use gas primarily for cooking, clothes drying, space and water heating), multi-family (multi-unit residential buildings that are centrally metered), and commercial and industrial customers (customers using gas service for business purposes). These customers use gas for a wide range of purposes:

- *Space Heating* – using natural gas to heat air or water that is subsequently circulated throughout the building to maintain desired indoor temperature. Space heating accounts for most of the gas consumption, particularly during cold peak days.
- *Water Heating* – using natural gas to heat water for household needs (*e.g.,* washing dishes, taking a shower).
- *Cooking* – using natural gas for cooking utilizing gas stoves and ovens in homes or in business facilities (*e.g.,* restaurants).
- *Industrial Processes* – using natural gas for production of goods and services (*e.g.,* fuel for industrial furnaces).
- *Other/Miscellaneous* – using gas in appliances (*e.g.,* gas fireplaces, gas clothes dryers).

National Grid has seen sustained growth in peak demand in the downstate New York areas due to economic development, as well as a concerted effort to move large commercial and industrial customers from heating oil to lower-emitting natural gas. On average, KEDNY's and KEDLI's combined peak day demand grew by approximately 52,000 Dth per year, even after accounting for the cumulative effect of past EE, demand response, and interruptible service programs to reduce load on peak days. This growth resulted, in part, from municipal programs (*e.g*., NYC Clean Heat) and incentives designed to promote the use of natural gas to displace more expensive, higher-emitting fuels.[24] To support this growth, and in recognition of the need to enhance resiliency following Superstorm Sandy, New York City, in 2013, was actively encouraging increased supply capacity to enhance the reliability of the region's energy networks.[25] This growth occurred with the support of the Commission, which approved a number of programs and incentives designed to promote the

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[24] On December 22, 2021, New York City enacted an ordinance that subjects newly constructed buildings to certain emissions limits that would prohibit the installation of natural gas and other fossil fuel-fired systems. This requirement applies to new buildings beginning January 1, 2024 for buildings less than seven stories or July 2, 2027 for buildings seven stories or more. The ordinance does not mandate the phase out of natural gas use in existing buildings. It allows oil-to-gas heating conversions in existing buildings, non-heating gas customer upgrades to heating, and conversion of non-firm customers to firm gas service. The code changes are expected to reduce total downstate New York gas demand by only 35 MDth/day, or 1.0% in Winter 2027/2028. By Winter 2035/2036, the code changes are expected to reduce total downstate New York gas demand by 127 MDth/day, or 3.3%.

[25] NYC Special Initiative for Rebuilding and Resiliency, *"A Stronger, More Resilient New York"* (June 2013), at 127 ("The natural gas connections to New York City generally have sufficient capacity to provide the city's customers with gas, but on days when demand is high, all five city-gate connections are needed to prevent forced shutdowns. The City will continue to support ongoing projects by gas pipeline operators to install additional city-gate capacity linking New York City to new natural gas pipelines.")

increased use of natural gas.[26] Commission policy clearly supported natural gas growth.[27] More recently, the Companies have committed to manage their business with the goal of reducing billed gas usage, refraining from gas marketing activities, eliminating financial incentives for adding new customers, terminating any gas conversion and other incentive programs, and working with various stakeholders (electric utilities and trade organizations) to promote the adoption of geothermal and other alternative energy options.[28]

C. *Downstate New York Long-Term Capacity Reports*

In November 2019, the Companies and DPS Staff entered the Settlement that resolved all claims relating to the Companies' imposition of restrictions on service connections implemented in 2019. The Settlement provided a framework for evaluating the long-term energy supply issues, including a process whereby National Grid agreed to develop options to meet New York's long-term supply needs and facilitate a series of public meetings on those options with customers, residents, advocates, business leaders, local elected officials, and other stakeholders.[29]

Pursuant to the Settlement, the Companies prepared the *Natural Gas Long Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island* (the "Long-Term Report") that provided an analysis of the gas capacity constraints affecting National Grid's downstate New York service territory and discussed the reasonably available options for meeting long-term customer demand. In addition to having over 800 participants in a series of six public meetings, the Companies received written comments from more than 5,000 individuals and organizations, including detailed comments from key stakeholders. Following the meetings and public comment period, National Grid published, in May 2020, its *Natural Gas Long-Term Capacity Supplemental Report for Brooklyn, Queens, Staten Island and Long Island* (the "Supplemental Report").[30] The Supplemental Report summarized the feedback received during the public comment period and provided additional information and analysis on the various long-term natural gas supply options. Based on that analysis, National Grid is now advancing a portfolio of infrastructure enhancements and non-infrastructure

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[26] *See, e.g.*, the Joint Proposal dated September 7, 2016 and adopted by the Commission in the Companies' previous base rate proceedings in Case 16-G-0058 and 16-G-0059, which provided both Companies an incentive to achieve growth (pages 59, 107) as well as a Neighborhood Expansion program for KEDLI (page 107).

[27] Case 12-G-0297, *Proceeding on Motion of the Commission to Examine Policies Regarding Expansion of Natural Gas Service*, "Order Instituting Proceeding And Establishing Further Procedures" (issued and effective November 12, 2012) ("Natural gas is cleaner than other fossil fuels used for home heating and under current market conditions costs a third as much . . . Therefore, by this order we institute a proceeding to examine our policies concerning the use of natural gas and consider whether we should take steps to foster its use through expansion of the natural gas delivery system or otherwise."). This proceeding was closed in 2022.

[28] *See generally,* Joint Proposal, Section VII.

[29] National Grid conducted six meetings that were attended by hundreds of members of the public and enabled extensive comments from individuals and organizations representing a wide array of stakeholder interests. The first meeting was held in-person on March 9, 2020, in Nassau County, and the other five meetings were transitioned to a virtual format due to public distancing concerns and requirements.

[30] National Grid's long term capacity reports and supporting information are available at https://ngridsolutions.com.

programs, known collectively as the "Distributed Infrastructure Solution," to address the gas supply gap in downstate New York.

In June 2021, National Grid published its *Natural Gas Long Term Capacity – Second Supplemental Report* ("Second Supplemental Report"), which built on the prior reports addressing the region's gas capacity constraints. The Second Supplemental Report provided an updated assessment of New York's gas demand and supply situation, the status of the various components of the Distributed Infrastructure Solution (*e.g.*, on-system projects and demand-side management programs), and an evaluation of potential alternate options to meet future demand. The Second Supplemental Report, informed by the Companies' updated June 2021 demand forecast, confirmed the need for the Distributed Infrastructure Solution and concluded that a distributed approach remains the best available option to balance supply and demand; stating:

> As demonstrated by the evidence and analysis in this Second Supplement Report, National Grid faces a projected demand-supply gap starting in winter 2022/2023 based on existing gas supply capacity and the latest demand forecast, and the Distributed Infrastructure Solution is the best available solution for addressing that challenge. National Grid plans to continue to pursue the successful implementation of all parts of that solution [and, in fact, the Companies were able to deliver CNG and city gate supplies to address supply capacity for the winters 2022/23 and 2023/24].
>
> To date, National Grid has made progress on implementation of the Distributed Infrastructure Solution, but the solution faces real risks in the form of permitting delays or denials. There is a material risk for pauses in the Companies' ability to connect new customers in the future due to lack of adequate natural gas capacity given the greater implementation challenges associated with all alternative approaches to the Distributed Infrastructure Solution. In particular, delays to timely permitting of the Greenpoint Vaporizer 13/14 Project or the outright rejection of the Project even if all other components of the Distributed Infrastructure Solution proceeded according to plan would create a projected gap between gas supply capacity and Design Day demand in winter 2023/2024.[31]

The Second Supplemental Report also described how the distributed infrastructure approach positions National Grid to support "net zero" policies by providing flexibility to right-size gas capacity in the future as gas demand growth eventually slows, stops, and reverses. Again, the public was invited to comment, attend a public meeting, and participate in a survey on elements of the Long-Term Report.

In August 2021, National Grid published the *Natural Gas Long Term Capacity – Third Supplemental Report* ("Third Supplemental Report"), which again highlighted the projected demand-supply gap and restated the justification for the Distributed Infrastructure Solution. The Third Supplemental

[31] Again, the supply gap now emerges in 2024/25 because of the Companies' ability to deliver incremental CNG and city gate supplies.

Report described the stakeholder engagement effort around the Second Supplemental Report and summarized the public feedback received. Key observations and themes included:

1. The Distributed Infrastructure Solution remains the best option to eliminate the demand-supply gap and helps achieve New York's CLCPA targets;
2. Our solution has been shaped by listening to stakeholders throughout our extensive outreach (*i.e.*, the Companies developed the non-pipeline alternative), and the Distributed Infrastructure Solution is based on public feedback on a preferred approach;
3. The Distributed Infrastructure Solution allows the Companies to avoid service restrictions over the next several years while offering the flexibility to meet net zero scenarios when customer demand for natural gas slows and eventually reverses;
4. National Grid and DPS Staff agreed to engage an independent evaluation of the Distributed Infrastructure Solution; and
5. The Companies are committed to fully implementing the Distributed Infrastructure Solution and look forward to continued stakeholder engagement via the New York State-wide gas planning proceeding and other channels.

The Third Supplemental Report described National Grid's commitment to net zero and the ongoing effort to drive decarbonization. For example, the report explained how the Distributed Infrastructure Solution increasingly relies on non-infrastructure/demand side management in the long run, which aligns with net zero goals. The Third Supplemental Report also described how the infrastructure components of the distributed solution could be scaled-back as gas demand declines, as envisioned by the CLCPA. Finally, the report explained that the key findings and conclusions in the Second Supplemental Report continue to hold (*i.e.*, the updated supply/demand analysis confirms the Distributed Infrastructure Solution is still needed and the best available option; regulatory approvals and permits are essential for avoiding restrictions on new customer connections and maintaining reliability; and denials of needed approvals (*e.g.*, Greenpoint LNG vaporizers permit) would necessitate reliance on inferior fallback options with no demonstrated stakeholder support).

D. *Independent Engineering Assessment*

As discussed above, the Second Supplemental Report underwent an independent review, conducted by PA Consulting working at the direction of DPS Staff. National Grid advocated conducting this independent assessment in the interest of promoting transparency and stress testing the Companies' analysis presented in the Second Supplemental Report. PA Consulting's assessment generally corroborated the extent of National Grid's gas constraint challenge; validates the need for additional capacity to service customers; and views the Distributed Infrastructure Solution as a "reasonable" solution, while acknowledging the risks to delivery (*e.g.,* permitting, scaling up demand-side solutions quickly enough). PA Consulting's report highlighted that timely permitting of the Greenpoint Vaporizers and other on-system projects presents a high risk of a gas moratorium in the near term (the next 3-5 years), as these projects are necessary to meet peak demand in coming winters. The report also noted that other projects considered by the Companies (*e.g.,* LNG barges) present relatively more execution and permitting risks and, therefore, are not reasonable alternatives at this time. The demand-side measures will take years to ramp-up (with market potential, resources, and customer adoption) to the point that infrastructure could be avoided altogether.

The findings in the PA Report (i) corroborate that the Companies' forecast and assessment of the supply gap is generally reasonable and (ii) conclude that the Distributed Infrastructure Solution is a similarly reasonable approach to addressing the supply gap, while acknowledging the risks to delivering the individual components.[32]

E. Independent Monitor

As part of the Settlement, the Companies agreed to an independent monitor to oversee our gas supply operations and compliance with the Settlement. In the Closing Report, the independent monitor reached the following conclusions:[33]

First, that continued action was required to avoid future moratoria:

> "[G]iven the extensive forecasting, advance planning and time required to construct gas supply projects and to put into operation demand side management programs, critical additional actions are required with urgency. Put another way, although the currently forecasted gap between natural gas supply capacity and demand may be some years off, continuing efforts must be taken in the short term if that risk is to be mitigated effectively and with reasonable confidence. Despite the several projects and improvements already employed and underway by National Grid pursuant to the Settlement, the potential for a moratorium in future years remains a very real concern. . . Accordingly, the Monitor urges National Grid and the DPS to move forward with continued and persistent vigilance."[34]

Second, that the Greenpoint Vaporizer 13/14 Project was key to addressing the supply gap, but was at risk because of permitting delays:

> *Vaporizers 13 and 14.* Key to National Grid's Distributed Infrastructure Solution are two new LNG vaporizers, the construction of which still requires receipt of an air permit from the New York State Department of Environmental Conservation ("DEC"). National Grid previously had projected its receipt of the air permit so that it could complete construction and have Vaporizers 13 and 14 in service by December 2021. (Seventh Quarterly Report at 4.) But the DEC air permit is required before major construction can begin, so National Grid pushed the in-service date to January 2023, aiming to have the new vaporizers operational during Winter 2022/2023. By National Grid's most recent calculations set out in the Second Supplemental LT Report (at 56-57, 64), the current need date for Vaporizers 13 and 14 is Winter 2023/2024, but National Grid plans to have Vaporizers 13 and 14 in service in advance in order to gain operational experience with the new vaporizers before the winter when they will be truly "needed."

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[32] *See* Case No. 19-G-0678, PA Consulting's Assessment of National Grid's Second Supplemental Report (filed September 10, 2021) ("PA Report"), at 8 ("In summary, National Grid's [Distributed Infrastructure Solution] (including the proposed infrastructure projects) is a reasonable approach at this point in time given uncertainty regarding load growth and the efficacy of the DSM programs, assuming that avoiding moratorium risk is of critical importance to regulators and other stakeholders.").

[33] Case 19-G-0678, National Grid Monitorship: Closing Report (filed September 14, 2021) (the "Closing Report").

[34] Closing Report, at 2.

> National Grid's ability to deliver Vaporizers 13 and 14 before Winter 2022/2023 as planned remains in doubt as National Grid awaits an air permit. National Grid recently agreed to an extension of DEC's time to make a decision on the air permit until November 4, 2021 and, even assuming the air permit is granted, National Grid executives have described the required construction schedule to meet the planned January 2023 in-service date as a "high risk schedule," *i.e*., the schedule lacks any "float" and thus any additional delays in construction would delay the project's in-service date. Further underscoring the uncertainty around the air permit, on July 15, 2021, the DEC issued requests for additional information to National Grid calling for certain environmental information. What effect, if any, such information will have on the DEC's decision remains unknown. As acknowledged by National Grid, "the primary risk to implementation" of Vaporizers 13 and 14 "is not obtaining the necessary permitting for the project, or not obtaining them in a timely manner." (Second Supp. LT Report at 64.)"[35]

Third, that National Grid has taken "substantial efforts" to address the supply gap but significant risks of future moratoria remained:

> In the Monitor's opinion, National Grid has taken substantial efforts consistent with the Settlement Agreement and with the Monitor's recommendations in order to develop its long-term plan through an iterative process involving substantially greater transparency and public discussion than in the past. Having said that, the resulting Distributed Infrastructure Solution pursued by National Grid remains emergent -- permitting remains outstanding, complex facilities must be built, customers must engage on demand side management, etc. -- and cannot be relied upon with confidence to deliver the required supply capacity to meet demand in upcoming winters. Accordingly, additional focus on these developing projects should be given by all concerned, including National Grid, its customers, and the DPS.[36]

In summary, while the Monitor was critical of certain aspects of the Companies' performance and provided various recommendations for improvement (nearly all of which were accepted and implemented), the Monitor's work highlighted the need to identify projects and programs to meet customers' near-term energy demands and the associated risks and consequences of future restrictions on gas service connections should the identified solutions, including the Greenpoint Vaporizers, fail to materialize.

F. KEDNY/KEDLI Rate Case

In the Commission's Order adopting the Joint Proposal, the Commission both acknowledged the Distributed Infrastructure Solution's potential for emissions reduction through increasing reliance on energy efficiency and other non-infrastructure components and found that the exhaustive record in the rate case did not identify any viable alternative projects to the distributed infrastructure for

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[35] Closing Report, at 14. The timeline for acting on the permit has been extended several times. Most recently, in the interest of developing a complete record, as well as a further independent assessment of the need for the Vaporizer 13/14 Project, National Grid and the DEC agreed to further extend the time to act on the pending air permit until 30 days after a Commission issues an order on this report. *See*, Executed Waiver, dated May 6, 2022, available at www.greenpointenergycenter.com.

[36] Closing Report, at 18.

meeting peak demand. The Commission noted the Companies' analysis showing that meeting forecast customer demand by adding Vaporizers 13 and 14, in conjunction with incremental energy efficiency, demand response, and electrification programs, would create "global warming potential savings" compared to meeting customer demand solely through reliance on additional pipeline capacity. In reaching this conclusion, the Commission noted that LNG vaporization is considered the resource of last resort to ensure reliability and is only used when all other assets have been called upon and have not been sufficient to ensure the necessary minimum system pressures to guarantee reliability. The Commission also noted that the extensive record in the case contained no evidence of any viable, short-term solutions that would take the place of the Greenpoint facility and, therefore, that the capital expenditures associated with the vaporizers are necessary for KEDNY to maintain safe and reliable gas service at this time. Furthermore, the Commission found the vaporizers and other projects would not disproportionally impact disadvantaged communities. Among other factors, the Commission noted that the addition of two vaporizers at the Greenpoint LNG facility would not add to the storage capacity of the two LNG tanks, but rather allow for more LNG to be vaporized on the coldest days of the year.[37] Significantly, the Commission also reinforced that access to safe and adequate energy is "fundamental to protecting the public health and welfare," which supports the need for prudent investments to ensure reliable delivery.[38]

<u>SECTION 3</u>: GAS DEMAND FORECAST

The peak demand forecast is the starting point for any gas system planning analysis. The consequences of a supply/demand imbalance that leads to an unplanned outage on an extremely cold day can be severe, and restoration efforts after a shut off require multiple visits to each home and business affected to initially shutoff, and then subsequently relight customers when gas to the distribution system is restored. Recovery from such events is a labor-intensive, time-consuming process that can last weeks. Therefore, maintaining regular operations during several day cold snaps, the coldest day, and the highest use peak hours is critical. Local distribution companies address this requirement by developing design planning criteria to meet demand on a "Design Day/Design Hour" (*i.e.,* during the peak hours of an extremely cold day for which utilities ensure they can serve demand).

A. *Forecast Methodology*

Each spring, National Grid conducts an annual process to model and forecast the natural gas requirements for its gas distribution companies, which includes a historic lookback to incorporate actual data from the preceding winter as compared against previous forecasts. National Grid uses the forecasts to anticipate the needs of its distribution systems each winter so that National Grid can take necessary steps to ensure that it can meet projected gas supply and system engineering needs for design day conditions. National Grid prepares the following for each distribution company as part of its annual gas load forecast:

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[37] Order, at 81.
[38] PA Report, at 12; Order, at 112.

- Retail Forecast: forecast customer usage at the burner tip (*i.e.,* the point at which gas is used as fuel).
- Wholesale Forecast: the amount of incoming gas needed to satisfy the retail forecast, as measured at the Companies' city gate stations. This forecast is adjusted upwards from the retail forecast to account for loss within the system, such as unmetered usage, line losses, and metering errors.
- Design Day Forecast: The wholesale requirements for the Design Day. This is used to ensure that the Companies have the resources to meet customer demand on the coldest days.

The following describes the high-level process of building the gas demand forecast:

1. Unadjusted baseline forecast: This is a macro-economic forecast that uses regression analysis to determine the statistical relationship between historical customer usage patterns and economic variables, such as: GDP, population, housing, income, employment, and oil and gas prices. This assumes current energy efficiency programs and electrification-of-heat continue at similar rates. The projected economic variables include the forecasted impact of the pandemic on the economy.
2. Factor in saturation of customer growth: Growth in the number of customers served comes from new construction and conversions of existing structures to gas heating from other fuels. In this step, the Companies estimate how many more existing structures would convert to natural gas and saturates customer growth due to conversions at that point. The Companies also estimate how much new construction will not connect to gas due to New York City's building code changes restricting gas connections (NYC Int. 2317), which will accelerate electrification in new construction in NYC and reduces new construction gas customer growth forecast in the unadjusted baseline.
3. Factor in increases in energy efficiency: In this step the forecast is modified to account for projected acceleration in the rate of energy efficiency relative to historic energy efficiency achievement rates due to New Efficiency: New York ("NE:NY"), the Companies' Annual DSM Filing, and Local Law 97,[39] which all support CLCPA emissions reductions targets.
4. Factor in increases in electrification-of-heat: Increasing penetration of heat pumps as a substitute for natural gas-fired heat is accounted for by reducing the projected number of customers in the Unadjusted Baseline forecast. The increases in electrification-of-heat are primarily driven by NE:NY heat-pump targets and LIPA heat pump targets. In addition, the Companies assume the rate of organic adoption will start to increase over the forecast horizon. The forecast incorporates increased heat pump penetration in New York City in furtherance of Local Law 97 compliance.
5. Factor in customer demand response: The design day forecast is adjusted to reflect demand response by firm customers in KEDNY and KEDLI. Demand response from interruptible and non-firm demand response customers is accounted for in the unadjusted baseline forecast.

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[39] Passed by New York City in April 2019, Local Law 97 mandates that buildings >25,000 sq. ft. must achieve an emissions performance target or pay a compliance penalty. Local Law 97 targets a compliance period beginning in 2024.

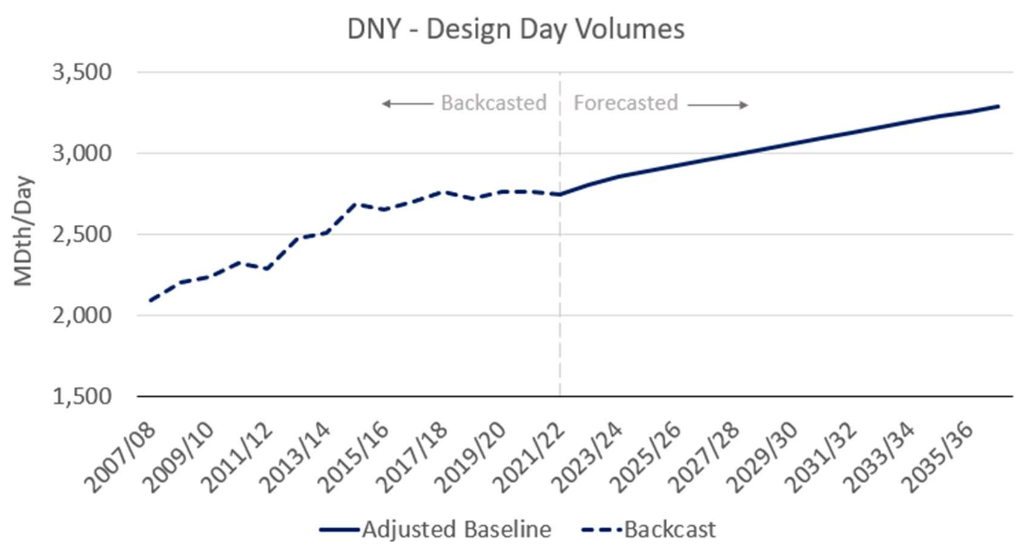
6. Adjusted baseline: The final adjusted baseline forecast is the unadjusted baseline factoring in energy efficiency, electrification-of-heat, and demand response. The adjusted baseline is the forecast that is used for planning purposes.

B. June 2022 Forecast

The June 2019 and June 2020 demand forecasts informed the initial development of the Distributed Infrastructure Solution and, specifically, the need for the Greenpoint vaporizers (discussed in the *Long Term Capacity Supplemental Report* (June 2020)). The June 2021 forecast indicated the demand/supply gap would continue because of anticipated growth in customer demand, which further validated the need for the vaporizers (discussed in the Long Term Capacity Second Supplemental Report (June 2021)).

The latest forecast (June 2022) projects that downstate New York Design Day gas demand will increase approximately 1.3% per annum, from 2,747 MDth/day[40] in winter 2021/2022 to 3,230 MDth/day in the winter of 2034/2035. Growth in the baseline demand forecast adjusted for energy efficiency, demand response, and heat electrification is less than the average growth rate experienced over the historical period, which was 2.2% per year from winter 2007/2008 to winter 2020/2021. Figure 3-1 below shows historical (*i.e.*, backcasted)[41] and projected growth for Design Day gas demand.

Figure 3-1: Historical Period (Backcasted) and Forecasted Downstate New York Design Day Demand. Forecasted period is the 2022 Adjusted Baseline Demand Forecast.

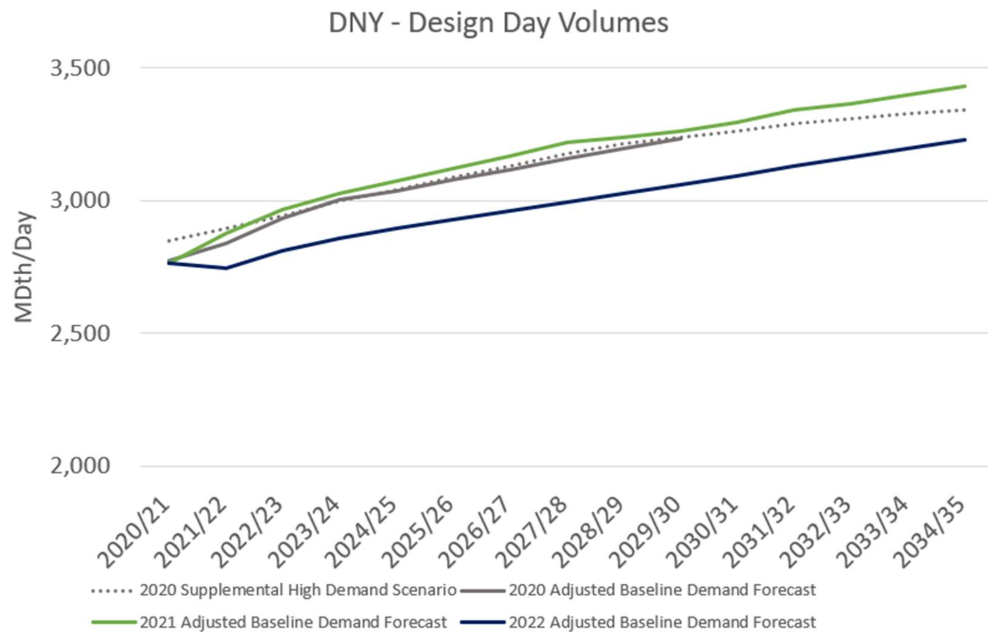


[40] MDth=Thousands of Dekatherms. One dekatherm is equal to one million British thermal units ("Btu"). The energy content of 1,000 cubic feet of natural gas measured at standard conditions is approximately equal to one dekatherm.

[41] The backcasted (historic) period is determined using regression equations of observed weather and gas demand to determine what gas demand would have been had Design Day conditions occurred.

National Grid's latest adjusted baseline demand forecast is lower than the 2021 adjusted baseline forecast and the forecast provided in the supplemental report. The decrease is driven by an expected decrease in commercial load, and reduced new construction load due to NYC Int. 2317 ("Use of substances with certain emissions profiles"), which will accelerate electrification in new construction within the City of New York.

Figure 3-1: Comparison of 2022, 2021, and 2020 Adjusted Baseline Demand Forecasts and 2020 Supplemental Report High Demand Scenarios



Note: Y-axis is broken to focus on changes at the margin

C. Downstate Region Economic Outlook

Forecast economic and demographic growth, and relative energy prices, drive the unadjusted baseline demand forecast. Economic and demographic growth corresponds to businesses expanding output, employment, building space and gas use, as well as new residential construction. Relative energy prices for heating options for customers drive fuel choice. Downstate New York natural gas prices have been well below heating oil and electricity for over a decade, making natural gas a fuel of choice for new construction and heating conversions. This is expected to continue as the gas price advantage over heating oil and electricity is forecast to widen over the next twenty years.

Downstate New York ("DNY") gross domestic product (GDP), the broadest measure of area economic activity, grew 6.0% in 2021, substantially less than the forecast of 7.2% growth. Moreover, for 2022 downstate GDP growth has been revised down to 6.7% from a forecast of 7.0% last year. The reason is that the strong 2021 and 2022 economic recovery forecasted last year has been disrupted by unanticipated outbreaks of the Delta and Omicron variants, the war in Ukraine, and restrictive federal policy. Also, because of the resulting supply shortages and price spikes, the Federal Reserve is expected to raise interest rates more aggressively than last year's forecast. Finally, while last year's forecast assumed government spending would rise in 2022 due to passage of some version of President Biden's "Build Back Better" spending package, this year's forecast assumes no such spending package.

This year's forecast assumes that any future pandemic outbreaks will be much less disruptive to the economy than in 2021 and 2022. Also, the forecast assumes that global oil prices, which have stabilized around $100 per barrel, will not rise further on a sustained basis. Natural gas prices, which have risen along with oil prices but not as much in the US, are expected to remain low compared to oil, maintaining the gas price advantage over oil.

Over the long-term beyond 2024, downstate economic growth is expected to be very close to last year's forecast. The forecast assumes full employment is reached in early 2023 and that supply-side constraints and price spikes caused by the pandemic and the war will have dissipated. However, the DNY office sector, which has not returned to normal, will still be in limbo. Over time, the office sector is expected to become more mixed use, with some offices moving to the suburbs, including Long Island.

D. Forecast Scenarios

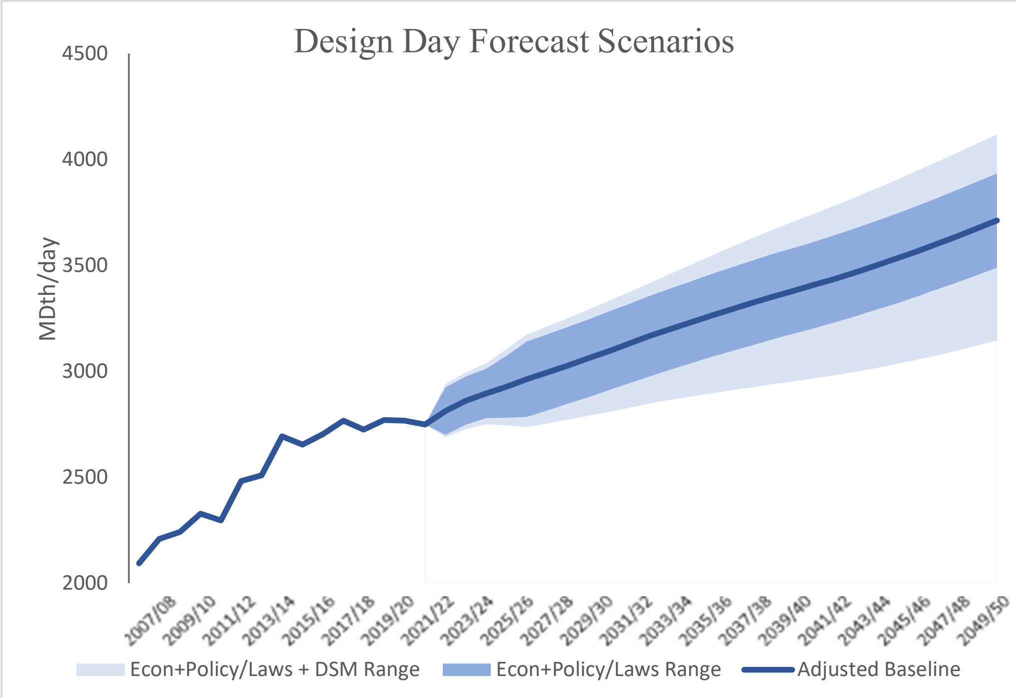
Beginning in 2020, National Grid began producing several forecast scenarios that consider different economic and policy parameters as well as different levels of achievement of our DSM programs and objectives. The purpose of developing these scenarios is to acknowledge and consider the range of reasonable gas supply requirements the Companies may see from their customers considering dynamic customer behaviors, as opposed to relying exclusively on a precise design day forecast.

Over the past several years, we have seen a broad range of economic conditions that have a substantial impact on our forecast of customer requirements, including but not limited to COVID-19 pandemic factors, inflation, and increased energy prices worldwide. We have also seen usage patterns change because of hybrid work, especially around large cities. Multiple clean energy policies have been proposed and enacted that we expect to impact customer energy usage, and we expect more in the future. We continue to deploy our demand-side management programs, which are built on cooperation with customers and vendors/installers, and believe strongly in our programs, but we have faced headwinds with respect to contractor and material availability, as well as customer adoption.

Some of these factors would support a more conservative outlook of customer requirements. For example, accelerated or aggressive policies that place limitations on natural gas use may support a lower forecast. We may also see more customers fully replace their natural gas heating systems with heat pumps. However, some factors may support a more aggressive outlook of customer requirements, such as a more robust economic recovery from the COVID-19 pandemic, or lower-than-expected performance from our Demand Side Management ("DSM") programs.

Given this range of reasonable outcomes, we have developed forecast scenarios based on high and low economic and policy factors, and additional scenarios that also include high and low levels of DSM program achievements. The figure below applies these scenarios to the adjusted baseline forecast presented in Figure 3-1 above.

Figure 3-3: Historical Period (Backcasted) and Forecasted Downstate New York Design Day Demand Scenarios.



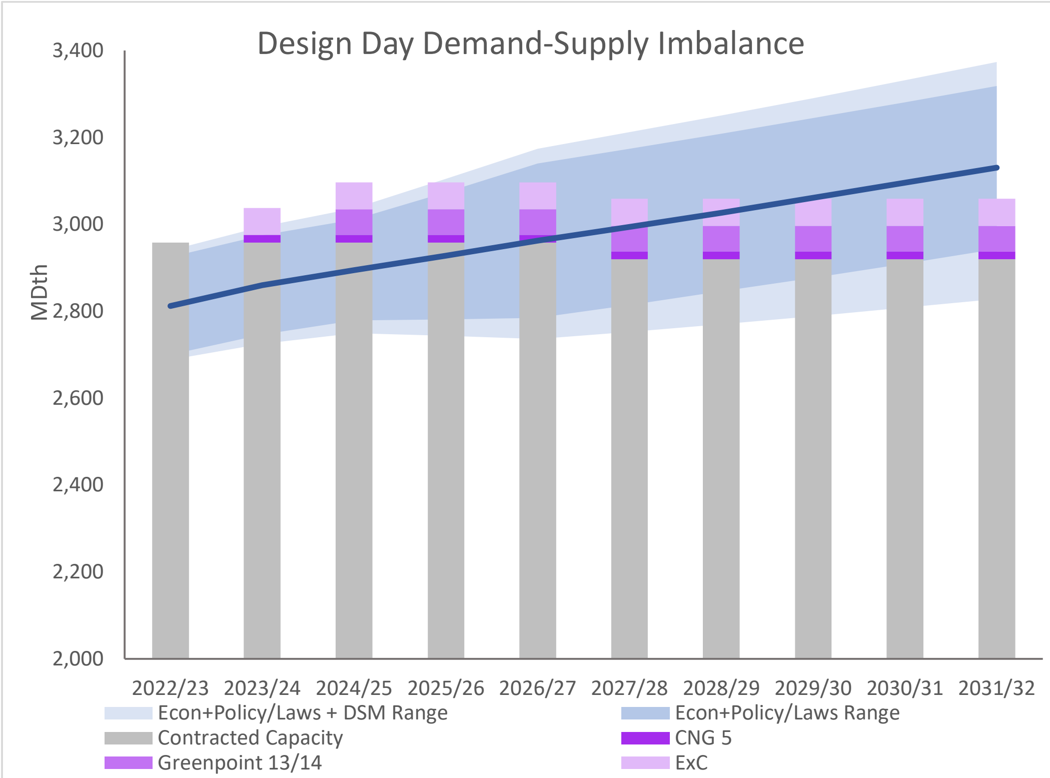
Note: Y-axis is broken to focus on changes at the margin

SECTION 4: STATUS OF DISTRIBUTED INFRASTRUCTURE SOLUTIONS

In the Long Term Gas Capacity Reports, National Grid presented the Distributed Infrastructure Solution as the best available option to resolve long-term gas capacity constraints. This solution involves an aggressive set of incremental DSM programs to help customers reduce their natural gas usage, the size of which is unprecedented in New York, coupled with additional portable CNG capacity, LNG vaporization enhancements, and the Enhancement by Compression ("ExC") project being pursued by the Iroquois Gas Transmission System. The Greenpoint Vaporizers, which are a component of the Distributed Infrastructure Solution, are discussed at length in this report. Appendix B describes the status of each of the other major components of the Distributed Infrastructure Solution.

The Distributed Infrastructure Solution remains the best available solution to meet our customers' energy requirements. While the timing and magnitude of the demand-supply gap has been updated as we refreshed our forecast of customer requirements, the need for each component of the Distributed Infrastructure Solution remains. The following figure provides the demand-supply imbalance overlaid on the forecast scenarios shown in Figure 3-3 above.

Figure 4-1: Design Day Demand-Supply Imbalance including Distributed Infrastructure Components



Note: Y-axis is broken to focus on changes at the margin

SECTION 5: PROJECT DESCRIPTION AND ENGINEERING ASSESSMENT

A. LNG Facility Background

The Greenpoint LNG Plant has been in service since 1968. Located at the Greenpoint Energy Center, the LNG plant occupies 50 acres including approximately 1/4 mile of waterfront along the Newtown Creek. The plant has two single containment LNG storage tanks with a total storage capacity of 1.6 billion standard cubic feet ("BCFs"). LNG is an ideal method for storing supply to be used during peak days because the change from a gaseous state to a liquid state results in approximately 600 times less volume. The plant liquifies and stores gas from the National Grid system during low demand periods, and the plant vaporizes LNG to return gas to the system when it is needed most. LNG is stored at the facility in two existing LNG storage tanks, which are not changing as part of the proposed project. LNG is vaporized on peak demand days (typically during the coldest days of the year) to ensure there is adequate capacity in National Grid's gas system to service its customers.

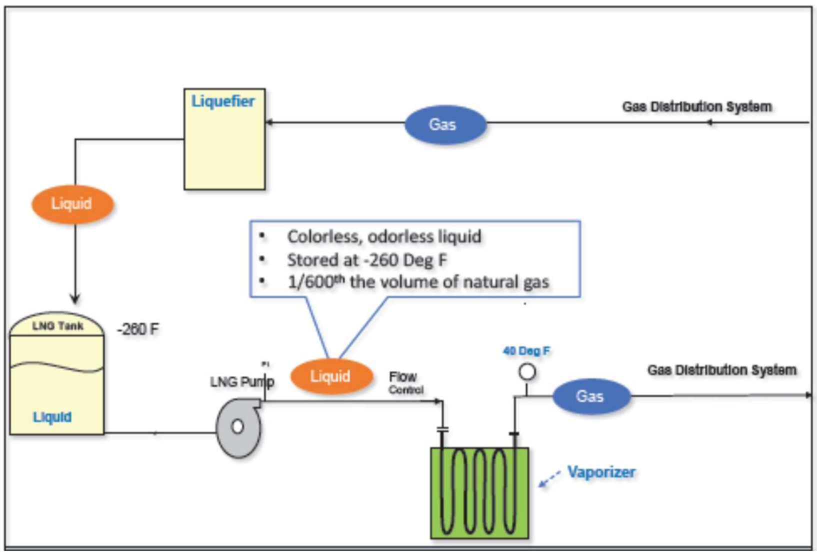
B. Project Description

The Project will install two low-pressure LNG vaporizers at the Greenpoint LNG facility to expand the plant's overall output capacity. The two additional vaporizers, designated as "Vaporizers 13 and 14", would bring the total number of vaporizers at this facility to eight. This will increase the capacity at the facility for a total send-out flow rate of 340 million standard cubic feet per day

("MMSCFD"). The new vaporizers will be a submerged combustion design, each with an output rate of 60 MMSCFD and will regasify into the 60 PSIG gas distribution system.

LNG vaporizers are heat exchangers that regasify LNG. LNG is pumped to the vaporizers, where a water bath heats LNG to a vapor state. The water is heated through the submerged combustion unit, a process that sparges hot combustion gas under water resulting in an efficient exchange of heat energy. The Project would involve installation of two new 42.76 MMBtu/hr vaporizers to return natural gas to the National Grid system from stored LNG. The proposed new vaporizers operate with an improved energy efficiency of 95.8 percent.

<u>Figure 5-1</u>: LNG Vaporizer Schematic Diagram



The new vaporizers do not increase annual output from the facility or frequency of plant operation because vaporization at the facility is limited by the operational parameters approved by the Commission, including temperature thresholds and triggers for non-firm customers, as well as the capacity of the existing storage tanks, which are not changing. Liquefaction is a slow process that occurs during extended periods of low-demand, such that it takes approximately 225 days to fill the existing storage tanks (which are not changing as part of the proposed project). Vaporization, on the other hand, is a quick process, such that the storage tanks can be emptied in approximately 6-10 days. The new vaporizers will allow the facility to vaporize its current annual capacity at a faster rate to meet peak demand during short-term, high demand periods, with redundancy in the event of equipment failure. Although operated infrequently, the vaporizers are critical to the overall gas supply portfolio. In addition to energy efficiency and gas

conservation measures, this project is one of the alternatives needed to meet peak demand pursuant to the Supplemental Report.

C. Engineering Assessment

With more than 1.9 million customers in the Companies' downstate New York service territories, and a sustained trend over the last 10 years of adding thousands of new customers per year,[42] National Grid must ensure its gas distribution network infrastructure can meet customers' energy needs during periods of peak demand. To this end, the gas distribution system is designed to meet forecast customer demand on a "Design Day" (*i.e.,* the coldest winter day that brings the highest daily customer demand for which the Companies plan) and under "Design Hour" conditions (*i.e*., the peak hourly demand on such a Design Day). Importantly, this is done with zero contingency or reserve margin. In the event that actual peak demand is higher than projected Design Day demand (because of more severe weather or the uncertainty inherent in the demand forecast) or if there is an unexpected disruption to gas supply, gas infrastructure, or demand-side resource availability, gas outages may result.[43] National Grid models the downstate New York gas supply and distribution requirements based upon a Design Day average temperature of 0° Fahrenheit in Central Park (*i.e*., 65 Heating Degree Days).[44]

Insufficient gas capacity under peak demand leads to lower pressure conditions in the gas distribution network that can cause heating and other end-use equipment to stop working for customers and create safety risks. The only way to properly ensure the safety of customers and communities under such conditions is to curtail (*i.e*., shut off) large customers and to potentially curtail service to entire sections of the gas network, affecting many households and businesses, with restoration of service potentially taking a week or longer. The electric and gas service interruptions that occurred as a result of Winter Storm Uri (February 2021) in Texas serve as a powerful reminder of the potential health and economic impacts to customers from loss of heating during extreme cold weather.

Each year, National Grid performs an analysis on its gas system to identify the reinforcement projects that are needed over the following five years to maintain minimum system pressures and support

[42] Pursuant to the Public Service Law and other applicable laws and regulations, National Grid is required to connect and service all customers that request gas service in downstate New York unless precluded by certain conditions, such as the incomplete construction of necessary facilities, insufficient capacity/supply, or other considerations for public safety.

[43] For example, in the fall of 2019, Enbridge notified National Grid of a potential delivery shortfall through its pipeline network estimated at 106 MDth/day. While the Companies were able to secure contingency supplies to make up for the Enbridge shortfall, it is important to note that if the Enbridge situation had not occurred, these additional contracted supplies would not have been able to increase our supply capacity due to operational constraints that limit the total volume our system can accept.

[44] National Grid commissioned an analysis by Marquette Energy Analytics of weather conditions (accounting for both temperature and wind that drive peak gas demand for heating) that corroborates the Companies' Design Day standard as consistent with industry practice for Design Day standards in terms of likelihood of occurrence.

forecast system growth.[45] Reinforcement projects are designed to maintain minimum design pressures throughout the gas system under design hour conditions and traditionally have been constructed as they become necessary for the most efficient use of capital dollars. The five-year capital plan is revised and issued annually so that it can be adjusted for changes to the forecast, differences between actual load growth and estimated load growth, reinforcement project delays and deferrals, public works activity, main replacement program activity, and updates/improvements to the Synergi computer network analysis models.[46]

The annual review assesses the gas system and network model under the high load conditions experienced during a cold day from the previous winter period. High send-out/demand conditions provide the best view into system constraints and/or model accuracy evidenced through available field pressure and flow data. System reliability and risk is assessed at an aggregate and site-specific level by comparing data discrepancies to established tolerance targets. All points that exceed tolerances and would experience below minimum pressures are reviewed to determine the possible causes of the discrepancies and develop follow up actions for each location. The winter model calibration and performance report documents the results of this analysis and provides conclusions and recommendations aimed at improving performance of the network models and gas distribution network. Once the Synergi models are loaded with the forecast customer growth, the Companies identify the distribution system reinforcement projects and regulator capacity projects that must be constructed to maintain the minimum system design pressures and support average annual system growth.

D. <u>Greenpoint Vaporizers Assessment</u>

For more than a decade, gas demand in KEDNY has been increasing steadily for reasons addressed earlier in this document. While on-system infrastructure has been designed to address local areas where poor pressures were developing due to increases in individual customer demand, the aggregate increase has been trending toward exceeding the existing upstream pipelines' ability to deliver adequate gas supply to KEDNY. Supply projects normally take longer than on-system projects to implement, so numerous projects to increase supply to the area were considered years ahead of when they were needed to enable them to be in service by the estimated need date. Because the vast majority of growth in KEDNY was happening in Brooklyn and Queens, the projects that were considered all needed to get additional supply to those areas and maintain system pressures at acceptable levels or improve them in the process. A new delivery point in Brooklyn and the expansion of a second point in Brooklyn resulted from this effort. However, as #6 and #4 fuel oil

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[45] Federal (49 CFR § 192.623) and New York State (16 NYCRR § 255.623) regulations establish minimum pressure requirements. The Companies also establish minimum pressure requirements for operating its networks.

[46] As part of the annual assessment, National Grid reviews and evaluates the operating condition of the gas network along with the accuracy of the Synergi network models used to simulate field operating conditions. Network models are used for critical short and long-term recommendations including decisions related to capital investments (*e.g.*, reinforcement and reliability projects, new customers' requirements) on the gas system, and decisions associated with system operations. Accuracy of the network models is critical to ensuring the safe, reliable, and cost-effective operation of the gas distribution system, as well as continued service to customers.

phase outs in NYC continued and many of those impacted by Superstorm Sandy sought to eliminate fuel oil from their buildings altogether, demand continued to increase and additional supply into Brooklyn became necessary.

At the time of the *Supplemental Long Term Report* (2020), it was determined that the Greenpoint LNG plant could vaporize its inventory at a faster rate if KEDNY added what are now referred to as Vaporizers 13 and 14. This would allow KEDNY to meet the design day and peak hour needs of the system for a time without an incremental supply project by utilizing the existing supply assets to a higher degree. The output from the new vaporizers will be delivered directly into the Brooklyn 60 psig distribution system, addressing the Brooklyn/Queens delivery objective that was identified as a key need.

The reliability aspects of this Project are significant. Among other reasons, National Grid has direct control over on-system LNG vaporization. Because the LNG is stored locally, and the new vaporizers inject directly into the distribution system, it can be dispatched as needed (subject to various time of year conditions), providing resiliency for KEDNY if an event occurs on any of the pipelines or NYFS assets. The vaporizer option is also faster to construct, significantly less expensive, and is much less disruptive to local residents than alternative projects (*e.g.*, looping the Clove Lakes line)[47] because all of the work will take place within the plant property. If the project is not available, work on the Clove Lakes loop needs to proceed now because that will take much longer to implement and drive higher dependence on CNG in the interim period. LNG vaporization is a superior option to CNG trucking operations (because it does not require out of state truck deliveries) and will be used to minimize CNG truck dispatching to the extent practical.

E. Project Deliverability, Implementation, Reliability, and Safety

Given the current challenges to siting new energy infrastructure, project deliverability and implementation are important considerations in assessing the viability of potential solutions. These include:

- the ability to secure needed permits;
- any policy changes required to enable the project;
- any required regulatory approvals; and
- requirements to secure equipment and contractor resources.

In the fall of 2021, National Grid completed construction of two new vaporizers at the Greenpoint LNG Plant. This project replaced the then-existing Vaporizers 3 and 4, which were decades old and at the end of their useful lives, with new vaporizers (designated as Vaporizer Units 11 and 12). These new units are now in-service and enhancing the Greenpoint LNG facility's peak hour and peak day send-out capacity. Because National Grid recently engineered, permitted, constructed, and commissioned a vaporization project at Greenpoint, the Companies are confident in their ability to deliver this type of project – this time with the benefit of lessons learned from the work on Vaporizer Units 11/12.

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[47] Discussed in greater detail in Section 8.

For the current Greenpoint Vaporizer Project, National Grid has taken all necessary steps to bring Units 13/14 online but is waiting on a final NYSDEC Air State Facility permit to commence construction. Detailed engineering, procurement, and delivery of long lead materials have all been completed, environmental reviews and public meetings conducted, and preliminary work that may be performed before the issuance of a permit is in progress, pending receipt of the final required air permit. The Project has received NYC DOB permits and FDNY approvals for construction within New York City. The Greenpoint Vaporizer 13/14 Project is the only distributed infrastructure project that can be brought online in time to meet projected demand. Specific considerations include:

- *Safety* – Vaporizers are a safe and proven technology and have been installed and used worldwide for decades. Because all combustion takes place under water at relatively low temperatures (water baths typically operate at 120°F), there is minimal safety risk to operations personnel. National Grid will work closely with FDNY on approvals and will ensure facility siting meets or exceeds all applicable codes. National Grid follows best practice in process safety and operational safety methods in design, installation, and operation of all assets. Once installed, National Grid will actively patrol, monitor, and control the assets to minimize the potential for incidents. In particular, a safety instrumentation system will be installed that automatically brings the process into a safe state when abnormal process conditions are detected.

- *Reliability* – Vaporizers have a simple design that allows for easy scheduled and unscheduled maintenance. Additionally, all materials will be made with corrosion resistant and long-lasting materials, such as stainless steel.

<u>SECTION 6</u>: ENVIRONMENTAL AND COMMUNITY IMPACTS

In the Long Term Report, the Companies identified ecological and environmental criteria for assessing potential solutions, including the relative community impacts of construction and ongoing operation. In connection with the pending Air State Facility Permit application before the NYSDEC, National Grid has performed a GHG assessment for Greenpoint Vaporizer 13/14 Project, as is required by the CLCPA, which is still under review by the NYSDEC. Information related to the Project is available on National Grid's dedicated website: https://greenpointenergycenter.com.

<u>*NYSDEC Air State Facility Permit*</u>. National Grid is seeking to re-permit the Greenpoint Energy Center from a Major Title V permit to an Air State Facility permit, as well as install two new LNG vaporizers. The decision to re-permit the facility is due to emissions levels that are well below the major permit threshold. The Air State Facility permit will include new permit conditions to cap or limit emissions of nitrogen oxides (NOx) to less than 25 tons per year, which is roughly half the existing Title V permit limit.

Existing Permit	New Permit
✓ Title V Facility Air Permit	✓ State Facility Air Permit
✓ *NOx < 47.4 tons per year*	✓ *NOx < 24.9 tons per year*

CLCPA GHG Assessment. National Grid's CLCPA GHG Assessment[48] demonstrates that the Project would result in a decrease of the energy consumption and GHG emissions from the facility's vaporizers, making it consistent with the CLCPA goals. The new vaporizers do not increase the annual output from the facility or frequency of plant operation because vaporization at the facility is limited by operational parameters and the capacity of the existing storage tanks. The new vaporizers will allow the facility to vaporize its current annual capacity at a faster rate to meet demand during short-term, high demand periods, with redundancy in the event of equipment failure. The vaporizers are operated infrequently but are critical to the overall gas supply portfolio. New, more efficient vaporizers would result in a decrease of the natural gas consumption from the facility's vaporizers. In the future, with increased electrification, it is anticipated that the proposed vaporizers will run less frequently.

Net Zero/GHG Mitigation Efforts. The vaporizers are effectively a non-pipes solution that allows KEDNY to serve peak demand without adding additional pipeline capacity or other less favored options, while at the same time pursuing a series of programs/projects in furtherance of net zero goals. These include (i) commitments to manage the downstate gas business with the goal of reducing billed gas usage, coupled with pledges not to engage in gas marketing activities, eliminate financial incentives for adding new customers, terminate any gas conversion and other incentive programs, and work with various stakeholders (*i.e.,* electric utilities and trade organizations) to promote the adoption of geothermal and other alternative energy options; (ii) funding more than $118 million of EE and demand response programs in downstate New York, together with a separate request for incremental energy efficiency, weatherization and other demand side management programs; (iii) reducing methane emissions by eliminating more than 650 miles of leak prone pipe, reducing the backlog of system leaks, and collaborating with stakeholders on new methods for identifying/repairing the highest emitting leaks, and (iv) collaborating with the New York City Mayor's Office of Sustainability and Con Edison on Pathways to Carbon-Neutral New York City to identify three emissions reduction options for New York City to deeply decarbonize by 2050.

Ecological Impact. Installation will result in temporary environmental impacts related to air quality, storm water, noise, and waste generation. Once operational, there will be periodic emissions from the vaporizer combustion process on the limited days of operations. However, the Project's emissions will be lower than other LNG alternatives because operation of the vaporizers will be strictly limited to peak days or local operational needs.

Community Impact: The new vaporizers (Vaporizers 13 and 14) will be located within the existing footprint of the Greenpoint site and enclosed within a new structure. The installation process does not require significant excavation or drilling and the new vaporizers will be installed in the vicinity of the existing vaporizers. Therefore, there will be minimal visible impact to the neighboring communities.

The recent work on a very similar project (Units 11/12) demonstrates this type of project can be completed with minimal ecological and community impacts.

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[48] *See*, AKRF, "National Grid Greenpoint Energy Center – CLCPA GHG Assessment," dated October 20, 2021 (available at https://greenpointenergycenter.com/wp-content/uploads/2021/10/National-Grid-Greenpoint_DEC_CLCPA-GHG-Assessment_20211020_Final.pdf).

Public/Stakeholder Outreach. The extensive public process to notify the public of the Greenpoint Vaporizer 13/14 Project is discussed above. Additionally, in the connection with the Air State Facility permit application, National Grid developed and executed a public participation plan ("PPP") that focuses on the local community and provides additional outreach and public participation opportunities as part of the environmental permit review process. The NYSDEC public hearings for the Air State Facility permit took place on March 10, March 11, and March 18, 2021. Meetings with Brooklyn Community Board No. 1 were held on May 27, 2021 and June 2, 2022. A public information session with an opportunity for questions and answers was held on October 21, 2021. Project information, the PPP, and other documents are available on the dedicated project website.[49]

Community Initiatives. National Grid is committed to improving the quality of life in the communities we serve through economic development, charitable and educational programs, and we take pride in a long history of community engagement in Brooklyn, especially in the Greenpoint, Brownsville, Bushwick, Bedford, Stuyvesant, and East Williamsburg neighborhoods. Our support has included youth development, park reclamation and redevelopment, food insecurity and economic development, philanthropic giving, and employee volunteerism among other items. In addition, the Companies continue to develop and cultivate new partnerships to enhance our longstanding commitment to the area and, over the years, National Grid has donated property and made our facilities available to the local communities. We are also committed to partnering with the community and promoting sustainable energy solutions for our customers.

SECTION 7: PROJECT COSTS

The Joint Proposal provides that the independent consultant's assessment will consider two measures of the All-In Cost for each project – All-In Cost per Design Dth/day and All-in Cost per Dth of Estimated Use. The All-In Cost per Design Dth/day for each considered project "will be calculated as [the sum of the fixed cost per year of the project plus the fixed Operations and Maintenance ("O&M") cost of the project (*i.e.*, total annual non-gas cost)] divided by [the projected Design Day Dth of use of project (to arrive at modeled per Dth of use non-gas cost)] plus the variable commodity cost per Dth of the project plus the variable O&M cost per Dth (if any)."[50] The All-in Cost per Dth of Estimated Use for each considered project "will be calculated as [the sum of the fixed cost per year of the project plus the fixed O&M cost of the project (*i.e.*, total annual non-gas cost)] divided by [the projected annual use of project (to arrive at modeled per Dth of use non-gas cost)] plus the variable commodity cost per Dth of the project plus the variable O&M cost per Dth (if any)."[51]

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[49] www.GreenpointEnergyCenter.com
[50] Joint Proposal, at 45-46.
[51] *Id.*

A. *Greenpoint Vaporizer 13/14 Project*

Cost components for the Greenpoint Vaporizer 13/14 Project include:

Cost Element	Costs
Capital Cost Estimate through 2021	$32,352,340
Capital Estimate Calendar Year 2022	$18,602,166
Capital Estimate Calendar Year 2023	$11,181,250
Capital Estimate Calendar Year 2024	$2,493,746
Annual O&M Estimate	$43,600
Inflation	2%
Property Tax Rate	5.43%

The operations and maintenance ("O&M") components include the average costs to test, calibrate, operate, and maintain two vaporizers based on historical plant utilization. Other O&M costs at the plant should not be impacted by the addition of these vaporizers.

B. *Infrastructure Alternative – Cloves Lake Uprate Project*

Cost components of a potential infrastructure alternative, the Clove Lakes Uprate project, include:

Cost Element	Costs
Capital Cost Estimate for Calendar Years 2022-2029	$321,500,000
Annual O&M Estimate (including line patrol and standby costs as well as fixed capacity costs)	$21,969,732
Five and Seven Year Periodic Inspection Costs	$1,253,000
Inflation	2%
Property Tax Rate	5.43%

The O&M components include typical damage prevention patrols, miscellaneous support and protect activities, annual valve inspections and maintenance including battery replacements for remote control valves, cathodic protection checks, and integrity driven In Line Inspection ("ILI") and External Corrosion Direct Assessment ("ECDA") and validation/repair excavations for a typical approximately eight-mile long gas main as described in the Appendices to this Report.

C. *Demand-Side Management*

Cost components of a potential DSM solution include:

Cost Element	Costs
Cost per dekatherm per season, DR	$474
Inflation	2%

D. All-In Cost

The chart below summarizes the costs for the Project measured in $/Dth for each option:

Project	Capital Costs ($000)	Annual O&M ($000)	Net Present Value ($000)	Design Day Dth	$/Dth
Greenpoint Vaporizer 13/14 Project	64,630	0.044	95,706	58,000	$1,628
Cloves Lake Uprate Project	321,500	21,970	764,124	80,000	$9,552
Demand Side Alternative	-	-	38,927	6,052	$6,432

The Greenpoint Vaporizer 13/14 Project provides on-system reliability and reinforcement benefits for the winter operating season and does so utilizing supplies already located within the service territory. The Clove Lakes Uprate Project provides reliability and reinforcement benefits over the course of the entire year by providing a parallel path for gas to travel once it reaches National Grid's system, but it relies on incremental supplies being available upstream of National Grid's system to provide those benefits during peak demand periods or whenever a disruption in supplies to the NYC market area occurs. Demand response has the lowest availability, as it can only be utilized during peak demand periods, and depends on customer compliance with the terms of the program. A supply shortfall and/or customer outages may result if the needed reduction in demand is not achieved. The presumed availability of these options to address Design Day conditions is utilized to compare the cost per Dth in the right column of the preceding table and excludes the additional benefits that the Greenpoint Vaporizers 13/14 and Clove Lakes Uprate Projects provide.

Appendix C provides additional information on the cost elements of each option described above.

SECTION 8: ALTERNATIVES CONSIDERED

The Long Term Capacity Report, Supplemental Report, Second Supplemental Report, Third Supplemental Report and related materials describe in detail the Companies' efforts to identify and assess various alternatives. These alternatives are set forth in Figure 8-1 below. This analysis confirms that the Distributed Infrastructure Solution, including the Greenpoint Vaporizer 13/14 Project, remains the best available solution to address the projected supply-demand gap and is consistent with New York's Net Zero goals. The Distributed Infrastructure Solution strikes a balance among scale, feasibility, affordability, and alignment with our clean energy goals including the CLCPA and Net Zero. While some potential options may satisfy one or several of these criteria, the Companies could only consider options that satisfy all of them. While not without risk, the Companies determined the Distributed Infrastructure Solution is feasible, based on an assessment of a broad range of implementation considerations, including the current legal and regulatory framework in New York, permitting, construction, and operations. Other potential solutions presented relatively greater execution risks.

National Grid must ensure that customers can afford the energy they need to support their homes and businesses. Every feasible alternative to the Distributed Infrastructure Solution was determined to be more costly for customers when taking into account direct costs as well as indirect costs related to emissions.

Figure 8-1: Alternate Projects Considered (from Second Supplemental Report)

Contingency Options	Size (MDth/day)	Levelized Cost ($/MDth/day)	Feasibility
Distributed Infrastructure Options			
Clove Lakes Transmission Loop Project	80	~$700	◕
LNG Barge (scalable)	50 (per barge)	~$1,000	◑
Micro-LNG Tank	18	~$800	◔
Non-Gas Infrastructure Options			
Incremental DR over and above the Distributed Infrastructure Solution	Variable	~$800	◑
Incremental Heat Electrification	Variable	~$2,500	◔

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Because the need for the Greenpoint Vaporizer 13/14 Project was determined using the adjusted baseline gas demand forecast as a baseline, and because that baseline incorporates significant amounts of anticipated demand reductions from DSM programs (energy efficiency, weatherization, gas demand response, and electrification implemented by PSEG-LI and Con Edison), only the amounts of DSM incremental to that forecast could feasibly serve as an alternative to the Project. In the best-case scenario, only gas demand response could provide demand reductions over and above those embedded amounts, and it is those reductions that are shown in the Demand Side Alternative row of the table in Section 7 above. The conclusion should not be drawn from this that National Grid is not working diligently to scale DSM programs at an unprecedented pace and scale - it is. Nevertheless, there are real and present barriers and constraints, outlined in Section C of Appendix B of this report, to the ability of those programs to scale at a pace needed to serve as an alternative to the Project.

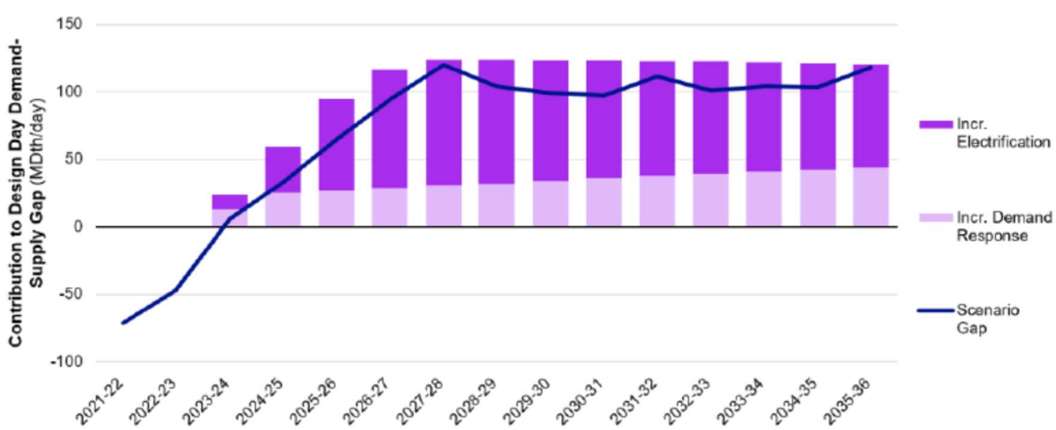
It should also be noted that National Grid's gas demand response programs, despite being more advanced and aggressive than those implemented by most other utilities, are continuing to scale and mature, and it will take until the winter of 2026/27 for them to scale to the level of being able to provide 7,945 Dth of design day delivered reductions over and above what is embedded in the adjusted baseline forecast. In fact, by the winter of 2024/25, demand response will only be able to provide an estimated 7,336 Dth of design day reductions above the levels embedded in the adjusted baseline forecast.

In either case, it is clear that DSM could not serve as an alternative to the Greenpoint project. The Companies still firmly believe that DSM is an essential part of Distributed Infrastructure Solution, and that they will continue to provide demand reductions, reduce carbon emissions, and save money for those customers who implement it. Because of that, the Companies will continue to do everything within their power and regulatory authority to implement demand-side solutions and scale them as quickly and cost-effectively as possible. However, there is no scenario under which it could do so in a timeframe or at a scale that would enable it to supplant the extra supply that the Greenpoint LNG vaporizers would provide on peak days.

Based on National Grid's analysis – looking at the costs of the different approaches and how quickly the Companies could implement the solution, and taking into account engineering time and permitting hurdles (*i.e.,* feasibility) – the Companies assessed that, for the contingency scenario gaps resulting from delays in the implementation of either the Greenpoint Vaporizer 13/14 Project or the ExC Project, the least expensive approach was a combination of incremental demand response and heat electrification. The most viable contingency was the Clove Lakes Project as a potential substitute for the Greenpoint Vaporizer 13/14 Project paired with expanded DSM. In all cases, the costs of these solutions are far in excess of the costs of the Distributed Infrastructure Solution and present significantly higher execution risks. An increase in investment in demand response and heat electrification programs is necessary in all contingency scenarios. However, relying on a combined solution of non-gas infrastructure with distributed infrastructure was less expensive and had a greater likelihood of implementation success than if the Companies were to attempt a pure non-gas infrastructure solution, which would be heavily dependent on a rapid scale up of incremental heat electrification efforts.

Indeed, in the Second Supplemental Report, the Companies started with an analysis of a pure non-gas infrastructure solution, based entirely on the implementation of incremental DSM programs over and above those already included in the Distributed Infrastructure Solution. Depending on the contingency scenario, these new DSM programs would need to be ramped up very rapidly over time. Figure 8-2 below (from the Second Supplemental Report) illustrates how a potential scale up in incremental DSM would need to occur to address the contingency scenario gap assuming the Greenpoint Vaporizer 13/14 Project and the ExC Project were denied.

<u>Figure 8-2</u>: DSM Program size without both the LNG Vaporization and ExC Projects



The analysis in the Second Supplemental Report concluded "that applying a purely non-gas infrastructure solution would require a massive increase in investment in [demand response] and heat electrification programs very quickly. The additional costs of the incremental heat electrification program alone, which would make up the bulk of a purely non-gas infrastructure solution in closing a contingency scenario gap resulting from an infrastructure project denial, could be as high as $1.23 billion netted against any savings resulting from not constructing the distributed infrastructure projects."

A substantial amount of DSM is already embedded in the gas forecast. National Grid's ability to further scale DSM beyond these levels would face substantial barriers, many of which are beyond the Companies' direct control, including:

- The ability to influence electrification is limited by available funding and rate mechanisms to subsidize electric conversions for current and prospective gas customers;
- There are currently insufficient contractors and vendors who are experienced in weatherization to execute programs at the required levels;
- Basic materials (insulation and weatherstripping) are in short supply and increasing in price;
- Weatherization is very expensive due to the materials and labor required, and due to the fact that it is invasive to customer buildings. In a time of high inflation and economic uncertainty, this is proving to be a barrier; and
- Although National Grid has instituted nation-leading gas DR programs, our understanding of the market is showing that there is an upper limit to the amount of demand reductions that can be provided by gas demand response.

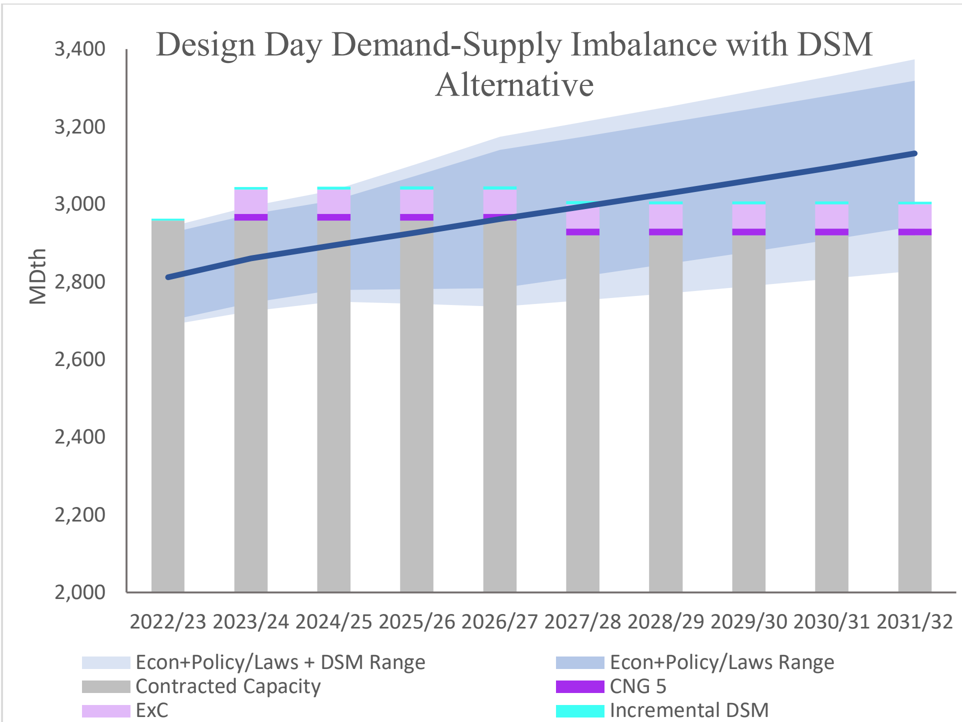
Also, as utilities develop a better understanding of how customers install and use heat pumps, there is some indication that electrification may not reduce gas peak demand to the degree that some have assumed. For example, on the coldest days of the winter, customers with heat pumps may switch to their backup, gas-fired heating systems. For this case, design day conditions and the corresponding system capacity infrastructure needs remain unchanged even though annual gas usage will be reduced.

Electrification presents a significant opportunity to reduce annual gas usage and associated emissions if the electricity is produced with no emissions. To this end, in the Joint Proposal, National Grid agreed to an unprecedented set of commitments to promote electrification to achieve demand destruction, including a commitment to developing educational material, in coordination with their Energy Efficiency and demand response programs, that will inform customers of alternative heating options, including air- and ground-source heat pumps and geothermal heating systems.[52] While the Companies' believe these efforts will ultimately encourage a significant segment of current/prospective customers to participate in energy efficiency, demand response and electrification programs, the ability to scale DSM is sufficiently uncertain/unproven to provide a reliable substitute for targeted infrastructure in the near term.

[52] JP Section IV.7.5.2.

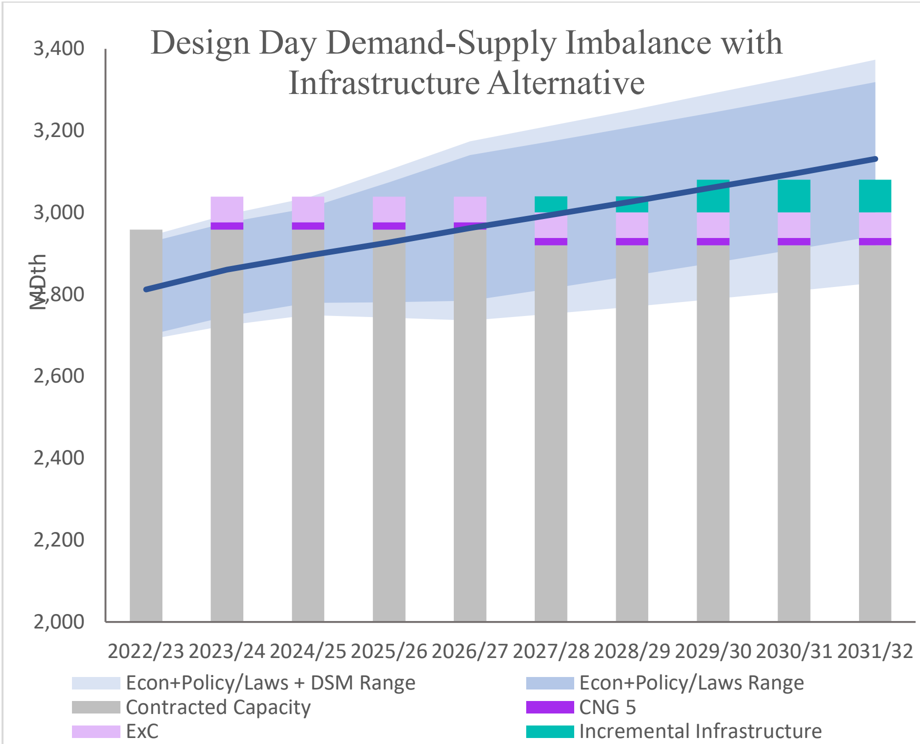
While the Companies have identified conceptual demand-side and supply-side alternatives to the Project, these alternatives could not be implemented in time and/or at sufficient scale to avoid a design-day gas supply imbalance. Figures 8-3 and 8-4 show the demand-supply imbalance for each of the alternatives considered in lieu of the Project.

Figure 8-3: Design Day Demand-Supply Imbalance with DSM Alternative



Note: Y-axis is broken to focus on changes at the margin

Figure 8-4: Design Day Demand-Supply Imbalance with Infrastructure Alternative



Note: Y-axis is broken to focus on changes at the margin

Greenhouse Gas Emissions Impacts of Alternatives

Global warming potential (GWP) is a measure that recognizes the impact of different greenhouse gases (GHGs) on the Earth's atmospheric warming relative to CO_2. In the Companies' Second Supplemental Long-Term Capacity Report, we provided a comparison of the 20-year and 100-year GWP impacts of the non-infrastructure alternative and the infrastructure alternative to the Project as a representation of the relative GHG emission impacts to atmospheric conditions for each alternative.

The GHG emissions quantified in this analysis are converted to CO_2-equivalence ("CO_2e") based on their 20-year and 100-year GWP as identified by the Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report. The atmospheric impact of each solution's GWP in tons of CO_2e is estimated for each contingency solution. This accounts for the net GHG emissions from distributed infrastructure resources and the net GHG emissions from demand side reduction measures. The conversion factors from this report are shown in Figure 8-6 below.

GHG emission savings are calculated by multiplying GHG emission rates for natural gas, fuel oil, and electricity production shown in Figure 8-5 below by the amount of energy attributed to each source netted against the baseline scenario of the Distributed Infrastructure Solution. Pipeline gas and fuel oil emissions rates are assumed to remain constant over time, while emissions associated with electricity production are assumed to decline linearly to zero emissions by 2040 in accordance with the state's goal of 100% renewable electricity by 2040. Results are expressed in terms of CO_2e to provide a single measure for comparison that accounts for the relative impacts on global warming attributed to different types of greenhouse gases (CO_2, N_2O, CH_4) that are emitted at different rates depending on the fuel source, as identified in Figure 8-5. For comparison, one ton of CO_2e represents the emissions associated with about 2,280 miles driven in a typical passenger vehicle.

Figure 8-5: GHG Emission Rates by Fuel Source

Greenhouse Gas	Pipeline Gas [lb per MMBtu]	Fuel Oil [lb per MMBtu]	2020 Electricity Production [lb per MWh]	2040 Electricity Production [lb per MWh]
CO_2	117	165	575	0
N_2O	0.00022	0.0013	0.24	0
CH_4	0.022	0.066	0	0

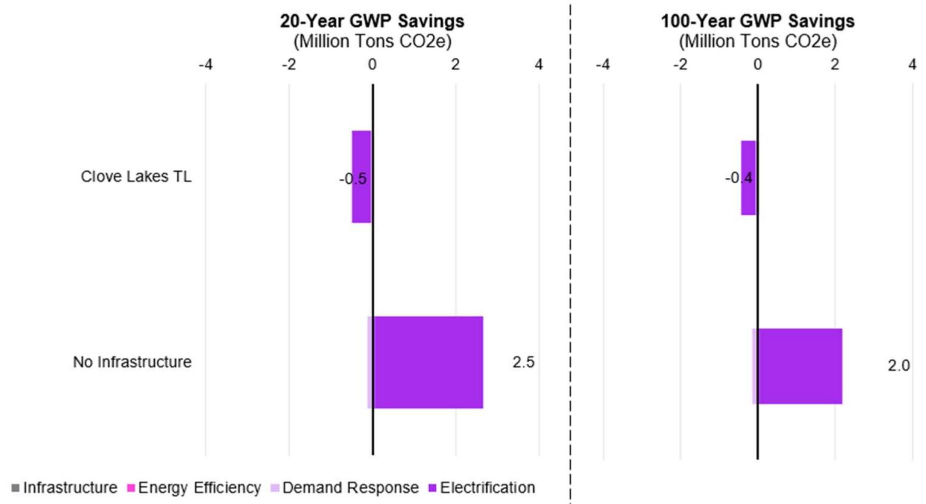
Figure 8-6: 20-Year and 100-Year Global Warming Potential Relative to CO_2 by Greenhouse Gas

Greenhouse Gas	20-Year GWP Factor	100-Year GWP Factor
CO_2	1	1
N_2O	264	265
CH_4	84	28

Source: https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf

Figure 8-7 shows the net GWP savings of two analyzed solutions if the Project is rejected, Clove Lakes and No Infrastructure. In the charts below, a positive value indicates a net savings of total CO_2e compared to the Distributed Infrastructure Solution, which includes the Project, while a negative value indicates a net increase in total CO_2e compared to the Distributed Infrastructure Solution.

Figure 8-7: Net Global Warming Potential Savings of Analyzed Solutions If LNG Vaporization Project Does Not Proceed



Notes: Global warming potential savings includes CO_2, N_2O, and CH_4, which were converted to CO_2-equivalents using the factors in Figure 8-6.

The Clove Lakes alternative results in a higher level of emissions compared with the Project, represented as negative GWP savings relative to the Distributed Infrastructure Solution. Because this alternative provides a greater amount of supply compared with the project (80 MDth/day vs. 58.8 MDth/day), a portion of electrifications could theoretically be avoided, which would result in increased CO_2e impacts. However, the Companies would endeavor to reduce or eliminate the incremental emissions associated with the Clove Lakes alternative through electrification of heat or other measures.

The No Infrastructure alternative, as presented in the Second Supplemental Long Term Capacity Report, relies on additional demand response and electrification to ensure supply can meet demand. Demand response has a negative impact on GWP savings because the assumption is that participating customers will burn fuel oil in lieu of natural gas to meet their demand response program participation obligations. However, electrification has a positive impact on GWP savings, resulting in an overall positive impact for the No Infrastructure solution relative to the Distributed Infrastructure Solution from a GHG emissions perspective.

SECTION 9: CAPACITY DEMAND METRICS

The Capacity Demand Metrics are intended to ensure that the Companies are taking aggressive actions to promote energy efficiency, demand response and electrification, and seeking to offset the need for additional gas supply infrastructure through non-traditional solutions. The Companies' *Rate Year 2 and First Quarter 2022 Capacity Demand Metric Report*, filed in on April 28, 2022,[53] provides an update on (1) the Companies' demand response ("DR") forecasts, (2) actions to

[53] Case 19-G-0309 and 19-G-0310, Rate Year 2 and First Quarter 2022 Capacity Demand Metric Report (dated April 28, 2022).

implement energy efficiency ("EE") and DR programs, (3) the Companies' performance under the Capacity Demand Metrics for Rate Year 2, and (4) the status of the Companies' performance under the Capacity Demand Metrics for the quarter ending March 31, 2022. As described in the report, the Companies have made good progress implementing a portfolio of non-infrastructure solutions to reduce customers' gas consumption, particularly on a peak day and peak hour basis. The Companies met or exceeded the annual targets for all five metrics – demand response, non-pipe third party solutions, electrification, and leak-prone pipe NPAs – in Rate Year 2. They have met two of the Rate Year 3 metrics and are on track to meet two others.[54][55]

A. Energy Efficiency

The Energy Efficiency Capacity Demand Metric requires the Companies to meet their respective total annual targets established by the Commission in the NE:NY Proceeding for energy efficiency. This metric was achieved in Rate Year 2 (Calendar Year 2021).

Company	NE:NY 2021 annual savings target (MMBtu)	Actual achieved gross annual energy savings (MMBtu, as of 12/31/21)
KEDNY	510,740	614,418
KEDLI	433,821	550,171

B. Demand Response

The Demand Response Capacity Demand Metric requires the Companies to meet or exceed a target potential peak demand reduction from customers participating in the Companies' Daily Demand Response Programs during the winter 2021/22 (period of November 1, 2021, through March 31, 2022).

54 In the May 13, 2022 Order on the 2021 Annual DSM Filing, the Energy Efficiency Capacity Demand Metrics for 2022 were set at levels that were 111% and 102% higher, respectively, for KEDNY and KEDLI than the 2021 targets. Although the Companies continue to make substantial efforts to scale their energy effice

55 As noted in the KEDNY and KEDLI Supplemental Demand-Side Management Filing, the projected numbers of homes and businesses that can be weatherized through the Companies' peak demand-focused energy efficiency programs during the 2022-23 program year are lower than originally anticipated. *See,* Cases 19-G-0309 and 19-G-0310, *KEDNY and KEDLI Rate Proceedings*, Demand-Side Management Filing (March 25, 2022). These revised projections are due to market conditions (including materials and contractor shortages) as well as time required to start up the new programs. The Companies are making extraordinary efforts to weatherize as many buildings as possible during the 2022-23 program year; however it is uncertain whether the Rate Year 3 Energy Efficiency Capacity Demand Metric set by the Commission in its May 13, 2022 Order Regarding Demand-Side Management Programs (which measures savings from each Company's peak-demand focused programs and existing NE:NY energy efficiency programs on a combined basis) will be achievable.

Winter 2021-22 Daily Enrollment Target (dths)	Daily enrollment Achieved (dths) for Winter 2021-22
19,569	21,115

C. *Non-Pipe/Third Party Solutions*

The Non-Pipe/Third Party Solution Metric requires the Companies to annually issue at least one request-for-proposal ("RFP") seeking nontraditional, cost-effective peak supply alternatives (*i.e.*, for a non-pipeline alternative solution(s)). The target is an aggregate target across both Companies' service territories; there is not a separate target for each company.

2021 Target (RFPs Issued)	Achieved as of 12/31/21(RFPs Issued)
1	1

On December 13, 2021, the Companies issued a Demand-Side NPA Request for Proposal ("RFP") for North Queens Gas System Capacity Constraints. In that RFP, the Companies seek "permanent demand reduction to address existing and forecasted capacity constraints in our gas system in northern Queens," and to achieve that reduction "via proven, cost-effective measures, and can include energy efficiency, weatherization, and/or electrification, but not via demand response or front-of-meter supply solutions."

The Companies have identified areas in the KEDNY and KEDLI service territory with anticipated capacity constraints, and have issued three RFIs to gain preliminary insight from the market and align competencies between third parties and the Companies' system needs. The Companies have seen good engagement on those RFIs from third parties through clarifying questions and follow-up discussions. The results from the RFIs – specifically, the ones issued for the Bayville and Southeast Suffolk service areas – will inform the Companies' next steps on issuing the RFP for this cycle, which was released on July 29th.

D. *Electrification*

The Electrification Metric requires the Companies to collaborate with Consolidated Edison Company of New York, Inc. ("Con Edison") and PSE&G Long Island and LIPA (collectively "PSEG-LI/LIPA") regarding prospective customers who are potential candidates for electrification, and to refer a minimum number of customers annually to Con Edison and PSEG-LI/LIPA to determine if the customers are interested in electrification. When the Companies refer a customer to Con Edison or PSEG-LI/LIPA, they provide that customer with information on Con Edison or PSEG-LI/LIPA's heat pump programs, regardless of interest level. The Companies have met the number of referrals metric in each of their service territories as shown in the table below.

Referral EDC	2021 Target	Actual (as of 12/31/2021)
Con Edison	75	93
PSEG-LI	125	680

E. *Leak-Prone Pipe – NPAs*

The Leak-Prone Pipe/NPAs Metric requires the Companies to annually identify at least five segments of LPP in each of the Companies' service territories that could be abandoned if all customers' natural gas loads were met with cost-effective NPAs that would allow the section of LPP to be abandoned. For each such section of LPP, the Companies will consider NPAs allowing the section of LPP to be abandoned, or otherwise demonstrate that abandonment of such section of LPP is not possible. The Companies have met the metric target of identifying five segments of LPP in each service territory.

Company	2021 Target	Actual (as of 12/31/21)
KEDNY	5	5
KEDLI	5	5

Accordingly, the Companies have, to date, met or exceeded their Rate Year 2 Capacity Demand Metrics set forth in the Joint Proposal. Information on the First Quarter 2022 Status is available in the April 2022 Quarterly Capacity Demand Metric Status report.

SECTION 10: MORATORIUM ASSESSMENT

In the Moratorium Management Order, the Commission approved moratorium management procedures appliable to all gas LDCs to provide transparency, consistency, and equity to customers. The Commission emphasized that LDCs have an obligation to provide safe and reliable service to customers under the regulations, and moratoria should only be used as a "last step."[56] The Moratorium Management Order provides that LDCs should provide initial notice of a potential moratorium two years in advance. The filing should include, *inter alia*, the expected scope and duration, affected customers, moratorium metrics, available assistance programs, low- and moderate-income and disadvantaged community population numbers/gas usage, and method for customers to determine gas availability prior to execution of a contract.

National Grid's Distributed Infrastructure Solution would, if timely executed and assuming no other material changes to customer demand and currently available supplies, avoid restrictions for at the next several winters. However, if any component of the Distributed Infrastructure Solution faces implementation delays, there is a risk that National Grid will not be able to meet projected customer demand in the coming years. Faced with an inability to meet projected customer Design Day

[56] Moratorium Management Order, at 24.

demand, a targeted pause on new customer connections could be required in the future. The most immediate risk facing the Distributed Infrastructure Solution is the need for the Greenpoint Vaporizer 13/14 Project.[57]

SECTION 11: CONCLUSION AND NEXT STEPS

The Companies are committed to serving our customers and communities reliably, as we have for more than 100 years. Today, we are facing supply challenges in areas of New York that will require new and innovative solutions to responsibly meet our customers' energy needs. To that end, the Companies are pursuing a combination of targeted infrastructure projects, coupled with unprecedented levels of non-infrastructure programs, to meet customers' energy needs. This approach was developed through a public process that was agreed with the State of New York – and charged National Grid with finding solutions to address supply constraints and avoid service restrictions. National Grid's Distributed Infrastructure Solution has undergone independent review in several proceedings, all concluding that the package of infrastructure and non-infrastructure solutions was a reasonable approach to meeting the customers' energy needs. This report further demonstrates that the Greenpoint Vaporizer 13/14 Project is a prudent, cost-effective solution to meet specific operating conditions on KEDNY's system. The Companies have also met their performance targets for delivering energy efficiency, demand response, electrification referrals, and other non-infrastructure solutions for reducing overall gas usage. For these reasons, the Companies should be permitted to recover the prudently incurred costs to construct and operate the Greenpoint Vaporizer 13/14 Project.

Pursuant to the Joint Proposal, intervenors and members of the public will have the opportunity to submit written comments through the Commission's website in Case 19-G-0309 and 19-G-0310. Stakeholder meetings will also be held in September 2022 to solicit feedback on the project and post notice of the meeting in the case docket on the Commission's website. Additional information on the meeting will be provided in the Commission's docket in Case 19-G-0309 and 19-G-0310, the Companies' website, and other channels.

[57] It should be noted that the Clove Lakes Uprate alternative will take longer to implement than the Greenpoint Vaporizer 13/14 Project installation and may face permitting challenges of its own that could delay its implementation and that there is insufficient incremental demand response to permanently delay the Greenpoint Vaporizer 13/14 project.

APPENDIX A

Publicly Available Materials

Proceeding	Materials	Location
National Grid's Long-Term Report Process	• Long-Term Reports: ○ Long-Term Capacity Report ○ Supplemental Report ○ 2nd Supplemental Report ○ 3rd Supplement Report ○ December '21 Update Report • Technical Appendix and Assumptions • Summaries • Public meeting materials and transcripts	https://ngridsolutions.com/
NYSPSC: Case No. 19-G-0678, Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid	• Settlement Agreement • Monitor's reports and responses • Implementation Plans • Action Plans • Independent assessments Transcripts and public comments	https://www.dps.ny.gov/ PSC's Documents Management System Case: 19-G-0678
NYSDEC: Air State Facility Permit DEC ID # 2-6101-00071/00024 Greenpoint Energy Center	• Permit application • Correspondence • Project overviews and responses to information requests • CLCPA assessment • Public Participation Plan • Public meeting materials	https://greenpointenergycenter.com/
NYSPSC: Case No. 19-G-0309 and 19-G-0310, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service	• Rate case testimony • Settlement Joint Proposal • PSC Rate Case Order • Public comments	https://www.dps.ny.gov/ PSC's Documents Management System Case: 19-G-0309

APPENDIX B

Distributed Infrastructure Solution Update

The following is a status update on each component of the Distributed Infrastructure Solution:

A. *ExC Project Status and Updates*

On March 25, 2022, FERC issued Iroquois Gas Transmission System's Enhancement by Compression ("ExC") Project's Certificate of Public Convenience and Necessity. The certificate authority is conditioned, in part, on the pipeline completing construction within three years of the date the order was issued. Additional approvals required include state air permits. Currently, the primary risk to implementation is Iroquois not obtaining all the necessary state permits for the project, or not obtaining them in a timely manner.

B. *CNG Trucking – Status and Updates*

Since the Second Supplemental Report, National Grid has selected a site for the fifth CNG site on Long Island. The Companies have commenced procurement of long-lead materials required for implementation of this solution. The Companies are targeting to have the site constructed and ready for service for the 2022/23 winter but continue to assess the required in-service date of the site to meet forecasted Design Day demand.

Risks for the project are those that are consistent with complex projects of similar scope including: construction, procurement, availability of labor, market capacity, and permitting. These risks are mitigated through stakeholder engagement, advanced procurement of long lead materials, and complex capital delivery processes.

C. *Demand-Side Solutions*

The Distributed Infrastructure Solution relies on four major non-infrastructure options: energy efficiency ("EE"), demand response ("DR"), heat electrification, and Non-Pipe Alternatives ("NPAs"). It is important to note that National Grid's adjusted gas load forecast already incorporates estimated demand reductions from Commission-authorized DSM solutions; however, the Distributed Infrastructure Solution requires additional contributions from DSM programs. Accordingly, the levels of DSM required to close the demand-supply gap in the long term are unprecedented. In our peer benchmarking we have found no other utility who has attempted to roll out DSM programs at this scale so rapidly. The Second Supplemental Report provided a conceptual example of how DSM strategies might be deployed in the longer term to address the projected demand-supply gap. However, the programs, technologies, and business models required to deliver such aggressive savings are still in their infancy and have yet to demonstrate the level of success needed. The Companies will continue to invest in the evolution of the DSM programs with the goal of maximizing their potential as non-infrastructure solutions.

The status and risks of each element is further described in the sections that follow.

Incremental Energy Efficiency Program

In October 2021, National Grid submitted its initial DSM filing, which contained, among other items, a request for additional funding and associated targets for weatherization programs in excess of the programs embedded in the gas load forecast. Based on the learnings from the weatherization programs since their launch in Fall 2021, National Grid subsequently revised its filing in March 2022 to lower the requested funding levels. In May 2022, the New York Public Service Commission ("PSC") issued an Order that approved the funding recovery for those programs and set ambitious annual targets for the Companies to achieve using the Companies' requested budgets.

In parallel with the DSM filing, National Grid soft-launched two new weatherization efforts in Fall 2021: a residential weatherization program and increased weatherization incentives for measures to commercial and multifamily customers through our existing Commercial and Industrial ("C&I") and Multifamily Customer programs. Those programs have unprecedented ambitions in the marketplace, and the Companies continue to believe they will be an important pillar in reducing peak gas demand.

Nevertheless, these programs face headwinds, some of them related to the growing pains often experienced by programs that are entirely new to the market, and some of them related to economic and market factors that are largely outside of the Companies' control. These include contractor capacity, workforce shortages, supply chain constraints, inflation, economic uncertainty, long sales and project cycles, and the time needed to scale complicated new programs.[58] The Companies have devoted significant resources during the first half of the year to address these constraints and is seeing progress on those factors over which it has some control (*e.g.*, contractor capacity and workforce development). Furthermore, preliminary results from a study being conducted by the Companies suggest that weatherization measures may have a higher peak coincidence factor (*i.e.,* will do more to reduce peak gas usage) than previously thought.

Electrification

The Electrification Metric requires the Companies to collaborate with Consolidated Edison Company of New York, Inc. ("Con Edison") and PSE&G Long Island and LIPA (collectively "PSEG-LI/LIPA") regarding prospective customers who are potential candidates for electrification, and to refer a minimum number of customers annually to Con Edison and PSEG-LI/LIPA to determine if the customers are interested in electrification. When the Companies refer a customer to Con Edison or PSEG-LI/LIPA, they provide that customer with information on Con Edison's or PSEG-LI/LIPA's heat pump programs, regardless of interest level. The Companies have met the number of referrals metric in each of their service territories.

Demand Response

Since the publication of the Second Supplemental Report, the Companies have made significant revisions to the long-term vision for Gas DR programs. The directionality of these revisions was

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[58] For more details, see Case 19-G-0309 and Case 19-G-0310, "Supplement Filing of The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid for Approval of Incremental Demand-Side Management Programs" (March 25. 2022) at 6-8.

communicated in the December 2021 Status Report, wherein the Companies raised the need to further investigate market potential, refine program design and features, reconsider the incentive structure and program targets, and further explore third-party participation to scale programs.

Since the last status update in December 2021, the Companies have evaluated an additional winter season of program performance, as described below, which has informed revised projections of gas DR program participation captured in the June 2022 forecast update. The **Load Shedding Program** is the largest of the four Gas DR programs that the Companies operate, accounting for approximately 95% of load reductions associated with the Companies' Gas DR programs. For the winter 2021/22 season, 201 facilities enrolled with an aggregate commitment of 21.1 MDth of daily gas usage reduction (over the sum total of the eight-hour program event window) on a Design Day. Applying a reliability derating factor of 60% (*i.e.*, with the assumption that only 60% of such enrolled load would perform under Design Day conditions), this translates to 12.7 MDth/Day of potential savings. The majority of participants in this program switch to an alternative fuel to participate in DR events, typically fuel oil, as their facilities have dual-fuel capabilities on-site; either because they previously were on a non-firm rate that required it, they have an operational mandate to do so (*e.g.*, a resiliency requirement), or because they decided to retain fuel flexibility.

The **Load Shifting Program** is in its early stages, but closely mirrors the DR pilot[59] that was instituted by the Companies beginning in 2017 and closed in 2020. In this program, customers reduce gas usage during peak hours but will not be required to reduce total gas consumption over the entire peak day. This offers an attractive, flexible option for customers who can reduce usage during key parts of the day (*e.g.*, waiting to heat up their facilities or completing a production run at a different time), but are unwilling or unable to reduce their usage over a full day. The Load Shifting Program may be a valuable tool to manage our intraday demand profile. This program was first launched for the 2021/2022 winter season, resulting in 28 facilities enrolled for the winter 2022/23 season with potential Design Hour reduction of 184 Dth/hour. This program is operated in total for four hours, which implies up to 736 Dth savings for the aggregate event window. However, customers in this program can load shift. This, along with the likelihood that not all enrolled resources will perform at full commitment levels (i.e., reliability derating), implies a much lower savings on a daily level.

In the **Residential/Small-and-Medium Business (SMB) program**, customers enroll their smart thermostats and provide National Grid with the authorization to adjust their setpoints during event hours. Enrollment into the Bring Your Own Thermostat ("BYOT") program is on a rolling basis, and customers remain in the program unless they request to unenroll or are removed by National Grid for failure to adhere to program rules. As of this report, there are approximately 10,400 devices enrolled in the program, a more than 200% increase from the corresponding period last year. Two elements, among others, have contributed to that increase: (1) eligible customers in our Long Island territory were able to enroll for the first time in 2021; and (2) the number of thermostat models allowed to enroll in the program has increased (and will continue to do so). Data collected from this past winter show that customers reduced their usage during event hours. Moreover, despite the increased usage during pre-heat and snapback hours, there was a net daily reduction in usage. The Companies plan to utilize learnings from the past winter and upcoming winters, as well as other customer research to increase program participation and refine or introduce new program features in future years.

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[59] Gas DR Demonstration Project, which the Commission adopted in Cases 16-G-0058 and 16-G-0059.

The Companies have received approval for proposed firm DR programs ("Gas DR Order").[60] As directed by the Gas DR Order, the Companies filed for Tariff Amendments to add the firm DR programs to the tariffs. These tariffs have currently been adopted on a temporary basis by the PSC and became effective November 1, 2021. The Companies will file revised Tariff Amendments that incorporate the program design changes and revisions for the upcoming 2022/23 winter season with the Annual DR filing that was submitted on June 15, 2022.

The Companies are currently enrolling customers for the 2022/23 winter capability period and anticipate growth in program enrollment. Revised targets for the 2022/23 winter capability period incorporate a significant change in target levels driven primarily by a downward revision to the load shedding program targets. These targets were presented in detail in the Annual DSM filing submitted in July 2022.

The biggest implementation risks for DR involve customer acquisition, retention, and performance. We need to increase the size of the DR portfolio, sell it every year, and ensure that customers perform, both through ensuring they are prepared and creating incentives/penalties that align our goals with the goals of customers. If participating customers transition away from gas under other programs (*e.g.*, electrification of heat), we will need to replace them from a smaller pool of customers.

For the 2021/22 winter season, National Grid had a stretch enrollment target of 27 MDth potential reduction on a Design Day to the Load Shedding program. Enrollments into the Load Shedding program closed at 21.1 MDth potential reduction on a Design Day, an 18% increase from the prior year. Preliminary analysis from the 2021/22 enrollments highlighted the need to further investigate market potential, refine program design and features, reconsider the incentive structure and program targets, and further explore third-party participation and regulatory policy, as we work towards scaling the DR program to the quantities proposed in the Distributed Infrastructure Solution. An internal market potential and customer base analysis pointed to significant limitations around customers who have access to equipment or the ability for demand destruction through other means than was estimated for the Original Long-Term Gas Capacity Report. We will continue to utilize the learnings from past season enrollment experience as well as program performance to refine the potential of firm DR programs. Specifically, the Companies will continue to assess market potential for the flagship Load Shedding program. Additionally, if the Companies were to embark on developing new programs that would meet the gap left by revisions to the Load Shedding program potential, there may be a need to address areas such as advanced metering infrastructure and rate design. Even then, there may be significant challenges to deliver the scale of savings presented in the original report, and the Companies would need to target many smaller customers with discretionary usage reductions to realize those incremental savings. This, as well as the increased cost inherent in reaching the marginal customer, for both existing and any new programs, may impact the cost-effectiveness of the program.

To address the risk of customers choosing not to participate in DR events, we have developed a direct load control ("DLC") subprogram for firm DR customers in which we install a device at customer sites that curtails their usage and, if applicable, switches them to a backup fuel (similar to the arrangement for most non-firm customers). We currently assume that 60% of enrolled quantities can be counted on during Design Days (*i.e.*, reliability expectation), and have seen Test Event performance range from 72% to 82% under non-Event conditions (*i.e.*, temperatures above our 10 degree event threshold). Using the established DLC and non-DLC tiers for our Load Shedding DR

[60] Case 19-G-0086 and 19-G-0087, "Order Authorizing Tariff Amendments to Effectuate Gas Demand Response Programs for Firm Gas Customers," October 07, 2021.

program has allowed us to quantify the difference between DLC and non-DLC performance. Based on the observed difference of 20% higher for DLC compared to non-DLC, we will be proposing an increase to our DLC offering in the hopes of raising the assumed reliability expectation for this program.

Finally, the impact of customers moving from non-firm to firm rates, despite the improved economics of non-firm rates, remains a risk.

Incremental Heat Electrification

The estimated levels of design day demand reductions occurring because of electrification in the Supplemental Reports rested on a vital assumption: that "full-load" heat pump installations contribute directly to gas peak load reductions.[61] However, recent evidence indicates that, at least for the foreseeable short-term and medium-term that assumption is largely incorrect. This is because of two primary factors:

1. The first relates to the way customers install and operate their full-load heat pump systems. Despite installing systems that meet the "full load" of their heating needs, most customers elect to retain their previous systems, whether out of convenience or as a backup.[62] In addition, the drastic drop in heat pump efficiency and effectiveness at very low temperatures leads customers to generally elect to switch to their backup systems on very cold days. Thus, those customers will consume the same amount of natural gas at or near design day conditions as they would have prior to installing the heat pump system.

2. The second relates to the design of Con Edison and PSEG-LI heat pump programs: (1) although Con Edison has elected to develop and scale a decommissioning program, which incentivizes customers to remove and decommission their backup heating equipment, thereby ensuring a total reduction in those customers' peak natural gas consumption, the impact of that program is limited and its scalability is uncertain; and (2) PSEG-LI provides incentives for integrated controls, which enable a customer to automatically switch between their heat pump and a backup system at a given temperature setpoint, thereby ensuring that more backup natural gas systems will remain in place. The sum result is that although Con Edison and PSEG-LI's heat pump programs as currently designed may make significant strides toward reducing annual natural gas consumption, they may do little to reduce peak gas demand.

Another risk to meeting the ambitious electrification levels identified in the Supplemental Long Term Gas Capacity Reports is that gas-only utilities do not have the regulatory authority to utilize gas ratepayer funds to incentivize equipment utilized by electric utility customers. This was an issue

[61] "Full-load" heat pumps refer to heat pump installations that satisfy at least 90% of total system heating load at design conditions but does not indicate that a customer has entirely replaced a pre-existing heating system (whether electric resistance, natural gas, propane, or fuel oil) with a heat pump system.

[62] It is safe to assume that customers who install full-load ground-source heat pump (GSHP) systems elect to remove their backup heating system, because the high cost of GSHPs would make much less economic sense. However, GSHPs currently represent a very low percentage of total heat pump installations.

identified by DPS Staff in the Gas System Planning Proposal[63] and again in the Commission's recent Gas System Planning Order.[64]

To address these concerns, the Companies are exploring the possibility of a pilot program that would offer current customers a bonus or incentive to disconnect entirely from the gas system. This would be aimed at customers who are installing heat pumps and might otherwise consider retaining their backup gas system. Additionally, the Companies recently filed a report in which it described the application of the 100-foot allowance within its NYC and Long Island service territories and outlined a way in which that same program could potentially provide an incentive to customers who have requested gas service and then commit to using heat pumps instead, meaning that they are able to forgo the installation of a gas connection.[65] This incentive, which could be used for eligible electrification costs, would be equal to the lesser of the cost to electrify and the average cost of connecting a customer to the gas network in a given service territory. Neither program has received regulatory approval, and as such their impact on gas demand cannot yet be reliably estimated. Nevertheless, the Companies believe that these and potentially other programs not yet envisioned have the potential to encourage a subset of customers (either current or potential customers) to adopt electrification without contributing to peak load gas growth.

The Companies have started working with the electric distribution companies ("EDCs", *i.e.*, Con Edison and PSEG-LI/LIPA) to discuss what a collaborative effort on electrification programs might look like. The coordinated effort focuses on laying out the regulatory framework to prepare for much greater levels of heat electrification in the future with a joint emphasis on determining the most economical way to meet the demand gap through heat electrification. A potential pilot in collaboration with the EDCs and other industry partners is in discussion. The goals of the studies and pilot to be conducted may include:

- Influencing more full load conversions within the existing EDC programs
- Influencing higher levels of heat electrification adoption in gas constrained areas
- Testing of incentive levels and strategies to accelerate market penetration over Baseline Electrification
- Determining how to drive customers to electrify heat prior to failure of their existing gas systems (early replacement)
- Enhanced marketing, outreach, market potential, customer education on top of existing EDC and statewide initiatives
- Identifying a framework for coordinating with EDCs on impacts to their electric networks and suggested approaches to mitigate those impacts (*e.g.*, supporting an electrical "make ready" program to address increased electrical loads)
- Determining barriers to accelerated heat electrification, such as workforce development, in collaboration with existing EDC and statewide initiatives
- Pursuing studies to reveal new solutions and strategies
- Determining incentives required for accelerated electrification of heat required for LMI customers and environmental justice zones

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[63] Case 20-G-0131, Gas System Planning Process Proposal (February 12, 2021), at 27.

[64] Cases 20-G-0131 and 12-G-0297, "Order Adopting Gas System Planning Process" (issued May 12, 2022), at pp. 13, 48, Appendix p. 18.

[65] Case 19-G-0309 and 19-G-0310, "KEDNY and KEDLI Rate Case Proceedings, New Gas Connections Cost Report" (filed May 12, 2022).

Throughout this process, the Companies will also leverage collaboration opportunities and shared resources with the New York State Energy Research and Development Authority (NYSERDA) to reach the goals mentioned above.

Non-Pipeline Alternatives (NPA)

National Grid has developed an NPA framework that will allow for solicitation of NPA solutions for system needs. In parallel, we are engaging with the market (*i.e.*, third-party solutions providers) to better understand what solutions they may be able to provide in response to future NPA RFPs. We released our first NPA RFP on December 13, 2021. This RFP was focused on securing a reduction of 5,600 Dth of Design Day demand in northern Queens. Only one bid was received in response to this RFP and this bid was submitted by an "aggregator" who compiled several different solutions into one portfolio. This was encouraging because it meant that market participants might come together to solve larger system needs. However, the bid was only able to deliver 17.6% of the required demand reduction, which meant that we were not able to proceed with the NPA as the planned infrastructure would still be required.

Since that time, National Grid has issued two RFIs in the KEDLI service territory. As these projects are smaller in terms of their required Design Day reduction, 165 Dth and 250 Dth respectively, and the demand reduction will be created outside of New York City, which may remove barriers to certain solutions (*e.g.,* geothermal), the results of these RFIs are expected to be different from the aforementioned RFP. Sufficient market interest was expressed through those RFIs to support the issuance of an RFP for those areas to Suppliers who could potentially offer viable NPA solutions, which is anticipated to be released in late July or early August. The NPA team will continue to have weekly discussions with internal groups to identify additional NPA projects for RFIs and RFPs.

National Grid continues to actively collaborate with other gas utilities that are developing NPA programs. There is a monthly check-in for program operators to share updates and best practices. Additionally, the recently issued Gas System Planning Order asks for additional formal coordination among the Joint Utilities in NY. This should produce common framework elements for NPA that will hopefully improve market coordination. These elements will be filed in early August 2022 as part of a 90-day filing required by the Order Adopting Gas System Planning Process.

Finally, during the process of developing the Queens RFP, National Grid worked with REV Connect to conduct a Mini Sprint outreach to potential responders for this RFP. There was discussion during that process of having a Sprint, as compared to a Mini Sprint, at a future date. This continues to be an option that National Grid supports.

There is still uncertainty about the levels of demand reductions available through NPAs. The response to the first RFP has not provided data that would reduce this uncertainty. National Grid remains committed to exploring NPAs and seeking ways to deploy them. Another risk that remains is that, though third-parties will be able to offer proposed solutions, these proposals may represent similar types of DSM solutions as those proposed by National Grid. These proposals may, therefore, be subject to similar challenges as programs deployed by National Grid (*e.g*., market adoption rates). If this is the case, NPAs will not represent incremental load relief to what may be achieved by programs operated by National Grid.

As the market becomes more familiar with NPA solicitations, however, it is likely that our ability to deploy NPAs that are complementary to, not overlapping with, any planned programs will improve.

E. *Contingency Plan Status*

In the event certain circumstances prevent or delay the Distributed Infrastructure Solution from being fully implemented, National Grid has evaluated alternative approaches to solve the projected Demand-Supply Gap, including alternative infrastructure projects and additional non-gas infrastructure options. In a scenario where one or more of the Distributed Infrastructure Solution enhancements to existing infrastructure are denied, the lead time and feasibility for any alternative approach would entail significant risk that projected customer demand could not be met. As described in detail in the Second Supplemental Report, the alternative approaches that best balance cost and feasibility would include incremental gas DR and heat electrification along with substitute infrastructure projects—specifically, the Clove Lakes Project and/or an LNG Barge project—but all alternative approaches have much higher costs and greater risks to successful and timely implementation than the Distributed Infrastructure Solution.

Greenpoint Vaporization Expansion (13 and 14)

Estimated In Service		5/31/2024
Capex Cost Estimate through 2021		32,352,340
Capex Estimate CY 2022		18,602,166
Capex Estimate CY 2023		11,181,250
Capex Estimate CY 2024		2,493,746
Annual O&M Estimate		43,600
Inflation		2%
Property Tax Rate		5.43%
Period		25 years
Discount rates:	RY3 WACC	6.22%
	RY3 Pre-Tax WACC	7.83%

May-24	2024	2025	2026	2027	2028	2029	2030	2031
64,629,502	43,600	44,472	3,419,333	3,420,240	3,421,166	3,422,109	3,423,072	3,424,054
2032	2033	2034	2035	2036	2037	2038	2039	2040
3,425,056	3,426,078	3,427,120	3,428,183	3,429,267	3,430,373	3,431,501	3,432,651	3,433,825
2041	2042	2043	2044	2045	2046	2047	2048	
3,435,022	3,436,243	3,437,489	3,438,759	3,440,055	3,441,376	3,442,724	3,444,099	

Net Present Value	$95,705,886
Estimated incremental vaporization capability (peak-day dekatherms	58,800
NPV cost per design day dekatherm	$1,628

Assumptions:

Annual O&M estimate includes	
Operation of the vaporizers	18,250
Maintenance of the vaporizers	25,350
	43,600

Estimated 2,450 dekatherms on design day peak hour. Design hour flow is 1/24th of design day flow

Property tax rate is an average tax rate for the assessment year roll for years 2016-2021.

Property tax assumption for special franchise tax property RCNLD methodology is that the replacement cost new will be offset by the accumulated depreciation.
Therefore, hold tax basis consistent with original cost.

Demand-Side Resource Estimate

		2022	2023	2024	2025	2026	2027	2028	2029	2030
Dth provided by DR		5,170	6,527	7,336	7,774	7,945	7,712	7,479	7,244	7,006
Dth provided by EE		0	0	0	0	0	0	0	0	0
Dth provided by electrification		0	0	0	0	0	0	0	0	0
Dth provided by NPAs		0	0	0	0	0	0	0	0	0
Total estimated incremental dth		5,170	6,527	7,336	7,774	7,945	7,712	7,479	7,244	7,006

Cost per dth per season, DR		$474
Cost per dth, EE		$12,000
Cost per dth, electrification		$15,500
Inflation		2%
Period		25 years
Discount rates:	RY3 WACC	6.22%
	RY3 Pre-Tax WACC	7.83%

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual DR cost	$2,450,623	3,155,537	3,617,502	3,910,179	4,076,153	4,036,064	3,992,134	3,944,446	3,890,652
Annual EE cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual electrification cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual total cost	$2,450,623	$3,155,537	$3,617,502	$3,910,179	$4,076,153	$4,036,064	$3,992,134	$3,944,446	$3,890,652

Net Present Value	$38,926,727
Estimated 25-yr average incremental dth	6,052
NPV cost per design day dth	$6,432

Assumptions:

See report explanation of why only DR provides incremental demand reductions adjusted beyond baseline forecast

All demand reductions provided by DR are incremental to the amounts embedded in the 2022 Gas Load Forecast

DR cost per dekatherm per season (i.e. Nov 1 - Mar 31) factors in assumed 60% reliability and is based on 2022-23 program estimates

DR only has a one-year useful life, and hence the cost renews annually

Demand-Side Resource Estimate

		2031	2032	2033	2034	2035	2036	2037
Dth provided by DR		6,762	6,513	6,260	6,001	5,867	5,731	5,594
Dth provided by EE		0	0	0	0	0	0	0
Dth provided by electrification		0	0	0	0	0	0	0
Dth provided by NPAs		0	0	0	0	0	0	0
Total estimated incremental dth		6,762	6,513	6,260	6,001	5,867	5,731	5,594

Cost per dth per season, DR		$474
Cost per dth, EE		$12,000
Cost per dth, electrification		$15,500
Inflation		2%
Period		25 years
Discount rates:	RY3 WACC	6.22%
	RY3 Pre-Tax WACC	7.83%

	2031	2032	2033	2034	2035	2036	2037
Annual DR cost	3,830,422	3,763,410	3,689,256	3,607,582	3,597,442	3,584,584	3,568,879
Annual EE cost	$0	$0	$0	$0	$0	$0	$0
Annual electrification cost	$0	$0	$0	$0	$0	$0	$0
Annual total cost	$3,830,422	$3,763,410	$3,689,256	$3,607,582	$3,597,442	$3,584,584	$3,568,879

Net Present Value	$38,926,727
Estimated 25-yr average incremental dth	6,052
NPV cost per design day dth	$6,432

Assumptions:

See report explanation of why only DR provides incremental demand reductions adjusted beyond baseline forecast

All demand reductions provided by DR are incremental to the amounts embedded in the 2022 Gas Load Forecast

DR cost per dekatherm per season (i.e. Nov 1 - Mar 31) factors in assumed 60% reliability and is based on 2022-23 program estimates

DR only has a one-year useful life, and hence the cost renews annually

Demand-Side Resource Estimate

		2038	2039	2040	2041	2042	2043	2044	2045	2046
Dth provided by DR		5,456	5,316	5,175	5,032	4,888	4,742	4,595	4,589	4,583
Dth provided by EE		0	0	0	0	0	0	0	0	0
Dth provided by electrification		0	0	0	0	0	0	0	0	0
Dth provided by NPAs		0	0	0	0	0	0	0	0	0
Total estimated incremental dth		5,456	5,316	5,175	5,032	4,888	4,742	4,595	4,589	4,583

Cost per dth per season, DR		$474
Cost per dth, EE		$12,000
Cost per dth, electrification		$15,500
Inflation		2%
Period		25 years
Discount rates:	RY3 WACC	6.22%
	RY3 Pre-Tax WACC	7.83%

	2038	2039	2040	2041	2042	2043	2044	2045	2046
Annual DR cost	3,550,188	3,528,371	3,503,281	3,474,764	3,442,663	3,406,814	3,367,046	3,430,161	3,494,368
Annual EE cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual electrification cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual total cost	$3,550,188	$3,528,371	$3,503,281	$3,474,764	$3,442,663	$3,406,814	$3,367,046	$3,430,161	$3,494,368

Net Present Value	$38,926,727
Estimated 25-yr average incremental dth	6,052
NPV cost per design day dth	$6,432

Assumptions:

See report explanation of why only DR provides incremental demand reductions adjusted beyond baseline forecast

All demand reductions provided by DR are incremental to the amounts embedded in the 2022 Gas Load Forecast

DR cost per dekatherm per season (i.e. Nov 1 - Mar 31) factors in assumed 60% reliability and is based on 2022-23 program estimates

DR only has a one-year useful life, and hence the cost renews annually

Infrastructure Alternative - Clove Lakes Uprate

		First Half 11/30/2027 Second Half	Although alternative project would have approximately 50% of project in-service at the end of 2027 and the balance at the end of 2029, reflecting in-service date consistent with
Estimated In Service		11/30/2029	Greenpoint Vaporizers 5/24 in-service date for comparability purposes.
Capex Estimate CY 2022		1,500,000	
Capex Estimate CY 2023		10,000,000	
Capex Estimate CY 2024		60,000,000	
Capex Estimate CY 2025		60,000,000	
Capex Estimate CY 2026		60,000,000	
Capex Estimate CY 2027		60,000,000	
Capex Estimate CY 2028		60,000,000	
Capex Estimate CY 2029		10,000,000	
Annual O&M Estimate (standard O&M for 8 miles of T main)		5,894	
Annual Line Patrol and Standby Costs - 1st Year		29,214	
Annual Line Patrol and Standby Costs - 2nd and subsequent years		13,838	
Every 5 Years O&M Estimate (standard O&M for 8 miles of T main)		4,560	
Every 7 Years O&M Estimate (standard O&M for 8 miles of T main)		1,248,440	
Annual O&M Estimate (fixed costs of pipeline capacity)		21,950,000	
Inflation		2%	
Property Tax Rate		5.43%	
Period		25 years	
Discount rates:	RY3 WACC	6.22%	
	RY3 Pre-Tax WACC	7.83%	

May-24	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
321,500,000	21,985,108	22,409,127	40,314,760	40,771,906	41,243,131	41,713,810	43,604,883	42,693,767	43,198,493	43,718,764	44,238,431	44,774,051

2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
45,320,383	47,492,632	46,452,062	47,025,817	47,617,185	48,220,379	48,835,638	49,469,845	51,958,433	50,756,234	51,422,210	52,101,505	52,801,720

Net Present Value	$764,124,201
Estimated incremental dekatherms peak-day	80,000
NPV cost per design day dekatherm	$9,552

Assumptions:
Estimated 4,000 dekatherms on design day peak hour. Design hour flow is 1/20th of design day flow.

Property tax rate is an average tax rate for the assessment year roll for years 2016-2021.

Property tax assumption for special franchise tax property RCNLD methodology is that the replacement cost new will be offset by the accumulated depreciation.
Therefore, hold tax basis consistent with original cost.

Property tax assumption for special franchise tax property RCNLD methodology is that the replacement cost new will be offset by the accumulated depreciation.
Therefore, hold tax basis consistent with original cost.

Annual O&M estimate (standard O&M for mile of T main) includes:

Annual Valve Inspections		cost/hour	2 RCV's	8 Transmission Valves	3 Pig Receiver Valves	4 Pig Launcher Valves	Total
Supervisor	.0625 hrs. per valve	65	130	520	195	195	1,040
Operator	2 hrs. per valve	49	98	392	147	147	784
Assistant	2 hrs. per valve	35	70	280	105	105	560
Tech	2 hrs. per RCV	55	110	-	-	-	110
			408	1,192	447	447	2,494
Annual Test Point Survey							
Corrosion crew & equipment - 2 men crew, annual testing at only test stations on entire pipeline							3,400
Total Annual O&M estimate							5,894

Annual Line Patrol and Standby Costs	Hours	Patrol Hourly Rate	Patrol Daily Cost	Patrol Weekly Cost	Standby Weekly	Weekly Hr/ Rate Standby	Standby Weekly Cost	Total Weekly Cost	Annual Cost
1st year of operation - 5 day/week patrol	2	48.05	96.10	480.50	0.65	384	249.86	730.36	29,214
2nd and subsequent years of operation - weekly patrol	2	48.05	96.10	96.10	0.65	384	249.86	345.96	13,838

Every 5 years Replace Battery System							
2 Techs	16 hrs.	55	1,760	-	-	-	1,760
Battery cost	2 RCVs		1,400				2,800
Total Cost							4,560

Every 7 years Integrity Inspection and Maintenance

In-Line Inspection			
	ILI Vendor	One Combo smart pig /tool run	125,000
	Cleaning pigs	Multiple cleaning pigs	35,000
	AGM Tracking	Tracking support of all pigs	30,000
ILI support			
	BPI	site support with BPI crews for 5-8 days of ILI work (cleaning pigs and smart tool runs)	200,000
	Lifting-Rigging	Bay Crane for 2 days and backhoe for 5-7 days	150,000
	Environmental		25,000
	Material		5,000
Launcher/Receiver Maintenance			
	Atmospheric inspection and repair		8,000
Pre & Post ILI Engineering analysis			
	Engineering analysis	Data analysis by IMP Engineers and coordinating with ILI vendor, survey and Corrosion crews which included field visits	15,000
	Sub-Total		593,000
Post ILI Repair (Per Excavation)			
	Hallen Excavation	Excavation cost is varying from $70,000-$95,000 for each excavation	80,000
	SKYTesting	per excavation site	2,000
	MMT	per excavation site	10,000
	MSR	per excavation site	15,000
	Engineers	2 engineers for 7 days	3,920
	Corrosion tech & equipment	3 crews for 5 days	15,000
	IMP Inspector	1 IMP inspector for 7 days	7,560
	Material	coating repair materials such as Wax tape, rock shield, gloves, tools etc.	5,000
	Sub total		138,480
	Total excavation & repair cost	Considering minimum 3 excavations & repair in every assessment cycle (7-years cycle)	415,440
ECDA detail survey			
	Proposed miles		8
	Corrosion crews survey cost	Survey cost is varying from 25,000 to 35000 per mile (In-House or Contractor).	30,000
Note: If coating integrity has concerns, then this additional ECDA testing		(CIS,PCM & A-Frame) need to be considered for Integrity Inspection.	
	Sub-Total		240,000
Total IMP O&M Cost		Per 7-Years inspection and maintenance	1,248,440

Annual O&M Estimate (fixed costs of pipeline capacity)

Tetco Pipeline rate for NJ-NY expansion capacity monthly rate per dekatherm	22.856
x 12 months	12
Tetco Pipeline rate for NJ-NY expansion capacity annual rate per dekatherm	274.272
Estimated incremental dekatherms peak-day	80,000
Annual O&M Estimate (fixed costs of pipeline capacity)	21,950,000