Natural Gas Long-Term Capacity - Second Supplemental Report

for Brooklyn, Queens, Staten Island
and Long Island ("Downstate NY")
June 2021

National Grid US

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1. Introduction

On February 24, 2020, National Grid ("National Grid" or the "Company") released the Natural Gas Long-Term Capacity Report (the "Original Report") for its service territories in Brooklyn, Queens, Staten Island and Long Island ("Downstate NY"). The Original Report provided a detailed analysis of the natural gas capacity constraints in the region and the available options for meeting long-term demand. In addition, National Grid held a series of six public meetings and received thousands of written comments on the Original Report and the options.

After reviewing the extensive feedback and public engagement on the Original Report and compiling additional detailed content, National Grid published the Natural Gas Long-Term Capacity Supplemental Report on May 8, 2020 (the "Supplemental Report"). In that report, the Company responded to the public's comments on the Original Report, including on the options presented to address the long-term capacity constraint, and recommended two solutions as the best among all the options presented—an interstate pipeline option or a portfolio of targeted distributed infrastructure and non-gas infrastructure options. Soon thereafter, the state permit applications for the large-scale pipeline project ("Option B") were denied, and National Grid has been executing the other recommended solution—identified in the Supplemental Report as "Option A: LNG Vaporization and Iroquois Gas Transmission System, L.P. ("Iroquois") enhancements to existing infrastructure, combined with incremental energy efficiency (EE) and demand response (DR)."

National Grid is focused on implementing this "Option A" solution, which has been augmented since first introduced. This solution now involves an even more aggressive set of incremental demand-side management ("DSM") programs to help customers reduce their natural gas usage, the size of which is unprecedented in New York. The Company is also developing additional portable compressed natural gas ("CNG") capacity and has continued to progress development and seek permits for the proposed LNG vaporization enhancements at its existing Greenpoint facility. The Company is also supportive of the Enhancement by Compression ("ExC") project being pursued by the Iroquois Gas Transmission System.

Altogether, these programs, projects and additional contracts are collectively referred to as the "Distributed Infrastructure Solution" throughout this report ("Second Supplemental Report").

National Grid has also made significant corporate commitments that align with New York's ambitious climate change goals as laid out in the Climate Leadership and Community Protection Act ("CLCPA"). In October 2020, National Grid refined its plan to achieve New York's net zero greenhouse gas ("GHG") emissions by 2050 goal ("Net Zero") via its "Net Zero by 2050" plan and updated its Responsible Business Charter to include those ambitions.[1] Measured against these goals, National Grid believes its Distributed Infrastructure Solution is consistent with the CLCPA goals, the Company's Net Zero plan, and a clean energy future.

Despite all the progress National Grid has made on its Distributed Infrastructure Solution, permitting delays have created risks to the infrastructure projects' in-service dates. The DSM programs also face implementation challenges in terms of the need for regulatory approval and funding and the execution risk from the extraordinary magnitude and ramp up of these programs and the unpredictable nature of customer participation. These challenges create a real risk of National Grid not being able to meet future customer demand, requiring an updated assessment of potential impact and consideration of alternatives if components of the Distributed Infrastructure Solution fall short.

[1] https://www.nationalgridus.com/media/pdfs/our-company/netzeroby2050plan.pdf and https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf

Given the ongoing challenges of meeting customer gas demand in Downstate NY, the purpose of this Second Supplemental Report is as follows:

- Frame the Downstate NY gas capacity needs and National Grid's Distributed Infrastructure Solution in the context of New York's CLCPA Net Zero commitment, the Company's Net Zero plan and the long-term demand forecast.

- Provide an update of the Company's long-term demand forecast for Downstate NY and the status of its existing capacity and operational constraints. The 2021 Adjusted Baseline Demand Forecast shows a higher level of demand compared to the 2020 forecast despite the disruption of the pandemic, leading to a slightly higher near-term design day demand-supply gap between the forecast and capacity.

- Provide an update on National Grid's progress in implementing its Distributed Infrastructure Solution to solve the design day demand-supply gap, which the Company continues to believe is the most viable solution, and explain the risks to finalizing implementation of the Solution.

- Lastly, present an updated set of options in the event National Grid's Distributed Infrastructure Solution is significantly delayed or not fully implemented, evaluate the cost and implementation feasibility of those options and explain the future risks to customer connections and uninterrupted service.

As with the Original Report, we invite readers to provide feedback on this Second Supplemental Report and the recommendations contained herein. In addition to filing the Second Supplemental Report with the New York Public Service Commission, we will be publishing this report on our website and will deploy other options for sharing the report with stakeholders, including a reader friendly summary, web content, and a virtual meeting.

2. Executive Summary

2.1. National Grid provides safe, reliable and affordable energy to more than 1.9 million customers in Downstate New York.

From hard-working families to small businesses, National Grid's customers throughout Brooklyn, Queens, Staten Island and Long Island ("Downstate NY") depend on National Grid to deliver safe, reliable and affordable natural gas to their homes and businesses -- especially on the coldest of days when customer gas demand is at its peak. National Grid must meet this profound energy obligation even as we plan for a future where traditional natural gas demand may decline as a result of new policies to reduce greenhouse gas emissions.

2.2. National Grid strongly supports New York's goals to reduce greenhouse gas (GHG) emissions economy-wide and reach the goal of net zero emissions.

On July 18, 2019, Governor Andrew M. Cuomo signed into law the Climate Leadership and Community Protection Act ("CLCPA"), one of the most ambitious climate laws in the United States, requiring New York to reduce economy-wide GHG emissions 40% from 1990 levels by 2030 and to achieve net zero ("Net Zero") greenhouse gas emissions by 2050 (with emissions reduced by no less than 85%, and remaining emissions eligible to be offset to achieve the Net Zero goal). National Grid is fully committed to a clean energy future and helping New York achieve its energy and environmental goals under the CLCPA and has designed our Distributed Infrastructure Solution in a manner that is consistent with these Net Zero efforts.

As part of its commitment to building a cleaner energy future for New York, National Grid published in October 2020 our "Net Zero by 2050" plan[2] and updated our Responsible Business Charter[3], affirming our commitment to: (i) reduce GHG emissions from our direct operations by 80% by 2030, 90% by 2040, and to net zero by 2050; (ii) reduce GHG emissions from the gas we sell to customers by 20% by 2030, and further reduce these emissions beyond 2030 consistent with New York's targets as laid out in the CLCPA; and (iii) prioritize ten major focus areas to achieve Net Zero for our US operations and the energy we deliver to customers. Among those ten major focus areas, five specifically involve the Company's gas network:

- Reduce gas demand through energy efficiency ("EE"), demand response ("DR"), and non-pipeline alternative ("NPA") solutions;
- Decarbonize the gas network with renewable natural gas and hydrogen (*i.e.*, reducing the carbon intensity of delivered gas);
- Reduce methane emissions from our own gas network and the entire value chain;
- Integrate innovative technologies to decarbonize heat (*e.g.*, electric heat pumps, hybrid gas-electric heating systems, and geothermal district energy systems); and
- Invest in large scale carbon management.

[2] https://www.nationalgridus.com/media/pdfs/our-company/netzeroby2050plan.pdf
[3] https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf

2.3. National Grid has taken action to reduce GHG emissions in New York.

Across every community we serve, National Grid is deeply committed to the goal of Net Zero and has a long track record supporting the reduction of GHG emissions. We have helped New York to rank in the top five most energy-efficient states in the nation through our existing EE and DR programs several years in a row, and these programs continue to grow. Under the state's New Efficiency: New York ("NE:NY") transformation of utility energy efficiency programs, National Grid's annual gas energy efficiency savings targets grow by more than three-and-a-half-fold from 2020 to 2025. By 2030, the Company also anticipates being able to reduce the methane emissions from our infrastructure by 80% against a 1990 baseline through pipe replacement programs and leak detection and repair advancements. And, just last year, the Company exceeded customer enrollment targets for our demand response programs for the winter 2020/21.

In addition, we are continuing to advance and invest in cleaner fuels by reviewing requests from developers who have new supplies of renewable natural gas ("RNG") and seeking new supply sources, as demonstrated by the new RNG facility at the Newtown Creek Wastewater Treatment Plan and our standardized interconnection process for new RNG facilities. To help drive the next clean energy innovation, the Company has also partnered with entities like the New York State Energy Research and Development Authority ("NYSERDA") and research universities, including Stony Brook University, to advance additional ways to decarbonize the gas network through hydrogen blending and other sources of RNG.

National Grid collaborated with Con Edison and the NYC Mayor's Office of Sustainability on a multi-year project to study strategies that could help New York City meet its energy and climate goals and to develop insight into key decarbonization options. The study, entitled "Pathways to a Carbon-Neutral NYC," (the "NYC Decarbonization Study") was published in April 2021[4], and it made several key findings, including the need for rapid adoption of energy efficient and advanced heating equipment, the need for greater building electrification with the support of 100% zero-emission electricity, and the need to transform the gas network into one that delivers low carbon gas (from hydrogen and RNG) for buildings that do not electrify to reduce their net carbon footprint. The NYC Decarbonization Study notes how the gas distribution infrastructure system will continue to play an enduring and critical role in achieving our shared goal of decarbonization.

Currently, the CLCPA-established New York State Climate Action Council is in the process of creating a scoping plan for the CLCPA's emissions reductions, to be filed with the governor and legislature at the end of 2022. The Council's advisory panels have recently made their recommendations, which include, among other things, future prohibitions on both new gas customer connections and gas equipment replacement, with these changes phased in over time starting in 2025. National Grid continues to evaluate this evolving policy landscape as we plan to meet our customers' needs.

2.4. National Grid is ensuring critical energy reliability during the coldest periods when demand is at its highest while empowering New York's transformation to a Net Zero energy system.

With more than 1.9 million customers in our Downstate NY service territory and with a sustained trend over the last 10 years of adding roughly 12,000 customers per year, National Grid must forecast our customers' future natural gas demand and ensure that our portfolio of natural gas supply, gas distribution network infrastructure, and demand-side management programs can meet our diverse customers' energy needs even under challenging conditions.

[4] https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf

To this end, we design our gas distribution system and plan our natural gas capacity to meet forecasted customer demand on a "Design Day" (*i.e*., the coldest winter day that brings the highest daily customer demand for which the Company plans) and under "Design Hour" conditions (*i.e.*, the peak hourly demand on such a Design Day). Importantly, we do this 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 in the event that there is an unexpected disruption to gas supply, gas infrastructure, or demand-side resource availability.[5] National Grid models the Downstate NY gas supply and distribution requirements based upon a Design Day average temperature of 0° Fahrenheit in Central Park (*i.e.*, 65 Heating Degree Days). Since the Supplemental Report, National Grid commissioned an analysis by Marquette Energy Analytics of Downstate NY weather conditions (accounting for both temperature and wind that drive peak gas demand for heating) that corroborates our Design Day standard as consistent with the gas utility mainstream for Design Day standards in terms of likelihood of occurrence.

Given the reality of extreme weather conditions, the consequences of having insufficient natural gas capacity to meet peak customer demand under extremely cold winter weather conditions can be severe. Insufficient gas capacity under such 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. Given the importance of providing energy reliably and safely, even during the most demanding of periods, National Grid believes we must do everything possible to ensure the gas network maintains enough pressure and operates safely. In addition, the energy service interruptions that occurred as a result of the February 2021 winter storm in Texas serve as a powerful reminder to all of us of the importance of working together to develop a clear energy strategy that plans for the inevitability of severe weather conditions given the magnitude of potential economic and health impacts to customers from loss of heating during extreme cold.

2.5. Consistent with prior years' forecasts, National Grid projects continued gas demand growth in our latest annual long-term gas demand forecast, even after accounting for the impacts of the COVID-19 pandemic and New York's currently enacted, ambitious energy efficiency and heat electrification programs.

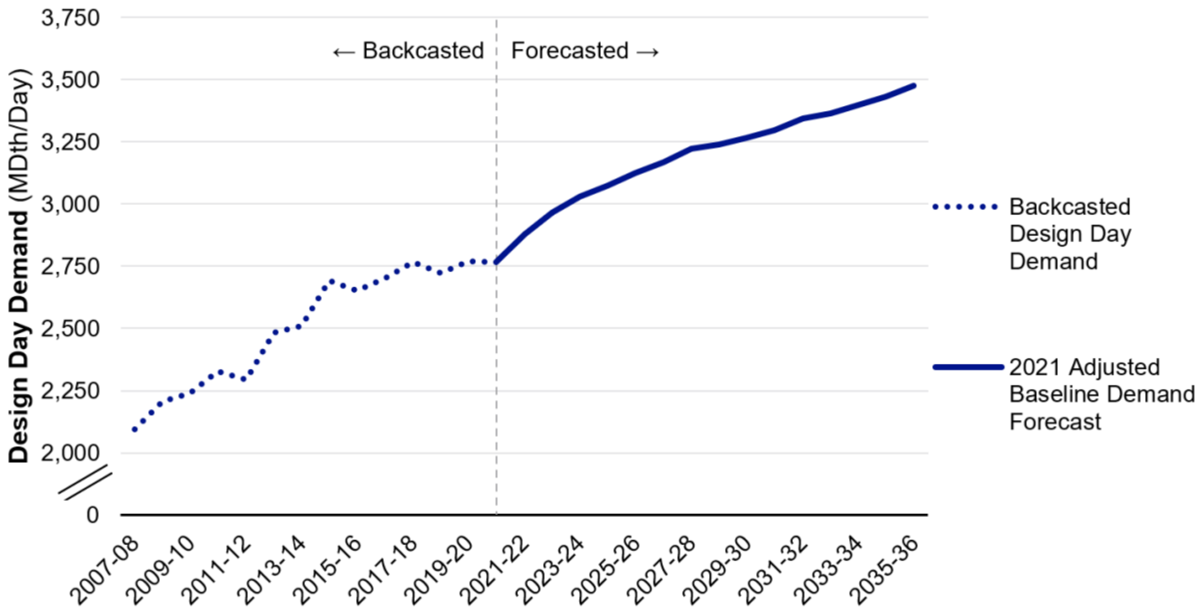
We forecast our customers' gas demand taking into account all relevant factors, including historical usage and independent economic projections (reflecting the latest view on the effects of the COVID-19 pandemic), heating oil versus natural gas price differentials, and adjustments for factors such as energy efficiency, demand response and heat electrification programs. Based on those factors, our latest forecast projects that Downstate NY Design Day gas demand will increase approximately 1.5% per annum, from 2,766 MDth/day[6] in winter 2020/2021 to 3,430 MDth/day in the winter of 2034/2035.

[5] "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 forecasted peak demand is not exceeded and that all available gas capacity resources will be available at 100% with no disruption when needed.

[6] 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.

Growth in the baseline demand forecast adjusted for energy efficiency, demand response, and heat electrification (the "Adjusted Baseline Demand Forecast") is significantly 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. However, Design Day gas demand is expected to grow much faster than even the historical rate over the next three years, averaging 3.1% per annum from winter 2020/2021 to winter 2023/2024, due to the strong economic rebound forecast for Downstate NY after the COVID-19 pandemic. Figure 2-1 below shows historical (*i.e.*, backcasted)[7] and projected growth for Design Day gas demand.

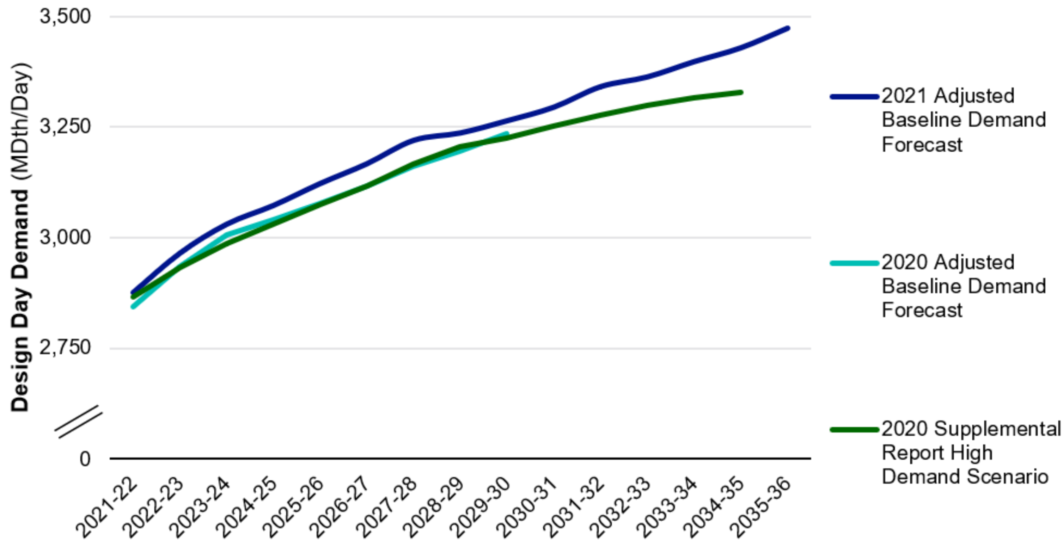
Figure 2-1: Historical Period (BackCasted) and Forecasted Downstate NY Design Day Demand



Reflective of the latest independent economic forecasts, National Grid's latest Adjusted Baseline Demand Forecast is slightly higher than the 'High Demand' forecast provided in the May 2020 Supplemental Report and the subsequent long-term gas demand forecast presented in the "National Grid Supply and Demand Analysis Related to Service Areas with Known Supply and Constraint Vulnerabilities" filed by the Company with the New York Public Service Commission (the "Commission" or the "NY PSC") on July 17, 2020, in Case 20-G-0131. The 2021 Adjusted Baseline Demand Forecast is higher in each year by an average of 40 MDth/day (or 1.3%) than the 2020 Supplemental Report High Demand Scenario over the next 10 years (see Figure 2-2 below).

[7] The backcasted (historic) period is determined as follows: each year, the Company uses regression equations to weather normalize the sendout data and the estimated demand at the Design Day standard, estimated using respective year's regression coefficients, gives the back-casted Design Day demand for that year.

Figure 2-2: Comparison of 2021 and 2020 Adjusted Baseline Demand Forecasts and 2020 Supplemental Report High Demand Scenario



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

2.6. Based on the updated Adjusted Baseline Demand Forecast, National Grid projects that a gap between total Downstate NY customer peak gas demand and available gas capacity emerges in the winter of 2022/23 and grows thereafter, before accounting for planned gas capacity projects and incremental demand reductions under the Distributed Infrastructure Solution.

National Grid has delivered every on-system supply project in our operations plan, including constructing new and expanded compressed natural gas ("CNG") transfer sites capable of delivering up to 62 MDth/Day by winter 2021/2022, and has secured additional long-term contracts for capacity on existing interstate pipelines . The total portfolio of available gas capacity (the "Existing Capacity") now stands at 2,957 MDth/day by 2022/2023 as shown on Table 2-1 below (as compared to 2,939 in the Supplemental Report).

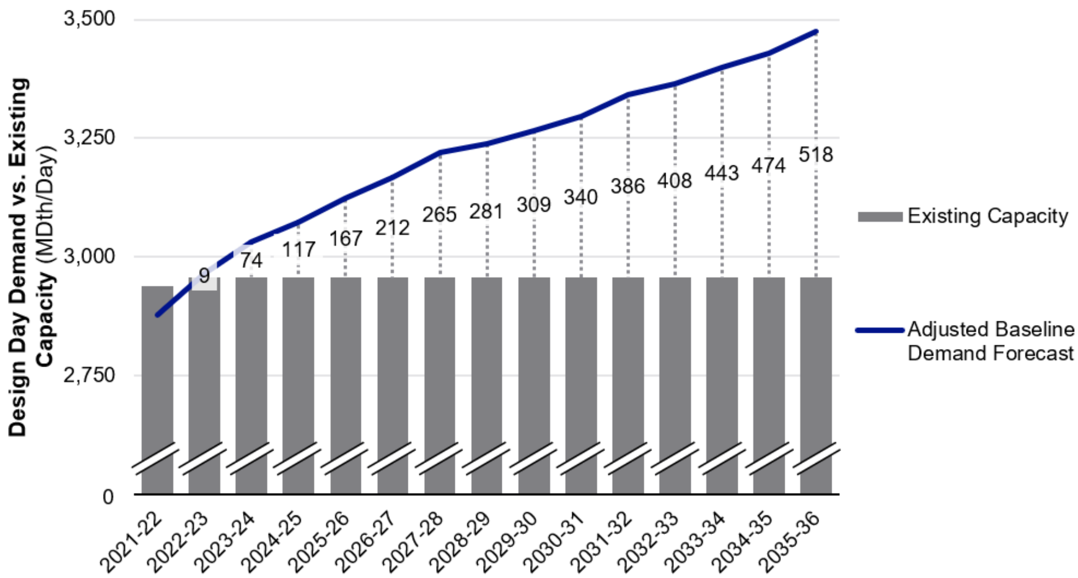
Table 2-1: Existing Capacity

Supply Stack (MDth/day)	2022 23
Long-Term Fixed Pipeline & Storage	2,377
LNG	395
Short-Term Contracted Peaking & Cogen	123
CNG	62
RNG	1
Total Gas Capacity	2,957

However, this Existing Capacity only meets customer demand through 2021/2022. Absent implementation of the Distributed Infrastructure Solution, we anticipate seeing a gap between peak period gas demand under the Adjusted Baseline Demand Forecast and Existing Capacity (the

"Demand-Supply Gap") starting at 9 MDth/day in winter 2022/2023 and continuing to grow up to a gap of 518 MDth/Day in 2035/2036, as illustrated by Figure 2-3.[8]

Figure 2-3: Projected Demand-Supply Gap before Distributed Infrastructure Solution Implementation

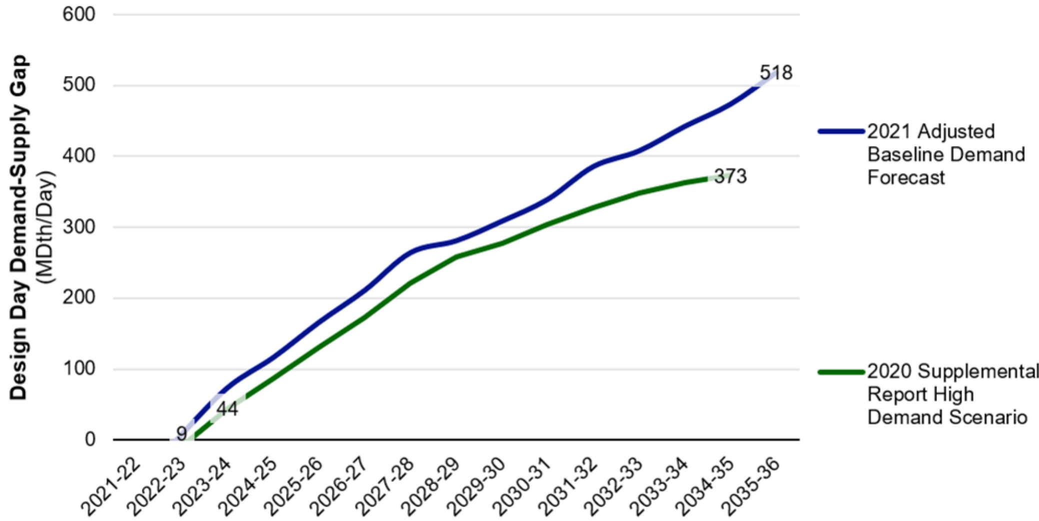


Note: Y-axis is broken to focus on gap at the margin

This Demand-Supply Gap is slightly larger and starts earlier than the projected in the 2020 Supplemental Report, even with the increased long-term gas capacity the Company has secured. This results from the shift upward in the 2021 Adjusted Baseline Demand Forecast compared to the 2020 Supplemental Report's demand forecast ("High Demand Scenario"). The first projected Demand-Supply Gap is a year earlier (2022/2023) than in the 2020 Supplemental Report High Demand Scenario; moreover, whereas the 2020 Supplemental Report High Demand Scenario projected a Demand-Supply Gap starting in 2023/2024 of 44 MDth/day, the latest projection puts the 2023/2024 Demand-Supply Gap at 74 MDth/day. This is depicted in Figure 2-4 below.

[8] This Demand-Supply Gap assumes that all existing pipeline capacity is re-contracted. Moreover, this report compares total gas supply capacity against aggregate Design Day demand for the Company's customers in Downstate NY to assess whether the Company faces a gas capacity constraint. However, the Company also must conduct detailed hydraulic modeling of its gas network jointly with Consolidated Edison annually to understand actual projected gas flows and any locational constraints or low-pressure concerns.

Figure 2-4: Demand Gap Comparison between 2020 and 2021 Forecasts



Note: in the Supplemental Report it was implicitly assumed that expiring city gate peaking and cogen capacity could be re-contracted indefinitely. That re-contracted capacity is netted out of the gap shown here to compare on a like-basis with the Supplemental Report.

2.7. Last year, National Grid determined that the Distributed Infrastructure Solution – a combination of incremental EE and DR programs and distributed infrastructure projects that expand the capacity of existing gas infrastructure – best balanced cost, reliability, and feasibility to address the projected Demand-Supply Gap. This conclusion remains unchanged.

In last year's reports, the Company presented several options to close the projected Design Day Demand-Supply Gap and, after extensive public engagement and feedback, recommended two solutions. Following rejection of the permit applications for the large infrastructure solution, National Grid focused on implementing the other of the two recommended solutions—the Distributed Infrastructure Solution.

Specifically, for the Distributed Infrastructure Solution, National Grid recommended combining: (1) incremental demand side management ("DSM") programs comprising an aggressive set of incremental EE over and above the growth in demand reduction required by NE:NY as well as new gas DR programs; (2) the LNG Vaporization Option ("LNG Vaporization Project"), which adds two additional LNG vaporizers at National Grid's Greenpoint Facility; and (3) the Iroquois Enhancement by Compression option ("ExC Project"), which involves the construction of additional compression facilities to increase capacity on the Iroquois Gas Transmission System.

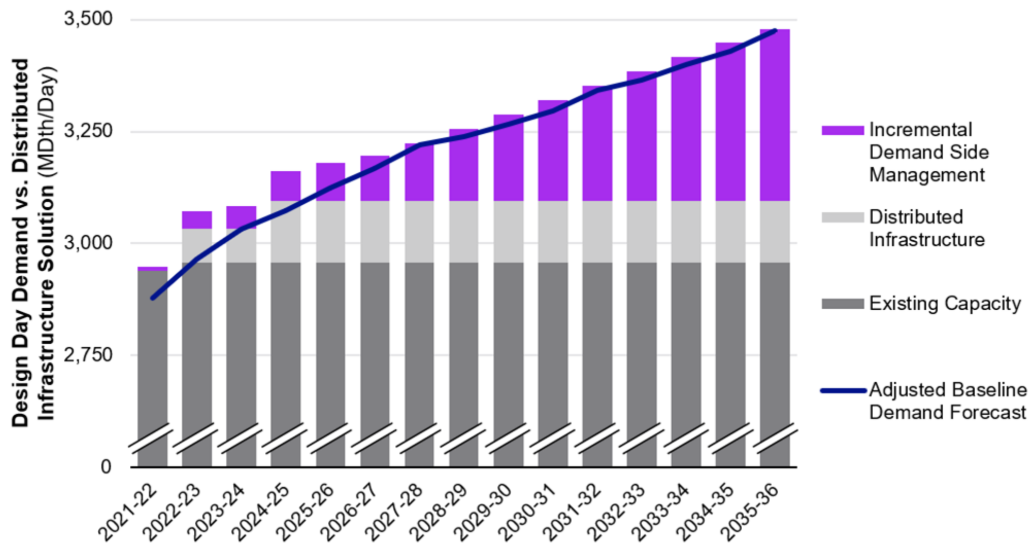
Since the Supplemental Report, the Company has updated this solution with a plan to add incremental portable CNG capacity, further expanding the largest CNG operation of its kind in the United States, which takes advantage of the maximum potential for National Grid to expand portable CNG in light of siting, operational and market constraints. National Grid also further refined the EE, DR and heat electrification components of the incremental DSM part of the Distributed Infrastructure Solution. Collectively, all of these components now make up the Distributed Infrastructure Solution as set forth in Table 2-2.

Table 2-2: Distributed Infrastructure Solution Components

Component	Gas Capacity / Demand Reduction *(MDth/day)*
Demand Side Management Programs	
Incremental EE	**Grows to 64**
Incremental DR	**Grows to 37**
Heat Electrification and NPA Market Solicitation	**Grows to ~300**
Enhanced Infrastructure Projects	
LNG Vaporization Project	**59**
ExC Project	**63**
CNG Facilities	**Grows to 80 total**

Taking into account the latest Adjusted Baseline Demand Forecast, the Existing Capacity, and the alternatives to current Distributed Infrastructure Solution components this report re-confirms that the Distributed Infrastructure Solution is the most cost-effective and lowest risk solution to our Design Day Demand-Supply Gap amongst the available options.[9] Figure 2-5: Distributed Infrastructure Solution Comparison demonstrates how the combined components of the Distributed Infrastructure Solution resolve the projected Design Day Demand-Supply Gap.

Figure 2-5: Distributed Infrastructure Solution Comparison to Supply-Demand Gap



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

[9] This solution is dependent on National Grid continuing to maximize existing contracted pipeline capacity and peaking capacity.

2.8. National Grid's Distributed Infrastructure Solution relies on the distributed infrastructure projects to close the Design Day Demand-Supply Gap in the near term; after the winter of 2025/2026, the Distributed Infrastructure Solution only deploys incremental Demand-Side Management ("DSM") programs to address the Demand-Supply Gap.

In the near term, the distributed infrastructure components of the Distributed Infrastructure Solution are the biggest components of the solution and are critically important to meeting gas demand over these next few winters as incremental DSM programs ramp up.

Nonetheless, incremental DSM programs are essential to the Distributed infrastructure Solution, which relies on gas demand reduction to meet three quarters of the projected Demand-Supply Gap in 2035/2036. In fact, the Distributed Infrastructure Solution includes no expansions of gas supply capacity after 2024/2025 and relies on incremental DSM components to offset all projected Design Day gas demand growth after 2027/2028, effectively keeping the Design Day gas demand constant thereafter (see Figure 2-6 below) such that no additional infrastructure projects beyond the LNG Vaporization Project and ExC Project would be needed.[10]

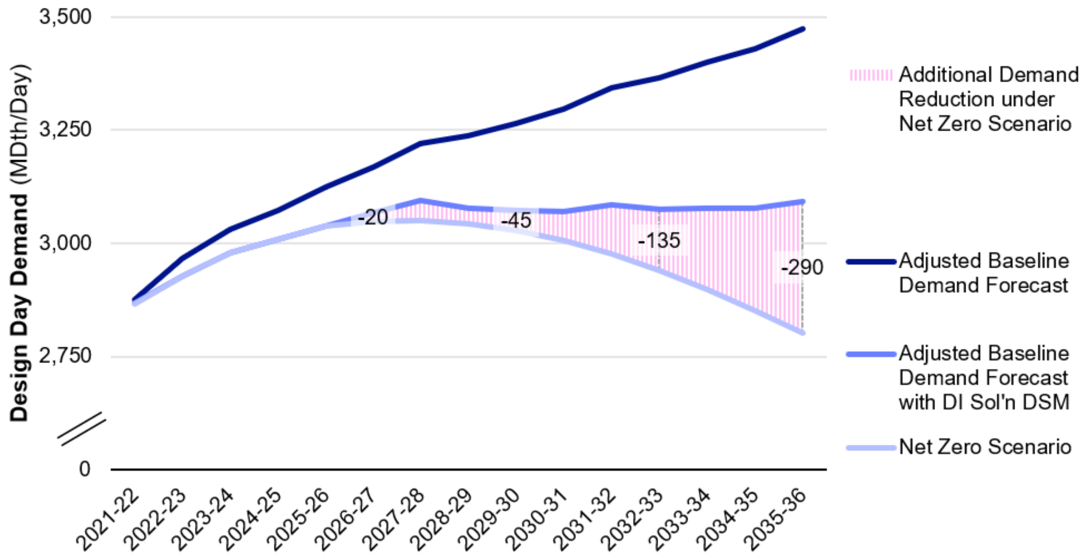
2.9. National Grid tested the Distributed Infrastructure Solution against a 'Net Zero Scenario' demand projection that assumes aggressive new policies are adopted under the CLCPA that slow, stop, and reverse the projected growth of gas demand. Measured against this scenario, the Distributed Infrastructure Solution is consistent with New York's Net Zero goals by meeting near-term customer gas demand growth while offering the flexibility to right size National Grid's gas capacity portfolio over time.

The Company leveraged work done as part of the NYC Decarbonization Study to inform a scenario in which demand for gas follows a trajectory aligned with that study's "Low Carbon Fuels" pathway.[11] This scenario (the "Net Zero Scenario") assumes new policies and programs under the CLCPA and other laws are implemented such as future gas connection bans. Under this Net Zero Scenario, after taking into account Distributed Infrastructure Solution incremental DSM, Design Day demand growth slows relative to the Adjusted Baseline Demand Forecast after 2025-2026 (taking into account implementation lag from those new CLCPA policies and programs), stops around 2027-28, and then reverses (see Figure 2-6).

[10] This report assumes all demand reduction against the Adjusted Baseline Demand Forecast is from programmatic energy efficiency, demand response, and heat electrification; however, some may also come from new codes and standards or other policies.

[11] The Low Carbon Fuels Pathway reduces emissions by reducing the use of fossil fuels through energy efficiency and some electrification and replacing remaining fossil fuels with low carbon alternatives in the buildings and transportation sectors. See https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf (page vii).

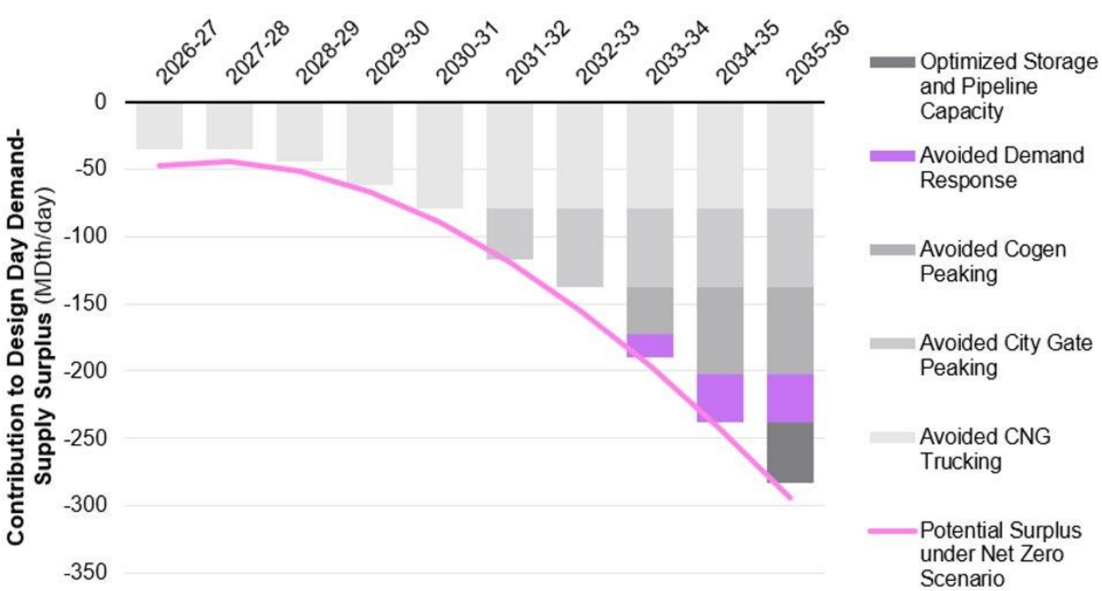
Figure 2-6: Design Day Demand Scenario Comparison



Testing the Distributed Infrastructure Solution against this Net Zero Scenario demonstrates how this solution helps enable the clean energy future by meeting customer energy demand reliably in the next several years via projects that expand the existing gas infrastructure capacity to meet customer demand and pairing those with incremental DSM programs that scale up to offset projected future gas demand growth.

The Distributed Infrastructure Solution also allows the Company to right-size natural gas supply capacity if gas demand begins to decline. As an example, in the Net Zero Scenario, the Company would be able to reduce reliance on CNG sites which would both provide cost savings and lessen reliance on a more GHG-intensive fuel. Figure 2-7: Illustrative Gas Capacity Portfolio Right-Sizing under Net Zero Demand Scenario7 depicts an example of how components of the Distributed Infrastructure Solution and today's Existing Capacity could be right sized.

Figure 2-7: Illustrative Gas Capacity Portfolio Right-Sizing under Net Zero Demand Scenario



Note: Potential surplus under Net Zero Scenario refers to a combination of Additional Demand Reduction under the Net Zero Scenario and any small surplus that was embedded in the Distributed Infrastructure Solution due to imperfect timing of supply and demand matching.

2.10. National Grid has made substantial progress implementing the Distributed Infrastructure Solution components, including the incremental demand-side programs and distributed infrastructure projects.

Since the May 2020 Supplemental Report recommended the Distributed Infrastructure Solution, National Grid has made extensive progress on implementation, including innovative program design for our DSM solutions, resulting in what will be one of the largest and most aggressive DSM programs in the State upon full implementation. The Company also quickly implemented the planned CNG sites from the last report, has advanced the LNG Vaporization Project and is supporting the Iroquois ExC Project, where Iroquois, the interstate pipeline company, is responsible for project implementation. Table 2-3 summarizes the progress the Company has made in designing and refining the Distributed Infrastructure Solution, and the current status of each component.

Table 2-3: Distributed Infrastructure Solution Progress

Segment	Progress & Status
Energy Efficiency	Designed new incremental EE programs, specifically new intensive weatherization programs and a new "Energy Efficient Connections" program to facilitate EE at the point of new demand coming on to the system - to be filed later in 2021 with the New York Public Service Commission.
Demand Response	Includes three new programs focused on daily reductions in gas consumption and more targeted and pronounced hourly reductions in peak demand; filed in mid-June 2021.
Heat Electrification and NPA	Pursuing a collaboration with electric distribution companies ("EDCs") to study the best pathway to achieve incremental heat electrification targets and supporting the EDCs' NE:NY target goals through the lead referral program. The Company will hold annual NPA solicitations to seek innovations to deliver DSM more cost effectively than traditional utility programs[12]
CNG	Increased capacity to 62 MDth/day; new capacity in development to increase total CNG capacity to 80 MDth/day
LNG Vaporization	Fully designed and engineered; extensive environmental reviews performed and public meetings held; awaiting final permits to proceed to construction
ExC Project	Iroquois submitted the project to FERC on January 31, 2020, and National Grid filed a letter in support to emphasize the need. Iroquois is still awaiting FERC approval to proceed

[12] While the NPA market solicitations do not yet add capacity to close the Demand-Supply Gap, the Company still views them as part of its Distributed Infrastructure Solution

2.11. Despite the progress made to date, the Distributed Infrastructure Solution faces challenges and risks to completion that include permitting and regulatory risk and obstacles to scaling up incremental DSM programs.

Despite the steps taken by National Grid to implement the Distributed Infrastructure Solution, the solution faces risks to successful implementation. The distributed infrastructure projects face permitting delays and the risk of not obtaining needed regulatory approvals. The incremental demand-side programs face implementation risks in terms of uncertainty of regulatory approval and funding and uncertainty of meeting targets given the ambitious levels of these programs' demand reduction targets, and the unpredictable nature of customer participation.

In particular, while only a few permits remain for the LNG Vaporization Project, the Company has experienced substantial delays in obtaining those permits and the LNG Vaporization Project is key to being able to solve for the Demand-Supply Gap in the near future. Similarly, the ExC project, which Iroquois submitted to FERC in January 2020, is still awaiting approval after a year and a half, and Iroquois is now not expected to ascertain whether it will receive all necessary permits and approvals until 2022. With the implementation lags and other risks inherent in achieving the savings under the DSM programs and the still evolving external work around Net Zero, it is critically important that these distributed infrastructure projects move forward as quickly as possible to meet the growing demands of Downstate NY.

Table 2-4 summarizes the key implementation risks for each of the individual components of the Distributed Infrastructure Solution.

Table 2-4: Key Implementation Risks of Distributed Infrastructure Solution Components

Project	Risk	Risk Likelihood	Impact	Description
Incremental Energy Efficiency	Market Resourcing Market Potential Legal and Regulatory Delays	MEDIUM	HIGH	• Lack of market resources to execute projects • Overestimation of market potential and ability to reach accelerated levels of adoption • Failure to get legal and regulatory approval of programs and their costs
Demand Response Programs	Market Potential Program Reliability Legal and Regulatory Delays	MEDIUM	HIGH	• Overestimation of market potential and ability to reach accelerated levels of adoption • If reductions are unreliable, may not have other DR program workarounds • Failure to get legal and regulatory approval of programs and their costs
Incremental Electrification	Market Resourcing Market Potential Legal and Regulatory Delays High costs	HIGH	HIGH	• Lack of market resources to execute projects • Overestimation of market potential and ability to reach accelerated levels of adoption • Heat Electrification is currently uneconomical for many customers, esp. low-income customers, and, as costs for heat electrification programs are higher than for all other demand-side programs,

				needed incentive programs would require multiple legal and regulatory approvals.
LNG Vaporization Project	Failure to obtain FDNY and DEC permits	MEDIUM	HIGHEST	• Without these permits, National Grid cannot construct the LNG Vaporization Project • The LNG Vaporization Project is deemed by the Company to be the only distributed infrastructure project that can be brought on line in time to meet projected demand
ExC Project	Failure to obtain FERC approval and subsequent state/ local permits	MEDIUM	HIGH	• Without FERC approval, and then the state and local permits, Iroquois cannot move forward with the ExC Project.
Additional CNG Facility	Inability to procure land; permitting and construction delays	MEDIUM	HIGH	• Scarcity of available land in service territory could impact the size and scale of the additional site; permitting and construction delays could impact timing of implementation.

2.12. 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 both alternative infrastructure projects and additional non-gas infrastructure options.

We have analyzed a set of contingency scenarios that capture the impacts of certain potential setbacks to the Distributed Infrastructure Solution; while not an exhaustive list, these include: permitting delays or rejection of the ExC Project, permitting delays or rejection of the LNG Vaporization Project, a combination of both, or failure of our incremental DSM programs to fully meet their targets. For each of these contingency scenarios, we quantified what projected supply-demand gaps would emerge without complete and timely implementation of the Distributed Infrastructure Solution.

Figure 2-8: Contingency Scenario Gaps by Year depicts the gaps that might occur in such scenarios (positive numbers indicate gaps). In each scenario, we are assuming that all other components of the Distributed Infrastructure Solution are fully implemented and meet their targets**.**

Figure 2-8: Contingency Scenario Gaps by Year (MDth/day)

Contingency Scenario	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
DI Sol'n in Full	-72	-105	-53	-88	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
ExC Delayed (LNG Vap on-time)	-72	-105	-53	-26	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
ExC Rejected (LNG Vap on-time)	-72	-105	-53	-26	6	35	61	45	40	38	52	42	45	45	58
LNG Vap Delayed (ExC on-time)	-72	-47	6	-88	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
LNG Vap Rejected (ExC on-time)	-72	-47	6	-29	2	32	57	41	36	35	49	39	41	41	54
ExC & LNG Vap Delayed	-72	-47	6	-26	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
ExC & LNG Vap Rejected	-72	-47	6	33	65	94	120	104	99	97	111	101	104	104	117
80% of DI Sol'n DSM	-70	-98	-43	-75	-40	-7	24	14	16	21	41	38	47	53	72

As indicated by Figure 2-8 above, the largest gaps (“contingency scenario gaps”) result from the denial of one or more of the distributed infrastructure projects. The first year a contingency scenario gap emerges is the winter of 2023/2024, even assuming completion of the incremental CNG capacity and successful implementation of the DSM programs planned as part of the Distributed Infrastructure Solution.

The contingency scenario gap analysis above and in this report compares available gas capacity and Design Day demand at an aggregate level for the Company’s entire service territory.[13] In fact, each year National Grid and Consolidated Edison engage in an extensive, detailed joint effort to conduct hydraulic modeling of their systems to reflect actual expected gas flows under Design Hour conditions. This more detailed analysis captures specific locational gas capacity constraints that the aggregate-level analysis in this report cannot identify. As such, while useful to understand risks and evaluate options, the aggregate supply-demand gap analysis above may not tell the whole story in terms of how a setback to the Distributed Infrastructure Solution would create challenges. This goes beyond just the potential for locational gas capacity constraints. For example, in the contingency scenario where the LNG Vaporization Project is delayed, a contingency scenario gap appears in winter 2022/2023. Overlaying additional setbacks (e.g., inability to expand CNG capacity or delays in meeting incremental DSM demand reduction targets) would exacerbate this gap. Under the Distributed Infrastructure Solution the incremental DSM components have time to scale up and further prove themselves (such as building out the track record for relatively new DR programs) before they are essential to ensure reliability. In contrast, with a delay to the LNG Vaporization Project, the incremental DSM component is thrust into the role of ensuring reliability years ahead of schedule.

Because we have already experienced delays in permitting our Distributed Infrastructure Solution, the likelihood of one or more of these contingency scenarios coming to pass is substantial. Faced with these contingency scenarios, National Grid has examined all available options to meet these potential contingency scenario gaps.

As a starting point, National Grid reviewed and updated the list of additional options from the Supplemental Report. We have also considered other options, including one new distributed infrastructure option.

While all the additional options described in the Original Report and the Supplemental Report continue to have potential, the Company chose to focus on distributed infrastructure and non-gas infrastructure options to close the contingency scenario gaps rather than any large infrastructure options due to the low likelihood of a new large infrastructure project being permitted, as exemplified by the rejection of the Company’s large infrastructure solution from the Supplemental Report.

To develop the most viable approach for closing a contingency scenario gap, National Grid filtered out those options that could not provide meaningful capacity contribution in the near term. The approach then analyzed the remaining options’ likelihood for successful implementation in light of legal and permitting hurdles. The Company then excluded from consideration the options where overcoming those hurdles seemed extremely unlikely. Following the filtering process, the Company’s list of options (“contingency options”) is presented in Table 2-5.[14]

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[13] This report was prepared using National Grid’s latest Adjusted Baseline Demand Forecast, which is prepared annually in June. The detailed hydraulic modeling process with Consolidated Edison relies on the latest forecasts from both companies, takes iterations over several months to complete, and cannot start until after National Grid and Consolidated Edison update their annual long-term gas demand forecasts. As such, the annual hydraulic modeling analysis was still underway at the time this report was completed.

[14] The Company considered but filtered out due to scale and/or feasibility additional seasonal peaking capacity, local RNG production, and incremental gas energy efficiency. Options filtered out due to smaller scale might be pursued as opportunities arise, such as newly identified gas energy efficiency programs or local RNG.

Table 2-5: List of Contingency Options to Solve Contingency Scenario Gaps

Contingency Options	Size *(MDth/day)*
Distributed Infrastructure Options	
Clove Lakes Transmission Loop Project	80
LNG Barge (scalable)	50 (per barge/scalable)
Micro-LNG Tank	18
Non-Gas Infrastructure Options	
Incremental DR over and above the Distributed Infrastructure Solution	Up to 44 MDth/day
Heat Electrification over and above the Distributed Infrastructure Solution	Up to 90 MDth/day

The Company considered several combinations of these contingency options, including a pure non-gas infrastructure approach, to address the various contingency scenario gaps.

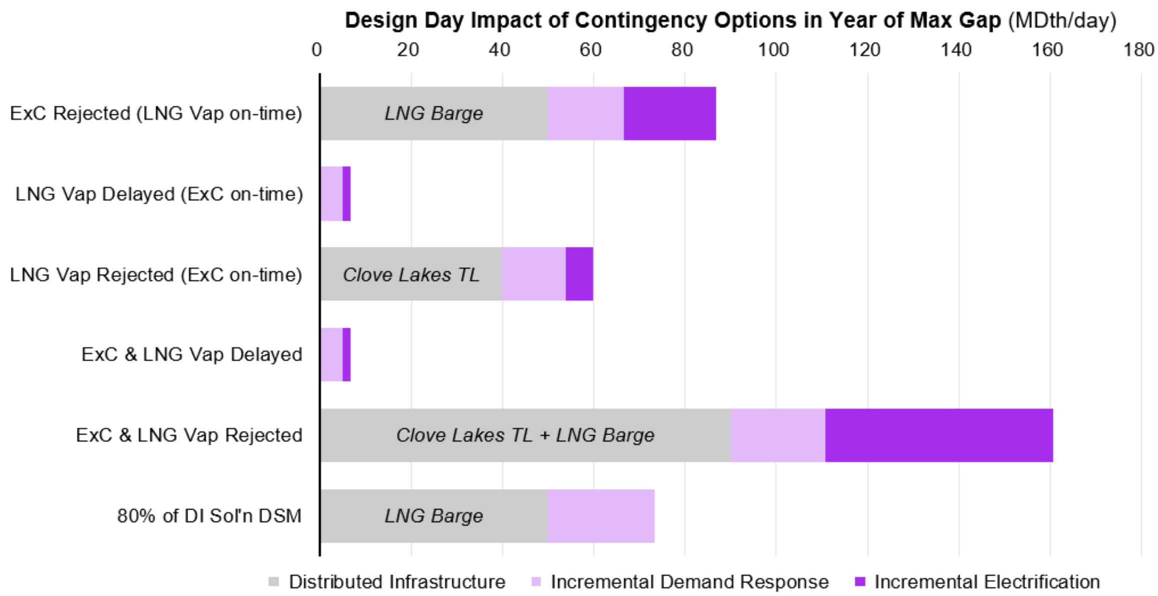
2.13. In a scenario where one or both of the Distributed Infrastructure Solution enhancements to existing infrastructure are denied, the lead time and feasibility for any alternative approach would entail significant risk that projected customer demand could not be met. The alternative approaches that best balance cost and feasibility would include incremental gas demand response and heat electrification along with substitute infrastructure projects—specifically, the Clove Lakes Transmission Loop 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.

The Company's primary factors in the evaluation of the contingency options to address contingency scenario gaps were cost, deliverability and potential for success.

Looking at the costs of the alternatives and how quickly the Company could implement the solution, taking into account engineering time and permitting hurdles, the Company assessed that, for the contingency scenario gaps resulting from delays in the implementation of either the LNG Vaporization Project or the ExC Project, the least expensive approach was a combination of incremental demand response and heat electrification. For the gaps caused by denials of either the LNG Vaporization Project or the ExC Project, the least expensive approaches included either a combination of the Clove Lakes Transmission Loop option ("Clove Lakes Transmission Loop") and/or the LNG Barge option with incremental demand response and heat electrification. In all cases, the costs of these approaches are far in excess of the costs of the Distributed Infrastructure Solution as currently planned.

Figure 2-9 depicts the approaches the Company found to be the most feasible to solve each contingency scenario gap.[15]

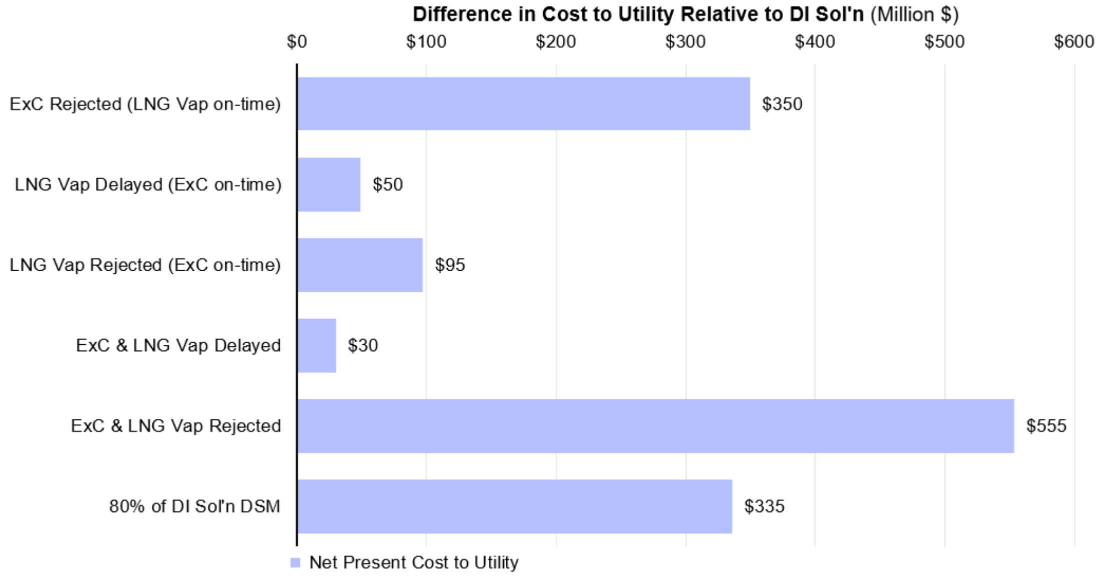
Figure 2-9: Contingency Scenarios Approaches



The costs for each of these approaches, which are the lowest for each contingency scenario, are shown in Figure 2-10 below. For example, the least-cost contingency solution to a rejection of the LNG Vaporization Project and the ExC Project would include the Clove Lakes Transmission Loop, a LNG Barge and incremental DSM and would be $555 million more expensive than the Distributed Infrastructure Solution. Over the next five years, even this least-cost alternative approach would increase total customer bills by approximately 6.6% as compared to the Distributed Infrastructure Solution.

[15] The Clove Lakes Transmission Loop is the least costly option to replace the LNG Vaporization Project if the LNG Vaporization Project is denied, as both primarily support KEDNY territory. Because ExC primarily supports the Company's KEDLI territory, if it is denied, the Company would need to look to an LNG Barge due to operational constraints related to the Clove Lakes Transmission Loop option. If both projects are rejected, National Grid would look to develop both options.

Figure 2-10: Contingency Scenario Solution Net Utility Costs



Note: Net present value of the contingency approach is lower in the case when both ExC & LNG Vap are delayed than when only LNG Vap is delayed due to the fact that ExC is constructed and paid for one year later. Though delay in ExC construction does not lead to an apparent incremental supply-demand gap in the aggregated model, it would prevent National Grid from potentially scaling down reliance on and cost of running CNG trucking, which could lead to savings not reflected in the above calculation.

In each of the contingency scenarios, an increase in investment in demand response and heat electrification programs in a very short amount of time will be necessary. Relying on a combined solution of non-gas infrastructure with distributed infrastructure in those scenarios where either the LNG Vaporization Project or the ExC Project is denied, however, was less expensive than if the Company were to attempt a pure non-gas infrastructure solution, which would be heavily dependent on a rapid scale up of incremental heat electrification efforts. For example, in the scenario where the LNG Vaporization Project and the ExC Project are rejected, relying only on an exclusively non-gas infrastructure solution instead of the least cost solution presented in Figure 2-9 would require full heat electrification customer conversions at nearly 6 times the level currently planned under NE:NY through 2025 at a current estimated total cost of $1.23 Billion.[16] This same exclusively non-gas infrastructure alternative approach would lead to average total customer bills nearly 10% higher than under the Distributed Infrastructure Solution through 2025. The contingency scenarios approaches are also relying heavily on demand response; in particular it would require significantly reducing (by as much as 50%) the historic migration of existing demand response non-firm customers (dual fuel customers) to firm rates and converting as many as 10-15% of existing firm customers to demand response non-firm customers. This is not an easy task considering this historic migration to firm rates is driven by broad market trends and regulatory policy changes (e.g., bans on certain types of heating oils) which have a broad range of financial, regulatory and logistical implications.

As indicated by Figure 2-10, all of the alternative approaches to the Distributed Infrastructure Solution come at a higher cost – between an incremental $30M and $555M in net present value depending on the contingency scenario. These alternative approaches also carry more feasibility risk than the Distributed Infrastructure Solution. Both the Clove Lakes Transmission Loop option and LNG Barge option would likely face difficult permitting hurdles, as evidenced by the difficulties the Company has faced with the current projects. The incremental demand response and heat electrification options also carry uncertainty due to being reliant on extensive customer participation. Timing is another concern, as any alternative approach would need to meet highly aggressive and

[16] Section 7.3 contains a complete discussion of the potential contingency solutions and their costs.

challenging timelines for approvals and implementation to successfully address a contingency scenario gap.

2.14. Customer curtailment is the option of last resort for maintaining system reliability if the Company cannot meet customer demand growth in the face of the timing and feasibility challenges of an alternative approach to the Distributed Infrastructure Solution and if even restrictions on new customer connections cannot sufficiently reduce customer demand.

If the Distributed Infrastructure Solution cannot be fully implemented in a timely manner, there may be a need for a targeted or more widespread pause in new customer connections. There is a risk that even restrictions on new customer connections could prove insufficient to avoid all projected Design Day demand growth. In the event that available gas supply capacity cannot meet customer demand during peak conditions, the Company would need to rely as a last resort on the Company's customer curtailment plan, starting by interrupting service to large commercial and industrial customers and potentially shutting off sections of its gas network affecting large numbers of homes and businesses.

2.15. The Company continues to seek new supply/demand options, including through market solicitations for Non-Pipeline Alternatives (NPAs) and Innovative Supply-Side Proposals to meet our customers' needs and New York's Net Zero goal.

National Grid continues to exhaustively consider all options for meeting projected customer needs. In addition to the options evaluated in the Original Report, Supplemental Report, and now this report, the Company is looking externally to market innovators to uncover any additional options that can be deployed. To this end, National Grid is soliciting ideas on both the non-traditional gas supply side and on the demand-side from a wide array of competitive and innovative technology and energy companies.

National Grid has issued a request for information (RFI) for innovative supply-side options, expected to yield proposals related to RNG, CNG and LNG options for consideration, and will be issuing its first NPA request for proposals (RFP) later this year. The Company is also advancing new models for gas utility delivery of clean heating solutions and studying the potential for innovative new technologies on the demand side.

The Company welcomes new ideas and innovative solutions in response to its RFIs, RFPs and this report. The Company can fold new options identified via these market solicitations into the overall Distributed Infrastructure Solution as appropriate.

2.16. In conclusion, National Grid confirms that the Distributed Infrastructure Solution remains the best available solution to resolve the projected Demand-Supply Gap, and National Grid welcomes stakeholder feedback on this finding and its evaluation of the alternative approaches.

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.

To date, National Grid has made progress on implementation of the Distributed Infrastructure Solution, but the Distributed Infrastructure Solution faces real risks in the form of permitting delays or denials. There is a material risk for pauses in the Company's 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 LNG Vaporization Project or the outright rejection of that 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.

The Distributed Infrastructure Solution builds on New York's current, ambitious gas energy efficiency and heat electrification programs and targets with its incremental DSM . Moreover, the Distributed Infrastructure Solution addresses near-term reliability needs while providing the flexibility to right-size National Grid's gas capacity portfolio over time as additional Net Zero policies and programs change the gas demand outlook.

Reinforcing this assessment of how the Distributed Infrastructure Solution aligns with Net Zero, National Grid has committed, in keeping with a joint proposal (the "Joint Proposal") filed with the Commission on May 14, 2021 in the currently pending KEDNY/KEDLI rate case (Cases 19-G-0309 and 19-G-0310), to a number of additional reports evaluating how the Company's business may further evolve to support the goals of the CLCPA, NYC's Local Law 97 and the Company's Net Zero Plan.

In Case 20-G-0131, the Commission will establish a new process and requirements for long-term planning by New York's gas utilities. The anticipated requirements for National Grid to prepare regular long-term plans and conduct related stakeholder engagement will build on this Second Supplemental Report and provide ongoing transparency and opportunities for stakeholder feedback. This enhanced approach will help ensure that the Company's long-term plan continues to align with New York's Net Zero goal and emerging policies and programs..

As with the Original Report, we invite readers to provide feedback on this Second Supplemental Report and the analysis and conclusions contained herein. The Company also welcomes creative ideas and innovative solutions to its market solicitations for both the supply-side and demand-side proposals described above. In addition to filing the Second Supplemental Report with the Commission, we will be publishing this report on our website and will deploy other options for sharing the report with stakeholders, including a virtual meeting.[17]

[17] The Second Supplemental Report and related content, including the details for providing stakeholder feedback, are available at: https://ngridsolutions.com/.

3. National Grid's Natural Gas Networks and Net Zero

3.1. NYS and NYC's Evolving Policy Context

On July 18, 2019, Governor Andrew M. Cuomo signed into law the Climate Leadership and Community Protection Act (CLCPA), one of the most ambitious climate laws in this country, requiring New York to reduce economy-wide GHG emissions 40% by 2030 and no less than 85% by 2050 from 1990 levels. In April of that same year, New York City passed Local Law 97 ("Local Law 97"), requiring a reduction in GHG emissions from large buildings (>25,000 sq. ft) by 80% by 2050. In February 2020, Mayor DeBlasio issued Executive Order No. 52 to limit expansion of fossil fuel infrastructure in New York City, followed by an announcement in January 2021 to seek an end to new gas connections in new construction by 2030, with subsequent NYC city council introduction of legislation in May 2021. In March 2020, the Commission launched its gas planning proceeding (Case 20-G-0131) to ensure alignment of natural gas planning processes with forward-looking system and policy needs, including standards for potential moratoria on new customer additions.

Currently, the CLCPA-established NY State Climate Action Council (CAC or Council) is in the process of creating a scoping plan for the CLCPA's emissions reductions, to be filed with the governor and legislature at the end of 2022. Draft recommendations from the Council's advisory panels include, among other things, future prohibitions on both new gas customer connections and gas equipment replacement. We anticipate seeing regulatory and legislative actions initiated in accordance with the Council's final scoping plan beginning in 2023, with potential effective dates in the 2025-30 timeframe and beyond. In NYC, Local Law 97 implementation will include recommendations from the Advisory Board due January 1, 2023, with the first building emissions limits going into effect in 2024.

3.2. National Grid's Commitment to Advancing Net Zero GHG Emissions

National Grid recognizes climate change as a defining challenge of our time. The decisions we take now will influence the future of our planet and life on earth, and we know we must make significant changes to curb harmful emissions. In October 2020, National Grid plc published the global Responsible Business Charter, reflecting both our commitment to reduce GHG emissions from our direct operations to Net Zero and our ambition to reduce emissions from selling gas to our customers consistent with targets in our jurisdictions.[18] At the same time, we recognize that economy-wide energy transformations will require unprecedented efforts by all of society, and that the implications of these transformations for our customers – including required investments, changes in uses of technology, and transition costs — are not yet fully understood.

Our US Net Zero Plan, also published in October 2020, identified 10 major focus areas for advancement of Net Zero goals for our US operations and the energy we deliver to customers.[19] Among those 10 major focus areas, 5 specifically address the Company's gas networks; namely:

- Reducing gas demand through energy efficiency, demand response, and non-pipeline solutions;
- Decarbonizing the gas network with renewable natural gas and hydrogen (i.e. reducing carbon intensity of delivered gas);
- Reducing methane emissions from our own gas network and the entire value chain;
- Integrating innovative technologies to decarbonize heat (e.g. heat electrification, hybrid gas-electric heating systems, and geothermal district energy systems); and

[18] https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf
[19] https://www.nationalgridus.com/media/pdfs/our-company/netzeroby2050plan.pdf

- Investing in large scale carbon management.

These focus areas will be critical to advancing state and municipal climate policies to reduce building sector emissions in New York, in tandem with the scale-up of renewable power generation across New York State to reduce the carbon intensity of the region's electric supply.

To develop further insight into key actions needed to advance Net Zero for New York City, National Grid recently collaborated with Con Edison and the Mayor's Office of Sustainability on a multi-year study effort, entitled "Pathways to a Carbon-Neutral NYC," (the "NYC Decarbonization Study")[20] published in April 2021. The study assessed three pathways: Electrification, Low Carbon Fuels and Diversified, and all of them achieved at least 80% emission reductions by 2050.

Key points from the study pathways include:

- Energy efficiency (EE) measures are aggressive; at least 90% of the buildings in NYC will go through some level of EE measure.
- Electrification of heat ranges from 30% (Low Carbon Fuels Pathway) to 62% (Diversified Pathway) of NYC buildings. This translates to a range from 340,000 to 642,000 buildings in NYC with electric heating systems (average weekly conversion rate from today to 2050 ranging from approximately 225 to 425 buildings)
- Total gas demand across all sectors decreases by at least 60% across all the pathways by 2050. However, the gas network has an enduring role: i.e. heat electrification does not go above 62% of NYC buildings even in the Diversified Pathway. Hybrid heating systems (electric heat pumps with gas backup for the coldest days) play a key role in meeting heating needs for many types of buildings, as well as reducing incremental electric peak network costs.
- The gas network in NYC not only supplies an enormous amount of energy today (three times more energy on its peak day in winter than the electric network delivers on its peak day in summer), but it also plays an integral role in reducing emissions: The network transitions and supply sources shift away from geological gas towards low carbon gas, mainly RNG from existing biomass sources and hydrogen from renewable electricity, for end uses that do not electrify. Thanks to the carbon benefits of RNG and green hydrogen, the emissions reductions available to the building sector through the use of Low Carbon Fuels are larger than that in the Electrification pathway.
- Low-carbon fuels also help to mitigate the amount of incremental electric system capacity (generation, transmission and distribution) required in the Electrification pathways. In the Electrification and Diversified pathways, NYC's electricity system transitions from a summer-peaking system to a winter-peaking system, and the peak demand rises from the current 11 gigawatts (GW) to 14.5 GW. In the Low Carbon Fuels pathway, peak power demand in 2050 stays at the same level as today.
- Notably, with regard to the subject of this Second Supplemental Update, the NYC Decarbonization Study did not forecast annual expected gas demand reductions for purposes of reliability planning.[21] The study provided high-level potential trajectories for demand over the next three decades to 2050 for purposes of differentiating policy choices between the modeled pathways, rather than providing a reliable estimate of year-by-year demand changes. Utility-specific forecasts, such as the demand forecast in this Second

[20] https://www1.nyc.gov/site/sustainability/our-programs/carbon-neutral-nyc-pr-04-15-2021.page

[21] The discussion on page 27 of the NYC Decarbonization Study explains how the study should be considered in relation to utility demand forecasting and reliability planning efforts.

Supplemental Report, will continue to account for the likely incremental change in demand as policies and programs to achieve NY State and NY City goals are put in place. These forecasts do not directly mirror the trajectories in the study, as the programs, policies, and their subsequent results will continue to develop over time and at a pace that may be different than assumed in the NYC Decarbonization Study.

Based on National Grid's Net Zero Plan and the results of the NYC Decarbonization Study, our vision for our New York gas networks in 2050 is one in which the gas network delivers a smaller volume of fuels with a very low carbon intensity and is fully integrated with a very low-carbon electricity network. The gas network will play a fundamental role enabling the electricity network by helping balancing very significant amount of offshore wind and solar capacity. In addition, the gas network will also function as a storage system converting curtailed renewable power, during low power demand or high supply, to green hydrogen.

3.3. What We Are Already Doing to Reduce GHG Emissions in New York

The Company has already taken strides in many important areas for the benefit of our Downstate NY gas customers and stakeholders to reduce GHG emissions in line with our Net Zero Plan.

i. Reducing gas demand through energy efficiency, demand response, and non-pipeline solutions

Along with other utilities and NYSERDA, we have helped New York consistently rank in the top 5 most energy-efficient states in the nation.[22] In April 2019, we filed our plan to deliver on the goals of the New Efficiency New York (NE:NY) program, which supports the CLCPA's 2025 goal.[23] Under NE:NY, National Grid's annual gas energy efficiency savings targets grow by more than three-and-a-half-fold from 2020 to 2025. And, last year, the Company exceeded customer enrollment targets for our demand response programs for 2020/2021. These programs, combined with NYSERDA's and other utilities' energy efficiency efforts, aim to achieve annual incremental gas energy efficiency savings equivalent to 1.5% of demand every year going forward. As part of these plans, we have committed to spending 20% of incremental efficiency funding on income-eligible customers (such as no-cost home weatherization), with 40% of that program spending targeted to affordable multi-family buildings.

In addition, in the proposed rate case settlement recently reached, i.e. the Joint Proposal, the Company has committed to reducing billed gas usage, normalized for temperature, over the term of the rate plan by one half of one percent as compared to the currently forecasted usage. In that settlement the Company has also agreed to terminate all gas promotional and rebate programs (such as for heating oil-to-gas conversions), to conduct a study of how the Company's businesses may evolve in the future to support the goals of the CLCPA and Local Law 97, and to conduct a study of the depreciation impacts of climate change policies and laws on our gas assets.

ii. Reducing carbon intensity of delivered gas through the use of renewable natural gas and hydrogen

National Grid will soon be injecting additional RNG from wastewater and food waste through our partnership with NYC and its largest wastewater treatment plant, Newtown Creek.

[22] American Council for an Energy-Efficient Economy; https://www.aceee.org/state-policy/scorecard
[23] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={84413E33-C5B2-492B-BE1D-39A5A2CEFFBF}

To support the growth of RNG production in NY, we have collaborated with industry stakeholders to develop a set of interconnection guidelines addressing gas quality standards for RNG,[24] helping support additional RNG projects in preparing to deliver to our network.

In addition to the near-term opportunity provided by RNG, we are laying the foundation for the integration of hydrogen into our gas network through blending with natural gas and potentially delivering up to 100% hydrogen to some customers in the future. We are supporting national hydrogen research efforts in the US, in parallel with efforts underway in the United Kingdom with National Grid UK. Our company is a lead sponsor of the US Department of Energy's HyBlend Project, a major national effort exploring the ability to blend hydrogen into gas utility networks.[25] This builds on a local collaboration we have developed with NYSERDA and Stony Brook University which has been investigating hydrogen blending potential since 2019.

iii. Reducing methane emissions from our gas networks and the entire value chain

By 2030, we anticipate that methane emissions from our infrastructure will have reduced by 80% against a 1990 baseline. Through our gas main replacement programs, we are replacing approximately 170 miles per year of aging cast iron and unprotected steel gas mains with polyethylene plastic pipe. In parallel, we are improving how we identify, prioritize and repair large system leaks, integrating advanced leak detection technology and industry-leading work procedures. We have also led efforts with an industry group of upstream gas suppliers to reduce leakage across the value chain from wellhead to burner tip, and to establish environmental and social performance indicators for gas production.

iv. Integrating innovative technologies to decarbonize heat (e.g. heat electrification, hybrid gas-electric heating systems, and geothermal district energy systems)

As the NYC Decarbonization Study showed, electrification of heat with low-or-zero carbon electricity is a key part of the future of energy in NY. Under the NE:NY programs, the NY electric utilities (including our Niagara Mohawk Power affiliate in upstate New York) are providing rebates for air-source or ground source heat pumps, with ambitious targets funded in the 2019-25 energy efficiency program plans, under the NYS Clean Heat program. In downstate New York, National Grid is partnering with the NY electric utilities to provide them with customer leads for heat pump adoption to help them meet their heat electrification targets, which can offset gas demand growth on our networks.

We are also advancing a new model for gas utility delivery of clean heating solutions, through renewable district heating networks using geothermal energy. Our demonstration project in Riverhead, Long Island, used a shared geothermal loop system to provide lower-carbon heating and cooling service to a residential development, demonstrating the potential for a regulated geothermal heating and cooling service. We have proposed expanded demonstration programs in our downstate New York gas distribution rate case and the Niagara Mohawk rate cases and will continue to work toward the advancement of a regulated district heating business model with appropriate regulatory oversight as part of the puzzle of meeting our NY customers' energy needs.

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[24] https://www.nationalgridus.com/media/pronet/nga-interconnect-guide-for-rng-in-nys.pdf
[25] https://www.nationalgridus.com/News/2020/12/Accelerating-Hydrogen-Blending-to-Decarbonize-Heat/

3.4. Making Choices Consistent with Net Zero

The Company realizes that studies and steps like those above are just the beginning of an essential journey over the next three decades to reach Net Zero in New York.

Transforming New York's electric and gas systems to achieve Net Zero will require new technologies, energy policies, utility regulatory models, and new types of investments, many of which are still in early stages of development. The NYC Decarbonization Study noted, for example, that such factors as "technology availability, implementation feasibility, cost, future policies and customer preferences are highly uncertain" at this time.

National Grid is working together with our communities, policymakers, and stakeholders to help meet the challenges of decarbonization, and committed to making decisions consistent with Net Zero. We recognize the need for all stakeholders in New York, including ourselves, to do things differently in order to realize the energy transition.

Our proposed Distributed Infrastructure Solution helps to serve these goals by offsetting the projected growth in customer gas demand via incremental gas energy efficiency and demand programs while increasing available gas supply via projects that expand the capacity of the existing gas infrastructure, creating the flexibility to transition that existing infrastructure in the future to lower carbon fuels. In a Net Zero future, gas infrastructure can be repurposed through the integration of RNG from biomass sources and green hydrogen. As noted in the NYC Decarbonization Study, due to the carbon benefits of RNG and green hydrogen, the emissions reductions available to the building sector through the use of low carbon fuels are larger than that in an Electrification only pathway. The advantages of repurposing gas infrastructure for low-carbon fuels to enable Net Zero were similarly identified in the April 2021 study from the Columbia University Center on Global Energy Policy, "Investing in the US Natural Gas Pipeline System to Support Net-Zero Targets."[26]

National Grid has tested the robustness of the Distributed Infrastructure Solution against multiple demand scenarios in light of the potential for new policies under the CLCPA that affect gas demand growth. The Distributed Infrastructure Solution allows the Company to right-size natural gas supply capacity as new CLCPA policies begin to be realized. In other words, it allows the Company to reduce and remove elements from the Distributed Infrastructure Solution as demand decreases. As an example, the Company would be able to reduce its reliance on CNG sites as demand decreases, which would provide both savings and lessen reliance on a more GHG-intensive fuel. .

In parallel with the Distributed Infrastructure Solution, the company recognizes the need for continued rapid advancement of policies and market development for technologies and customer solutions required to reduce gas demand.

While some important decisions about our energy choices and infrastructure still lie ahead for policymakers and regulators in New York, as well as significant changes required by our customers to advance the energy transition, our Distributed Infrastructure Solution as outlined in this Second Supplement Report supports that transition to Net Zero.

[26] See https://www.energypolicy.columbia.edu/research/report/investing-us-natural-gas-pipeline-system-support-net-zero-targets.

4. Planning for Reliability/ Meeting Customer Needs

4.1. National Grid's Obligation to Serve and the Risks of a Limited Supply of Gas.

Pursuant to the Public Service Law and other applicable laws and regulations, National Grid has a duty to provide service to qualifying applicants in our service territories. Therefore, for both residential and non-residential applicants, National Grid is required to connect and service all customers that request gas service in Downstate NY unless precluded by certain conditions, such as the incomplete construction of necessary facilities, insufficient supply, or considerations for public safety.

While it is critically important that we provide this gas service to all customers in a safe, reliable manner, recent and continued growth provides a challenge. Today, we provide natural gas service to more than 1.9 million customers – 1.3 million throughout Brooklyn, parts of Queens, and Staten Island, and 0.6 million across Long Island. Over the last 10 years, the number of natural gas customers has consistently grown by about 12,000 customers per year, including in 2017, 2018, and 2019 when Downstate New York population fell and in 2020, during the COVID-19 recession. This customer growth – all residential and large multifamily heating and new commercial customers – drove a 2.1% average annual rise in gas demand during peak usage periods between 2009/2010 to 2019/2020. Because these increases have occurred without a corresponding increase in the available gas capacity, the Company faces gas capacity constraints on our Downstate NY gas network.

During periods of peak demand – the coldest days in winter – if there is not enough gas supply running through the network, there is a risk that the gas pressure will get too low and heat and other end-use equipment will stop working for customers. In these circumstances, the only way to prevent this from occurring and ensure customer safety is to interrupt service to customers, which could ultimately involve having to shut off gas to customers in constrained areas of the distribution network so the remaining areas maintain enough pressure. The Company refers to this as "customer curtailment," and it is only implemented after all other operational contingencies have been exhausted.

Shutting off areas of the distribution network due to insufficient natural gas during periods of peak demand leaves impacted customers without heat when they need it most. These gas outages are longer than a typical electric blackout that results from demand exceeding what the electric system can deliver, with more challenging consequences. For example, gas outages require labor-intensive responses and mass-mobilization of resources as they require customer-by-customer meter shutoffs and restorations. Also, during service restoration a technician needs to enter customer premises to relight appliances. As a result, it is common for full restoration of the gas system to require an extended period of time to complete with the length of time dependent on the number of affected customers, but potentially being a week or longer. Further, a gas outage can have unforeseen impacts on the electric distribution system. If an outage coincides with high gas demand due to cold weather, the loss of space heating poses a threat to public safety requiring speedy deployment of alternative heating equipment (in the form of electric space heaters) and relocation of vulnerable residents. The mass deployment of electric space heaters can lead to periods of time where electric supply cannot fulfill electric demand. For cold weather restorations where electric space heaters are deployed, it is important that the electric service provider has sufficient and reliable capacity and can coordinate with the gas provider to ensure the electric system is not overloaded.

The Company has taken extensive measures to address its near-term capacity concerns following the Settlement Agreement in Case 19-G-0678[27], including adding supply capacity through CNG and dedicating over $8 million in shareholder funds toward energy efficiency and demand response.

Based on the foregoing, it is critically important that we plan ahead for natural gas demand and ensure that we have appropriate ongoing supply to meet customer needs. There are significant lead times for adding supply infrastructure as projects need permits, engineering design, and construction to bring new capacity online. Likewise, programs to increase energy efficiency, reduce peak demand, and increase the use of alternative energy sources take time to fund, implement, and ramp up. This Second Supplemental Report is part of the process, providing an analysis of expected natural gas demand, how that compares to existing gas capacity, the progress made implementing the Distributed Infrastructure Solution to meet projected customer demand, and an evaluation of the next-best alternatives thereto.

4.2. 15-Year Outlook Consideration

As stated in the Original Report, effective planning requires a thorough evaluation of future needs, typically over a horizon that extends out for at least 10 years. Such planning takes into account:

- Long lead times for infrastructure;
- Time required to ramp up DSM programs;
- Scale efficiencies for investment; and
- Evolving policies and programs that affect gas demand in the long term

For these reasons, as the Company did in the Original Report, we have forecasted ahead for a period of approximately 15 years, through the winter of 2035/2036.

4.3. Gas System Planning Considerations and Assumptions

A comprehensive gas system planning analysis requires the utility to look at several elements:

Planning Standards: National Grid plans and designs its gas distribution system and its natural gas capacity and supply to meet forecasted demand on a "Design Day" (*i.e.*, the coldest winter day and thus highest customer demand for which the Company plans). National Grid models the Downstate NY gas supply and distribution requirements based upon a Design Day average temperature of 0° Fahrenheit in Central Park (65 Heating Degree Days).[28] The Company does not carry a reserve margin for its gas system, as compared to the electric system, which carries an installed reserve margin (currently 20.7% in New York).[29] As such, if demand exceeds supply on the gas system, it is very likely that some customers would lose service for extended periods of time. This can happen if demand exceeds the Design Day forecast on the gas system due to extreme weather, or if supply is

[27] 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*, Settlement Agreement approved by order dated November 26, 2019.

[28] A heating degree day compares the mean outdoor temperature recorded for a location over a 24-hour period to a standard temperature, 65° Fahrenheit in the United States. The lower the outside temperature, the higher the number of heating degree days. For example, a day with a mean temperature of 40°F has 25 HDD. Two such cold days in a row have a total of 50 HDD for the two-day period. See "Units and Calculators Explained: Degree Days," U.S. Energy Information Administration, available at https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php.

[29] In their Gas System Planning Process Proposal, Staff contemplates that the utilities will plan for a margin of error of approximately +/- 2 % around forecasting. See Staff Gas System Planning Process Proposal filed February 12, 2021 in Case 20-G-0131, page 16. If adopted, the Company's demand gap may increase even further than shown in this Second Supplemental Report.

reduced by limits on the availability of the interstate pipeline system or the portfolio of supply contracts,[30] a failure of on-system supply assets (*e.g.*, LNG or CNG), or issues with third-party energy marketers meeting their delivery obligations.

Demand Forecast: National Grid annually develops a long-term demand forecast so that it can plan to meet its customers' needs. This is described in detail below.

Supply Portfolio: National Grid develops its gas supply portfolio to ensure it will have sufficient supply to meet gas demand for the entire Design Day. Within the Design Day, we are also required to ensure there is enough capacity during peak hours – *i.e.*, when maximum gas is consumed as customers turn up their thermostats, cook, and use gas for hot water heating. This typically occurs in the early morning hours (6–10 a.m.) and again in the evening (4–8 p.m.). To ensure we can provide the gas needed by our customers during those time periods, we look at our supply needs during what we refer to as Design Hour. National Grid historically uses a conversion rate of 5% to go from Design Day demand to Design Hour (*i.e.*, Design Hour is 5% or 1/20th of the total Design Day demand).

System Configurations: The Company also ensures its distribution system can deliver gas while maintaining pressure to meet Design Day and Design Hour need. This includes planning investments in the gas distribution network to provide distribution capacity sufficient to meet Design Hour demand. If demand exceeds the Design Day or Design Hour requirements (for example because it is colder than the Design Day Criteria), it is likely that the Company would not be able to deliver gas to all customers. In such instances, the Company's tariffs allow us to temporarily curtail or interrupt gas service, as well as implement operational flow orders, to prevent outages or other unsafe operating conditions. These curtailment plans which are intended to avoid consequential outages when customers would go without heat in extreme cold are described below.

Potential Solutions: When analysis of the Company's gas demand forecast, supply portfolio, and system configurations identify gas capacity constraints, the Company evaluates a range of potential solutions spanning gas supply, gas infrastructure, and non-gas infrastructure solutions, such as energy efficiency, demand response, and heat electrification.

Curtailment Plan

For the electricity system, if demand increases beyond what the system can deliver, as a last resort, that imbalance can be resolved via rolling blackouts, which may be used, for example, on extremely hot days. Such rolling blackouts are usually relatively brief events measured in hours. Similarly, gas utilities can use customer curtailment as a last resort option to balance demand and supply and ensure system and customer safety. However, in contrast to electric rolling blackouts, gas customer curtailments can lead to extended loss of service for customers. Re-lighting customers is labor-intensive and can take an extended period of time to restore full service depending on the scope of the outage. This means leaving customers without heat or hot water on the coldest days, with implications for public health and safety. It is for this reason that it is prudent to plan the gas system for the extreme cold, even though it does not occur frequently. Similar to the focus among utilities, regulators, and municipalities on network resiliency when it comes to modernizing our systems by storm hardening them to withstand a minimum of a 1:100-year flooding event, being prepared for extreme temperatures is something that must be considered when designing our systems.[31]

[30] As demonstrated by events of this past winter, such disruptions can occur regularly with potentially significant implications on the gas supply to the region.

[31] Following Superstorm Sandy, the Company was challenged to consider the impacts of increasingly severe weather in its storm hardening programs and system design. The City of New York has suggested the Company should consider the Federal Emergency Management Agency's 100 and 500-year flood zones in its storm hardening planning for the gas network.

National Grid maintains a complete operations plan for the event that demand outpaces supply on the system. The plan, which has three main elements, was originally conceived for scenarios with an unexpected loss of supply where an upstream transmission asset goes out of service, but the plan would also apply to potential extreme cold conditions where the Company projected that customer demand exceeded available supply. The Company would only pursue this kind of curtailment scheme after exhausting all other operational contingencies.

The three elements would be pursued in order, and the Company would only progress to the next if it is necessary. First, the Company would call for Voluntary Load Reduction ("VLR") using pre-recorded messages which may ask customers to lower their thermostats to 65 degrees, for example. If the VLR does not deliver the necessary relief, the Company would pursue targeted *involuntary* curtailment according to its Strategic Supply Interruption Plan ("SSIP") in the second element of the plan. In accordance with Commission direction about customer prioritization, the Company has compiled, and mapped in its GIS model, the 5,000 largest C&I customers in both KEDNY and KEDLI excluding all critical customers such as hospitals, nursing homes, and public safety (police and fire departments and detention) facilities. The Company would notify customers subject to SSIP before dispatching field crews to manually shut off service at the meter, which may take 24-48 hours to shut off the 500 largest accounts. The Company would move from the 500 largest accounts to the next 500 largest accounts, and so on so that it prioritizes the largest potential reductions that impact the smallest number of customers first. The Company estimates that fully implementing the SSIP for the largest 500 customers in KEDNY could reduce demand by approximately 65MDth/day. Finally, if the SSIP does not lower demand sufficiently, the Company would pursue its Emergency Gas Outage Management Plan ("EGOMP") where field crews would isolate sections of the system to shed load on a locational basis. This would have the effect of curtailing service to large numbers of customers in specific geographic areas, including households and businesses beyond the large accounts included in the SSIP.

National Grid has prepared to implement our curtailment plan with both internal workshops and exercises with internal and external parties. The Company introduced the plan with three workshops in late 2019 at which it introduced a scenario with stakeholders and worked through areas of concern to refine and improve the plan. Beginning in February 2020, National Grid hosted six different tabletop exercises to test the Incident Command Structure. The largest such exercise, modeling a Design Day incident where a lateral serving 30,000 went out, included representatives from the NYC Mayor's Office, NYC OEM, NYS DPS, FDNY, NYPD, NY/NJ Port Authority and NYCHA. However, the implementation risks of the SSIP and the EGOMP, including but not limited to manual processes, inclement weather, customer communications, other external coordination and safety, are very high.

This process is conceptually similar to the one pursued by independent system operators on the electric transmission network who first call all available resources, including demand response before moving into load shedding events. However, the recovery process from disconnecting customers or areas of the system on the gas network is much lengthier than on the electric system since time- and labor-intensive intervention at each customer premise is required to safely resume service.

4.4. Demand Forecast

4.4.1. Design Day Standards

As noted above, the Company's Design Day standard is based on a 24-hour period with an average temperature of 0 degrees Fahrenheit in Central Park (65 Heating Degree Days). As in the Original

Report, the demand forecast presented in this Second Supplemental Report is based on the Company's Design Day standard.

In response to the Original Report, the Company received a number of public comments challenging the Company's Design Day standard. The key challenge was the argument that the Company's Design Day standard is overly conservative, since Central Park has not experienced a zero degree average temperature day since 1934. In response to the concerns raised, the Company's Supplemental Report provided a deeper analysis of the factors involved in changing the Design Day, including Design Hour considerations, temperature, wind chill, and forecasting error/operating contingency, and concluded that modifying the Design Day would require a more extensive study and participation from other stakeholders.

In a continued effort to refine and ensure that the Company's Design Day standard is appropriate, the Company retained Marquette Energy Analytics to review historical weather conditions for Central Park for purposes of evaluating the Company's Design Day standard. Using hourly historical weather data going back to 1950, Marquette Energy Analytics found that when using both wind and temperature[32], the Company's Design Day is a 1-in-33 year event. Marquette Energy Analytics' modeling finds National Grid's current Design Day standard is equivalent to a daily average temperature of three degrees Fahrenheit with 16 mph winds. January 20, 1985, 36 years from the date of publication, was the last day to exceed the Company's Design Day standard and one of two days since 1950, a span of 71 years, that surpassed a1-in-90 year event conditions, far above the Company's current Design Day standard.

Extreme cold weather events happen regularly. For example, the February 2021 event in Texas, Oklahoma, was a 1-in-40 year event in some affected areas, a 1-in-50-year event in others, and a 1-in-90-year event in some places. In New York, Niagara Falls experienced a 1-in-35-year event on January 30th, 2019. The divergent experience of these locations under extreme cold indicate the prudence of planning for extreme, but realistic cold. In short, the Company's Design Day standard is not overly conservative, and data supports the need to plan its supply and system for such extreme weather.

The Design Day standard is one of the key matters being examined and addressed in the statewide gas planning proceeding (Case 20-G-0131), where Department of Public Service Staff has proposed that gas utilities file triennial Long-Term Plans. In its initial and reply comments filed jointly with other New York gas utilities in that proceeding, National Grid agreed with the Department of Public Service Staff's proposal that Design Day standards be "re-examined" and "re-validated" in each gas utility's initial Long-Term Plan, and National Grid and the other gas utilities offered to include Design Day and Design Hour planning as topics for stakeholder informational sessions held prior to the filing of their initial Long-Term Plans.[33]

4.4.2. Demand Forecast Methodology

Demand Forecast Methodology

National Grid conducts an annual process to model and forecast our customers' long-term natural gas requirements for KEDNY and KEDLI, which includes a historic lookback to incorporate actual data from the preceding winter as compared against previous forecasts.

[32] The Company's Design Day standard does not assume a specific wind speed. Marquette's analysis assumes a 0-degree Fahrenheit day with a 12 MPH wind speed, the average wind speed on the coldest days. A 3 degree Fahrenheit day with 16 MPH is equivalent to a 0 degree Fahrenheit day with 12 MPH winds.

[33] Joint Local Distribution Companies' Reply Comments on the Department of Public Service Staff's Natural Gas Planning Process and Moratorium Management Proposals, Case 20-G-0131, at 10.

National Grid uses the forecasts to inform its system engineering, operations, and supply planning so that we can deliver gas under Design Day and Design Hour conditions.

National Grid prepares the following for both KEDNY and KEDLI as part of its annual gas load forecast:

- Retail forecast: forecast of customer counts and usage at the customer meter.
- Wholesale forecasts: the amount of incoming gas needed to satisfy the retail forecast, as measured at the Company's city gate[34] stations—this forecast is adjusted upwards from the retail forecast to account for lost and unaccounted for gas within the system, such as unmetered usage, leaks, and metering errors.
- Design Day forecast: The wholesale requirements for the design day. This is used to ensure that the Company has 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 gross domestic product (GDP), population, housing, income, employment, and oil and gas prices. The Unadjusted Baseline forecast assumes that current energy efficiency and heat electrification programs continue at their current rates so that the independent forecasts of the economic variables drive the forecast outcomes..
2. Factor in increases in energy efficiency: In this step the forecast is modified to account for projected acceleration (or deceleration) in the rate of energy efficiency relative to historic energy efficiency achievement rates. The forecasts for KEDNY and KEDLI both assume that the NE:NY targets are fully achieved through 2025 and then continue through 2035. This energy efficiency contributes to Local Law 97 and CLCPA compliance.
3. Factor in increases in heat electrification: 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 heat electrification are primarily driven by the electric delivery companies' NE:NY and other published heat-pump targets. In addition, the Company assumes the rate of organic adoption of heat pumps will rise over the forecast horizon. The forecast incorporates increased heat pump penetration in New York City in furtherance of Local Law 97 compliance.
4. Factor in customer demand response: The design day forecast is adjusted to reflect demand response by firm customers in KEDNY and KEDLI. Similarly, lower demand from interruptible and non-firm demand response customers is accounted for in the unadjusted baseline forecast.
5. Adjusted Baseline: The final Adjusted Baseline forecast is the Unadjusted Baseline with energy efficiency, heat electrification and demand response factored in. The Company uses the Adjusted Baseline for planning purposes.

Demand Forecast Analysis

National Grid uses its historical retail billing system data as well as: historical and forecasted economic/demographic data from Moody's Analytics; natural gas and heating oil price forecasts from the U.S. Department of Energy ("DOE") Energy Information Administration ("EIA"); and historical weather data. With these data, the Company develops models of meter counts and of use-per-customer for various groupings of its customers: residential non-heating, residential heating,

[34] "City gate(s)" are the entry points into the distribution system where the amount of gas supplied by natural gas pipeline and transmission companies to the system is measured

commercial, industrial, multi-family, non-firm demand response customers, and others. Gas measured at city gates, the supply entry points into the Downstate NY gas distribution system, is also used to develop the forecast.

Economic Outlook

Forecasted economic growth, demographics, and energy prices drive the unadjusted baseline demand forecast. Economic growth corresponds to businesses expanding output, employment, building space and gas use as well as new residential construction.

The relative energy prices for heating options for customers have helped drive fuel choice. Downstate NY natural gas prices have been well below heating oil and electricity for over a decade, and this price advantage is expected to widen over the next fifteen years. Thus, the gas price advantage make gas a fuel of choice for new construction and for conversions when customers replace furnace equipment. Also, natural gas offers environmental advantages and convenience compared to oil.

The short-term Downstate NY economic forecast, through 2023, has been revised upward since last year. The recovery from the COVID-19 recession carries projections of record-breaking growth over the next two years. The forecast assumes effective herd immunity by late summer 2021, allowing more of the economy, schools and daycare to fully reopen. The recovery will be fueled by pent-up demand for many services such as entertainment, restaurants, tourism and travel and consumers who have extra purchasing power as savings rates rose during the pandemic.

However, over the longer term, after the economy reaches full employment in 2023, economic and demographic growth slow dramatically from 2024 to 2035.

The change in growth trajectory reflects potential structural changes unleased by the COVID-19 pandemic. Specifically, the forecast assumes a higher percentage of people will be working from home than before the pandemic which slows. the rebound in the Downstate New York office sector and residential growth as some workers may migrate to less expensive areas of the country.

Distributed Energy Resources

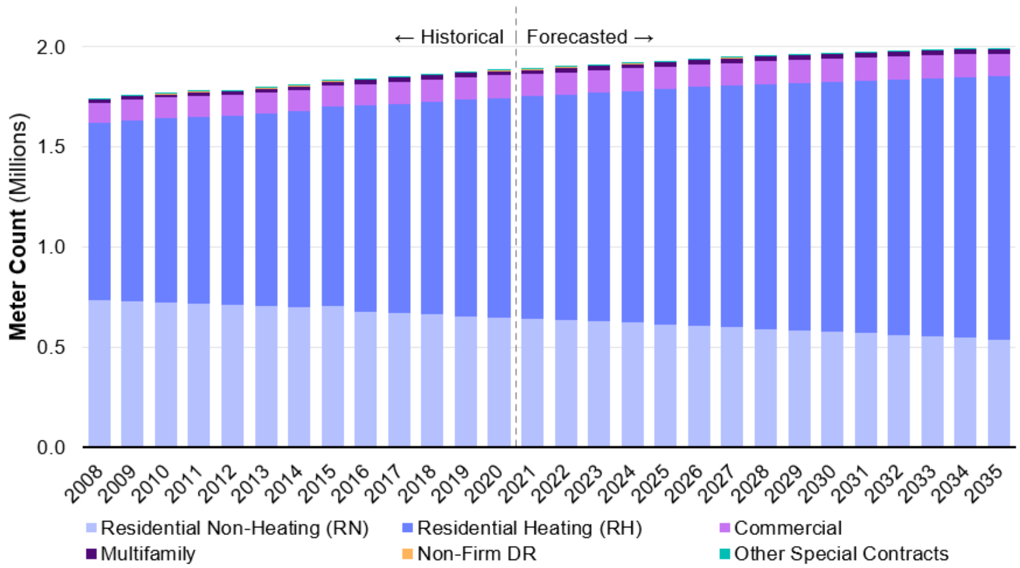
The demand forecast assumes increasing amounts of gas savings from distributed energy resources, defined here to include energy efficiency, demand response programs and the electrification of heat. These savings are in addition to the savings from current energy efficiency and heat electrification that are already included in the forecast. Expansion of energy efficiency programs leads to additional reductions to the baseline forecast of 4.8% of annual Dth load and 5.5% of Design Day load by 2035. Expansion of demand response has no impact on annual load but reduces design day load by an additional 0.3% throughout the forecast period. Reductions in the baseline forecast due to electrification of heat grow to 2.6% of both annual Dth load and design day load by 2035. Growth in distributed energy resources do not impact load significantly until after 2023 because energy efficiency and electrification of heat accumulate over time.

Further detail on the various assumptions and analysis of the Company's demand forecast can be found in Appendix A.

Customer Forecast

Downstate NY gas customer growth, captured in Figure 4-1, has been very consistent. The number of customers has never declined since 2008, rising through the Great Recession in 2009, recent Downstate NY population declines and the COVID-19 recession in 2020. Customer growth has been supported by consistent economic growth and the gas price advantage over heating oil and electricity. Total gas customer growth averaged 0.6% per year from 2008 to 2020, or 11,682 customers per year.

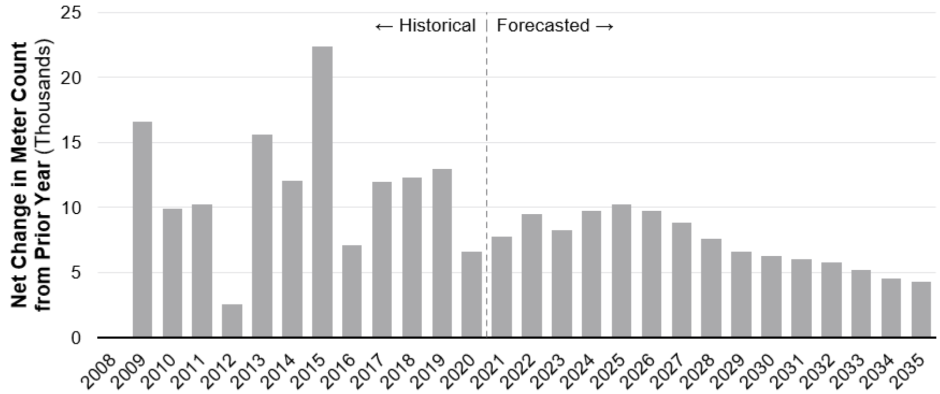
Figure 4-1: Downstate NY Customer Count



The historical rise in the number of gas customers is the net of (1) increases in the number of residential heating (RH), large multifamily (MF) and firm commercial (COM) customers; and (2) decreases in the number residential non-heating (RN), non-firm demand response (NFDR) and other large (OTH) customers. Since 2008, the RH class added an average of 17,905 customers per year; MF added 474 customers per year and COM added 761 customers per year. On the other hand, RN customers lost an average of 7,315 customers per year; NFDR lost 139 customers per year; and OTH lost 5 customers per year.

Over the forecast period, from 2020 to 2035, the growth in the total number of gas customers is forecast to slow to an average growth rate of 0.4% per year illustrated in Figure 4-2. Annual customer growth is greater than 0.4% in short-term as the Downstate NY recovers from the COVID-19 recession, but falls over the longer term as Downstate NY employment, income and housing stock growth slow and annual heat pump installations continue at the 2021 to 2025 NE:NY target rates. Total customer additions average 7,361 per year, 4,321 less than the historical average. The number of RN, NFDR and OTH customer counts are forecast to continue falling at close to their historical rates.

Figure 4-2: Downstate NY Net Change in Customer Count

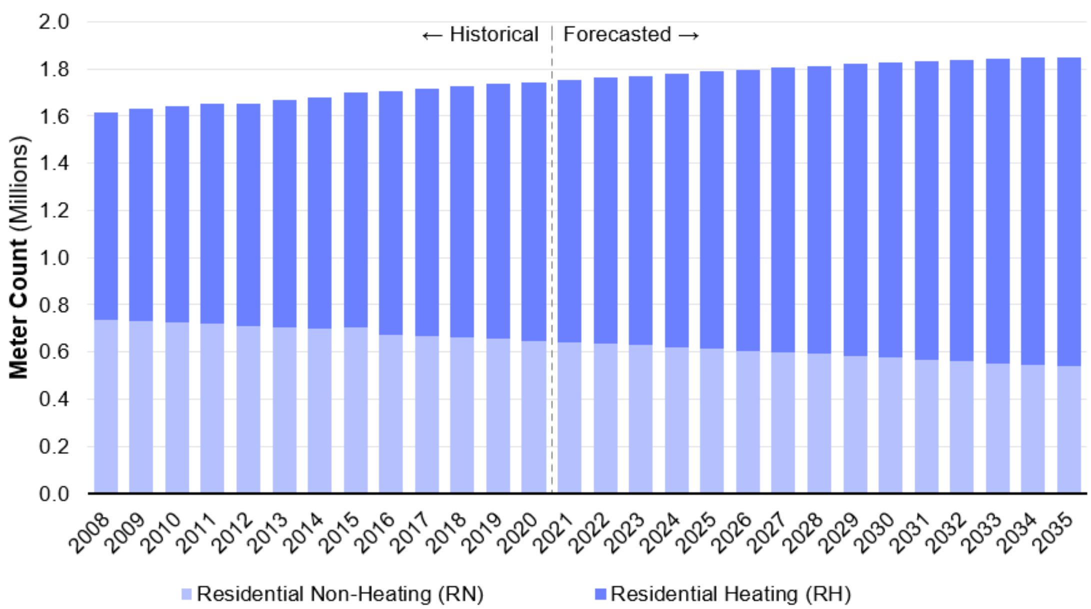


Source: National Grid customer data and 2021 base case customer forecast.

Residential Customer Forecast (RN and RH)

The residential class consists of residential non-heating (RN) and residential heating (RH) customers. RN are “low-use” customers who typically heat with oil but use gas for cooking, water heating, clothes drying, and other non-space heating purposes. RH customers, who comprise an increasing share of the residential class, as illustrated in Figure 4-3, use gas for the all the same purposes as RN customers, but also heat with gas, which greatly increases their consumption.

Figure 4-3: Downstate NY Residential Customer Count

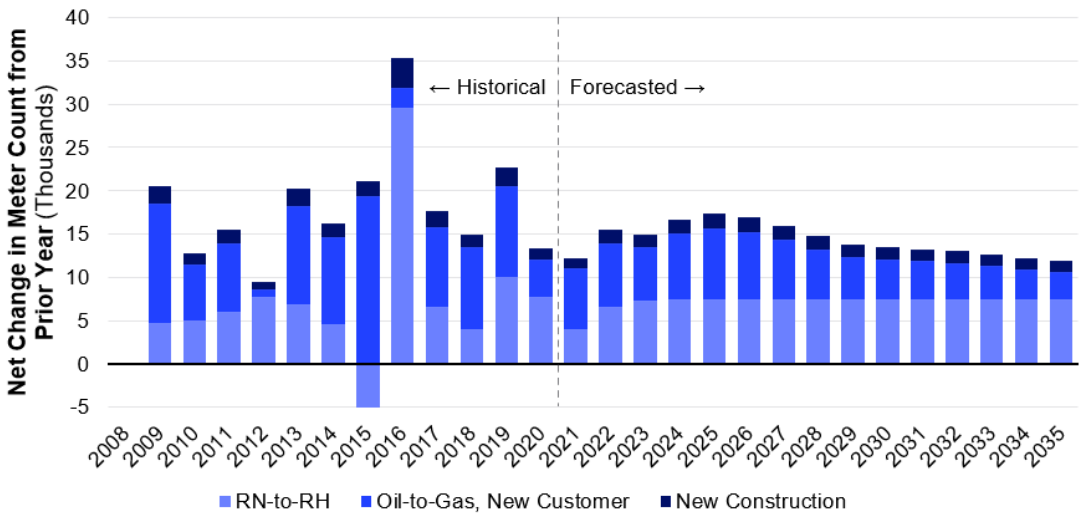


Source: National Grid data and 2021 base case forecast. Note that in 2015 and 2016 the Company reclassified several thousand RN customers to RH, for example, RN customers who converted to RH without a service upgrade or otherwise notifying National Grid. These customers were identified through load analysis.

The total number of residential customers increased at an average rate of 0.6% per year from 2008 to 2020, or by 10,590 customers per year captured in Figure 4-4. This included a 1.8% annual increase in the number of RH customers and a 1.1% annual decline in the number of RN customers, or an average annual loss of 7,315 of these customers. However, this did not reduce gas load because these were overwhelmingly RN-to-RH conversions. Rather, this shift to residential gas heating, among customers who generally continue to use gas for non-space heating purposes, increases demand. This is a long-term trend driven by the gas price advantage over heating oil which is expected to continue.

Growth in the total number of residential customers is forecast to slow to an average of 0.4% per year over the 2021 to 2035 forecast horizon, although growth will be stronger in the short-term. Slower long-term customer growth is due to both slower long-term demographics in Downstate NY and the electrification of heat. Growth in the number of RH customers is forecast to fall to 1.2% per year while the annual loss in RN customers continues at 1.2% per year. National Grid estimates that approximately 50% of RH customer additions are RN-to-RH conversions, 40% are new conversions and 10% are new construction.

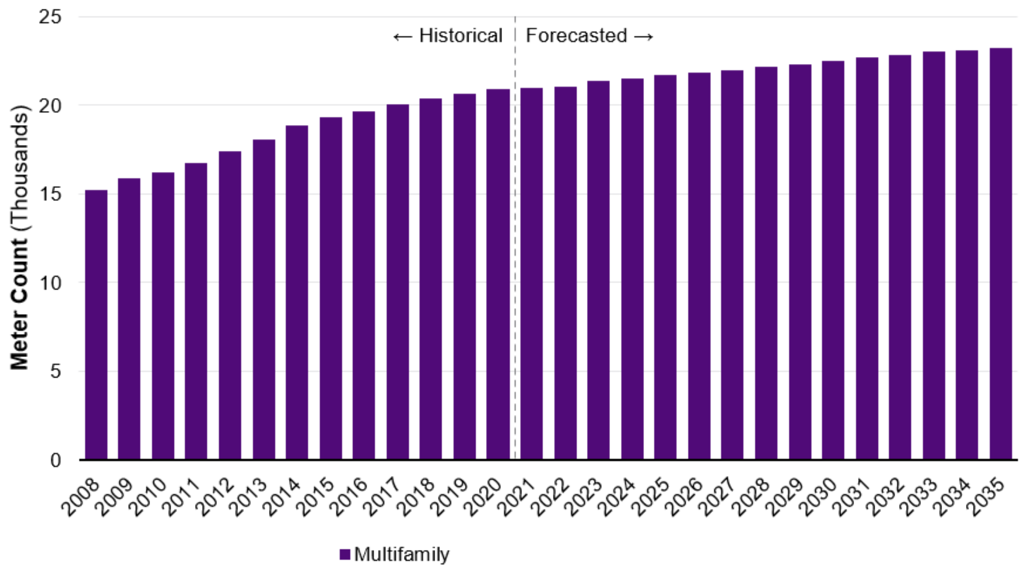
Figure 4-4: Downstate NY Forecast Residential Customer Additions



<u>Large Multifamily (MF)</u>

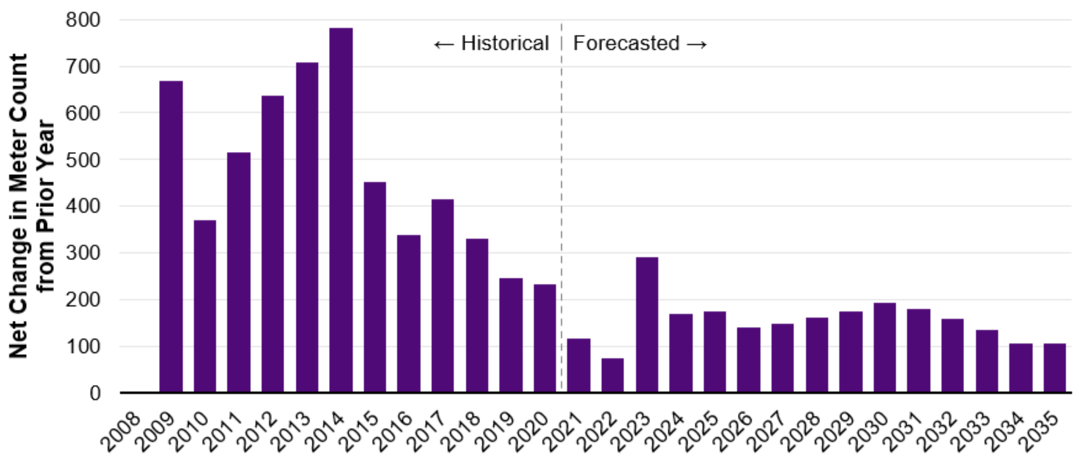
The MF class consists of large, master-metered apartment buildings using natural gas for heating. The number of MF customers rose 2.7% per year over the 2008 to 2020 historical period, or by 474 new MF customers per year on average captured in Figure 4-5. National Grid estimates that about 89% of these were new construction and 9% were conversions from oil heating, including from the Clean Heat program.

Figure 4-5: Downstate NY Multifamily Customer Count



Over the forecast period, from 2020 to 2035, MF customer growth is expected to slow to an average of 0.7% per year or 155 new customers per year, about a third of the annual number added during the historical period captured in Figure 4-6. This is the result of slower economic and demographic growth over the long-term as well as the electrification of heat.

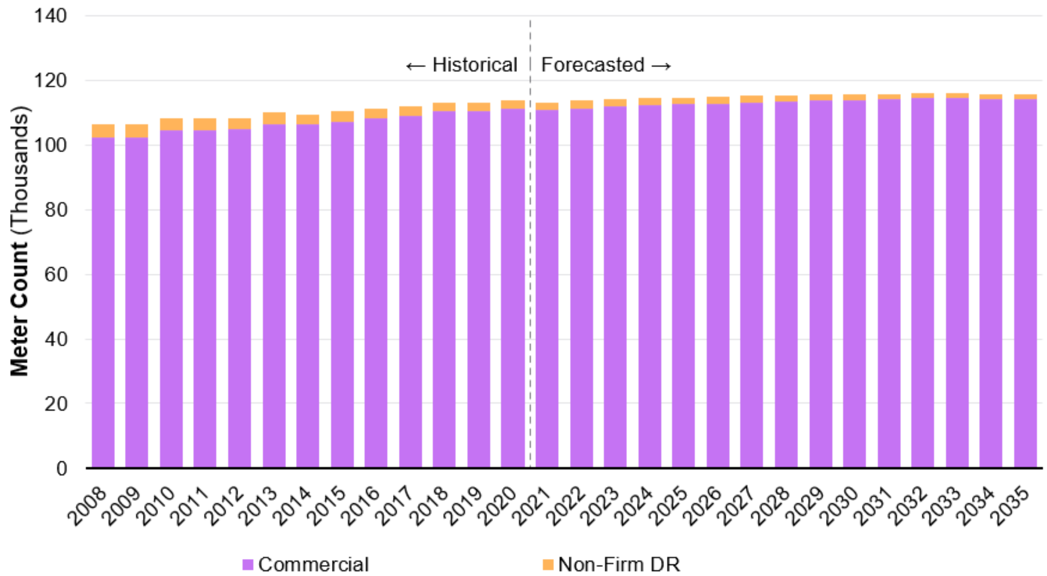
Figure 4-6: Downstate NY Forecast Large Multifamily Additions



<u>Firm Commercial (COM) and Non-Firm Demand Response (NFDR) Customers (formerly temperature controlled or "TC" customers)</u>

Firm commercial gas customers (COM) use gas for space heating, cooking, water heating and industrial processes. Growth in COM customers averaged 0.7% from 2008 to 2020, or 761 customers per year shown in Figure 4-7 Conversions from oil heating, new construction and conversion of NFDR customers to COM all contributed to this growth.

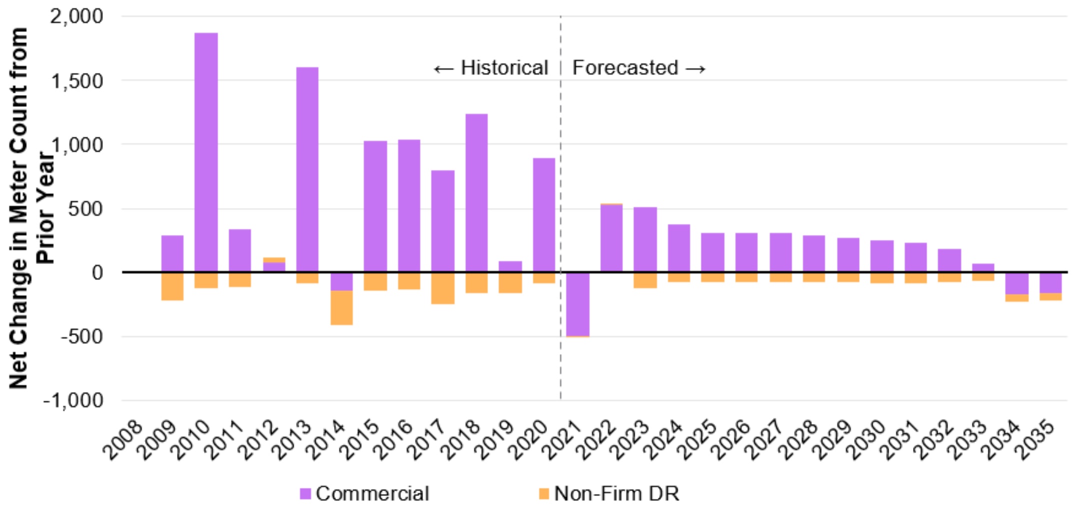
Figure 4-7: Downstate NY COM and NFDR Customer Count



NFDR customers are large commercial businesses that have the ability to heat with either natural gas or oil. National Grid's NFDR gas usage rates are lower than the COM rate, but they are interruptible. Customers cannot take gas service when outdoor temperature falls below a certain threshold. NFDR customers find it more cost-effective to take a lower NFDR rate and switch over to oil when this occurs. However, as oil backup systems become more costly relative to firm gas service, NFDR customers convert to COM. This is a long-term trend driven by the gas price advantage over heating oil. DNY consistently loses about 139 NFDR customers per year, a 4.3% average annual decline since 2008. However, the overwhelming majority of these are conversions to COM. Since NFDR customer use per customer ("UPC," the average annual gas volume consumed per customer) is much larger than the COM average, this tends to drive up COM UPC. Such reclassifications also add to total gas load since the reclassified customers start using gas on the coldest winter days whereas they used oil before. Design Day demand also rises.

Over the forecast period, growth in the number of COM customers slows to an average of annual rate of 0.2% per year, or 188 customers per year. The number of NFDR customers continue to fall but at a slower rate, -3.6% per year, leading to the loss of 67 NFDR customers per year. Forecast counts of these trends in NFDR and COM counts are captured in Figure 4-8.

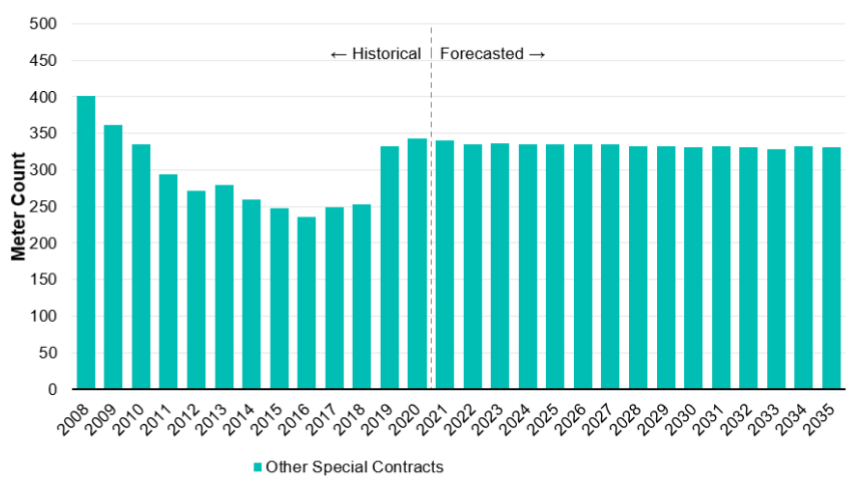
Figure 4-8: Downstate NY COM and NFDR Net Change



<u>Other Large Customers (OTH)</u>

National Grid serves 343 other large customers on special contracts (OTH) in Downstate New York. These are mainly power generators, including large firms with on-site combined heat and power (CHP) plants. These customers have only a modest impact on National Grid's DNY energy and capacity requirements because they generally have their own contracts to procure these products. The number of OTH customers generally trended down over 2008 to 2020 historical period but is expected to be relatively stable over the forecast horizon captured in Figure 4-9.

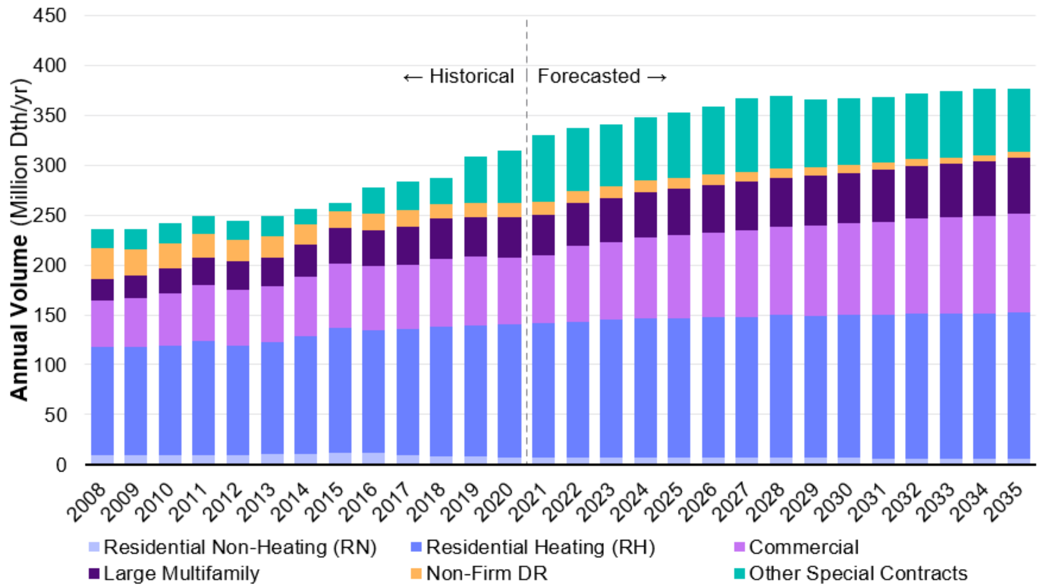
Figure 4-9: Downstate NY Forecast Other Large Customers



Energy Forecast Summary

The energy forecast projects retail gas consumption or "volumes" delivered to National Grid's Downstate NY customers, measured at the meter. Driven by customer growth and increasing UPC, as seen in Figure 4-10, total retail gas volumes rose at an average annual rate of 2.4% from 2008 to 2020. However, excluding OTH, retail volumes fell 0.2% year-over-year between 2019 and 2020. Year-over-year, residential volumes rose 0.5% in 2020 and MF volumes rose 2.2% but COM volumes fell 3.0% as many commercial businesses were partially shut down due to COVID-19. NFDR volumes fell 0.4%. OTH volumes rose 15.2%.

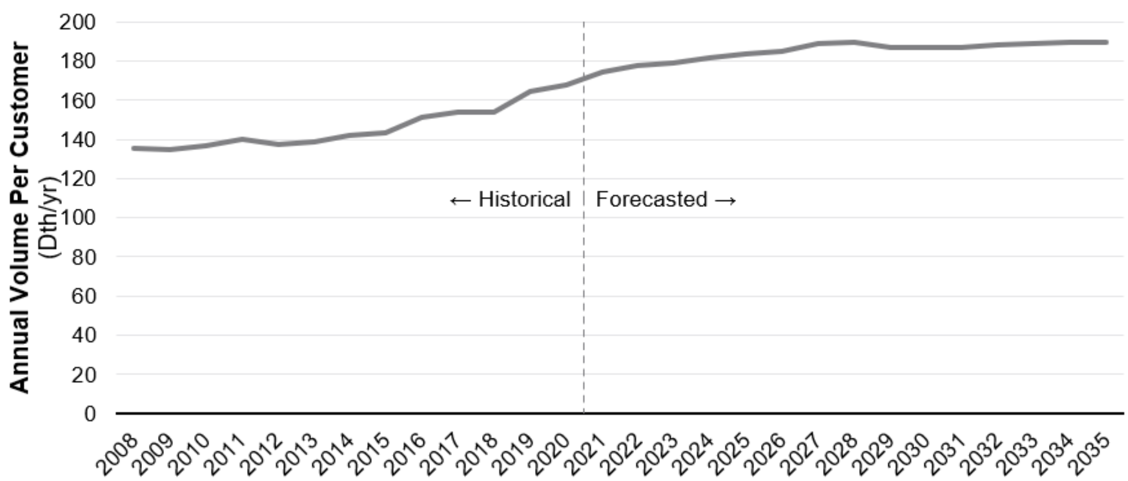
Figure 4-10: Downstate NY Annual Gas Use



Retail volume growth is forecast to fall to half the historical rate of 2.4% per year to an average rate of 1.2% per year, from 2020 to 2035. The slowdown is due to increasing amounts of energy efficiency (EE) and electrification of heat, as well as slower employment and demographic growth over the latter half of the forecast horizon. However, volume growth is much higher in 2021 and 2022 during the projected strong economic rebound from the pandemic. Distributed energy resources have a smaller impact in the early years of the forecast.

Total UPC, shown in Figure 4-11 rose at an average annual rate of 1.8% over the historical period (2008-2020). Increases were driven by COM and MF customers. RN UPC declined while RH UPC was essentially flat and NFDR UPC fell. UPC growth is forecast to slow to an average of only 0.8% per year due to EE, heat electrification and slower employment growth in the long term.

Figure 4-11: Historical and Forecast Energy Use

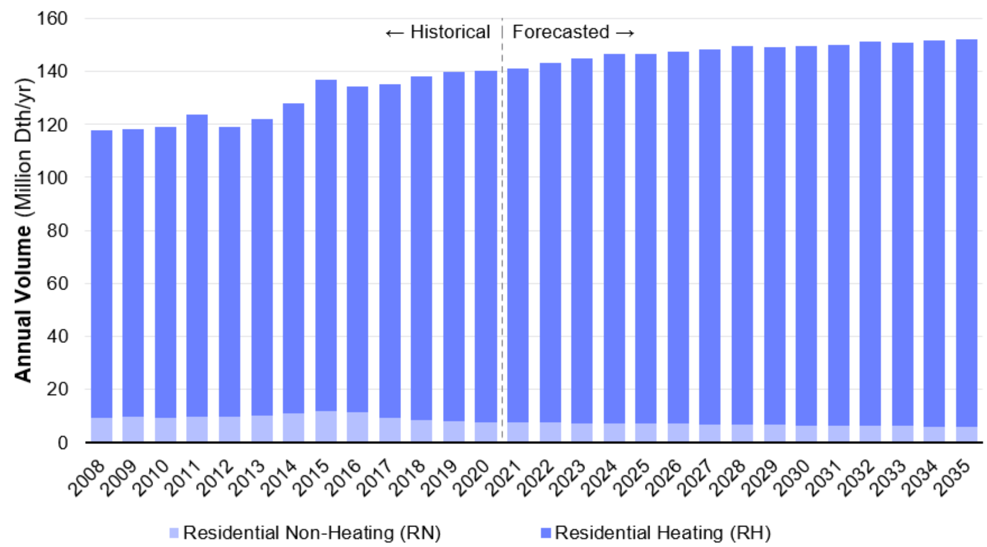


Source: National Grid customer billing system and 2021 base case energy forecast.

Residential Energy Forecast (RN and RH)

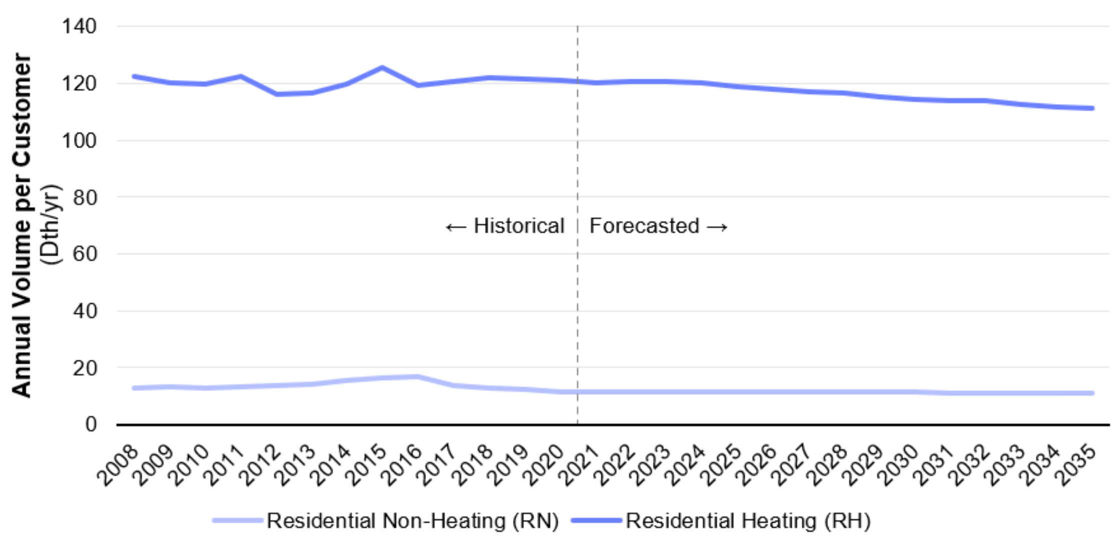
Residential volumes grew at an average rate of 1.5% per year from 2008 to 2020, as illustrated in Figure 4-12, driven by the increase in the number RH customers illustrated in Figure 4-3. RH volumes grew 1.7% per year, the result of a 1.8% annual increase in customers and a 0.1% annual drop in use per customer. RN volumes fell 1.8% per year over the historical period as both the number of customers and UPC declined.

Figure 4-12: Downstate NY Residential Gas Use



Growth in residential volumes is forecast to slow to an average annual rate of 0.5% from 2020 to 2035, just one third the historical average. This is due to slower RH customer growth, discussed above, and declines in RH UPC captured in Figure 4-13 from EE programs and heat electrification.

Figure 4-13: Historical and Forecast Residential UPC



Large Multifamily (MF) Energy Forecast

Figure 4-14 shows in increase in MF volumes of 5.3% per year, on average, from 2008 to 2020, driven by a 2.7% annual increase in the number of MF customers and a 2.6% annual increase in

UPC illustrated in Figure 4-15. Growth in MF volumes is forecast to slow to 2.1% per year, with customer growth of 0.7% per year and UPC growth of 1.4% per year due to increasing amounts of EE savings and electrification of heat.

Figure 4-14: Historical and Forecast Large Multifamily Energy Use

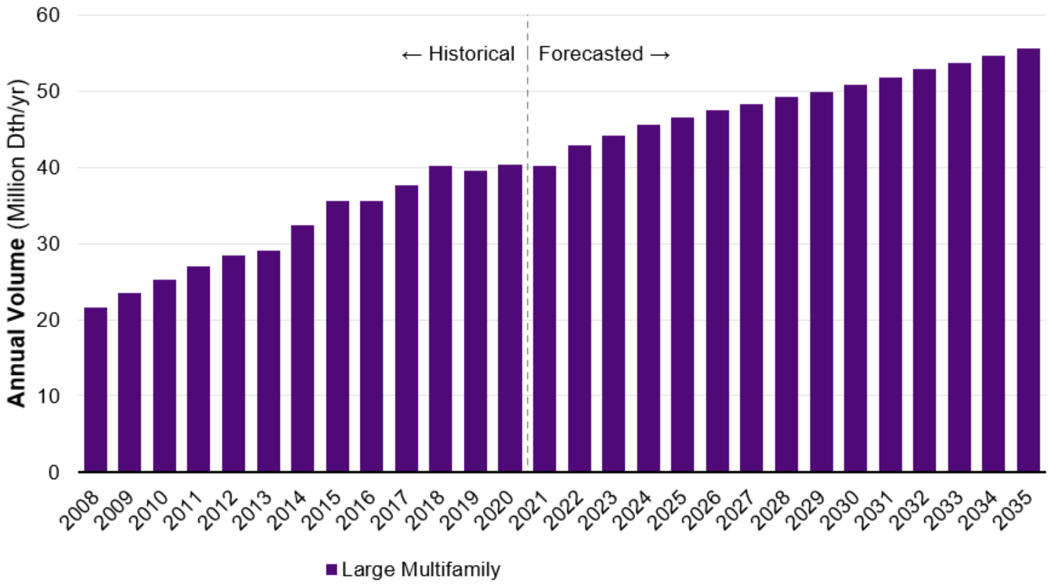
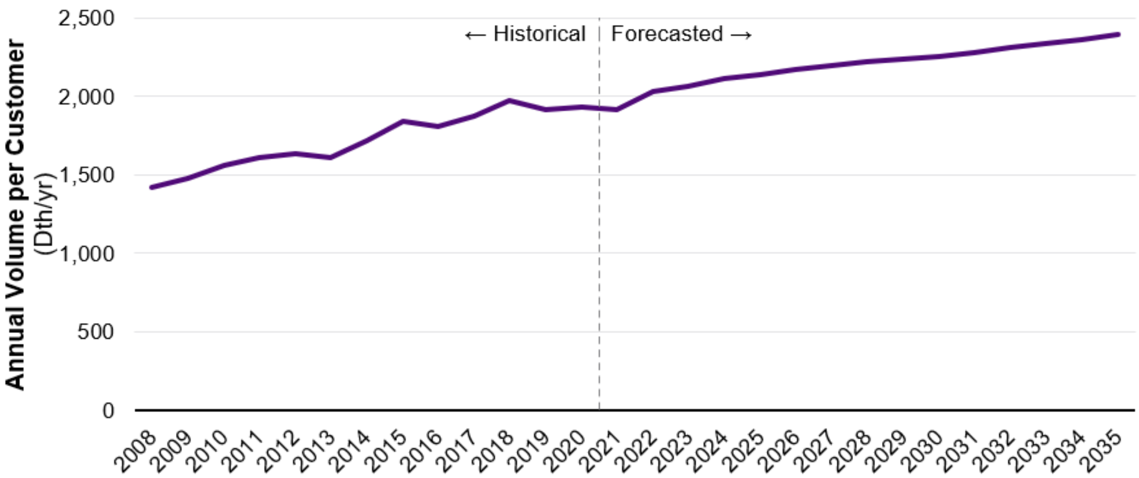


Figure 4-15: Historical and Forecast Large Multifamily UPC



<u>Firm Commercial (COM) and Non-Firm Demand Response (NFDR) Forecast</u>

Figure 4-16 shows COM volume growth averaged 3.1% per year from 2008 to 2020, the result of a 0.7% annual increase in the number of customers and a 2.4% annual rise in UPC illustrated in Figure 4-17. Growth in UPC was due to NFDR-to-COM conversions and growth in the UPC of existing COM customers, a reflection of the vibrant Downstate New York commercial sector over the past twelve years.

COM volume growth slows to an average of 2.7% per year from 2020 to 2035. Customer growth slows to just 0.2% per year while UPC growth increases slightly to 2.5%

Figure 4-16: Historical and Forecast COM Energy Use

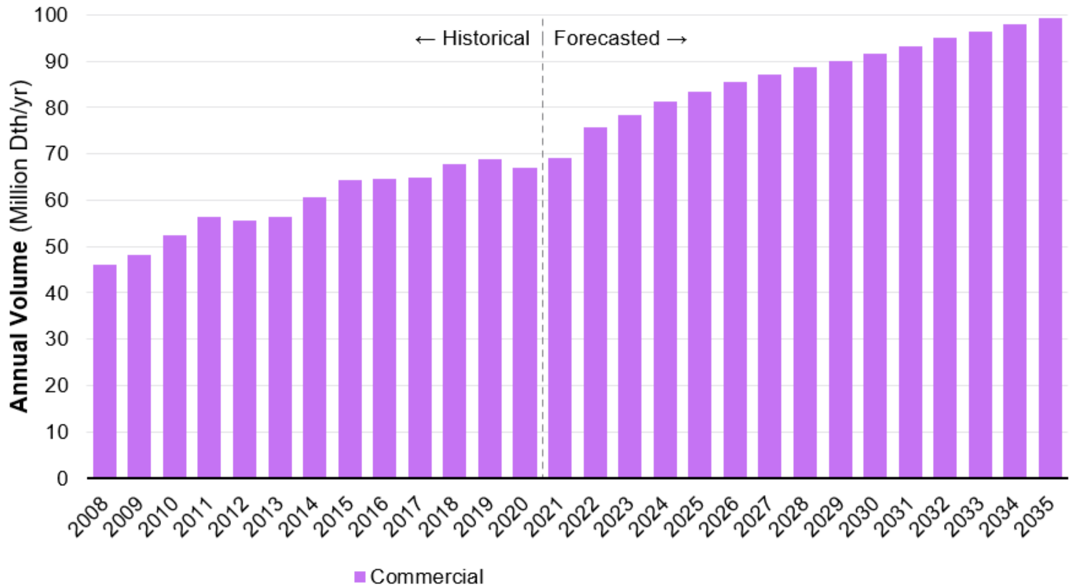
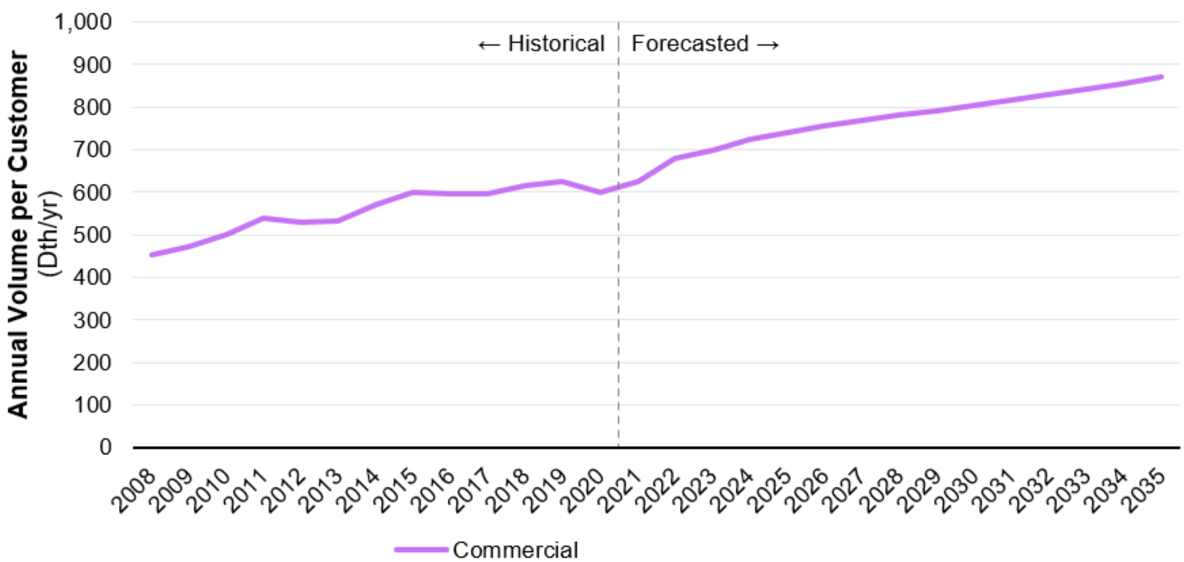


Figure 4-17: Historical and Forecast COM UPC



Total NFDR volumes fell at an average annual rate of 6.4% during the 2008 to 2020 historical period as shown in Figure 4-18. This was mainly the result of the on-going decline in the number of NFDR customers. As discussed above, these customers were generally NFDR-to-COM conversions, fueling firm commercial (COM) energy growth.

Figure 4-18: Historical and Forecast NFDR Gas Use

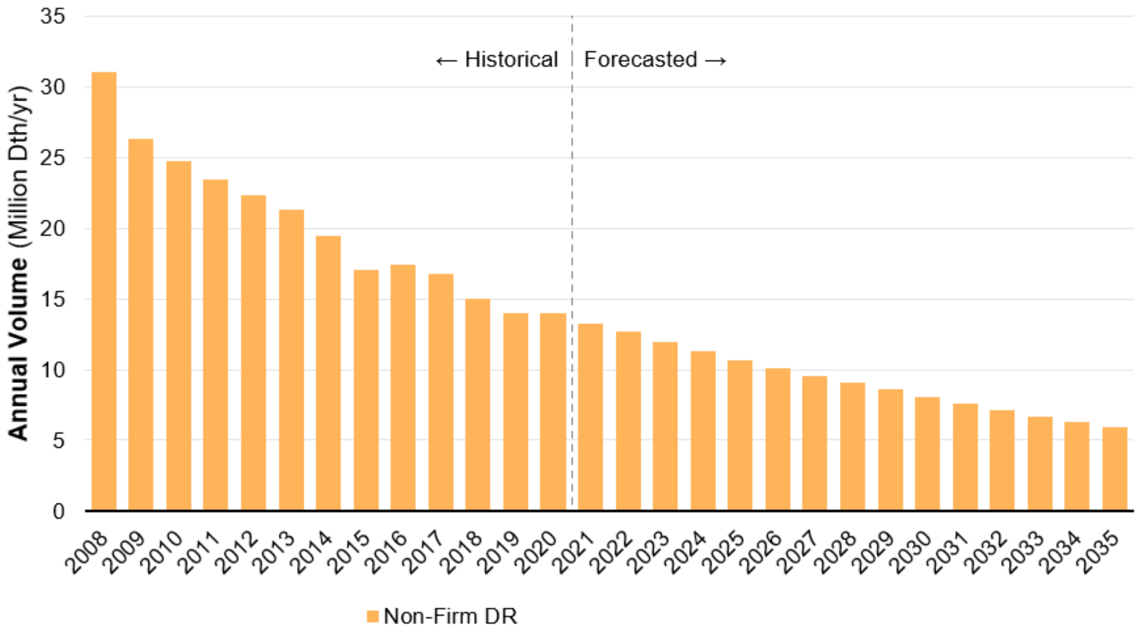
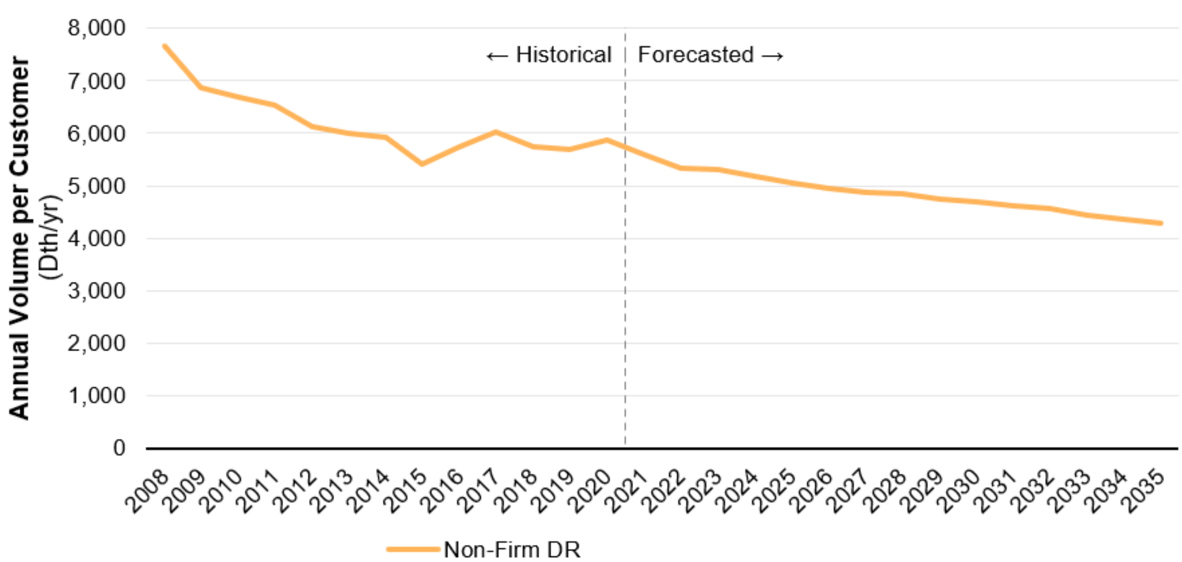


Figure 4-19 shows that as the NFDR class loses customers each year, the NFDR UPC falls, indicating that the larger customers are converting to firm commercial service, having a bigger impact on load.

Over the forecast period, from 2020 to 2035, NFDR gas consumption is forecast to continue falling at close to the historical rate, -5.6% per year as both the number of customers and their UPC continue to decline. Figure 4-19: Historical and Forecast NFDR UPC

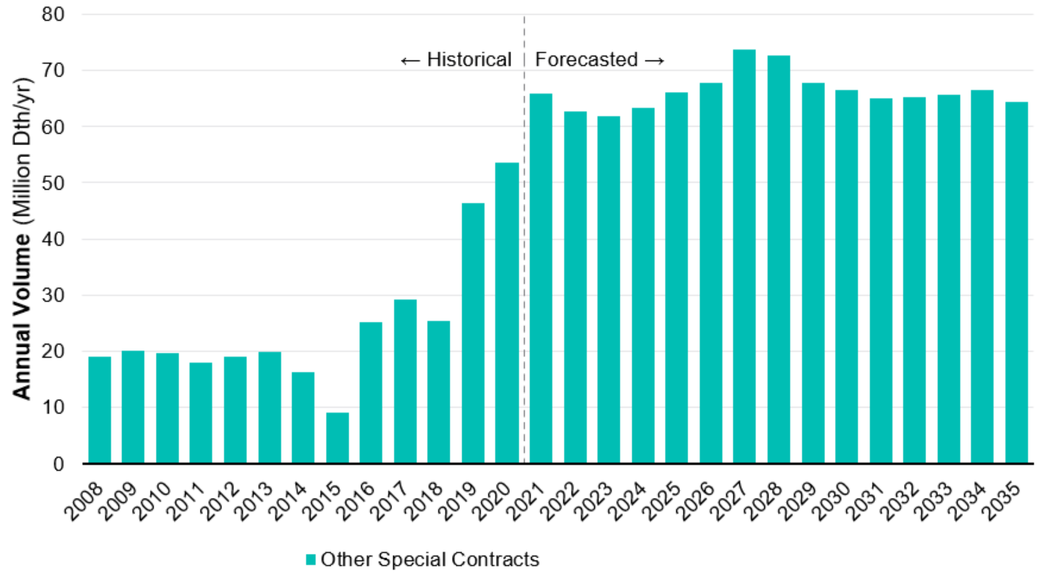
Figure 4-19: Historical and Forecast NFDR UPC



<u>Other Large Customer (OTH) Energy Forecast</u>

Figure 4-20 shows that OTH volumes rose 9.0% per year on average from 2008 to 2020. OTH consumption is forecast to rise by 1.2% per year over the year, on average, from 2020 to 2035.

Figure 4-20: Historical and Forecast Other Large Customer Energy Use

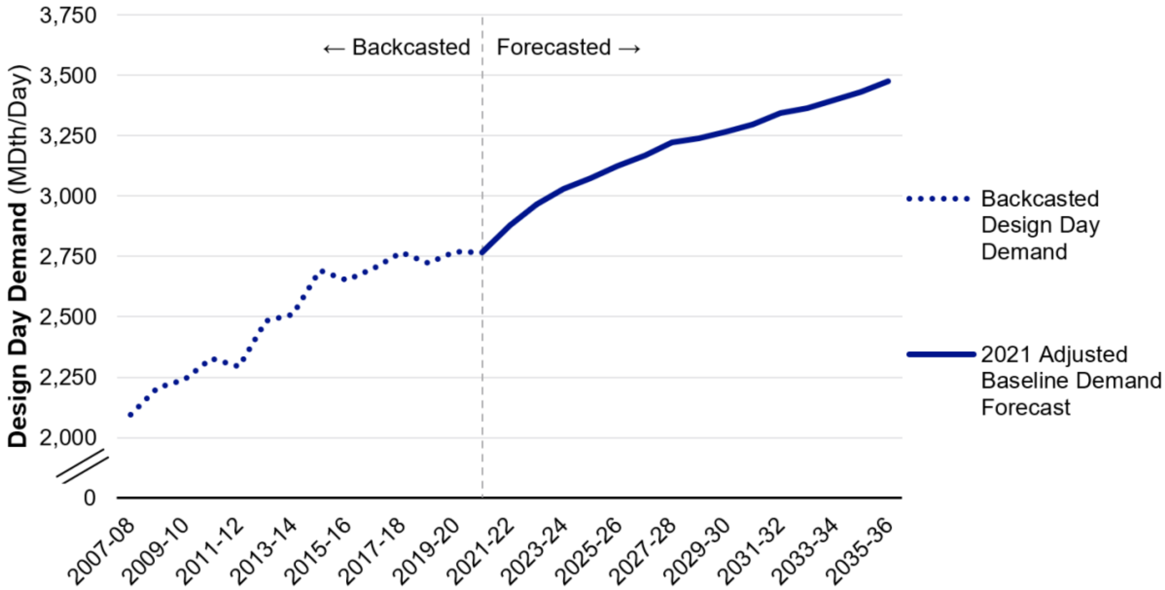


Design Day Demand Forecast Summary

The Design Day demand forecast projects sendout when Downstate NY retail customer demand is at its highest. This occurs on the “Design Day, that is the coldest non-holiday weekday of the winter planning period, with sustained temperatures of zero degrees Fahrenheit. Design Day volume measures the amount of gas capacity that must be procured to deliver sendout on the Design Day. This capacity can be procured from national suppliers at the city gates, if available, or other sources such as transporting in and injecting liquified natural gas. Distribution capacity must be also added to meet increased design day volumes, which involves more capital spending.

The Design Day forecast is based on the historical relationship between Design Day sendout, weather and annual sendout. Design Day volume growth averaged 2.4% per year over the historical period, from winter 2007/2008 to winter 2020/2021, as illustrated in Figure 4-21. This was faster than sendout volume growth because increases in RH and COM heating impact winter Design Day volumes proportionately more than annual volumes.

Figure 4-21: Backcasted (Historical) and Forecasted Downstate NY Design Day Demand

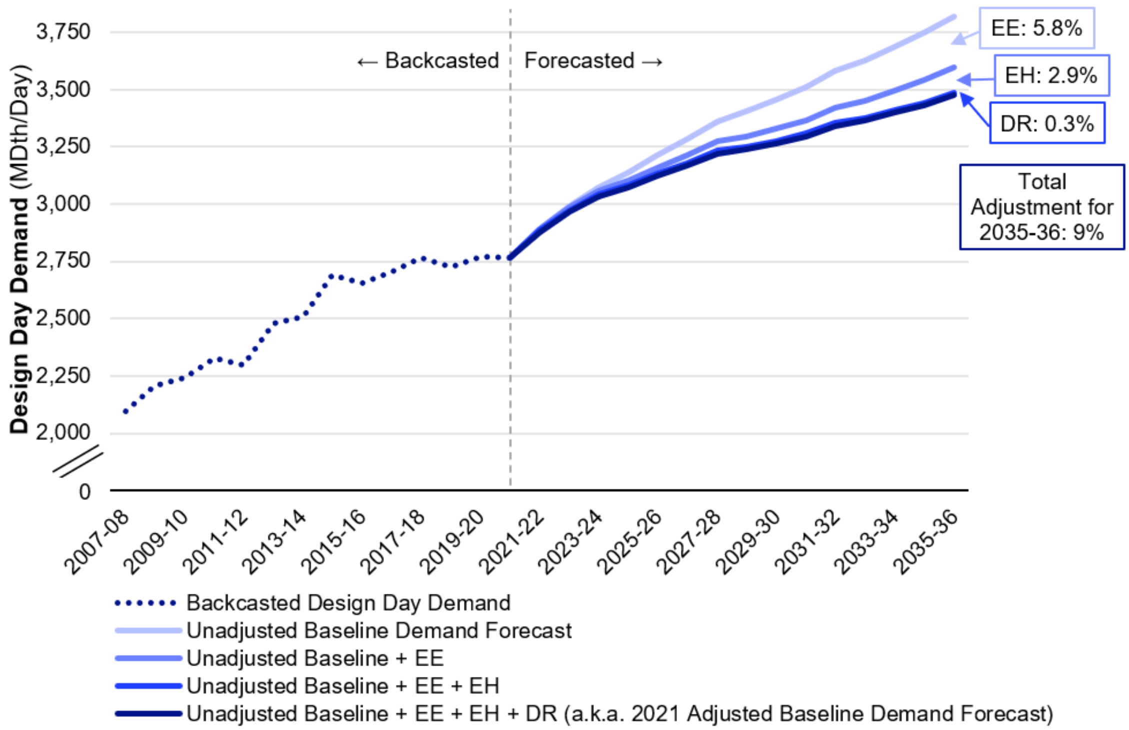


Design day load rose 1.7% in winter 2019/2020, which occurred before the COVID-19 recession. The Design Day load fell 0.1% in winter 2020/2021, which occurred during the winter surge in COVID-19 cases, renewed business restrictions and corresponding slowdown in economic growth.

Design day load is forecast to increase by over 3.0% per year in winters 2021/2022 and 2022/2023 before slowing significantly due to slower demographic and employment growth, increasing amounts of EE, heat electrification and demand response (DR). Design day volume growth averages 1.5% per year over the entire winter 2020/2021 to winter 2034/2035 forecast horizon, barely more than half the historical average.

Figure 4-22 shows the impact of NE:NY and the accelerated organic adoption of heat electrification in furtherance of climate goals by comparing the Unadjusted (without NE:NY and heat electrification targets) and Adjusted Baselines (with NE:NY and heat electrification targets). Note there is EE and heat electrification embedded in the Unadjusted Baseline at the same rate it has been recently occurring, and the Adjusted Baseline only shows the acceleration of those resources due to NE:NY and the accelerated organic adoption in furtherance of climate goals. In winter 2034/2035 these resources reduce the design day forecast by 8.5% or 318 MDth/day for Downstate NY, however these program targets do not begin to significantly reduce load until after winter 2022/2023.

Figure 4-22: Downstate NY unadjusted and adjusted Design Day historical and forecast volume



4.5. The Net Zero Demand Scenario

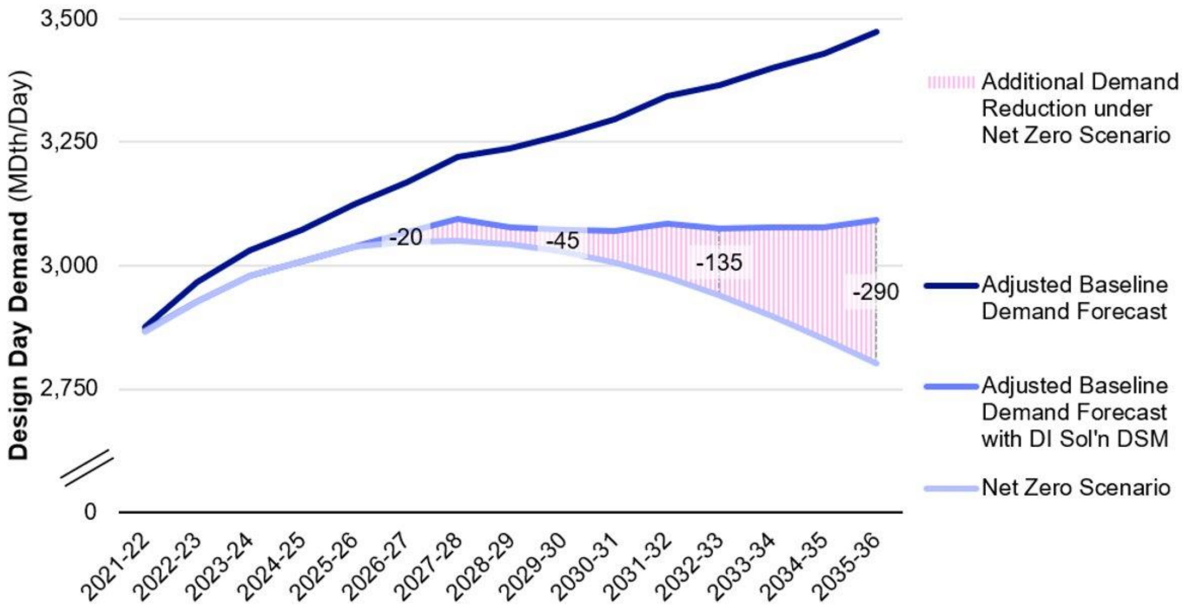
In addition to the Adjusted Baseline Demand Forecast described in detail above, National Grid also developed a gas demand scenario consistent with the NYC Decarbonization Study's "Low Carbon Fuels" pathway[35]. This scenario (the "Net Zero Scenario") assumes that the combination of the incremental DSM programs included in the Distributed Infrastructure Solution and unspecified new policies and programs under the CLCPA and potentially other laws that result in net gas demand for the Company's customers matches a trajectory derived from the NYC Decarbonization Study.[36] In this Net Zero Scenario, the Company's projected Design Day gas demand growth (after accounting for the Distributed Infrastructure Solution's incremental DSM) slows, stops, and reverses, with Design Day demand flattening out by the winter of 2027/28 and declining thereafter. The Net Zero Scenario demand is shown on Figure 4-23 below.

As explained below, National Grid used this Net Zero Scenario to test the robustness of the Distributed Infrastructure Solution to the evolving policy environment under the CLCPA.

[35] The Low Carbon Fuels Pathway reduces emissions by reducing the use of fossil fuels through energy efficiency and some electrification and replacing remaining fossil fuels with low carbon alternatives in the buildings and transportation sectors. See https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf (page vii).

[36] Specifically, the Net Zero Scenario is based on the "Low Carbon Fuels Pathway, with Higher Building Electrification Post-2030" from the NYC Decarbonization Study. The Company made assumptions to create annual Design Day projections from the NYC Decarbonization Study's five-year snapshots of annual gas demand. The Company assumed for the Net Zero Scenario that the Adjusted Baseline Demand Forecast would transition to this trajectory derived from the NYC Decarbonization Study after 2025, in light of the assumed timeframe for adoption and implementation of new policies and programs.

Figure 4-23: Adjusted Baseline Demand Forecast and the Net Zero Demand Scenario



4.6. Available Supply

This section summarizes National Grid's existing supply capacity.

Existing pipeline and LNG capacity

As stated in the Supplemental Report, National Grid's pipeline Design Day capacity totaled 2,125 MDth/day for 2020/21. In June 2020, National Grid issued a Request for Proposals ("RFP") seeking additional long term supply/capacity needed to meet forecasted firm requirements beginning November 2021. As a result of the RFP, National Grid contracted for 252 MDth/day of firm pipeline capacity delivering to National Grid's Downstate NY city gates. The addition of this new capacity, effective 11/1/2021, increases the total pipeline Design Day capacity to 2,377 MDth/day.

There have been no changes to National Grid's LNG Design Day capacity since the Supplemental Report. The Design Day available capacity from our existing Holtsville and Greenpoint facilities totals 395 MDth/day.

Pipeline "city-gate peaking" and Cogen peaking supply

The "contracted peaking supplies" referred to in the Original Report and Supplemental Report represent the sum of city gate peaking supplies and Cogen peaking supplies. City gate and Cogen peaking contracts deliver supply from third parties via pipeline to the Company's city gates. In the Supplemental Report, the Company identified the maximum volume of these supplies that could be procured totaling 365 MDth/day and made that amount of capacity part of the Distributed Infrastructure Solution. However, the 252 MDth of pipeline capacity contracted through the June 2020 RFP described above reduced the amount of available capacity in the market that would otherwise be offered in the form of short-term city gate peaking contracts. As a result, the maximum volume of contracted peaking supplies has been adjusted downward, and now totals 123 MDth/day. For the purposes of the Distributed Infrastructure Solution, the Company assumes that it can re-contract for this full amount of 123 MDth/day as needed indefinitely[37] Gas system constraints limit National Grid's ability to contract for additional supply/capacity to the existing city gates.

In addition to the 252 MDth/day of long term capacity secured through the June 2020 RFP, National Grid also contracted for 58MDth/day of city gate peaking supplies delivering to National Grid city gates beginning the winter of 2024/25. These types of arrangements expose the Company to high city-gate pricing during peak days as well as the possibility that the Company will be unable to continue procuring these primary firm deliveries from third parties to its city-gates to serve its firm customers. Because the underlying pipeline capacity used to satisfy peaking arrangements (both for city gates and cogeneration facilities) involves transportation rights held by third parties, the Company does not have a right of first refusal to continue those arrangements after their expiration. Although National Grid will endeavor to re-contract for these volumes as these arrangements expire, the ability to do so is not guaranteed. Because National Grid is not allowed to maintain a reserve margin, we only procure sufficient supply quantity dictated by the demand forecast and on-system needs.

Additional capacity through additional CNG Sites

The Compressed Natural Gas (CNG) Trucking effort includes the continued use of existing CNG facilities and the addition of new facilities to support system growth and meet demand during the coldest days of the winter heating season. Under this plan, CNG supply is secured upstream of our system, transported via tractor trailer to National Grid CNG sites in New York, and connected to equipment (i.e. decompression skids) to transfer the natural gas into National Grid's transmission and distribution systems. The CNG sites are mobilized and operated under temperature thresholds requiring supplemental supply to maintain system reliability for our customers during peak periods of demand.

Since the Supplemental Report, National Grid has expanded the CNG deliverability from 17 MDth/day to 62 MDth/day, creating the largest CNG operation of its kind in the United States. This capacity, which was beyond what was described in the Supplemental Report, was achieved through the addition of distributed transfer points across National Grid's DNY system. Future additional CNG capacity, which is included in the Company's Distributed Infrastructure Solution (see Section 5) is planned to bring this total up to 80 MDth/day which will close out National Grid's ability to further expand reliance on portable CNG due to siting, operational and market constraints.

Additional capacity through additional RNG interconnection

Renewable Natural Gas ("RNG") is methane that is released due to the breakdown of organic materials. This typically occurs via either anaerobic digestion (for wet feedstocks such as manure) or thermal gasification (for dry feedstocks such as woody biomass). It is also possible to produce a synthetic methane by combining hydrogen with carbon dioxide, but that is less common. The breakdown of organic materials is an inherent part of the waste stream for many things, including agriculture, tree-trimming, and biological processes. The byproduct of this breakdown is a mixture of gases that are typically 50-65% methane, with the bulk of the remainder being carbon dioxide. This

[37] There is a finite volume of supply that is categorized as "city-gate peaking." Each interstate pipeline that is regulated by the FERC makes publicly available an index of customers which details the pipelines' contractual terms with a customer, including the primary delivery point. Additionally, the pipelines are required to provide information as to what capacity remains operationally available and/or unsubscribed on their system for a given period of time. Using this information, National Grid is able to determine which entities, if any, hold firm capacity to our service territory; however the Company is not privy to any commitments the capacity holder may have already made using their assets. With that said, having extensively reviewed our modeling and assumptions, we adjusted our projected levels of pipeline peaking supplies based on the results of our June 2020 RFP.

is typically referred to as biogas. Biogas can be combusted on –site, or it can be upgraded to biomethane, which involves removing non-methane components to produce a gas that meets pipeline quality standards.

RNG production is not linked to geologic natural gas deposits and production. For instance, food waste and wastewater, common outputs of populated areas, can be digested to produce biogas and later biomethane. The Company has experience with this through its development of an RNG production facility at Newtown Creek. This facility was originally designed to take only wastewater as an input, but it has been expanded to include food waste and is expected to be producing almost 1 MDth/day of local gas supply.

As evidenced by the Newtown Creek experience, RNG projects are currently small relative to other sources of natural gas. However, they can provide an additional source of gas that can be developed in a location that provides system benefit, while also producing gas that has a lower lifecycle carbon intensity than geologic natural gas.

The Company has a project queue for RNG interconnection requests, but it is not yet clear how many, if any, will be able to move forward. There are various components of RNG site development that must be managed, including those that are outside of the control of the Company (e.g. external financing, permitting, etc.). The Company will continue to support RNG developers as the waste management, carbon reduction, and supply benefits of RNG make it a valuable portion of the energy mix. However, the Company has not included RNG, beyond the output of Newtown Creek, in its available supply or Distributed Infrastructure Solution due to uncertainties surrounding project development. Only locally produced RNG interconnected to the Company's transmission and distribution network can address the gas capacity constraint faced in Downstate New York. However, RNG procured upstream and delivered over the interstate pipeline network can meet overall customer energy needs and reduce GHG emissions.

Summarizing changes to National Grid's Downstate NY natural gas supply capacity

Figure 4-24 and Table 4-1 provide an updated view and explanation of National Grid's existing and projected supply stack. Figure 4-24 shows how the Company increased the amount of available supply capacity after 2020, due largely to the June 2020 RFP and the addition of additional CNG. Table 4-1 summarizes the changes for each component. Because of the finite volume of pipeline capacity, the Company would not be able to add to this supply capacity without all pieces of the Distributed Infrastructure Solution.

Figure 4-24: Summary of existing and near-term sources of Downstate NY gas supply through winter 22/23 without the Distributed Infrastructure Solution

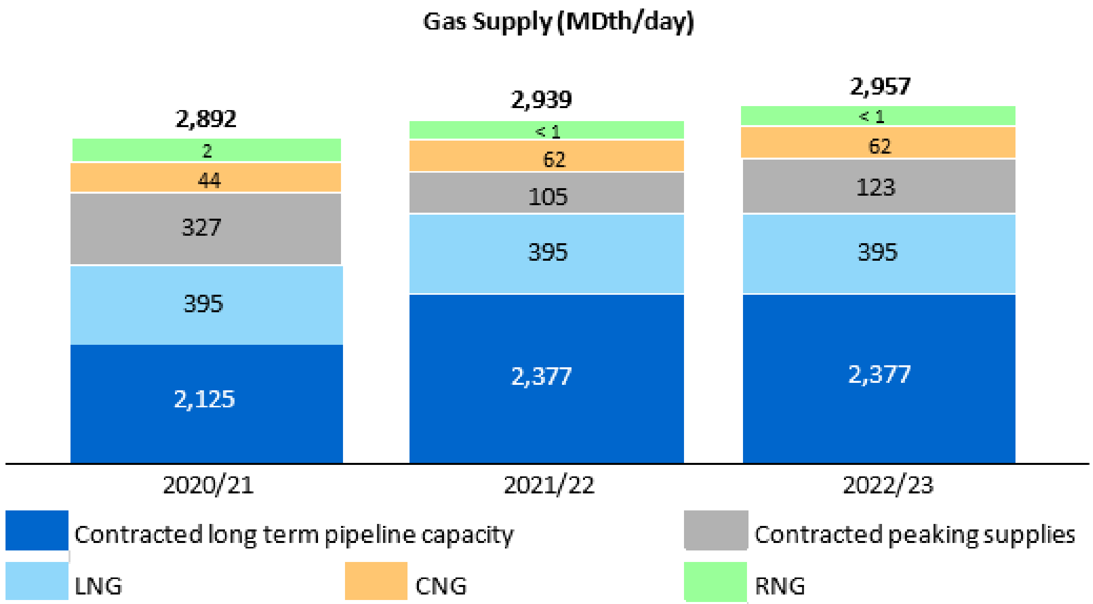


Table 4-1: National Grid's Downstate NY Gas Supply Capacity through Winter 22-23 absent the Distributed Infrastructure Solution

Supply Source	Design Day MDth	Description	Commercial / Operational Constraints and Opportunities
Contracted Long Term Pipeline Capacity	2,377	• Multiple long-term contracts delivering to Transco, Tetco, Tennessee and Iroquois city gates • Varying contract end dates, typically 1-15 years • Company maintains the right to extend or terminate contracts based on need	• Historically highly reliable but always subject to interstate pipeline unplanned outages and restrictions • Historically, these pipelines have allowed National Grid to operate with as much hourly flexibility as was required to serve demand on the coldest days of the winter. As pipelines have experienced increased demand in recent years, they have exercised their rights under their respective tariffs to issue hourly operational flow orders (OFOs) which reduce this flexibility.
LNG Facilities	395	• Owned and operated by National Grid • Capable of storage, liquefaction and vaporization • Holtsville in service since 1971 • Greenpoint in service since 1968	• Required maintenance will take tanks offline for several months. Tank outages will be staggered. The Holtsville tank will be first, followed by one Greenpoint tank. • Current maintenance operations plan is to have each tank offline April-October so as not to disrupt peak demand periods • A contingency plan will be required if maintenance stretches into winter • Proposal to add (2) new vaporizers at Greenpoint will provide approximately 60 MDth/day of additional supply capacity

Contracted Peaking Supplies (City Gate and Cogen)	105-123	• Contracts typically specify 10- 30 days of supply "calls" during the winter period • Contract terms for city gate peaking deals has a defined end date • Cogen peaking contracts are typically longer in duration than city gate peaking deals • Current level of Cogen peaking volumes are 65 MDth/day • City gate peaking volumes expected to range between 40-58 MDth/day	• With the recent acquisition of 252 MDth/day of year round capacity effective 11/1/2021, the Company is now less reliant on short term peaking supplies, and there is less peaking capacity available on the market • Cogen peaking contracts set to expire within the next 5 years • Failure to extend or replace cogen peaking contracts, due to peaking provider opting out, is a possibility • System limitations behind the city gates will limit the amount of city gate peaking supplies that National Grid can contract for Only large on-system infrastructure projects can significantly increase takeaway capacity at National Grid city gates
Compressed Natural Gas (CNG) trailers/ trucking	44-62	• CNG Transfer Facilities provide peak hour support of between 1,100 and 2,200 dt/hr. • Sites have logistics plans to provide the peak hour support for two, four-hour peak periods (AM and PM) • Sites are located on the system to maximize the supply through the DNY distribution and transmission systems	• National Grid has worked diligently with local officials and fire departments to ensure understanding of trucking requirements and safety plans • This supply option has historically been viewed as a contingency operation to augment baseload supply in the event of an unplanned shortage • System could be impacted by events such as road/bridge closures, high winds and inclement weather, but the company has planned to pre-position supplies to mitigate this risk • We are flexible to reducewhat we need from CNG should firm gas demand decline
Renewable Natural Gas (RNG)	< 1	• Fresh Kills Landfill agreement, providing 1,600 Dth/day, was terminated by NYC effective December 2020 • Newtown Creek is expected to provide 750 Dth/day once in service	• Unlike other gas contracts, RNG contracts are not "firm capacity" – they are not guaranteed to deliver during peak periods of demand but can provide a predictable volume on most days • Options to expand RNG behind the National Grid city gates will be driven by third-party developers and landowners • Options to expand RNG upstream of National Grid city gates will be driven by third party developers and interstate pipelines

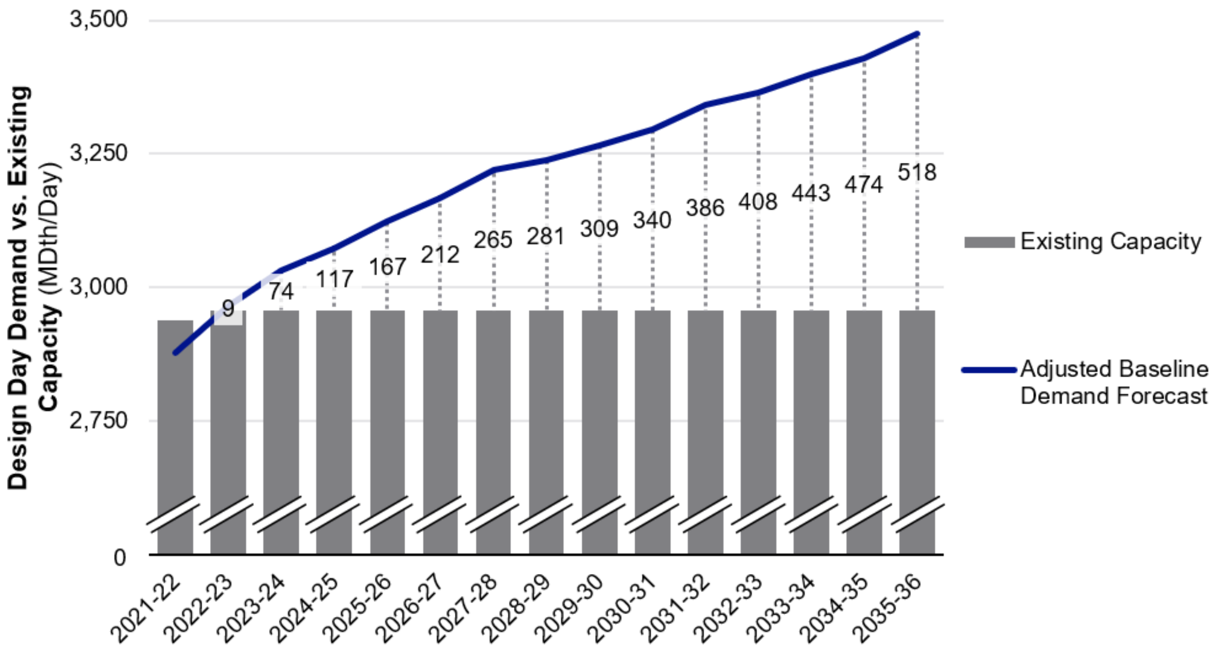
TOTAL	**2,892 – 2,957**	Once planned CNG buildout is complete: • 80% of supply capacity is "fixed" through longer-term pipeline contracts • 13% is peak LNG that is owned and operated by NG • ~7% is flexible through shorter term peaking contracts and CNG

4.7. The Updated Gap Between Downstate NY Projected Natural Gas Demand and National Grid's Supply Capacity

Based on the Adjusted Baseline Demand Forecast, we foresee being able to meet projected customer demand for the upcoming winter of 2021/2022 with currently available gas supply capacity. However, beginning with the winter of 2022/2023, without the additional enhancement to existing infrastructure and incremental DSM planned under the Distributed Infrastructure Solution, we anticipate seeing a Design Day demand-supply gap starting at 9 MDth/day and continuing to grow up to a gap of 518 MDth/Day in 2035 (assuming all existing gas supply capacity is re-contracted) as captured by Figure 4-25.

This gap is slightly higher than the gap projected in the Supplemental Report, even with the increased supply capacity the Company has procured, due to the increase in forecasted Design Day demand forecast since the Supplemental Report. Given the near-term emergence of the supply-demand gap, timely implementation of the Distributed Infrastructure Solution is necessary to address the gas capacity constraint.

Figure 4-25: Projected Demand/Supply Gap between existing capacity and forecasted demand



5. The Recommended Distributed Infrastructure Solution to close the Demand-Supply Gap

Last year, the Company presented several options to close the projected Design Day Demand-Supply Gap and, after extensive public engagement and feedback, recommended two solutions. Following rejection of the permit application for the large infrastructure solution, National Grid focused on implementing the other of the two recommended solutions, a combination of distributed infrastructure projects and incremental DSM programs, identified as “Option A” in the Supplemental Report. Since that time, we have updated “Option A” to include incremental portable CNG capacity, and we have refined the incremental DSM programs, to create the “Distributed Infrastructure Solution” presented herein. This report confirms that the Distributed Infrastructure Solution is the best available solution to address the projected supply-demand gap and is consistent with NY’s Net Zero goals; however, there are risks to its successful implementation.

In this Section, we will provide an update on all the components of the Distributed Infrastructure Solution to close the gap between demand and supply, including our progress to date on its implementation and the risks to its successful completion.

5.1. The Distributed Infrastructure Solution Components Close the Gap and are Consistent with Net Zero Goals

5.1.1. The Components of the Distributed Infrastructure Solution

The Distributed Infrastructure Solution consists of pairing two distributed infrastructure projects -- the Greenpoint LNG Vaporization Project ("LNG Vaporization Project") and the Iroquois Enhancement by Compression Project (the "ExC Project"), with the Company's plan to add incremental portable CNG capacity and aggressive incremental DSM programs made up of additional EE, DR and heat electrification programs.

We have made significant implementation progress regarding the Distributed Infrastructure Solution, including quickly implementing the planned CNG capacity from the last report, advancing the LNG Vaporization Project, and supporting the ExC Project. Our DSM planning has come a long way in terms of innovative program design and obtaining funding for the same.

Table 5-1 lists out the components of the Distributed Infrastructure Solution and summarizes the progress made, if any from "Option A" in the Supplemental Report.

Table 5-1: Distributed Infrastructure Solution Components and Updates

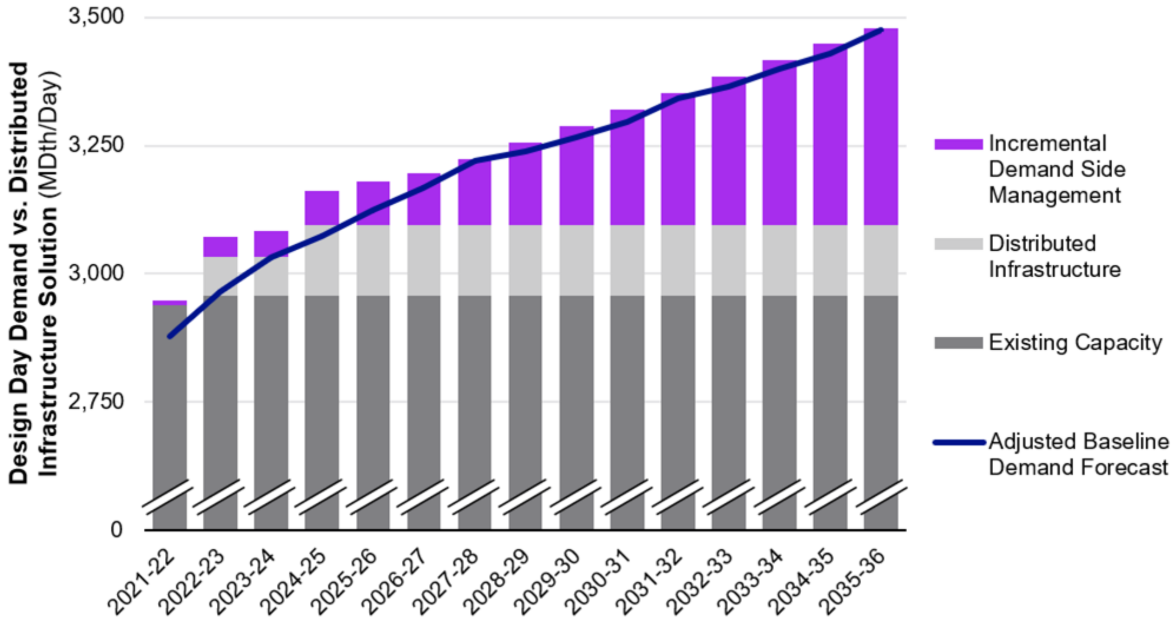
Distributed Infrastructure Solution Component	Option A Component in Supplemental Report	Updates to Option A in Second Supplemental Report
Distributed Infrastructure Projects		
LNG Vaporization Project	Same	None
ExC Project	Same	None
CNG Facilities	Increase to 53 MDth/day of CNG capacity assumed	Facilities constructed to support 62 MDth/day; Incremental CNG Transfer capability of 18 MDth/day under development.
Demand Side Management Programs		
Incremental EE	Weatherization Programs	More robust weatherization programs and new Energy Efficient Connections Program
Incremental DR	Maintaining customers on non-firm rates	New programs focused on daily reductions in gas consumption and targeting hourly reductions in peak demand
Heat Electrification and NPA Market Solicitation	Heat electrification not specified	More planning around incremental heat electrification and market solicitations for NPAs

5.1.2. The Distributed Infrastructure Solution Closes the Gap

Taking into account the latest Adjusted Baseline Demand Forecast, the Existing Capacity, and the alternatives to the current Distributed Infrastructure Solution components, this report re-confirms that the Distributed Infrastructure Solution is the most cost-effective and lowest risk solution to our

Design Day Demand-Supply Gap amongst the available options.[38] Figure 2-5: Distributed Infrastructure Solution Comparison demonstrates how the combined components of the Distributed Infrastructure Solution close the Design Day Demand-Supply Gap.

Figure 5-1: Distributed Infrastructure Solution to the Demand-Supply Gap



In the near term, the distributed infrastructure components of the Distributed Infrastructure Solution are the biggest component of the solution and are critically important to meeting gas demand over these next few winters as the incremental DSM programs ramp up.

In later years, Incremental DSM programs are essential to the Distributed infrastructure Solution, which relies on gas demand reduction to meet three quarters of the projected Design Day Demand-Supply Gap in 2035/2036. In fact, incremental DSM components are expected to offset all projected Design Day gas demand growth after 2025/26, effectively keeping the Design Day gas demand relatively constant in the years following winter of 2025/26 (see Figure 5-2 below) .

5.1.3. Consistency with Net Zero Goals

Measured against the Net Zero Scenario described in Section 4, the Distributed Infrastructure Solution is consistent with New York's Net Zero goals by meeting near-term customer gas demand growth while offering the flexibility to transition to low-carbon fuels and to right size National Grid's gas capacity portfolio over time.

The Net Zero Scenario, depicted below in Figure 5-2, assumes aggressive new policies are adopted under the CLCPA or other local laws (such as future restrictions on new gas connections), that slows gas demand growth (after accounting for the Distributed Infrastructure Solution's DSM demand reduction) beginning in 2025-2026 (taking into account assumed implementation timing for those CLCPA policies and programs), stops around 2027-28, and then reverses.

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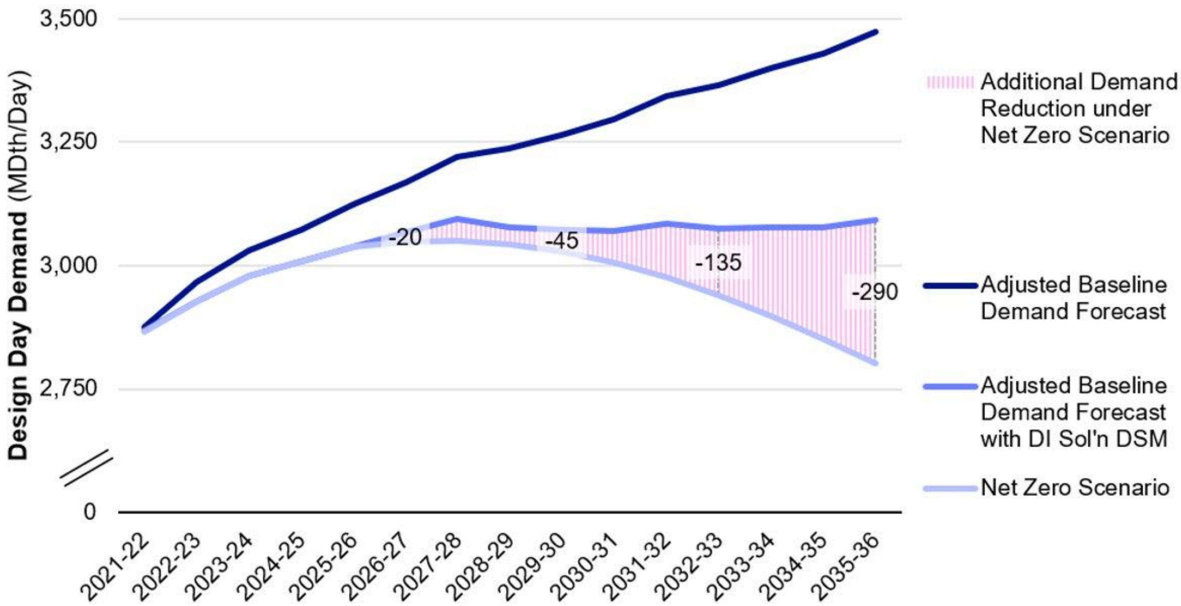
[38] This solution is dependent on National Grid continuing to maximize existing contracted pipeline capacity and peaking capacity.

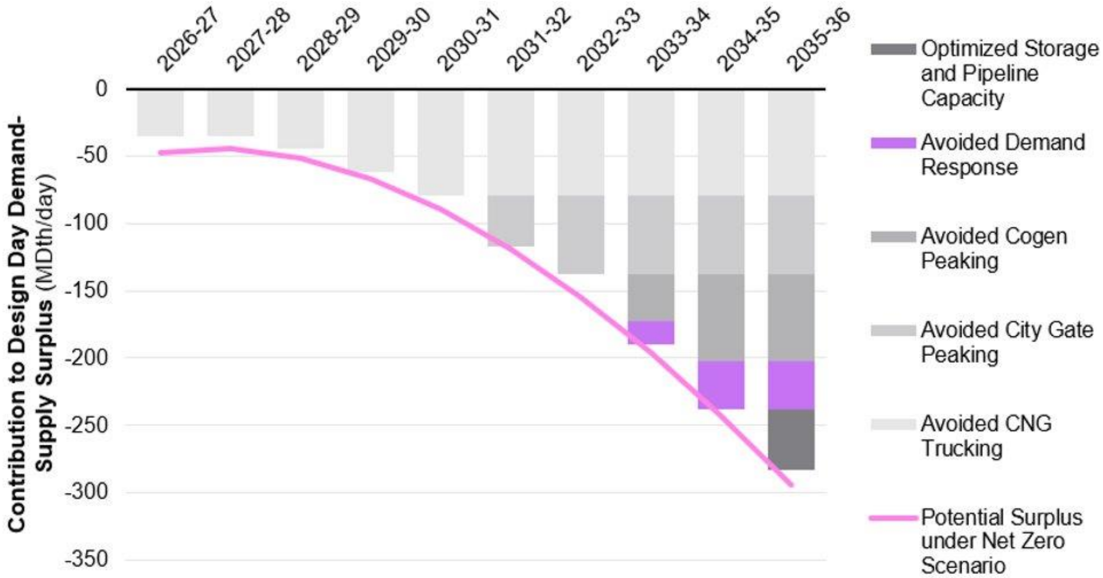
Figure 5-2: Design Day Demand Scenario Comparison



Enhancing our existing infrastructure via the LNG Vaporization Project and ExC Project allows the Company to meet customer demand as it increases in the near term as depicted under this scenario (through the winter of 2025/2026) and pairs these projects with incremental DSM programs that scale up to offset projected future gas demand growth beyond what can be met with these two distributed infrastructure projects. Enhancing our existing gas infrastructure through means such as the ExC Project and other infrastructure modernization projects also creates the flexibility to transition our infrastructure in the future to low-carbon fuels (*i.e.*, RNG and green hydrogen) and place less reliance on CNG sites.

The Distributed Infrastructure Solution additionally allows the Company to right-size natural gas supply capacity if gas demand begins to decline. As an example, in the Net Zero Scenario, the Company would be able to reduce reliance on CNG sites which would provide both cost savings and a lessened reliance on a more GHG-intensive form of gas supply. Thereafter, the Company would likely move -through options by cost, operational complexity, reliability and locational considerations where the final moves could include adjustments to optimize long term pipeline and storage capacity contracts which provide operationally simple, valuable and stable supply to customers. Figure 5-3 depicts an example of how components of the Distributed Infrastructure Solution and today's Existing Capacity could be right sized as described herein. The grey bars show capacity coming off the system, so are represented by negative values to show the decrease in system capacity.

Figure 5-3: Right-Sizing Scenario



Note: Potential surplus under Net Zero Scenario refers to a combination of Additional Demand Reduction under the Net Zero Scenario and any small surplus that was embedded in the Distributed Infrastructure Solution due to imperfect timing of supply and demand matchng.

Thus, in addition to its success in closing the Demand-Supply Gap based on our Adjusted Baseline Demand Forecast, the flexibility inherent in the Distributed Infrastructure Solution allows the Company to adapt its network and supply approaches in the future in response to potential further reductions in customer demand as depicted under the Net Zero Scenario, in keeping with New York's Net Zero goals under the CLCPA.

Based on this modeling, along with our quantitative and qualitative evaluations of the various components as described below, the Company has re-confirmed that the Distributed Infrastructure Solution is the most cost-effective and lowest risk solution available to address our demand-supply gap.

5.2. Summary Status of the Distributed Infrastructure Solution and Key Risks to Implementation

While National Grid has taken many steps to realize this Distributed Infrastructure Solution, there are certain risks identified to its successful implementation. Table 5-2 provides the current status of the Distributed Infrastructure Solution and the Key Risks to Implementation.

Table 5-2: Distributed Infrastructure Solution Status and Key Risks

Project	Status	Key Risks	Risk Likelihood	Risk Impact	Risk Description
LNG Vaporization Project	Design, Env. Review and Pub. Mtgs completed. Awaiting FDNY and DEC permits	Failure to obtain FDNY and DEC permits	MEDIUM	HIGHEST	• Without these permits, National Grid cannot construct the LNG Vaporization Project • The LNG Vaporization Project is deemed by the Company to be the only distributed infrastructure

					project that can be brought on line in time to meet projected demand
ExC Project	Iroquois filed for FERC Approval, Jan.2020.	Failure to obtain FERC approval and subsequent state / local permits	MEDIUM	HIGH	• Without FERC approval, and then the state and local permits, Iroquois cannot move forward with the ExC Project.
Additional CNG Facility	Projects have been delivered to allow supply up to 62 MDth/day; incremental site designed for additional 18 MDth/day	Inability to procure land; permitting delays or rejection	MEDIUM	HIGH	• Scarcity of available land in service territory could impact the size and scale of the additional site; permitting and construction delays could impact timing of implementation.
Incremental Energy Efficiency	Filing for EE programs in development, planned for later this year	Market Resourcing Market Potential Legal and Regulatory Delays	MEDIUM	HIGH	• Lack of market resources to execute projects • Overestimation of market potential and ability to reach accelerated levels of adoption • Failure to get regulatory approval of programs and their costs
Demand Response Programs	Filed for approval in June 2021	Market Potential Program Reliability Legal and Regulatory Delays	MEDIUM	HIGH	• Overestimation of market potential and ability to reach accelerated levels of adoption • If reductions are unreliable, may not have other DR program workarounds • Failure to get legal and regulatory approval of programs and their costs
Incremental Heat Electrification	Heat Electrification proposal in planning and design phase. Annual Market solicitations for NPAs	Market Resourcing Market Potential Legal and Regulatory Delays High costs	HIGH	HIGH	• Lack of market resources to execute projects • Overestimation of market potential and ability to reach accelerated levels of adoption • Heat Electrification is currently uneconomical for many customers, esp. low-income customers, and, as costs for heat electrification programs are higher than for all other DSM programs, heat electrification incentive programs would require multiple legal and regulatory approvals.

A more detailed status of each component of the Distributed Infrastructure Solution and the risks for their implementation are more fully set forth below.

5.3. Individual Component Updates, Status and Risks

In this section, we detail the following:

- An update, if any, on each individual component of the Distributed Infrastructure Solution which includes a brief description of the component and whether the project or program has changed from the Original Report and/or Supplemental Report
- The status of each component, and
- The key risks to the implementation of the component.

5.3.1. LNG Vaporization Project

LNG Vaporization Project - Description and Update

The LNG Vaporization Project adds two additional LNG Vaporizers, Vaporizers 13 & 14, at our existing National Grid Greenpoint facility in Brooklyn, New York.

As described in the Supplemental Report, the Greenpoint facility currently includes two LNG storage tanks, a liquefaction train, LNG truck unloading, and six LNG Vaporizers. The first tank and original vaporizers have been in service since 1968. National Grid has proposed to install two more vaporizers designated as “Vaporizers 13 and 14,” bringing the total number of vaporizers at this facility to eight.

LNG Vaporizers are heat exchangers that regasify liquefied natural gas. The vaporizers currently at the Greenpoint LNG site are Submerged Combustion Vaporizers (SCVs). Should the LNG Vaporization Project be permitted, this would add two additional SCVs. In the SCVs, LNG is pumped into a heat exchanger that lies in a water bath where it is heated and turned back into a vapor state. The water is heated through the submerged combustion unit, a process that sparges hot combustion gas under water resulting in a very efficient exchange of heat energy.

The addition of new vaporizers 13 and 14 will increase the output of the Greenpoint LNG Plant by approximately 60 MDth/day. These vaporizers can be operated intermittently to provide peaking capacity.[39]

LNG Vaporization Project - Status

National Grid has taken all necessary steps to bring the LNG Vaporization Project online but is waiting on final permits. Detailed engineering, procurement, and delivery of long lead materials have all been completed, environmental reviews and public meetings conducted, and fabrication is in progress, pending receipt of the necessary permits.

[39] Although previously included in this report as part of the LNG Vaporization Project, the LNG unloading station is unrelated to and has no impact on the project to include Vaporizer 13 & 14. The function of the LNG Vaporization Project is to add peaking supply to the system to meet demand on the coldest days of the winter. The function of the “LNG Unloading Station Replacement Project” is to provide a contingency plan for an emergency situation requiring an extraordinary response, such as LNG Trucking. The replacement of the existing LNG unloading station plays no role in vaporization at the Greenpoint facility.

Specifically, the project requires NYC Department of Buildings (DOB), and FDNY approval for construction within NYC. Permitting also includes, but is not limited to, all federal, state and local NYC environmental permit requirements (e.g., NYC DEP and NYS DEC). National Grid filed for these permits in 2020.

The DOB permits and the FDNY Mechanical Letter of Approval have been received. Other FDNY and DEC State Air Facility permits are still pending.

Assuming timely approval of all necessary permits, the project could be completed for the 2022/2023 heating season. If the permits are delayed, it could delay completion of this project out to the 2024/2025 heating season.

LNG Vaporization Project - Risks to Implementation

Currently, the primary risk to implementation is not obtaining the necessary permitting for the project, or not obtaining them in a timely manner. Failure to receive required permitting by the summer of 2021 would create a Demand-Supply Gap in 2023/24 without successful implementation of a successful contingency option. National Grid can manage all other risks related to construction and project delivery to ensure timely implementation.

Table 5-3: Key Risks to LNG Vaporization Project

Risk/Signpost	Likelihood	Impact	Description
Failure to obtain FDNY and DEC permits	**MEDIUM**	**HIGH**	Without these permits, National Grid cannot construct the LNG Vaporization Project

5.3.2. Iroquois Enhancement by Compression ("ExC") Project

ExC Project - Description and Update

The ExC Project involves construction of additional compression facilities to increase capacity on the Iroquois Gas Transmission System's ("Iroquois") existing infrastructure.

Iroquois owns and operates an existing 414-mile interstate natural gas pipeline extending from the U.S.-Canadian border at Waddington, NY, through New York State and western Connecticut to its terminus in Commack, NY, and from Huntington to the Bronx, NY. As a pipeline transporting gas in interstate commerce, Iroquois is regulated by the Federal Energy Regulatory Commission ("FERC") and must apply for and receive approval from FERC for any modifications to their certificate to operate, including the offering of new service. The ExC Project is expected to include the addition of incremental compression and/or gas cooling at or adjacent to Iroquois' existing Athens, Dover, Brookfield and Milford Compressor Stations for which that FERC approval is needed. The ExC Project will provide an additional 125 MDth/day of supply which will be split evenly by National Grid and Con Edison.

The Company participated in an open season for the Iroquois ExC Project in July 2019, when it executed a binding twenty (20) year precedent agreement for service with an anticipated in-service date of November 2023. As a result of the Company's participation, National Grid will receive 62.5 MDth/day of natural gas transportation capacity on the ExC Project once it commences service.

The project will enhance system reliability by delivering gas to the eastern most city-gate delivery point, where National Grid demand modeling indicates additional gas will be needed to satisfy ongoing customer needs.

There are no updates to this project's description from the Supplemental Report.

ExC Project Status

On January 31, 2020, Iroquois filed a certificate application with the FERC for the ExC Project; absent an order by FERC approving Iroquois's application for the ExC Project, Iroquois is legally precluded from being able to proceed with the project. In addition to receipt of the necessary FERC permits, Iroquois has filed to obtain air permits from New York and Connecticut for modifications to its existing facilities.

On May 27, 2021, FERC announced that it will prepare a supplemental Environmental Impact Statement (EIS) for the ExC Project, scheduled for September 3, 2021, with a 90-day federal authorization decision[40] of December 2, 2021, which is the date by which the review must be completed; on June 11, 2021, FERC issued a draft EIS in the matter of the ExC Project. FERC's final decision on ExC is expected sometime in 2022, which, even if approved, will likely delay the initial in-service date of November 2023 described in the Supplemental Report. At this time, it is uncertain when FERC may make that final decision. In addition to its FERC certificate, the ExC Project requires receipt of state permits in order to construct and operate in the states of CT and NY. It is unlikely that the CT DEEP or the NY DEC will act on Iroquois's permit applications prior to FERC's issuance of a certificate. The delayed receipt of these federal and state approvals could delay project completion into the 2024/2025 timeframe.

ExC Project – Risks to Implementation

Currently, the primary risk to implementation is Iroquois not obtaining all the necessary state and federal permitting for the project, or not obtaining them in a timely manner.

Table 5-4: Risks to ExC Project

Risk/Signpost	Likelihood	Impact	Description
Failure to obtain FERC approval and subsequent state and local permits	**MEDIUM**	**HIGH**	Without FERC approval, and then the state and local permits, Iroquois cannot move forward with the ExC Project.

5.3.3. Compressed Natural Gas (CNG) Trucking/Trailers Effort

CNG Trucking/Trailers Effort – Update

The CNG Trucking / Trailers effort is the largest of its type in the United States. National Grid has already expanded the CNG deliverability from 17 MDth/day to 62 MDth/day. For the purposes of the Distributed Infrastructure Solution, however, this effort has been updated to include the development of an additional distributed CNG facility to continue to support system growth and supply demand during the coldest days of the winter heating season. This is expected to have a

[40] A "federal authorization decision" is a decision or action by a federal agency or official, "or state administrative agency or officer acting under delegated federal authority," granting or denying requests for permits, certificates, opinions, approvals and other authorizations.

standard design for a CNG Site that includes the capability of delivering 2.2 MDth/hr (peak) or 17.6 MDth/day.

Beyond this additional site, the Company will not and cannot pursue supplies for additional CNG Transfer sites. In order to bring incremental supplies into the constrained Downstate NY region, procurement of CNG requires transportation of the supply from upstream sources outside of the Company's service territory. As the CNG market is still in the early stages of development, there are only a finite number of counterparties known to the Company that are able to provide a finite amount of compression capacity and transportation services to end users. In recent years and with uncertainty that a new pipeline project will be built, the Company has seen increased demand for these types of projects from other local distributions companies. As pipeline constraints increase in the northeast, it is uncertain whether there will be sufficient compression capacity and sellers of CNG within a reasonable distance able to reliably meet the Company's requirements.

Further, there are considerable risks to the Company's ability to locate and procure land close enough to the high demand areas in its Brooklyn, Queens and western Long Island service areas. A CNG site requires multiple acres of land within close proximity to critical low pressure points on the gas transmission system that are zoned in industrial districts – as to maintain sensitivity to residential areas. Largely, this type of real estate is extremely scarce within the Downstate NY footprint and it is not certain if adequate properties would be available to support additional CNG sites.

Finally, a significant challenge exists to maintain a highly qualified and competent labor force which can be dutifully employed to support these sites. Due to the seasonal nature of CNG Transfer Operations, the Company has been able to efficiently scale existing competent employees who are skilled in gas system operations. However, since these skills are acquired over many years of field experience, there is risk that the Company will not be able to manage the turnover of support for any incremental sites past what is currently planned.

CNG Trucking/Trailers Effort – Status

The additional facility is in the early stages of development but could be quickly constructed once the requirements described below are met.

This project will need to file for local and state level approvals for implementation. These requirements will likely include coordination and/or approvals from first responders, stormwater permits for construction activities, or other local municipal approvals.

The Company will also need to assess locations that would support this distributed supply source. Generally, this means selecting a location that has access to a location on the gas transmission system that could disperse the CNG widely throughout the DNY territory. Without this 'takeaway' requirement, the CNG would not be able to be delivered in enough quantities to support any material volume of capacity during cold weather operations. Implementation will also require the upstream CNG market's ability to support National Grid's scale of operations.

CNG Trucking/Trailers Effort – Risks to Implementation

A primary risk is the Company's ability to locate and procure land for this additional site. As noted above, CNG site requires multiple acres of land within close proximity to critical low pressure points on the gas transmission system that are zoned in industrial districts. This type of real estate is extremely hard to find in the Downstate NY area.

Other risks 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 advanced stakeholder engagement and codified complex capital delivery processes. National Grid believes it can manage the risks related to construction and project delivery to ensure timely implementation.

Table 5-5: Risks to CNG Project

Risk/Signpost	Likelihood	Impact	Description
Inability to procure land	**MEDIUM**	**HIGH**	Scarcity of available land in service territory could impact the size and scale of the additional site
Permitting risks	**LOW**	**HIGH**	Location-specific permitting and other risks typical to smaller construction projects; the company typically mitigates these risks through careful planning.

5.3.4. Demand-Side Solutions

The Distributed Infrastructure Solution relies on four major Non-Gas Infrastructure Options: Energy Efficiency (EE), Demand Response (DR), Heat Electrification, and Non-Pipe Alternatives (NPAs). Since the Original Report and Supplemental Report, National Grid's planning for these options has come a long way in terms of innovative program design, and the Company anticipates proposing an unprecedented level of new DSM programs this year that are a fundamental part of the Distributed Infrastructure Solution.

Incremental EE consists of strategies that provide savings over and above NE:NY targets, with programs and measures that prioritize demand reduction. These incremental EE measures would not necessarily have passed the benefit cost analysis ("BCA") test without taking into account the counterfactual cost of gas infrastructure in Downstate NY that would otherwise be needed to meet customer demand growth. The major focus of these incremental EE initiatives will be intensive weatherization programs, focused on Design Day thermal savings. Similarly, National Grid will build on our experience with demand response to design new programs that support Design Hour and Design Day requirements. In addition, National Grid will continue to promote heat electrification as an alternative to existing natural gas customers or oil heating customers, while exploring a collaborative pilot with the Electric Delivery Companies ("EDCs"). Beginning in 2021, National Grid will hold annual NPA solicitations to determine whether the market has innovations that could assist the Company with delivering DSM more cost effectively than traditional utility program delivery.

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. National Grid's efforts on the demand-side solutions have focused on developing programs to meet the demand reductions required in the next several years as part of the Distributed Infrastructure Solution. This Second Supplemental Report provides a conceptual example of how DSM strategies might be deployed in the longer term to address the projected Supply-Demand Gap. However, the programs, technologies, and business models that would be required to deliver such aggressive savings do not yet exist. We will continue to invest in the evolution of our DSM programs with the goal of maximizing their potential as non-infrastructure solutions.

Each element is further described in the sections that follow.

5.3.4.1. Incremental Energy Efficiency

Incremental Energy Efficiency Program – Description and Update

Energy efficiency is and will continue to be a key component of National Grid's gas DSM toolkit because it is one of the most cost-effective strategies for combating climate change, reducing air pollution, improving the competitiveness of our customers' businesses, reducing energy costs for consumers, increasing comfort, and improving property values. The Downstate NY NE:NY portfolio of programs includes commercial and industrial (C&I), small business, residential, and multifamily sector-specific offerings designed to serve the diverse needs of all four broad market sectors. The Company's current EE programs contain a number of traditional energy saving measures including residential space heating and water heating rebates, multi-family incentives, and C&I measures such as space heating, steam system upgrades, kitchen equipment and custom projects. Programs are detailed annually in National Grid's System Energy Efficiency Plans ("SEEPs") and are designed to support New York State's clean energy goals with a focus on reducing energy consumption and lowering customer costs. Program costs are recovered through rates.

Table 5-6 below shows National Grid's aggressive NE:NY targets across its KEDNY and KEDLI territories as well as the year over year percentage (YOY %) increase. NE:NY gas savings targets are presented in annual mmBtu[41] savings. Achieving these targets will provide approximately 25 MDth/day of demand reduction by 2025. This required year-over-year program growth associated with our NE:NY targets is already built into National Grid's Adjusted Baseline Demand Forecast, with the assumption that 100% of those targets will be met.

Table 5-6: NE:NY Annual Savings Targets

Year	KEDNY Gas (MMBTU)	KEDNY Gas YOY % Increase	KEDLI Gas (MMBTU)	KEDLI Gas YOY % Increase
2020	439,498		242,386	
2021	510,740	16%	433,821	79%
2022	674,740	32%	601,821	39%
2023	857,740	27%	756,821	26%
2024	1,082,740	26%	953,821	26%
2025	1,347,740	24%	1,129,821	18%

To help address the Demand-Supply Gap, National Grid's Incremental EE programs have targets over and above the NE:NY targets shown above, and, with Incremental DR, is a core contributor of the DSM portion of the Distributed Infrastructure Solution prior to 2025.

To achieve this Incremental EE, the Company is building new program offerings beyond those described in the NE:NY portfolio that target reducing Design Day demand. The nature of these programs will be primarily focused on intensive weatherization measures for several reasons: (1) Weatherization has a strong correlation with reducing peak energy demand; (2) weatherization measures have a long useful life, so will continue to reliably provide demand reduction into the future; (3) weatherization is a key component to make homes ready for the possible electrification of heat by reducing heating load; and (4) as National Grid does not currently offer weatherization programs in New York City or Long Island to market rate customers, weatherization programs do not conflict with National Grid's existing EE portfolio. Utility peer benchmarking underscores the demand reduction value of weatherization programs.

National Grid is launching two new weatherization programs in the Fall of 2021: (1) a residential weatherization program and (2) increased incentives for weatherization measures to commercial and multifamily customers through our existing C&I custom program.

- **Residential Weatherization:** The residential weatherization program will provide incentives to residential natural gas heating customers to make building envelope improvements to their

[41] One dekatherm is equal to one million British thermal units (Btu).

homes, such as insulation, air sealing, and window improvements. Incentives will include downstream incentives for customers, as well as midstream incentives to aggregators based on performance – which are designed to drive market engagement. National Grid will encourage aggregators to leverage financing and performance contracting models available in the market to encourage more customers to pursue weatherization retrofits. Incentives across aggregators and customers are currently planned to be $15/therm, based on National Grid's Massachusetts and Rhode Island programs and findings from peer benchmarking and weatherization customer survey work, but these may evolve based on additional vendor and customer feedback after program launch.

Customer education and marketing are critical elements of the program. National Grid is using a thermal imaging technology behavioral tool vendor, MyHeat, to collect thermal imaging data to improve and personalize customer outreach. MyHeat's technology reveals energy loss data for individual residential buildings across entire service territories, allowing the Company to identify homes with high consumption and heat loss and target those customers who would most benefit from installing weatherization measures.

The Company is also leveraging a third-party implementation vendor to manage the program on an end-to-end basis. The vendor will manage 1) leads from MyHeat into the weatherization program, 2) incentives to be provided to customers, 3) a rolling Request for Qualifications (RFQ) process in which aggregators will be selected (and provided a midstream incentive) to manage their own subset of trade allies to achieve National Grid's weatherization goals, reporting program savings and spending to the company, and (4) quality assurance of the aggregators.

- **Custom C&I and Multifamily Weatherization:** The Custom C&I and Multifamily program will provide increased incentives for weatherization measures (such as insulation, air sealing, and window improvements) for commercial and multifamily customers through the existing Custom C&I program. Incentives are currently planned to be $11/therm for multifamily commercial customers, based on National Grid's Massachusetts and Rhode Island programs, but these may change based on the results of upcoming marketing studies and customer surveys. Higher incentives may be needed to reach savings targets for weatherization in these markets.

  The Company already has a robust education and marketing plan for its existing Custom C&I programs, centered around driving participation through communication on financial incentives, third-party financing options, and technical assistance offered to key decision-makers, such as owners, facility and property managers, and C-suite employees.

  National Grid seeks to build on these efforts by leveraging learnings from its peer utility research to utilize portfolio-level cost benefit analysis to optimize offerings and incentive levels for the C&I program. Lessons learned from our peers are integral as we plan targeted offerings to small business and multifamily customers. Their experiences with bundling weatherization measures and direct installation are informing the development of offerings specific to this customer segment.

In addition, National Grid is developing a streamlined approach to make extensive building weatherization improvements available to small and medium sized businesses and multifamily complexes through prescriptive offerings as well as beginning to offer EE incentives to new gas connection customers. These programs will be ready to launch in the Fall of 2022: (1) a small business weatherization program (2) multifamily weatherization program and (3) Energy Efficient Connections.

- **Small Business Weatherization:** The Small Business Weatherization program will provide increased incentives for weatherization measures similar to the Custom C&I program above. An incentive level will be determined in order to drive customer adoption and participation. We anticipate the incentives will be similar to programs launched this year. These customers represent a large portion of the C&I Sector. We anticipate this program will be offered through a direct-install approach and/or prescriptive pathway to increase levels of participation. We understand these customers prefer a more streamlined and simplified approach to participating in energy efficiency programs. Offering a pathway that will meet these customers' needs is a priority in development for our 2022 portfolio.

- **Multifamily Weatherization:** The Multifamily Weatherization program will also provide increased incentives for weatherization measures. This Multifamily customer energy consumption is a notable portion of the Residential Sector within Downstate NY. Multifamily customers have a unique perspective and set of decision-making indicators. For example, occupant comfort is likely to be balanced against upgrade costs with partial information. We will be evaluating a direct-install approach and/or prescriptive pathway to increase levels of participation. Offering a pathway that works for these customers is a priority for development of our 2022 portfolio.

- **Energy Efficient Connections:** Energy Efficient Connections represents strategies that focus on reducing the gas demand prior to new customers joining the system by targeting new customers converting to gas space heating. We plan on implementing inspections to enforce the existing EE requirements in our tariffs. In addition, the Distributed Infrastructure Solution includes expansion of EE requirements from current standards.. While current programs are only available to existing customers, Energy Efficient Connections adds a pathway for new customers to access EE programs. Expanding participation to new customers provides a valuable opportunity to reduce demand that each customer adds to the system and supports our new customers with the comfort and health benefits that our EE programs provide.

A customer survey to better understand what drives our customers, how they perceive weatherization work, what economic criteria they use to implement capital or energy efficiency and other projects was completed in May 2021. We are currently reviewing this customer survey to better understand market drivers in order to improve our approach on EE. We are also leveraging lessons learned from recent peer benchmarking efforts, including targeting offerings to small business and multifamily customers that bundle weatherization measures and direct installation.

National Grid will also continue to pursue market studies and pilots to address the market potential of EE measures governed by equipment effective useful life, future regulatory drivers, new business models and new technologies to remain agile with our incremental EE portfolio of solutions.

In terms of cost, weatherization programs are one of the costliest of the incremental DSM programs over the next five years, but also deliver persistent savings (with measures that have a 25-year useful life on average) and are projected to deliver some of the biggest Design Day impacts, reaching a cumulative of approximately 18 MDth/day of demand reductions by Winter 2025/26.

Success for these weatherization programs will be determined by the total annual savings achieved and the number of participants in the program. The company will utilize internal sales and vendor sales channels to help recruit contractors to participate and drive awareness of the weatherization programs. The projected impact of these programs includes the small business program and multifamily program contributions. The savings demonstrated in these tables are contingent upon approval of the Demand Side Management filing the Company will make in summer 2021. The projected annual savings are listed in Table 5-7**.**

Table 5-7: Incremental Weatherization Program Summary of Contributions

Incremental Weatherization	Assumed Annual Incremental EE Targets (Dth/yr)					
Company	Cust Seg	2021	2022	2023	2024	2025
KEDNY	RH	2,750	110,550	165,825	207,281	259,102
KEDNY	COM	1,375	55,275	82,913	103,641	129,551
KEDNY	MF	1,375	55,275	82,913	103,641	129,551
KEDLI	RH	2,250	90,450	135,675	169,594	211,992
KEDLI	COM	1,125	45,225	67,838	84,797	105,996
KEDLI	MF	1,125	45,225	67,838	84,797	105,996
Total		10,000	402,000	603,000	753,750	942,188

Incremental Weatherization	Assumed Annual Incremental EE Targets (Dth/yr)					
Company	Cust Seg	2021	2022	2023	2024	2025
KEDNY	RH	2,750	110,550	165,825	207,281	259,102
KEDNY	COM	1,375	55,275	82,913	103,641	129,551
KEDNY	MF	1,375	55,275	82,913	103,641	129,551
KEDLI	RH	2,250	90,450	135,675	169,594	211,992
KEDLI	COM	1,125	45,225	67,838	84,797	105,996
KEDLI	MF	1,125	45,225	67,838	84,797	105,996
Total		10,000	402,000	603,000	753,750	942,188

Table 5-8: Incremental Energy Efficient Connections Program Summary of Contributions

EEC EE	Assumed Annual Incremental EE Targets (Dth/yr)					
Company	Cust Seg	2021	2022	2023	2024	2025
Both	RH	45,900	149,292	166,115	169,591	164,242
Both	COM	2,598	25,190	16,336	17,255	14,761
Both	MF	1,316	4,624	3,597	3,079	3,135
Total		49,814	179,106	186,048	189,925	182,138

EEC EE	Cumulative Design Day Impact (from 2021) (Dth/day)					
Company	Cust Seg	2021 22	2022 23	2023 24	2024 25	2025 26
Both	RH	0	2,571	4,759	6,993	9,156
Both	COM	0	366	581	808	1,003
Both	MF	0	78	126	166	207
Total		0	3,015	5,466	7,967	10,366

Incremental Energy Efficiency Program – Status

National Grid intends to file for the EE programs in its Demand Side Management Filing in summer 2021.

Incremental Energy Efficiency Program - Risks

There are numerous risks associated with this Incremental EE program. For one, the required level of weatherization scale up would exceed that of any peer programs studied, making it difficult to be certain about the projected savings. Another risk is that the level of weatherization and energy efficient gas equipment upgrades may saturate the market (reach a limit of feasible customer uptake) and therefore additional innovations will be required to meet both the NE:NY and incremental targets in Downstate NY beyond 2025. Other risks relate to costs, customer participation and regulatory concerns.

A description of the likelihood and impact of the key risks to both the NE:NY and Incremental EE programs set forth above is outlined in Table 5-9.

Table 5-9: Risks to DSM Program Success

Risks	Likelihood	Impact	Description
Market Resourcing	**MEDIUM**	**MEDIUM**	There may not be enough market resources (contractors, vendors) to execute programs at required participation levels.
Market Potential	**MEDIUM**	**HIGH**	Overestimation of market potential in that the DIS may be relying on more DSM than the market can deliver on time.
Costs & Adoption	**MEDIUM**	**HIGH**	Weatherization may continue to be uneconomical for customers, particularly LMI customers. May require increased incentives to spur adoption.
Persistent Increase in Cost of Building Materials	**MEDIUM**	**MEDIUM**	Costs of building materials are rising faster than the cost of inflation making projects less cost effective
Delays of Approval for Tariff Change	**MEDIUM**	**HIGH**	Increasing the EE mandate requires a tariff change that is subject to stakeholder and regulatory processes
Market Saturation	**MEDIUM**	**HIGH**	The market for EE measures may saturate earlier than forecasted, delivering less total demand day savings than needed.
Regulatory restrictions on incentivizing high efficiency gas equipment	**MEDIUM**	**MEDIUM**	If utilities are restricted from incentivizing high efficiency gas equipment in the future, including gas heat pumps, there is a risk that we will not be able to achieve long term EE targets

5.3.4.2. Demand Response

Incremental DR Program Update

DR in the Original Report was described as being two specific program types, namely a “Bring Your Own Thermostat” (BYOT) program focused on residential customers and retention of non-firm customers. The Company has since updated its DR portfolio as follows.

First, the Company has taken steps to deploy a portfolio of three* firm demand response programs:

1. **C&I DR** focused on producing daily reductions in gas consumption;

2. **C&I DR** focused on producing peak hour reductions without requiring a reduction in daily gas consumption; and

3. **Residential BYOT DR**, which, as described in the Supplemental Report, produces a more pronounced hourly impact as opposed to a daily reduction.

*A fourth firm DR program based on residential and small business owner behavioral change is also in development but was not included as part of the Distributed Infrastructure Solution plan as it requires additional study, as described more in Section 6.

Program 1 is the largest program deployed to date, with 156 facilities participating to reduce their usage over the gas day and to offer a potential reduction of 17.8 MDth on a Design Day (assuming 100% participation). The vast 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 wished to retain fuel flexibility. The customers participating in this program are likely to be the same customers that would consider non-firm rates.[42] Therefore, it is possible that we could have customers transition from a firm DR program to a non-firm rate or that we could have a non-firm customer submit a request to transition to a firm rate and then participate in a DR program. For this reason, we must carefully consider the incentive structures of the different programs so that we are not inadvertently motivating customer action that would make it more difficult to meet our system needs.

Program 2 is in its infancy, but closely mirrors the DR pilot that was instituted by the Company beginning in 2017. In Program 2, customers reduce gas usage during peak hours but will not be required to reduce total gas consumption over the entire peak day which 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, completing a production run at a different time), but are unwilling or unable to reduce their usage over a full day. Program 2 may be a valuable tool to manage our intraday demand profile. We expect to expand this program will be operational for Winter 2021/2022.

Program 3 is the BYOT program mentioned in the Original Report. Customers enroll their smart thermostats and provide National Grid with the authorization to adjust their setpoints during event hours. We had 2,251 devices enrolled in our Brooklyn and Queens territories at the end of Winter 20/21. Customers in our Long Island territory will be able to enroll by the end of 2021. Data collected from this past winter show that customers reduced their usage during event hours by 20-30% and their daily consumption by 2-3%. This is consistent with the reduction amount presented in the Original Report, confirming that this program could potentially provide up to 13 MDth/day if 50% of the residential population were enrolled.

Second, in addition to the DR programs described above, the Company has been working with non-firm customers to explain the value of remaining on their current/proposed rates and working to increase their access to EE opportunities, in an effort to retain them as non-firm customers. And, as part of the Distributed Infrastructure Solution DR portfolio, the Company is looking to create an additional incentive for non-firm customers to stay on the non-firm rates by increasing the discount that they receive relative to the applicable firm service that they would receive. The Joint Proposal includes updates to lower the non-firm demand response rates which will make them more attractive. The Company plans to proactively communicate with non-firm customers to inform them of the upcoming rate changes to encourage them to stay on their rates.

[42] Non-firm rates provide the greatest amount of reduction on a Design Day, as customers are assumed to be curtailed throughout the full 24 hours. This is in contrast to our DR programs, where customer reductions are currently 4-8 hours of a Design Day. Therefore, a customer who is on a non-firm rate may be offering up to 3x more demand reduction than a DR customer. The incentive structure for firm DR has been established with the cost reduction from being on a non-firm rate as an upper bound.

The non-firm service classification is important to helping the Company manage its Design Day loads. This service class requires that customers switch to a backup fuel when they are curtailed by the Company. This curtailment is typically dictated by low external temperatures, set annually as indicated in each Company's Gas Transportation Operating Procedure Manual. A potential Design Day would be colder than the threshold for curtailment under non-firm demand response. Since the Company does not plan for these customers to be taking gas on the coldest days, they are not built into the system engineering model. Non-firm rates provide the largest DR reduction on a Design Day, as customers are be curtailed throughout the full 24 hours. This is in contrast to our other DR programs, where customer reductions are currently 4-8 hours of a Design Day. Therefore, a non-firm customer may offer up to 3 times more demand reduction than a firm-DR customer. The Company has analyzed the non-firm customer class and believes that roughly 2/3rds of the remaining customers receive a sufficient incentive that they are considered a low probability of requesting a conversion to firm service. However, the remaining 1/3rd, represent some risk to switch. If those customers do switch to firm service, they will add nearly 28 MDth to the Design Day, making retention of these non-firm customers vital.

As discussed in Chapter 4, the Company has seen a significant decline in the number of non-firm customers we serve, with many, if not all, of those customers requesting and transitioning to a firm service rate. Stemming this trend is important in mitigating increases in Design Day demand.

Incremental DR Status

When the Original Report was written, there was not a clear pathway to fund DR programs. National Grid had submitted a proposal in our most recent rate case that would have provided modest levels of funding ($2-$3M per year) but current plans and needs indicate that we will need significantly more ($8M in 21/22, increasing to $25M in 25/26). The Settlement Agreement in Case 19-G-0678[43] includes the ability to recover costs for DR programs via two different surcharge mechanisms and makes allowances for the increased costs for the programs. This removes the funding risk that was described in the original reports for the DR component of the solution. Additionally, we have hired two full time employees (FTEs) who are focused on managing the Downstate NY DR programs, reducing some of the execution risk. These FTEs are working closely with our metering, regulatory, and gas operations groups to manage DR portfolio growth and to manage the non-firm customer class more actively.

Incremental DR Program Risks

The main focus for DR is continuing to increase program participation, figuring out the right mix of programs (both firm and non-firm), and continuing to improve our understanding of the reliability of DR programs. We continue to exceed our sales targets and have strong interest from customers, which is encouraging. Conversely, we have seen some low levels of performance during test events, which reinforces the need to understand the aggregate reliability of a DR portfolio as we increase our dependence on this resource.

The biggest implementation risks for demand response involves customer acquisition, retention, and performance. We need to increase the size of the DR portfolio, sell it every year (since we currently don't have multi-year enrollment structures), and ensure that customers perform, both through ensuring they are prepared to perform and creating incentives/penalties that align our goals with the goals of customers. We have tried to address this by adopting a direct load control (DLC) arrangement for firm DR customers, where we install a device at customer sites that curtails their usage and, if applicable, switches them to a backup fuel similar to arrangement for some non-firm

[43] 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*, Settlement Agreement approved by order dated November 26, 2019.

customers. The non-firm customer class has a reliability of ~95% during curtailments so adopting a similar control structure may lead to a similar level of performance reliability. The penalties for non-performance during non-firm curtailments are significant so that may motivate customers to perform, even if they would otherwise override the DLC setup. We have established both DLC and non-DLC tiers for our firm DR programs so that we can begin to test whether there is a quantifiable difference between DLC and non-DLC tiers. By measuring the reliability of the participants in different tiers, we can begin to improve our forecasts for firm DR performance and market potential.

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

A summary description of the likelihood and impact of certain risks to DR performance is outlined in Table 5-10.

Table 5-10: DR Risks

Risk/Signpost	Likelihood	Impact	Description
Customer Adoption/Retention Too Low To Meet Target	MEDIUM	HIGH	We have aggressive targets for deploying DR in the coming years. If customers do not sign up for the program, we will not be able to satisfy the component of the portfolio solution associated with DR.
DR Reductions Are Not Reliable	LOW/MEDIUM	HIGH	If DR reductions are not reliable, we may not be able to plan around them, even if we are able to develop/sell programs

5.3.4.3. Incremental Heat Electrification

Incremental Electrification of Heat - Description and Update

In March 2021, National Grid started the process to support the heat electrification programs run by the two EDCs in Downstate NY, Con Edison and PSEG-LI, through a Lead Referral process, meant to educate customers in Downstate NY of their heat electrification options. Customers who call National Grid to connect new gas service or expand existing gas service are now asked if they are interested in learning more about alternatives to gas. National Grid directs interested customers to Con Edison or PSEG-LI’s Electrification of Heat programs. National Grid will work with the EDCs to ensure that interested customers are directed to the appropriate EDC resources and contacts. The Company’s recently submitted Joint Proposal contains lead generation targets the Company must achieve for both Con Edison and PSEG-LI and can inform future program growth. When those referrals result in customers switching to electric heat pumps instead of natural gas, peak gas demand will be reduced. Early results show approximately 32% of respondents from this referral process state that they are interested in learning more about the heat pump programs available, the majority of which were in National Grid’s KEDLI territory. National Grid will work with the EDCs to quantify the success of the Lead Referral program by tracking the number of leads that ultimately elect an EDC heat pump incentive.

Heat Electrification incremental to Con Edison’s NE:NY targets and PSEG-LI’s heat electrification program (which together constitute “Baseline Electrification“) is a key component of National Grid’s gas DSM long-term strategy. Although costly at present, heat electrification is one of the most powerful strategies for advancing the pathway toward Net Zero and closing the Demand-Supply Gap.

After the mid-2020s, electrification is a significant contributor to the Distributed Infrastructure Solution, which demands a steep ramp up of required electric heat pump installations. During 2026-2030, to achieve the Distributed Infrastructure Solution, electrification efforts need to be increased more than 10-fold from ~2,300 customers per year in 2025 under Baseline Electrification to ~24,400 customers/year in 2031. This annual rate of heat electrification is also 10 times higher than in Baseline Electrification as captured in Table 5-11. There are major challenges to reach this number of customers per year at this pace. The scale of electrification required is driven by the high costs of customer and building conversions, but it is not yet clear if all funding sources and partners to achieve these levels of electrification will be available. This is driving the need for a pilot program to study how this level of electrification could be achieved, to determine what the best pathways may be for success, making these next few years of study crucial before launching these programs.

Table 5-11: Examples of heat electrification rates

Scenarios and solutions	Average annual installations 000 cust/year			Total installations 2021 2035	
Range (years)	2021-25	2026-30	2031-35	'000 cust.	vs. Baseline
Baseline Electrification	2.1	2.4	2.6	35	N/A
Distributed Infrastructure Solution in Full	2.3	21.4	24.4	240	~7x

Note: "Distributed Infrastructure Solution in Full" annual heat electrification numbers also includes Baseline Electrification numbers

Incremental Heat Electrification Status

National Grid intends on requesting resources and technical support services through its Demand Side Management filing to support this ongoing work.

Collaboration will also be an integral part of an incremental heat electrification program's success, and the Company has started to reach out to the EDCs to discuss what that might look like. The coordinated effort will focus 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(s) in collaboration with the EDCs and other industry partners is in development. The goals of the studies and pilot(s) 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 framework required for consultation 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 low-and moderate income customers and environmental justice zones

Throughout this process, the Company will also leverage collaboration opportunities and shared resources with NYSERDA to reach the goals mentioned above.

The initial estimate of pilot reach within the models in this report is approximately 1,130 gas customers to convert to full load electric heat pump systems by 2025. However, actual pilot reach is not yet final. The pilot would provide insight into planning required for the significant expansion of a robust incremental heat electrification program later in the 2020s.

The levels of incremental energy efficiency and heat electrification beyond 2025 assumed as part of the Distributed Infrastructure Solution are aspirational due to the unprecedented levels required. At this moment, we have not identified the programs, measures/technologies, business models or budgets that could produce these levels of DSM. The exact programmatic composition, utility responsibilities and incentive levels required to influence this level of adoption will evolve as policy, regulation and our experience of cutting-edge gas DSM evolves. National Grid is committed to finding solutions, innovating and collaborating as part of our ongoing DSM efforts in Downstate NY.

In the event there are delays to or rejections of the LNG Vaporization Project or ExC Project, some of the aggressive heat electrification may need to be accelerated, which would have significant execution risk given the amount of development work required and the scale at which would need to be implemented. This will be described in Section 6 as part of contingency planning.

Incremental Heat Electrification - Risks

In NYC, the energy system is highly complex, driven by market forces, regulations, weather and climate, and other factors including demographics and land use. Capital, labor and technology need to be readily available at the pace and scale to deliver successful programs. Customer buying behavior will have to align with the goals of heat electrification. Construction permit processes may dictate the rate at which heat electrification is feasible. A pathway for each market (industrial, commercial, multifamily, residential, etc.) must be feasible and available to accommodate anticipated targets of an accelerated heat electrification program.

A description of the likelihood and impact of certain risks to incremental heat electrification set forth above is outlined in Table 5-12.

Table 5-12: Heat Electrification Risks

Risk/Signpost	Likelihood	Impact	Description
Market Resourcing	**MEDIUM**	**MEDIUM**	There may not be enough market resources (contractors, vendors) to execute required number of projects.
Market Potential	**MEDIUM**	**HIGH**	Overestimation of market potential and ability to reach accelerated levels of adoption. Size of DSM needs grows if gas infrastructure solutions are not approved.
Customer Value Proposition & Adoption	**HIGH**	**HIGH**	Heat Electrification may continue to be uneconomical for customers, particularly LMI customers and will likely require higher incentives to spur adoption. Customer's may not choose to electrify their heat unless mandated by state/government due to lack of familiarity with technology, low cost of gas, high cost of electric and concern around perceived reliability with cold-climate heat pumps
Costs	**HIGH**	**HIGH**	Incremental heat electrification costs could be significantly higher than all other EE programs. LMI programs that align with this acceleration of heat electrification will cost even more than a market rate heat electrification program
Delays in executing MOU, electric system constraints, legal and regulatory processes	**MEDIUM**	**HIGH**	Incremental heat electrification would require an MOU with EDCs. If gas utilities are restricted from incentivizing electric equipment in the future we may not be able to achieve long term heat electrification targets

5.3.4.4. Non-pipeline alternatives (NPAs)

NPAs - Description

Non-pipeline alternatives ("NPA") have not been described in previous reports. This term, which does not yet have a legal definition, broadly describes initiatives that can reduce, delay, or eliminate the need for pipeline infrastructure. For the purposes of this Second Supplemental Report, however, we are referring to market solicitations for NPAs as described in our Joint Proposal.

More specifically, as described in the Joint Proposal, National Grid will annually issue at least one request-for-proposal ("RFP") seeking non-traditional, cost effective peak supply NPAs and annually identify at least five segments of leak-prone pipe in each service territory that could be abandoned if all customers' natural gas loads are met with cost-effective NPAs that would allow the section of pipe to be abandoned. For each such section, the Company will consider NPAs allowing the section to be abandoned, or otherwise demonstrate that abandonment of such section is not possible. Furthermore, for gas service requests that involve a main extension of more than 500 feet and serve five or more customers, the Company will perform a preliminary analysis of the potential to meet the needs of the prospective customers with a non-gas NPA. If this analysis shows that it is feasible and beneficial for customers from a cost perspective and would lead to reduced GHG emissions, the Company will contact those customers to present alternatives. If the customers are willing to consider an alternative to natural gas, the Company will issue RFPs for contractors and vendors for installing the non-gas NPA. More generally, where possible, National Grid will make evaluations of possible NPAs a standard item before proceeding with the construction of new or replacement gas transmission and distribution infrastructure.

NPAs may offer incremental demand reductions, increased efficiency, or lowered costs, depending on the specific application. Critically, NPAs are technology agnostic, so that a variety of solutions (e.g. thermal energy storage, air and ground-source heat pumps) can be proposed if they meet the operational requirements and are accepted by the impacted customers.

National Grid did not include any NPAs in its original "Option A" solution. In the intervening period, we have made sufficient progress regarding a framework to solicit, evaluate and implement NPAs that we now include them as part of the Distributed Infrastructure Solution.

NPAs - Status

National Grid intends to complete development of its NPA framework this year. 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 are expecting to file our first RFP for a Downstate NY NPA within this year as well.

NPAs - Risks to Implementation

It is not yet known what the impact of these NPAs will be in reducing demand. Though third-parties will be able to offer proposed solutions, these solutions may represent similar types of DSM solutions as those proposed 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 any planned programs will improve.

5.4. Overall Summary of Risks to Implementation of Distributed Infrastructure Solution

Currently the greatest risk to implementation of the Distributed Infrastructure Solution are the permitting and regulatory risks to distributed infrastructure projects. Following that, with regards to the DSM programs, the greatest challenges will be achieving shifts in customer behavior and adoption due to the unprecedented levels of these programs, and the unpredictable nature of customer participation.

6. Contingency Scenarios and Additional Options

6.1. Contingency Scenarios

In order to understand the implications of a failure to timely and complete implementation of the Distributed Infrastructure Solution components, we have analyzed a set of contingency scenarios that capture the impacts of certain potential setbacks to the Distributed Infrastructure Solution. While not an exhaustive list, these include: permitting delays or rejection for the ExC Project; permitting delays or rejection of the LNG Vaporization Project; a combination of both such setbacks; or failure of our incremental DSM programs to fully meet their demand reduction targets. For each of these contingency scenarios, we quantified what projected supply-demand gaps would emerge without complete and timely implementation of the Distributed Infrastructure Solution.

These contingency scenarios are described in Table 6-1. In each scenario, we are assuming that all other components of the Distributed Infrastructure Solution are fully implemented according to plan.

Table 6-1: Contingency Scenarios

Scenario	Description	Potential Delay
ExC Project is Delayed	Permitting process imposes delays	In service 2025-26
ExC Project is Rejected	Permits rejected by any relevant permitting authority	Indefinite
LNG Vaporization Project is Delayed	Permitting process imposes delays	In service 2024-25
LNG Vaporization Project is Rejected	Permits rejected by any relevant permitting authority	Indefinite
ExC & LNG Projects Delayed	Permitting process imposes delays	ExC: 2025-26; LNG: 2024-25
ExC & LNG Projects Rejected	Permits rejected by any relevant permitting authority	Indefinite
80% DSM Program Participation	Programs run into implementation challenges and only achieve 80% of targeted demand reductions	Not applicable

Figure 6-1 depicts the gaps that might occur in such scenarios by year for the Adjusted Baseline Demand Forecast (where positive numbers indicate a gap).

Figure 6-1: Heat Map of Design Day Gaps by Year by Demand Sensitivity Scenario

Contingency Scenario	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
DI Sol'n in Full	-72	-105	-53	-88	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
ExC Delayed (LNG Vap on-time)	-72	-105	-53	-26	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
ExC Rejected (LNG Vap on-time)	-72	-105	-53	-26	6	35	61	45	40	38	52	42	45	45	58
LNG Vap Delayed (ExC on-time)	-72	-47	6	-88	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
LNG Vap Rejected (ExC on-time)	-72	-47	6	-29	2	32	57	41	36	35	49	39	41	41	54
ExC & LNG Vap Delayed	-72	-47	6	-26	-57	-27	-1	-18	-22	-24	-10	-20	-17	-18	-4
ExC & LNG Vap Rejected	-72	-47	6	33	65	94	120	104	99	97	111	101	104	104	117
80% of DI Sol'n DSM	-70	-98	-43	-75	-40	-7	24	14	16	21	41	38	47	53	72

The supply-demand gap analysis above and in this report compares available gas capacity and Design Day demand at an aggregate level for the Company's entire service territory. However, each year National Grid and Consolidated Edison engage in an extensive, detailed joint effort to conduct hydraulic modeling of their systems to reflect actual expected gas flows under Design Hour conditions.[44] This more detailed analysis captures specific locational gas capacity constraints. Even in cases where no contingency scenario gap is found in the analysis in this Second Supplemental Report, there may be more local capacity constraints that the more detailed hydraulic modeling could uncover or the contingency scenario gaps may not fully capture the magnitude of the constraint. As such, while useful to understand risks and evaluate options, the aggregate supply-demand gap analysis above may not tell the whole story in terms of how a setback to the Distributed Infrastructure Solution would create challenges. This goes beyond just the potential for locational gas capacity constraints. Even gaps that appear small point to a series of cascading risks in each contingency scenario, and the full context is important. For example, in the contingency scenario where the LNG Vaporization Project is delayed, a contingency scenario gap appears in winter 2022/2023 and risk. Overlaying additional setbacks (e.g., inability to expand CNG capacity or delays in meeting incremental DSM demand reduction targets) would exacerbate this gap. Under the Distributed Infrastructure Solution, the incremental DSM components have time to scale up and further prove themselves, such as building out the track record for relatively new DR programs, before they are essential to ensure reliability. In contrast, with a delay to the LNG Vaporization Project, the incremental DSM component is thrust into the role of ensuring reliability years ahead of schedule.

Taking these caveats into account, the analysis ultimately demonstrates if the LNG Vaporization Project is rejected or delayed, supply gaps begin appearing in 2023-24, but are generally resolved at an aggregate level the following season when the ExC Project enters service. However, in the event the LNG Vaporization Project is rejected, persistent gaps begin again in 2025-26, suggesting the need for contingency solutions. Similarly, if the ExC Project is rejected, there are persistent gaps from 2025-26. Finally, given that the Distributed Infrastructure Solution depends heavily on incremental DSM to balance supply and demand, especially after the mid-2020s, a scenario where incremental DSM programs underdeliver on their targets leads to persistent contingency scenario gaps.

Because we have already experienced delays in permitting our Distributed Infrastructure Solution, the likelihood of one or more of these contingency scenarios coming to pass is substantial. To that end, National Grid has examined the available alternatives to meet these potential gaps and updated the list of additional options from the Supplemental Report. Among those options we considered, we added one new distributed infrastructure option: "Micro-LNG."

The Company continues to seek out new options, including through its market Request for Information (RFI) for Supply Side Non-Pipeline Alternatives (NPAs) as more fully described in Section 6.2.3, but is only including those options that are currently available for the purposes of this analysis.

6.2. Updates to Additional Options

We begin by presenting an additional potential distributed infrastructure supply option to close the Demand-Supply Gap, which we call the "Micro-LNG Option," where we construct a small stationary LNG tank that vaporizes gas directly into the distribution system. As in the Original Report, each supply option is evaluated against multiple factors. To make it easy to compare this new option against the others, this new option is presented in a consistent format, except for safety. As public safety is paramount in everything the Company does, National Grid is confident that any option pursued will protect the safety of the public and the Company's employees. Therefore, no option presented in this Second Supplemental Report would not be safe for the public and the Company's employees. Accordingly, our description of the new option will cover the following:

- **Overview** – a description of the infrastructure that would need to be built, or the program that would need to be implemented
- **Size** – Design Day capacity (MDth/day), total volume/frequency of use (throughout the year, or just to meet peak demand), and timing of capacity availability (e.g., does it all become immediately available, or is there a build of capacity over time)
- **Reliability (certainty of meeting demand)** – likelihood that the option will be able to deliver on its projected capacity, and the risks that it might not deliver
- **Cost** – aggregate cost to bring the capacity online, and annual costs with and without a discount rate, which includes infrastructure and/or program costs and adjustments for commodity costs.
- **Environmental impact** – greenhouse gas (GHG) emissions; air quality considerations; potential impact from construction and operation; environmental risk; and decarbonization potential (i.e. the ability of the option to support New York's decarbonization goals)
- **Community impact** – impact on business growth and development, and on customer convenience and choice; how components such as location of infrastructure and amount of trucking impact affected communities
- **Permitting, policy and regulatory requirements** – permits that will need to be approved, policy changes that could enable the option, and regulatory obstacles that would require approvals or changes
- **Requirements for implementation** – location siting; hiring for construction/program implementation; requirements to place equipment orders; etc.

Following the detailed description of this new option, we will provide a summary to facilitate comparison against the options presented in the Original Report and Supplemental Report.

6.2.1. Micro-LNG Tank Option

Description

Similar to an LNG Peaking facility, this option provides cold weather support from a stationary LNG tank from which gas is vaporized directly into the distribution system; the Micro LNG facility would not include any liquefaction capability and would therefore require trucked LNG to be transported directly to the site in order to refill the facility. The size of the Micro LNG tanks falls within the legal boundaries of the NYCRR 570 code as the total storage size is less than 70,000 gallons (~6,000 Dth); however continuous operation of a Micro LNG site for several hours would require fully loaded LNG trailers to be immediately available to refill the Micro LNG tanks. In this option, LNG would provide on-demand peak hour support that would require logistical support to resupply the facility via an over-the-road trucking service after the first few hours of operation.

Size

The restriction on storage capacity and operational considerations around trucking to fill the Micro LNG facility would limit the site to provide peaking support only, which is to mean that it could only be available to send out gas during the coldest hours of a winter day and with advanced coordination to ensure that LNG supply is available on standby to truck to the Micro LNG facility. This is different from the supplies that are delivered from the permanent Downstate NY LNG facilities, which can support the system as needed. The Micro-LNG facility could support between 1-2 MDth/hr provided the Company is able to replenish the LNG inventory through trucked supply. Total capacity could be between 15-18 MDth/day.

Reliability

As a portable site without liquefaction capability, the only option to continue to replenish and run the Micro LNG site after it has depleted the on-site inventory, would be through coordinated trucking activities; the Company would need to arrange for the purchase and transportation of LNG inventory from another location for redelivery and consumption at the Micro LNG site. Based on an LNG trailer capacity of 10,000 gallons, the Company would require availability of 21 LNG trailers for a single peak day. Depending on the source of LNG to supply the Micro LNG site, multiple days' worth of LNG supply would likely need to be staged and available in anticipation of sustained cold periods.

National Grid has significant experience operating small scale portable LNG storage facilities in its other service territories; however, those sites can access incremental LNG supplies to transport within close proximity to the injection point and along already approved trucking routes. Further, the current limitation of the 70,000 gallon limit for onsite storage creates reliability concerns that it may be infeasible to replenish the LNG inventory for sustained durations of cold weather. The Company could pursue the possibility of intrastate trucking in order to mitigate the distance traveled; however, doing so would diminish the available inventory at other Downstate NY Peak LNG facilities.

Cost

The cost of a Part 570 Compliant LNG facility would be less than the other LNG options. Initial estimates are that the investment cost would be approximately $70M and would require ongoing costs for maintenance, supply and transportation of approximately $5M/year.

Environmental Impact

Ecological Impact: Construction will result in moderate environmental impacts including decreased air quality, pollution to stormwater and other runoff, disruption to natural resources and habitats, noise, and waste generation. A Micro-LNG facility is a smaller facility compared to an LNG Peaking Shaving Plant and is thus expected to have smaller ecological impact during the construction phase.

Once operational there would be moderate impacts from the transportation of LNG requirement to refill the sites during the winter season. However, the logistics plan to refill the tanks would only be required on the coldest days of the winter season.

Climate Impact: The GHG emissions from a part 570 compliant LNG facility would be limited because, as a peak facility, the operation would be strictly limited to peak days or local operational needs only. When operational, this option would have GHG emissions similar to the other LNG options and 10-15% higher than standard natural gas. As compared to a CNG Transfer Site, emissions would be lower due to the larger volume of trucks that would be required to support each CNG Transfer Site and their associated GHG emissions.

Community Impact

Similar to siting the other permanent LNG facilities considered, community concerns would be high as a permanent facility would be sited in a community. Even when sited in industrial zones, significant community resistance is a common part of the siting process.

Permitting, Policy and Regulatory Requirements

The permitting process for this facility would likely require many levels of permits. Similar to the Peak LNG Plant (as presented in the Original Report), this facility would be built in New York for New York customers and thus fall under state jurisdiction. The main state level process is outlined in 6 NYCRR part 570.2, and would require the Company to submit a full application under that code to the NYS DEC. Further, National Grid would need to seek approval of either: (1) an intrastate transportation route approval from the NYS DOT as outlined in 6 NYCRR Part 570.4; or (2) approval from the FDNY to allow LNG transport through New York City on interstate routes.

Requirements for Implementation

In order for this option to be successful, a fully vetted transportation and logistics plan would need to be in place to support the refill requirements of this site. The current restrictions on both intrastate trucking of LNG and/or passage through New York City pose a threat to the ability of any small-scale LNG facility to reliably support system operations on a cold winter day.

Summary

Table 6-2 summarizes the assessment of the Micro-LNG Tank option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 6-2: Micro-LNG Assessment

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	A small (less than 70,000 gallons) stationary LNG tank that vaporizes directly into the distribution system.
Size	18 MDth/day	Designed to meet periods of peak demand
Reliability	◑	Historically peak LNG is a very reliable option, and National Grid has extensive experience in this area. However, specific challenges to LNG trucking for refill exist in New York for this option.
Cost	◑	Initial estimates are that the investment cost of ~$70M; ongoing costs for maintenance and transportation ~$5M/year.
Environmental Impact	◑	The short-term ecological impact from installation will be moderate during construction. Emissions impact would be low due to intermittent peak usage.
Community Impact	◔	Substantial anticipated stakeholder concerns about community impacts
Permitting, Policy and Regulatory Requirements	◔	Requires state/local approvals; permits would include NY PSC; NY SEQRA; NYC DOB and FDNY.
Requirements for Implementation	◑	If approved, total timeline at 4-6 years.

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

6.2.2. Updates to Assumptions on the Different Distributed Infrastructure Options

As a starting point, while all the additional options described in the Original Report and the Supplemental Report continue to have potential, the Company has chosen to focus on its distributed infrastructure and non-gas infrastructure options to close the gap rather than any large infrastructure options due to the low likelihood of a new large infrastructure project being permitted, as exemplified by the rejection of the permits for the Company's large infrastructure solution from the Supplemental Report.

Updates on the distributed infrastructure options from the Supplemental Report are described below. There are no updates to the Peak LNG Option from the Original Report or Supplemental Report; however, we have updated some of the cost and size aspects of the other options:

Clove Lakes Transmission Line Loop

The Clove Lakes Project was presented in the Original Report to address a restriction on National Grid's system and increase the company's ability to receive additional gas in Staten Island from an existing gate. This additional gas would be utilized to serve customers in Staten Island, Brooklyn and Queens. Any benefits to meeting KEDLI's peak hour needs would be limited to the displacement of gas that would otherwise travel from KEDLI to KEDNY to meet KEDNY system demands. The ability of the Clove Lakes Project to address the Company's gas capacity constraint depends on the Company being able to contract for additional capacity on the Tetco pipeline once it has the ability to move the increment gas supply across Staten Island via the new gas network capacity provided by the Clove Lakes Project. While the Company understands there to presently be capacity available on TETCO, there is no guarantee it will remain available.

LNG Barges

As described in the Original Report, the LNG Barge option would include the purchase and construction of one (or more) specialty LNG Barge(s). When vaporization equipment is integrated into the design, these are referred to as "Floating Storage and Regassification Barges" ("FSRB"). FSRBs are further categorized as either tow barges where a tugboat tows the vessel or an Articulated Tug/Barge Unit ("ATB") where the tugboat connects with pinions to a notch in the FSRB stern. There are a few potential locations to place these barges where a combination of water access, pier capacity, and gas system takeaway are favorable.

Utilizing an FSRB is a relatively new concept in utility local distribution gas systems; however, we have learned that extremely similar capabilities are being rapidly developed throughout the maritime industry – both domestically and abroad - as vessels transition to LNG as a bunker fuel source. Two Jones Act Compliant barges have recently been placed into service to support LNG Bunkering and there are several more under development to be commissioned over the next few years. There is a similar trend abroad, with multiple small-scale LNG vessels in operation across the globe supporting both bunkering and remote power generation infrastructure. With minor modifications, these barges could be retrofitted to support a Floating Storage and Regassification use to transfer supplies directly into National Grid's distribution system. In fact, National Grid issued a recent RFI specific to its Rhode Island gas utility regarding FSRB options and confirmed interest and capability in the market to provide such a solution. For Downstate NY, there are three potential types of U.S. sources of LNG under consideration: 1) US or Canadian east coast terminals such as Cove Point, MD and Elba Island, GA; 2) from a passing LNG tanker at sea; or 3) by LNG truck. Additionally, as an emerging alternative, new LNG by rail terminals are being proposed in the NJ/PA region.

The Company originally assessed that the total cost for deploying one barge system is ~$210M.

Upon additional analysis, we now estimate the total cost for deploying one barge system is ~$275M. This estimate includes the following costs: a US-built barge ($100M), mooring ($25M), interconnecting facilities and pier construction approximate cost ($100-150M depending on site), and upgrades to the current shoreside gas system ($10M). Further refinement of the costs would follow selecting the final specifications, including the site and size/capacity of the barge. We are currently reviewing the feasibility of multiple sites. For two barges, the total cost will likely be approximately $560M if both barges feed into the same port (there would only be one cost for shoreside piping upgrades).

The Company has also updated the likely permit requirements to include FERC, NMFS and NEPA along with the permitting agencies listed in the Original Report. For this reason and others, the Company has also extended the potential delivery time for this option from 5-6 years to 5-8 years.

Pipeline Seasonal Peaking and Cogeneration Capacity

As stated earlier in this Second Supplemental Report, there are two main factors driving the Company's ability to contract for city gate peaking supplies: 1) the amount and location that is available in the market; and 2) National Grid's operational constraints – its ability to utilize what is available. As these are short term contracts, the amount and location can change from year to year and there is a finite limit on each interstate pipeline. When new requirements forecasts are issued, operational capacity and constraints must be reviewed and modeled to determine which of these supplies can best serve those needs.

The Company identified previously that the maximum amount of these supplies (including capacity currently secured from cogeneration facilities) that could be procured totaled 365 MDth/day. The 252 MDth of pipeline capacity awarded in long-term contracts through the June 2020 RFP (described above) reduced the amount of available capacity in the market that would otherwise be offered in the form of short-term city gate peaking contracts. As such, for this Second Supplemental Report the maximum volume assumed as part of the Distributed Infrastructure Solution to come from the combination of city gate peaking capacity and cogeneration has been adjusted to 123 MDth/day in total.

Regarding that 123 MDth/day amount, National Grid will endeavor to re-contract for these volumes as these arrangements expire should the requirements forecast and on-system needs continue to support the need for additional volumes in later years. As noted previously, the ability to do so is not guaranteed.

RNG Production/Transportation & Distribution

RNG is pipeline gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle GHG emissions than geological natural gas. Producing renewable gas to augment supply involves the construction of RNG production plants or contracting for output of third-party plants.

Currently, there are more than 85 operational RNG projects for pipeline injection across the U.S. All existing RNG projects use biomass as feedstock – sources of biomass include: landfills, wastewater treatment plants, food waste, and livestock manure. The EPA's Renewable Fuel Standard program has been a critical driver of significant growth over the last few years, providing policy support to lower the emissions of the transportation sector.

Only RNG supply that is sourced within our service territory downstream of gas capacity constraints can mitigate the Supply-Demand Gap addressed in this report. Although RNG from outside our service territory is an attractive opportunity to decarbonize our gas supply more broadly to help achieve Net Zero, such RNG displaces geological natural gas that would otherwise be flowing through the limited interstate pipeline capacity serving our gas system, and therefore does not contribute toward incremental supply.

Since the initial publication of the Downstate NY report, National Grid's RNG supply contract from a plant in Staten Island was terminated by the supplier, resulting in a decrease of approximately 1 MDth/day in RNG production. Construction remains under way to enable connection of a an expected 0.75 MDth/day plant at Newtown Creek with commissioning of the Newtown Creek facility now expected to occur in 2021/2022. This has already been included in our description of available supply.

National Grid continues to review requests from developers who have RNG projects where they are interested in connecting to our natural gas system. Since the publication of the Original Report, the Company has not received any additional firm commitments for RNG supply from project developers. National Grid believes there continues to be opportunity to expand RNG in Downstate NY that can benefit from supportive policies and programs.

National Grid supports further policy developments that incentivize the use of RNG at the state and federal level to decarbonize the gas network and policies that incentivize the use of RNG as a source of renewable heat.

To materially increase RNG in the gas distribution system, significant effort is required by all stakeholders, including potential legislative action from the governments in our service territories and the building of internal capabilities at National Grid (e.g., research and design, engineering, etc.). National Grid remains committed and excited to capture the opportunity to expand the use of RNG to advance the Net Zero goal.

6.2.3. Updates to Assumptions on Non-Gas Infrastructure Options

As described in Section 5, the Demand Side Management ("DSM") portion of the Distributed Infrastructure Solution is comprised of four major elements : EE, DR, Incremental Heat Electrification and Non-Pipeline Alternatives (NPAs). Adding additional DSM programs above and beyond what is planned for the Distributed Infrastructure Solution would primarily focus on DR and Incremental Heat Electrification as more fully described below.

Energy Efficiency Options

While National Grid's weatherization and EEC programs will be critical components to help narrow the gas supply gap over the next five years, National Grid recognizes the even our NE:NY and incremental weatherization programs together will not be adequate to address the growing gap under a contingency scenario or in the longer term. As such, National Grid is currently developing additional programs to expand the portfolio in future years. Those programs include:

- Expansion to Energy Efficient Connections, amending our tariffs to mandate:
    - New construction gas connections to meet more stringent EE requirements prior to connection (i.e., Premium Efficient Gas Equipment, Controls and Weatherization)
    - Demand response readiness prior to connecting to our gas systems. Opportunity to target customers who are in the process of connecting to natural gas to participate in existing DR programs, providing peak hour savings.
- Expansion to Commercial Customers

    - Large C&I customers have a provision in the existing tariff requiring completion of an energy audit for an incentivized rate that could potentially be expanded upon
- Considering new business models, such as a pay-for-performance model and a Metered Energy Efficiency Transaction Structure (MEETS) model, which might lead to accelerated adoption or lower-cost adoption of energy efficiency measures.
- Continued collaboration with NYS utilities and advocacy for changes that would mitigate barriers to weatherization such as:
    - Collaboration and resource sharing
    - Maximization of any potential government funding that may be available over time
    - Alliances between trade partners, public and private partnerships
    - Creative programs geared toward incentivizing property managers or owners
    - Offering of health and safety measure incentives that support removal of those barriers
    - Streamlining or reducing the project timeframe and cost of installation where possible
    - Workforce Training and Development
- Studying new technologies and strategies such as sewage to district heat, which is being piloted in other cities around the nation, or gas-fired heat pumps, which have a higher efficiency than all other gas-fired heating equipment.
- Greater collaboration with NYSERDA
    - Collaborate with existing NYSERDA programs and identify opportunities to share resources to target more customers to achieve higher savings
    - Greater technology screenings to conduct prefeasibility studies, small demonstration/pilot projects and/or lab testing to assess the availability and applicability of new and innovative technologies such as:
        - Deep Energy Retrofits within DNY market-rate customer buildings
        - Innovative Building Envelope Measures
        - Advanced Control Strategies
        - Gas Heat Pump Lab Testing and Rating Standard Development
        - Carbon Capture Technology Pilots
        - Historic Building Offerings
        - Wind to Heat technologies

However, we are currently unable to quantify the additional benefit these nascent programs may provide in reducing demand, which is why the Company is not currently able to explicitly include these programs as part of a contingency plan at this time. Rather, for the purposes of this Second Supplemental Report, where incremental demand-side programs are modeled to address the contingency scenario gaps, those programs cover demand response and heat electrification.

Demand Response Options

In addition to our portfolio of firm demand response programs described in Section 3, the Company is developing a fourth program ("Program 4") focused on residential and small business ("SMB") behavioral DR that was not mentioned in the Original Report. It involves sending messages to customers notifying them that cold weather is in the forecast, asking them to conserve energy, and providing them with some suggestions on how to do so. This program would also have an option for customers to click a link indicating that they will commit to reducing their energy consumption. Out of nearly 490,000 customers that were contacted during Winter 20/21, 2,894 (0.5%) committed to make a reduction. It is difficult to know whether or not this program produces a reduction in consumption or if it simply provides a touch point for customers. Until we are able to verify that a reliable usage reduction occurs, it is unclear whether this program can be relied on to create demand reduction. The Company is therefore still in the process of studying this program.

Beyond Program 4 described above, there is likely to be a natural limit to the amount of demand reduction that can be produced by firm customers participating in the demand response programs. Most energy needs of firm customers are not flexible, either because of health and safety concerns (i.e. maintaining a safe temperature during the winter) or because they have adapted their operations to the availability of energy at all times. This differs from non-firm customers who have installed a backup fuel system specifically for the purpose of creating flexibility in their need for gas, even if their need for energy is not flexible. Many of the customers who have chosen to participate in firm DR programs have been customers who have flexibility, either because of the specific nature of their operations (e.g. optional power generation) or because they have a backup fuel system. This population of customers is finite. Once it has been saturated, the Company will need to explore how to continue to create demand reduction from other customers that have less flexibility.

There are two primary pathways to do this. The first is to achieve reductions by having a large number of customers produce small reductions in their individual energy needs. This is the approach that would be taken by the BYOT program that is already part of the Distributed Infrastructure Solution. The second pathway is to increase the number of customers for whom flexibility in their energy needs is viable and valuable. This could be done by increasing the incentive rates for DR programs, which would potentially justify interruption in processes or some level of discomfort on the part of the participants, or by increasing the number of customers that have an alternate fuel source that could reduce their gas demand during peak periods.[44] This may be an outcome of increasing the DR incentive rates or by providing a level of certainty regarding the future of the program so that customers feel they can invest in this equipment and have a viable pathway to cost recovery. In addition, the Company could purchase alternate fuel equipment to be installed at customer sites, with the understanding that customers would participate in some form of demand response for a period of time. This option should be directly evaluated against the cost of purchasing equipment for the customer that could be used year-round rather than simply during peak periods. This analysis would need to include the cost of energy experienced by the customer as well as any other factors (e.g., societal cost test factors) that would impact the economics of such an investment.

The Company is also studying new ways to not only encourage existing non-firm customers to remain on their rate, but to potentially encourage other customers to switch to non-firm rates. As described in Section 5, non-firm customers are important to helping the Company meet Design Day demand.

In its recent rate case filing, the Company proposed a rate modification that, for larger customers, is likely to present a significant incentive to remain on the rate. For smaller customers, however, the incentives may not create enough of a discount. This is because customers with lower annual usage requirements will experience a smaller discount in absolute terms. Based on the cost of fuel oil, the risk of penalties, and the challenges of maintaining a backup fuel system, it still may not be worth it for smaller customers to remain on the rate. Small customers present less of a risk to Design Day planning but they could still add several MDth in aggregate. Additionally, they may be less likely to retain their backup fuel system, meaning that they would have a harder time producing significant reductions in firm DR programs.

The Company has considered various ways to further incentivize these customers, though no action should be taken until the impact of the new rates is understood if approved by the New York Public

[44] An additional innovation in the DR portfolio that the Company has been reviewing is the development of a new tariff that would mirror the existing DR criteria to allow for the implementation of small-scale portable Compressed Natural Gas (CNG) to supplement pipeline supplies behind the meter. National Grid is currently investigating the viability of this demand-side idea further, including what kind of rate structure could appropriately incentivize customers to pursue CNG as an 'alternate fuel', what the market conditions might be, and what operational requirements and outreach would be needed to ensure safety. While not ripe enough for this report, this "behind the meter" CNG is a potential solution for the future.

Service Commission. Possible additional incentive structures include a flat cash payment for each year on the rate (possibly for the incremental Dth reductions relative to the existing DR programs or possibly for the value they would have earned in the DR program itself) or a flat cash payment for customers who request to switch to firm to stay on non-firm rates. Either of these structures could also be adjusted to be based on the Design Day usage of the customer. Regardless, any incentive must be thoughtfully considered and implemented so as to avoid inequity and to ensure that it is promoting the desired outcome.

The Company is actively analyzing all of these options, with a goal of identifying the mix of programs that will produce the necessary, reliable reduction in hourly and daily demand at a reasonable cost relative to alternatives. In addition, the Company is researching whether it could amend its tariff to mandate DR readiness and participation in DR programs before connecting new customers. Similar to the EE options above, however, it is unclear at this stage what additional benefit any of these programs may provide in reducing demand, and what the potential costs would be, which is why the Company is not able to include these programs as part of its Distributed Infrastructure Solution.

Incremental Heat Electrification Options

As described in Section 5, National Grid is actively exploring potential pilot ideas with the EDCs to test program elements such as the incentive levels required to make electrification of heat cost-effective for gas customers across different classes including residential, large multifamily and commercial buildings. Efforts would need to expand and include moving through a discovery process for some or all the following elements:

- Greater customer education, outreach, and engagement programs
- Working with EDCs, NY PSC, NYSERDA, and NYPA (New York Power Authority) to expand programs for accelerated conversions of residential oil customers to electric heat pumps
- Identification of additional barriers to heat electrification and development of solutions to mitigate those barriers
- Expanding the Lead Referral Program and quantifying its success
- Deep dive into the significant barriers associated with the Multifamily market
- Providing an incentive adder to EDC programs in exchange for disconnection or restriction of gas heating. May require decommissioning.
- Providing an incentive adder to EDC programs in exchange for hybrid advanced controls systems and DR participation.
- Providing an incentive adder to EDC programs for residential all-electric heat pump water heaters (HPWH). Requires advanced controls.
- Providing incentive for residential all-electric cooktops, dryers, etc.
- Studying Relevant Technologies for consideration in DNY such as:
    - *Variable Refrigerant Flow (VRF) systems*
    - *Water to Water Heat pumps*
    - *Air to Water Heat Pumps*
    - *Gas Smart Meters*
    - *Advanced Control Systems*
    - *Heat Pump Water Heaters*
- Creating Geothermal Micro-districts, like those described in the Original Report
- New Business Models
- Supporting and Researching New Technologies like high efficiency electric induction cooktops.

Beyond the discovery process, a contingency plan with an accelerated incremental heat electrification program would require streamlined development and implementation. Within the context of a non-gas infrastructure option, an unprecedented amount of heat electrification above and beyond the already aggressive targets under the Distributed Infrastructure Solution would be required -- at least six times as many installations in the next 5 years compared to what is anticipated in the Baseline Electrification. All the caveats, challenges and risks described in Section 5 become even more difficult to overcome within this scenario, and without the benefit of appropriate pilot programs, surveys and studies to establish the means.

To reiterate a few points, the energy system within NYC is highly complex, driven by market forces, regulations, weather, climate and many other factors. Capital, labor and technology need to be readily available at the accelerated pace and unparalleled scale needed. A significant amount of our customer base would need to pivot their behavior to align with the efforts of heat electrification. Construction permit processes and scale of the workforce are factors that would dictate the rate at which heat electrification is feasible. A pathway for each market (industrial, commercial, multifamily, residential, etc.) must be feasible and available to accommodate anticipated targets of an accelerated heat electrification program.

This would require a significant amount of funding, resources and coordination within a streamlined process to achieve. The major aspects to consider is the scale, timing and cost requirements to achieve such an extraordinary shift within the Downstate NY building market. This aggressive scale up of heat electrification targets would require policies and incentives to drive most of the customer base toward pursing these projects. Electric power generation and transmission/distributed infrastructure may need to be constructed in order to meet the increased electric demand growth.

Table 6-3 outlines the key risks to accelerated incremental heat electrification.

Table 6-3: Accelerated Incremental Heat Electrification Risks

Risks	Likelihood	Impact	Description
Market Resourcing and Potential	**HIGH**	**HIGH**	There may not be enough market resources (contractors, vendors) to execute required number of projects within the timeframe needed. There may not be enough market potential and ability to reach accelerated levels of adoption.
Customer Value Proposition & Adoption	**HIGH**	**HIGH**	Heat Electrification would need to become at least economical for customers, especially LMI customers. Customer's may not choose to electrify their heat unless mandated by state/government due to lack of familiarity with technology, low cost of gas, high cost of electricity and concern around perceived reliability with cold-climate heat pumps.
Costs & Funding	**HIGH**	**HIGH**	This incremental heat electrification requires higher incentives that would need to be approved by regulators and implemented rapidly. Incremental heat electrification costs would grow to become higher than all other EE programs and Incremental EE programs. Additionally, LMI programs that align with this acceleration of heat electrification will cost even more than a market rate heat electrification program. All barriers would need to be removed and streamlined pathways built and cost about three times more.
Delays in executing MOU, electric system constraints, legal and	**HIGH**	**HIGH**	Accelerated incremental heat electrification would require a streamlined MOU process with EDCs. We don't currently have coordinated planning efforts to that degree. This would need to be built out quickly and include coordination between multiple groups within both utilities, such as: load forecasting teams, legal, program development, program implementation, etc.

regulatory processes			Any program would need to be designed and implemented in close coordination with EDCs. We have initiated conversations with the EDCs on potential heat electrification pilots. However, we would need to align on vision immediately if we are required to pursue accelerated heat electrification as soon as this contingency plan is needed.
Demand Side Management Filing Timeframe	**HIGH**	**HIGH**	We currently we have estimates for incremental heat electrification scenarios in terms of program design, customer adoption, incentives, and costs. The actual program development would require a regulatory filing-level analysis that goes beyond what is currently available to the Company. A deeper dive into what incentive level is required for accelerating market adoption as required to address gas capacity constraints would be needed, in particular.
Meeting Capacity Metrics	**HIGH**	**HIGH**	Once an incremental DSM program is approved by the New York Public Service Commission, the program performance becomes part of the new capacity metrics proposed as part of the Company's pending rate case settlement. These capacity metrics must be met in order to reach full cost recovery for the Distributed Infrastructure Solution projects. Therefore, well-designed and effective incremental DSM are needed to support the other components of the Distributed Infrastructure Solution.
Reliability	**HIGH**	**HIGH**	Forecasted models need to include events such as cold snaps and heat waves specific to local grid design. The comparison and detailed review of electric and gas forecasts in a dynamic way to run scenarios for balancing activities related to this level of heat electrification would be needed to ensure reliability.

Non-Pipe Alternatives (NPAs)

It is unclear at this time what NPAs could exist that would be incremental to the plans put forth by the Company. Many of the companies that could provide NPA solutions of which we are aware offer EE or DR aggregation services, which may represent and overlap with programs that we have already planned. Therefore, this would not help us to close any gap above and beyond the programs we have already included. It is possible that there may be cost savings, reliability improvements, and/or increased customer adoption or new customer populations that could be achieved through a 3rd-party providing a solution as compared to the Company but that is not yet known and likely will vary based on the specific solution and circumstances.

6.2.4. National Grid Efforts to Unlock Innovative Ideas

Above and beyond the options described above, the Company has been looking to the market to seek new innovations to support its supply constraints, but as these innovations are still in the beginning stages of development, have limited potential, or are still in the request for information ("RFI") stage, they are not considered ready to be included as additional options for the purposes of this Second Supplemental Report. These include:

Request for Information – Innovative Supply-Side Proposals

To meet a portion of the peak day demand for natural gas consumption, the Company recently issued an RFI in order to identify and incorporate alternatives to construction of interstate pipeline capacity. National Grid appreciates that utilization of certain emerging technologies and supply-side resources capable of supplementing natural gas supplies to the region have not yet been undertaken in the United States or by similarly situated local distribution companies. As part of the solicitation and in an effort to meet its supply needs in the region, the Company will give consideration not only to those proposals involving expansion of its existing RNG, CNG and LNG

footprints, but also other innovative supply-side proposals that are not currently included in the Company's portfolio.
The Company is evaluating and considering all offers that successfully demonstrate an ability to reduce the Company's reliance on pipeline projects into the region as early as the heating season commencing November 1, 2022. Based on the known scalability of these types of projects, the Company does not anticipate that any one proposal will be able to meet all of its customer needs, nor that all proposals may be available to commence service by the following heating seasons, and therefore anticipates pursuit of multiple proposals able to deliver a range of volume from projects that can be phased in over several heating seasons. A separate solicitation will be conducted to evaluate proposals for demand-side reduction.

Requests for Proposals – Innovative Demand-Side Proposals (NPAs)

We are actively working with the market, both solution providers and other interested stakeholders (e.g. other gas utilities), to identify NPA opportunities that would complement our existing DSM portfolio and help us to meet our Design Day needs. As noted in Section 5, under our Joint Proposal, National Grid will be annually issuing at least one request-for-proposal ("RFP") seeking non-traditional, cost effective peak supply NPAs and annually identify at least five segments of leak-prone pipe in each service territory that could be abandoned if all customers' natural gas loads are met with cost-effective NPAs. In addition, more generally and where possible, National Grid will make evaluations of possible NPAs a standard item before proceeding with the construction of new or replacement gas transmission and distribution infrastructure. In accordance therewith, the Company has identified over 60 companies that offer services that might help to deploy demand-side NPAs, and the Company will be communicating with these companies about the demand-side NPA technologies available in the market and the ability of those technologies to reduce demand.

6.2.5. Refined List of Additional Options

Based on the criteria described above, the refined set of additional options with potential to close a contingency gap is shown in Table 6-4**.**

Table 6-4: Additional Options for Contingency Analysis

Additional Options	Size *(MDth/day)*
Distributed Infrastructure Options	
Peak LNG Facility	100
LNG Barges	50 (per barge, scalable)
Clove Lakes Transmission Loop Project	80
Additional Pipeline Seasonal Peaking Capacity	--[45]
Local RNG Production/Transportation & Distribution	--[46]
Micro-LNG Tank	18
Non-gas Infrastructure Options	

[45] The size of this option is currently small, around or less than a MDth/Day, but will be pursued opportunistically as capacity becomes available.
[46] Similar to the above, the size of this option is currently small in the local market, slightly more than a MDth/Day, but will be pursued opportunistically as this and other lower carbon fuel alternatives grow in the future and become available. Total regional RNG capacity matters less than locational-specific considerations as only options located downstream of National Grid's take stations help relieve the capacity constraints that are the subject of this report.

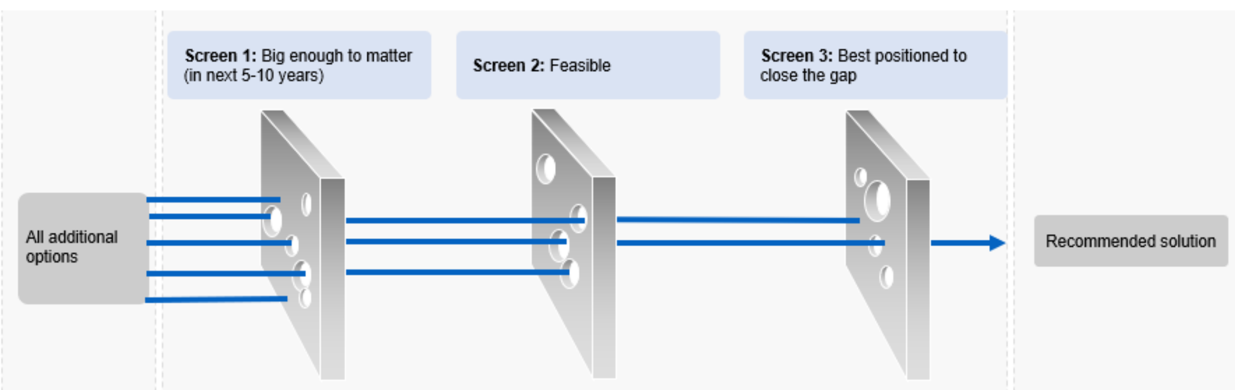
Incremental EE over and above the Distributed Infrastructure Solution	--[47]
Incremental DR over and above the Distributed Infrastructure Solution	Up to 44 MDth/day
Heat Electrification over and above the Distributed Infrastructure Solution	Up to 90 MDth/day

7. Contingency Scenario Solutions

While Section 5 described National Grid's Distributed Infrastructure Solution, and Section 6 described the Company's suite of additional options for closing the gaps created under the contingency scenarios, this Section 7 describes the process that National Grid undertook to evaluate those additional options to determine what the best alternative approaches are to address the contingency scenario gaps and develop contingency plans. In all cases, these contingency plans have higher costs and have much higher implementation risks than the Distributed Infrastructure Solution.

The Company began this analysis by applying three screens -- size, potential for successful implementation, and ability to meet the forecasted need on a cost-effective basis -- to each additional option to arrive at a plausible contingency plan if the Distributed Infrastructure plan does not proceed on schedule. These screens are described below in more detail. Options that do not pass each screen are filtered out as illustrated in Figure 7-1.

Figure 7-1: Screening Process



7.1. Screen 1: Size Filter

The first screen the Company applied to any additional option tested is size. In particular, the Company evaluated whether this option could provide a meaningful material capacity contribution to be a meaningful alternative to address a contingency scenario gap in the next five to ten years.

Three options failed Screen 1:

- Energy Efficiency incremental to Distributed Infrastructure Solution – the levels of Energy Efficiency already included in the Distributed infrastructure Solution are already in line with best practices and will already be challenging to achieve on the time scale required; National

[47] The size of this option is unknown at this time but will be pursued opportunistically as new programs are developed that are capable of providing demand reduction.

Grid will continue to explore and pursuing additional opportunities in Energy Efficiency where possible, nonetheless

- RNG, which is part of the Company's vision for a low-carbon future, does not have sufficient scale in the short-term as a local gas capacity resource to pass this screen; however, the Company intends to actively pursue additional RNG and other low-carbon fuel solutions in the future to help achieve Net Zero.
- City-gate peaking supply due to limited ability to deliver the gas from the city-gate to customers due to city-gate and adjacent distribution infrastructure limitations

7.2. Screen 2: Feasibility Filter

After size, the Company screened the remaining options on their likelihood of successful implementation. Successful implementation encompasses a broad range of implementation concerns including the current legal and regulatory framework in New York, permitting, construction and operations.

Based on these criteria, Screen 2 eliminated the Peak LNG Facility due to the fact that the legal requirements necessary for this option to be feasible are not currently in place.

7.3. Screen 3: Evaluation against Contingency scenarios

Screen 3 evaluated the remaining options against the contingency scenarios to identify the most affordable, feasible and reliable options to address potential contingency scenario gaps. The suite of five options (the "contingency options") that remain after screens 1 and 2 are tested under screen 3 are presented in Table 7-1.

Table 7-1: Options that Passed Screen 1 and 2 for Screen 3

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

Based on National Grid's analysis -- looking at the costs of the different approaches and how quickly the Company could implement the solution, taking into account engineering time and permitting hurdles *(i.e.,* feasibility*)* -- the Company assessed that, for the contingency scenario gaps resulting from delays in the implementation of either the LNG Vaporization Project or the ExC Project, the least expensive approach was a combination of incremental demand response and heat electrification. For the gaps caused by denials of either the LNG Vaporization Project or the ExC Project or both, or where the DSM programs under the Distributed Infrastructure Solution fall 20% short of their targets, the least expensive approaches included either a combination of the Clove Lakes Transmission Loop option ("Clove Lakes Transmission Loop") and/or the LNG Barge option with incremental demand response and heat electrification. In other words, the most viable contingency plan depended on the specific contingency the Company would need to solve, with Clove Lakes a potential substitute for the LNG Vaporization Project and an LNG Barge a potential substitute for the ExC Project in both cases paired with expanded DSM. In all cases, the costs of these solutions are far in excess of the costs of the Distributed Infrastructure Solution as currently planned.

In coming to this determination, National Grid compared the cost and deliverability of both a combination approach of distributed infrastructure with DSM, and a pure non-gas infrastructure solution. Notably, in all of the contingency scenarios, an increase in investment in demand response and heat electrification programs is necessary. Relying on a combined solution of non-gas infrastructure with distributed infrastructure in those scenarios where either the LNG Vaporization Project or the ExC Project is denied, however, was less expensive and had a greater likelihood of implementation success than if the Company were to attempt a pure non-gas infrastructure solution, which would be heavily dependent on a rapid scale up of incremental heat electrification efforts.

In coming to this conclusion, the Company 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 7-2 illustrates how a potential scale up in incremental DSM would need to occur to address the contingency scenario gap assuming that the LNG Vaporization Project and the ExC Project are denied.

Figure 7-2: DSM Program size when both the LNG Vaporization and ExC Projects are denied

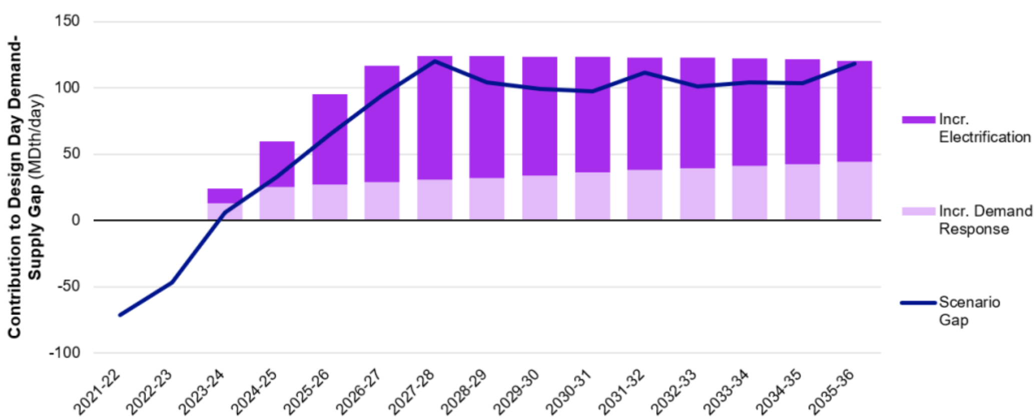
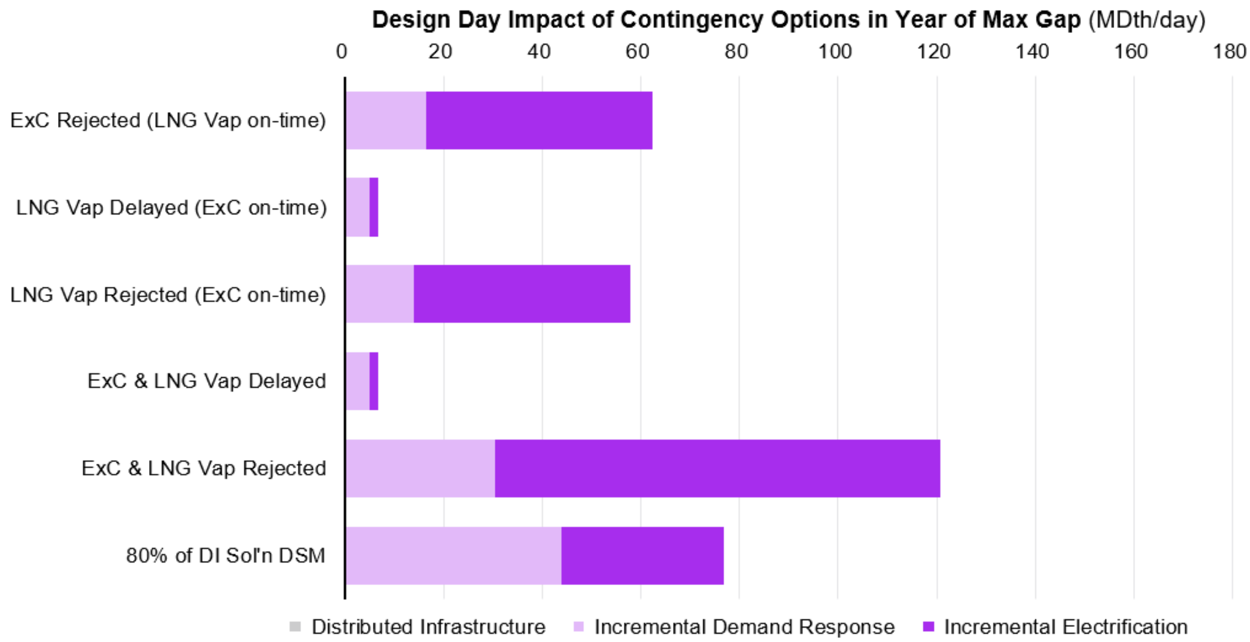


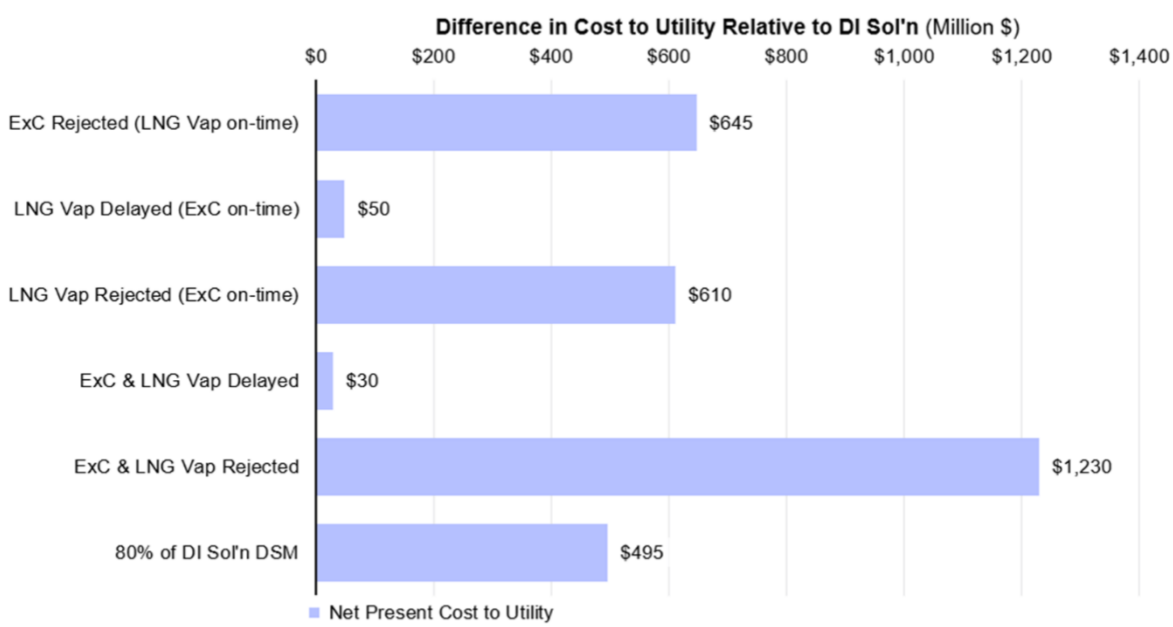
Figure 7-3 below shows the size in terms of demand reduction and the composition in terms of heat electrification and demand response of the most cost-effective exclusively non-gas infrastructure approach for each contingency scenario.

Figure 7-3: Composition of most cost-effective non-gas infrastructure solution for each contingency scenario



As demonstrated by these figures, applying a purely non-gas infrastructure solution would require a massive increase in investment in DR 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 ("Net Utility Cost"), as shown in Figure 7-4.

Figure 7-4: NPV of the most cost-effective non-gas infrastructure solution by contingency scenario



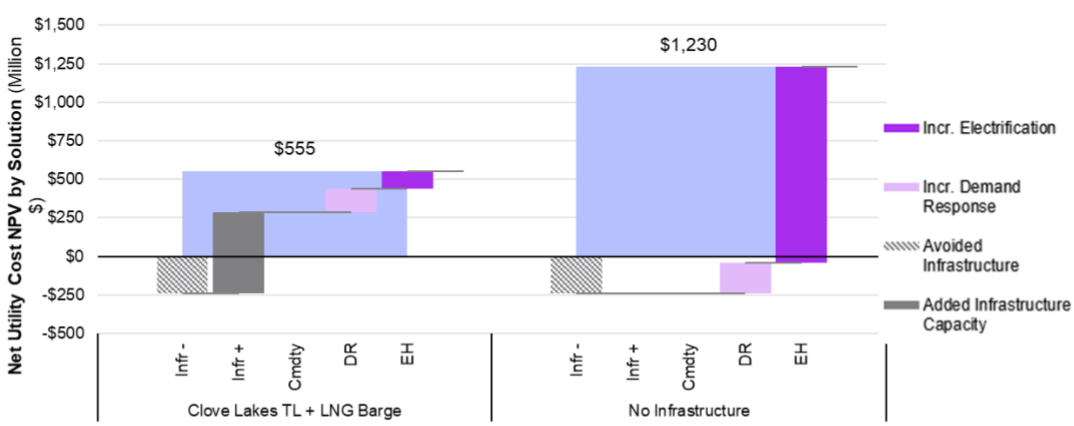
Separate from the cost analysis, the level and pace necessary to ramp up enough heat electrification and demand response to solve the contingency scenario gaps based on infrastructure project denials would also be unprecedented, accelerating and far exceeding the already ambitious levels of these programs included in the Distributed Infrastructure Solution. More specifically, if both the LNG Vaporization Project and the ExC Project are rejected, a purely non-gas infrastructure alternative approach would require six times as many full heat electrification customer installations in the next 5 years compared to what is anticipated in the Baseline Electrification (see Table 7-2). In order to accomplish this, the rate of annual heat electrification installations would need to increase dramatically from ~1,800 customers per year in 2021 to ~26,800 customers per year in 2025 (~15-fold increase over 5 years), signifying that the accelerated electrification program would be needed immediately. In particular, change at this scale would need additional legal and regulatory frameworks to achieve, which currently do not exist.

Moreover, in terms of both cost and implementation, the deployment of aggressive new heat electrification programs would require an understanding of the implications for the Downstate NY electricity system from increased electric demand. The implications of heat electrification for the electricity system are outside the scope of this report.

In contrast, an approach that combined distributed infrastructure options with non-gas infrastructure options resulted in less expensive solutions for the contingency scenario gaps resulting from denials of the LNG Vaporization Project and the ExC Project, even though this approach would still require a significant and unprecedented ramp up in heat electrification.

For example, in the contingency scenario where both the LNG Vaporization Project and the ExC Project are rejected, the approach that combines alternative distributed infrastructure options with additional DSM programs would be considerably lower in cost than a purely non-gas infrastructure approach, by more than $650M over the 15-year time horizon as illustrated in Figure 7-5.

Figure 7-5: Incremental cost of proposed solutions if both LNG Vaporization and ExC Projects are rejected



Moreover, combining alternative distributed infrastructure with additional DSM would likely prove to be a more feasible approach than relying on DSM alone. Table 7-2 gives the ramp up rates in heat electrification that would be necessary absent additional, complementary distributed infrastructure. As described in Section 6, there is considerable uncertainty with respect to designing and implementing programs that grow to this level of customer participation absent supportive legal and regulatory frameworks.

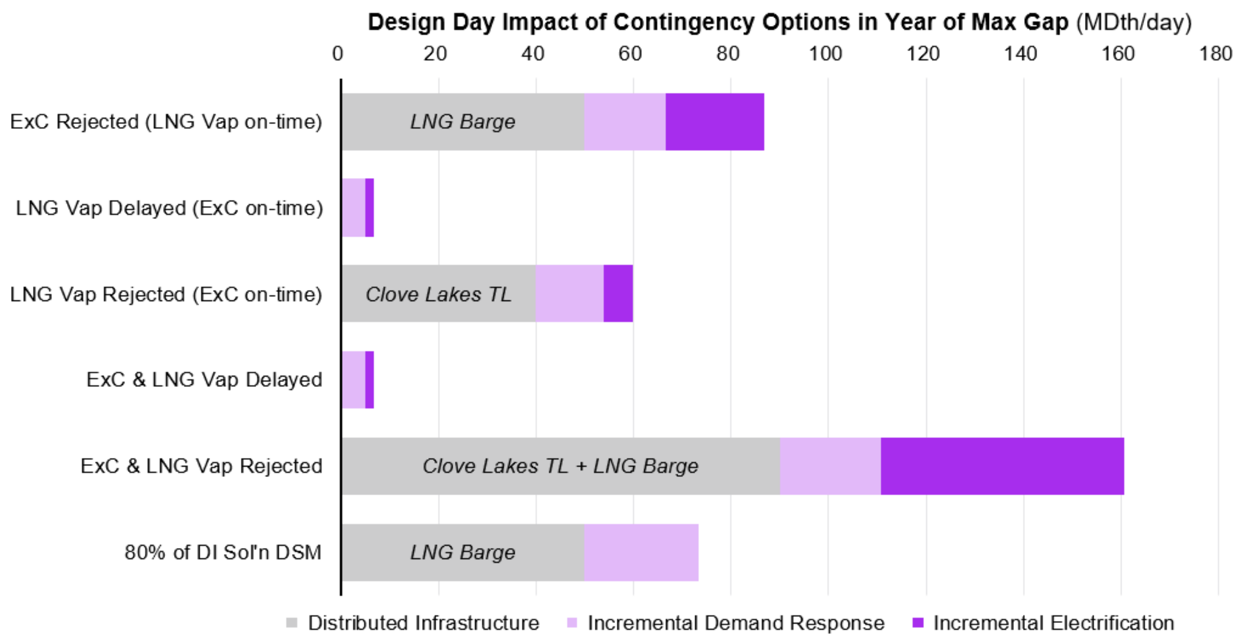
Table 7-2: Sample Heat Electrification rates by scenario and solution

Scenarios and contingency approaches	Heat electrifications 2021-2025		
	Average annual ('000 cust/yr)	Total ('000 cust)	vs. Baseline
Baseline Electrification	2.1	10.4	n/a
Distributed Infrastructure Solution in Full	2.3	11.5	~1x
LNG Vap Rejected | Contingency: Clove Lakes TL + DSM	3.9	19.4	~2x
LNG Vap & ExC rejected | Contingency: Clove Lakes TL + Barge + DSM	8.6	43.1	~4x
LNG Vap & ExC rejected| Contingency: DSM (non-gas infrastructure)	11.8	58.9	~6x

Note: All scenarios' heat electrification rates include the Baseline Electrification level

In summary, the Company has determined that, taking into account the cost and feasibility factors of all the solutions, the best contingency plans for each of the contingency scenario gaps are those shown in Figure 7-6.

Figure 7-6: Design Day Impact of Contingency Options in Year of Max Gap (MDth/day)

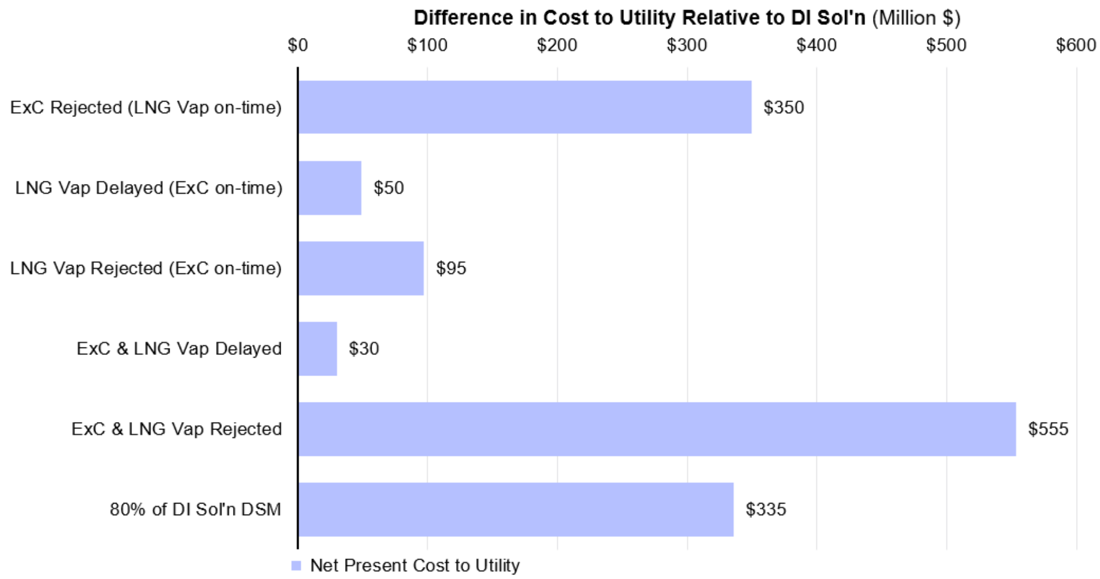


As Figure 7-6 demonstrates, in cases where the LNG Vaporization Project is rejected under the contingency scenarios, the best available alternative approach combines the Clove Lakes Transmission Loop option with additional heat electrification and further DSM incremental to the Distributed Infrastructure Solution. In cases where the ExC Project is rejected, the analysis find that a combination of an LNG Barge with heat electrification is the best alternative approach. Where both the LNG Vaporization Project and the ExC Project are rejected, combining Clove Lakes with LNG Barges may be necessary to meet demand. Under a contingency scenario where the DSM programs under the Distributed Infrastructure Solution do not meet their targets, an LNG Barge option combined with DR is the best approach.

Notwithstanding that the analysis finds that the Clove Lakes Transmission Loop and LNG Barge options are components of the best alternative approaches under various contingency scenarios, the permitting risks associated with these projects are high, as both the Clove Lakes Transmission Loop and LNG Barge option would likely face lengthy and uncertain permitting comparable to if not more challenging than the LNG Vaporization Project and the ExC Project.

Though combining alternative distributed infrastructure projects with additional DSM programs to address contingency scenario gaps allows the Company to address those gaps at lower cost than if it pursued a purely non-gas infrastructure approach, in any such scenario, these alternative approaches will incur additional costs ranging from $30M to $555M over and above the expected cost of the fully implemented Distributed Infrastructure Solution. Over the next five years on average, even the least-cost alternative approach (the alternative to the contingency scenario that assumes a delay to the LNG Vaporization Project) would increase total customer bills by approximately 1.6% as compared to the Distributed Infrastructure Solution.[48] Over the same period, the best alternative approach under the contingency scenario that assumes both the LNG Vaporization Project and the ExC Project are rejected would increase total customer bills by roughly 6.6% relative to under the Distributed Infrastructure Solution. For the same contingency scenario, a purely non-gas infrastructure alternative approach would lead to customer bill increases of almost 10% on average over the next five years.

Figure 7-7: Incremental Cost of Alternative Approach to Address Contingency Scenario Gaps Relative to the Distributed Infrastructure Solution



Though these various contingency plans would enable us to meet customer demand, all of these contingency plans are far less favorable for our customers both from an affordability and feasibility perspective than the Distributed Infrastructure Solution.[49]

Additional details on how different combinations of solutions were evaluated can be found in the Appendix.

7.4. Potential Risk for Customer Connection Pauses and Curtailments

In the event that the components of the Distributed Infrastructure Solution face setbacks to their successful and timely implementation, there is a substantial risk that National Grid will not be able to meet projected customer demand growth in the coming years given the implementation risks associated with any alternative approach. Faced with an inability to meet projected customer Design

[48] Customer bill impacts are provided in the Appendix.

[49] In addition to assessing the costs to National Grid and its customers of the contingency solutions, National Grid also performed Societal Cost Tests consistent with New York's general benefit-cost assessment practices, which did not change the underlying conclusion about the relative affordability of each solution.

Day demand, at least a targeted or pause in new customer connections could be required. However, even restrictions on new customer connections may not sufficiently slow or stop Design Day demand growth. As a last resort, if National Grid cannot meet peak customer demand, its option of last resort is to activate its customer curtailment plans.

7.4.1. Process for Customer Connection Pauses

Pursuant to the Commission's Order Instituting Proceeding, issued and effective March 19, 2020, in Case 20-G-0131, on February 12, 2021, Department of Public Service Staff issued two proposals – one on a new gas planning process ("Staff Planning Proposal") and another on moratorium management ("Staff Moratorium Proposal").

The Company will file its moratorium management proposal as required by the Staff Moratorium Proposal subsequent to Commission action on Staff's proposal. The elements of the Company's anticipated Moratorium Management filing will include, at a minimum, detailed guidelines and communications plans related to the following topics:

- <u>Declaration of a Moratorium</u>
    - Reliability Metrics for identification of vulnerable locations
    - Stakeholder strategies engagement focused on identifying solutions in advance of declaring a moratorium
    - Actions to offset demand through NPAs
    - Deploying EE and DR solutions
    - Key Communications components
    - Notifications to regulators
- <u>Treatment of Applicants & Customers During Moratorium</u>
    - Treat customers consistently across affected area
    - Develop a "Moratorium Customer Bill of Rights"
    - Develop an appears process for extraordinary cases
- <u>Connection Prioritization</u>
    - Identify the prioritization of customer classes, based on size, vulnerability, availability of alternatives, stage of project development, etc., related to availability of natural gas.
- <u>Moratorium Management Services</u>
    - Assistance for applicants and customers such as a hotline for moratorium-specific questions, a company-hosted informational web page, and assistance finding alternative energy services such as heat electrification options, energy efficiency and demand response.
- <u>Lifting of Moratorium</u>
    - The rules that will apply and metrics that will be relied on (e.g., recordings of pressure levels on specific points on the distribution system, metered usage, etc.) to justify lifting a moratorium.

While the final requirements from the New York Public Service Commission for moratorium management have yet to be determined, a moratorium could have a considerable lag, as much as 3-4 years from the date it is announced, before it produces a considerable reduction in gas demand growth. Multiple factors contribute to this lag. First, the advance notice suggested in the Staff Moratorium Proposal is two years. In that time, customers can sign up for new service. While different classes of customers connect more quickly than others, especially for the largest customers, it may take up to two years after the moratorium begins before the Company finishes connecting customers who applied before the moratorium took effect. Moreover, after a moratorium is announced, utilities including National Grid and Con Edison have seen an acceleration of new applications for gas connections upon announcement of a moratorium, in effect pulling forward in time future gas demand growth. To adequately address a Supply-Demand Gap, a moratorium would have to effectively limit the number of customers added to the gas network so as not to exceed the capacity to meet Design Day demand.

7.4.2. Process for Customer Curtailment

As described in Chapter 4, National Grid maintains a complete operations plan for the event that demand outpaces supply on the system. The plan, which has three main elements, was originally conceived for scenarios with an unexpected loss of supply, such as where an upstream gas transmission asset goes out of service, but the plan would also apply to potential extreme cold conditions where the Company projected that customer demand exceeded available supply. The Company would only pursue this kind of curtailment scheme after exhausting all other operational options.
The three elements would be pursued in order, and the Company would only progress to the next if it is necessary. First, the Company would call for Voluntary Load Reduction ("VLR") using pre-recorded messages which may ask customers to lower their thermostats to 65 degrees, for example. If the VLR does not deliver the necessary relief, the Company would pursue targeted *involuntary* curtailment according to its Strategic Supply Interruption Plan ("SSIP") in the second element of the plan. In accordance with Commission direction about customer prioritization, the Company has compiled, and mapped in its GIS model, the 5,000 largest C&I customers in both KEDNY and KEDLI excluding all critical customers such as hospitals, nursing homes, and public safety (police and fire departments and detention) facilities. The Company would notify customers subject to SSIP before dispatching field crews to manually shut off service at the meter, which may take 24-48 hours to shut off the 500 largest accounts. The Company would move from the 500 largest accounts to the next 500 largest accounts, and so on so that it prioritizes the largest potential reductions that impact the smallest number of customers first. The Company estimates that fully implementing the SSIP for the largest 500 customers in KEDNY could reduce demand by approximately 65 MDth/day. Finally, if the SSIP does not lower demand sufficiently, the Company would pursue its Emergency Gas Outage Management Plan ("EGOMP") where field crews would isolate sections of the system to shed load on a locational basis. This would have the effect of curtailing service to large numbers of customers in specific geographic areas, including households and businesses beyond the large accounts included in the SSIP.

National Grid has prepared to implement our curtailment plan with both internal workshops and exercises with internal and external parties. The Company introduced the plan with three workshops in late 2019 at which it introduced a scenario with stakeholders and worked through areas of concern to refine and improve the plan. Beginning in February 2020, National Grid hosted six different tabletop exercises to test the Incident Command Structure. The largest such exercise, modeling a Design Day incident where a pipeline lateral serving 30,000 customers went out, included representatives from the NYC Mayor's Office, NYC OEM, NYS DPS, FDNY, NYPD, NY/NJ Port Authority and NYCHA. Nonetheless, the SSIP and the EGOMP face significant implementation risks, including but not limited to manual processes, challenges dispatching field crews in inclement weather, customer communications, other external coordination and safety.

7.4.3. Quantification of Customer Connection and/or Curtailment Risk

The Company calculated the number of customers that account for Design Day demand equal to the contingency scenario gaps, as shown in Table 7-3. Of note, this table is a simplification as it only illustrates the number of customers that would be affected based on average blended customer usage rates across all customer classes (i.e. the numbers are a blend of residential, multi-family and C&I customers). Nevertheless, this table shows, for example, that under a contingency scenario where the LNG Vaporization Project is rejected, limiting new customer connections such that

National Grid has almost 4,000 fewer gas customers than forecasted by winter 2023/2024 would address the contingency scenario gap.

Table 7-3: Contingency Scenario Gaps as Number of Customers with Equivalent Design Day Demand

Scenario	21 22	2022 23	2023 24	2024 25	2025 26	2026 27	2027 28	2028 29	2029 30	2030 31	2031 32	2032 33	2033 34	2034 35	2035 36
LNG Vap Rejected	0	0	3,900	0	1,500	20,700	37,200	26,400	23,300	22,000	30,700	24,000	25,700	25,400	34,200
ExC Rejected	0	0	0	0	3,900	23,100	39,600	28,800	25,600	24,400	33,000	26,300	28,000	27,700	36,500
ExC & LNG Vap Rejected	0	0	3,900	21,900	42,600	61,500	77,700	66,500	63,200	61,800	70,100	63,000	64,600	64,000	72,500
80% of DI Sol n DSM	0	0	0	0	0	0	13,700	7,100	7,900	10,700	23,200	20,400	25,900	29,300	41,700

8. Conclusion and Next Steps

As demonstrated by the evidence and analysis in this Second Supplemental Report, National Grid faces a projected Supply-Demand Gap starting in winter 2022/2023 based on existing gas supply capacity and the latest demand forecast. 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.

To date, National Grid has made progress on implementation of the Distributed Infrastructure solution, but the Distributed Infrastructure Solution faces real risks in the form of permitting delays and denials as highlighted by the contingency scenarios described above. There is a material risk for pauses in the Company's 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 LNG Vaporization Project or the outright rejection of that 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.

The Distributed Infrastructure Solution builds on New York's current, ambitious gas energy efficiency and heat electrification programs and targets. Moreover, the Distributed Infrastructure Solution addresses near-term reliability needs while providing the flexibility to right-size National Grid's gas capacity portfolio over time as additional Net Zero policies and programs change the gas demand outlook.

Reinforcing this assessment of how the Distributed Infrastructure Solution aligns with Net Zero, National Grid has committed, in keeping with the Joint Proposal filed with the Commission on May 14, 2021, in the currently pending KEDNY/KEDLI rate case (Cases 19-G-0309 and 19-G-0310), to a number of additional reports evaluating how the Company's business may further evolve to support the goals of the CLCPA, NYC's Local Law 97 and the Company's Net Zero Plan.

In Case 20-G-0131, the New York Public Service Commission will establish a new process and requirements for long-term planning by New York's gas utilities. The anticipated requirements for National Grid to prepare regular long-term plans and conduct related stakeholder engagement will build on this Second Supplemental Report and provide ongoing transparency and opportunities for stakeholder feedback. This enhanced approach will help ensure that the Company's long-term plan continues to align with New York's Net Zero goal and emerging policies and programs.

As with the Original Report, we invite readers to provide feedback on this Second Supplemental Report and the analysis and conclusions contained herein. The Company also welcomes creative ideas and innovative solutions to its market solicitations for both the supply-side and demand-side proposals described above. In addition to filing the Second Supplemental Report with the New York Public Service Commission, we will be publishing this report on our website and will deploy other options for sharing the report with stakeholders, including a virtual meeting.[50]

[50] The Second Supplemental Report and related content, including the details for providing stakeholder feedback, are available at: https://ngridsolutions.com/.

9. Acronyms

9.1 Acronyms

ABS	American Bureau of Shipping
ATB	Articulated Tug Barge
BCA	Benefit-Cost Analysis
BCF	Billion Cubic Feet
BNY	Brooklyn Navy Yard
BOEM	Bureau of Ocean Energy Management
Btu	British Thermal Unit
BUG	Brooklyn Union Gas Co.
BYOT	Bring Your Own Thermostat
CNG	Compressed Natural Gas
C&I	Commercial & Industrial
CFR	Code of Federal Regulations
CLCPA	Climate Leadership and Community Protection Act
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2-e	Carbon Dioxide Equivalent
ConEd, Con Edison	Consolidated Edison
COM	Firm Commercial
COP	Coefficient of Performance
CT	Connecticut
CT DEEP	Connecticut Department of Energy and Environment Protection
DLC	Direct Load Control
DR	Demand Response
DOE	Department of Energy
DOT	Department of Transportation
DR	Demand Response
DSM	Demand-Side Management
Dth	Dekatherms
Dth/day	Dekatherms per Day
EE	Energy Efficiency
EGOMP	Emergency Gas Outage Management Plan
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EDC	Electric Distribution Company
EPA	Environmental Protection Agency
ExC	Enhancement by Compression
FDNY	New York City Fire Department
FERC	Federal Energy Regulatory Commission
FSRB	Floating Storage Regasification Barge
FSRU	Floating Storage Regasification Unit
FTE	Full time employee

GHG	Greenhouse Gas
GDP	Gross Domestic Product
GHP	Geothermal Heat Pump
GW	Gigawatt
HPWH	Heat pump water heaters
HVAC	Heating, ventilation, and air conditioning
I-GIT	Institute of Gas Innovation and Technology
IGTS	Iroquois Gas Transmission System
IMO	International Maritime Organization
ISPS	International Ship and Port Facility Security
KEDLI	KeySpan Energy Delivery Long Island
KEDNY	KeySpan Energy Delivery New York
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
LDC	Local Distribution Company
LI	Long Island
LL	Local Law (of New York)
LMI	Low-Moderate Income
LNG	Liquefied Natural Gas
MA	Massachusetts
MARAD	United States Maritime Administration
MARPOL	International Convention for the Prevention of Pollution from Ships
MDth	Thousands of Dekatherms
MDth/day	Thousands of Dekatherms per Day
MEETS	Metered Energy Efficiency Transaction Structure
MMBtu	Million British Thermal Units
MW	Megawatt
NE:NY	New Efficiency New York
NEPA	National Environmental Policy Act
NFDR	Non-Firm Demand Response
NGUSA	National Grid USA
NJ	New Jersey
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPA	Non-Pipe Alternatives
NTS	National Gas Transmission System
NY	New York
NYC	New York City
NYCCR	New York Codes, Rules and Regulations
NYPA	New York Power Authority
NYPD	New York Police Department
NY PSC	New York Public Service Commission
NYC DEP	New York City Department of Environmental Protection
NYC DOB	New York City Department of Buildings
NYC HA	New York City Housing Authority

NYC OEM	New York Emergency Management (f/k/a Office of Emergency Management
NYS DEC	New York State Department of Environmental Conservation
NYS DPS	New York State Department of Public Service
NYSEQRA	New York State Environmental Quality Review Act
NYSERDA	New York State Energy Research and Development Authority
OTH	Other Large
MF	Multifamily
O&M	Operations & Maintenance
PA	Pennsylvania
P2G	Power to Gas
PEM	Proton Exchange Membrane
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEG	Public Service Enterprise Group
RFI	Request for Information
RFQ	Request for Qualifications
RFP	Request for Proposals
RH	Residential Heating Customers
RI	Rhode Island
RN	Residential Non-Heating Customers
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
SCV	Submerged Combustion Vaporizers
SEEP	System Energy Efficiency Plans
SMB	Small Business
SMS	Safety Management System
SOLAS	Safety of Life at Sea
SSIP	Strategic Supply Interruption Plan
TETCO	Texas Eastern Transmission
Transco	Transcontinental Pipeline / Williams
USACE	United States Army Corps of Engineers
UPC	Usage Per Customer
USCG	United States Coast Guard
USFWS	United States Fish and Wildlife Service
VLR	Voluntary Load Reduction
WQC	Water Quality Certification
YOY	Year Over Year

Natural Gas Long-Term Capacity Second Supplemental Report for Brooklyn, Queens, Staten Island and Long Island (“Downstate NY”)

Appendix, June 2021

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Appendix A. Approach to Analysis of Contingency Scenarios and Their Possible Solutions

A.1. Overview

There are many steps of analyses that informed the main chapters of the Report, including:

- Developing the unadjusted demand forecast using econometric modeling
- Adjusting the demand forecast for increased demand side reduction efforts such as energy efficiency and electrification in NE:NY
- Developing a "Net Zero Scenario" based on that demand forecast which incorporates additional demand reduction that may occur
- Identifying contracted supply capacity and that that may be expiring but available to re-contract
- Developing assumptions for modeling of the proposed Distributed Infrastructure Solution, including:
    - Parameterizing distributed infrastructure resources such as LNG Vaporization at Greenpoint and the Iroquois Expansion Project
    - Parameterizing demand side management resources such as energy efficiency, demand response, and electrification of heat that is incremental to that included in the adjusted baseline demand forecast
- Identifying contingency scenarios
- Developing assumptions for modeling of additional options that could be used to address those contingency scenarios, including:
    - Identifying and screening list of possible distributed infrastructure options
    - Parameterizing the screened distributed infrastructure options such as LNG Barges and the Clove Lakes Transmission Loop for modeling
    - Identifying and screening list of possible demand side management options
    - Parameterizing the screened demand side management options such as non-firm demand response retention and electrification of heat
- Assembling solutions as combinations of those additional options that address the apparent demand-supply gap in each contingency scenario, including in each case a combination of strictly demand side management options that is a "no infrastructure solution"
- Comparing the various solutions for each contingency scenario in terms of the cost to the utility, to society, and to the ratepaying customer, the net global warming potential, and the feasibility
- Identifying the recommended solution for each contingency scenario
- Analyzing the recommended solutions at an aggregate level to identify the incremental options that should be pursued to prepare for the possible contingency scenarios

To the extent that many of these separate analyses are discussed in the main chapters of the Report, they will not be included in the Appendix. What follows is a more detailed discussion and presentation for those analyses that are not covered in depth elsewhere.

A.2. Modeling Assumptions for Components of the Distributed Infrastructure Solution

The Distributed Infrastructure Solution is discussed in depth in Section 5 of the Report. The contingency analysis presented later in the Report compares solutions assuming this Distributed Infrastructure Solution is the baseline. For example, under a contingency scenario where ExC is rejected, there would be cost savings in the form of not having to pay for ExC (in addition to increased costs from paying for other ways to meet the need). To that extent, assumptions were made for necessary parameters of the Distributed Infrastructure Solution. These assumptions are discussed below.

A.2.1. Distributed Infrastructure Component Assumptions

The analyzed contingency scenarios involving delayed or rejected infrastructure center on the LNG Vaporization Project and the ExC Project. In those contingency scenarios, some annual costs could be delayed or avoided. Note that in the delayed case the total cost of the options are not assumed to change. The assumed cost parameters of these resources is shown below:

Table A-1. Assumed Cost Parameters Associated with Potentially Delayed/Rejected Distributed Infrastructure

Component	Annualized Cost ($/yr)	Commodity Cost ($/Dth)	Notes
LNG Vaporization Project	$24,275,000	$5.25/Dth	Annualized cost based on the recourse rate of $1.0641/Dth-day listed in the IGTS filing multiplied by the assumed maximum daily quantity (62.5 MDth/day) for 365 days in the year
Iroquois Enhancement by Compression (ExC) Project	$8,150,000	$6.30/Dth	Annualized cost based on an assumed $60 Million upfront cost annualized into National Grid's rate base at 13.5% based on National Grid's experience, plus $50,000 per year of O&M

A mid-year convention was assumed for costs in the first year of service. For example, the ExC Project is assumed to cost $4,075,000 in 2024 because it is expected to come online for 2024/25, then cost the full $8,150,000 through the remainder of the analysis timeframe. Under the contingency scenario where the ExC Project is delayed for one year then, there are assumed to be cost savings of $4,075,000 per year in both 2024 and 2025.

A.2.2. Demand-Side Component Assumptions

As programmatic electrification is identified as the marginal component of the Distributed Infrastructure Solution, it is assumed as part of the contingency scenario solutions that it can be avoided so long as supply still meets demand. Therefore, for some solutions, programmatic electrification is avoided because it reduces overall solution costs. The parameterization of electrification in the Distributed Infrastructure Solution is the same as that used for the incremental electrification option considered as a component of contingency scenario solutions, and is discussed at length in Appendix B.

A.3. Modeling Assumptions for Screened Additional Options

A number of additional options incremental to those included in the Distributed Infrastructure Solution were identified as discussed in Sections 6 and 7 of the Report. The assumed parameterization of those options for modeling is discussed below.

A.3.1. Distributed Infrastructure Options

As noted in Section 7, the three screened distributed infrastructure options are the Clove Lakes Transmission Loop Project, LNG Barges, and a Micro-LNG Tank. The assumed annualized costs of these options are shown below.

Table A-2. Assumed Annualized Cost of Distributed Infrastructure Options

Component	Annualized Cost ($/yr)	Commodity Cost ($/Dth)	Notes
Clove Lakes Transmission Loop (TL) Project	$57,600,000	$5.50/Dth	Based on an assumed upfront cost of $320 Million annualized into National Grid's rate base at 13.5% based on National Grid's experience, plus the cost of additional capacity contracts based on the current recourse rate on TETCO of $0.491/Dth-day times the assumed maximum daily quantity (80 MDth/day) for 365 days in the year Note that half of this annualized cost is assumed starting with the first half of capacity that comes on-line, then the full cost is assumed to apply once the full capacity is on-line; see note in Table A-3
LNG Barges	$1,400,000 + ($55,000,000 per barge)	$9.00/Dth	Based on an assumed $10 Million upfront cost of on-system distributed upgrades annualized into National Grid's rate base at 13.5% based on National Grid's experience, plus the $275 Million per barge cost which is assumed to be owned and operated be a third-party that charges National Grid 20% of that upfront cost per year based on National Grid's experience
Micro-LNG Tank	$14,400,000	$16.03/Dth	Based on a $70 Million upfront cost annualized into National Grid's rate base at 13.5% based on National Grid's experience, plus the $5 Million assumed annual costs for maintenance, supply, and transportation

As with the the distributed infrastructure components of the Distributed Infrastructure Solution, a mid-year convention is applied to these costs for their first year in service.

Additional modeling parameters for the distributed infrastructure options are discussed below.

Table A-3. Assumed Operational Parameters of Distributed Infrastructure Options

Component	First Operational Season	Design Day Capacity	Lifecycle Emissions Rate Relative to Pipeline Gas	Notes
Clove Lakes Transmission Loop (TL) Project	50% of capacity in 2026-27, rest in 2028-29	80 MDth/day	100%	Nature of project allows for half of capacity to come on-line earlier; half of annual cost assumed to apply while half of capacity is available
LNG Barges	First in 2027-28, second in 2028-29 (if necessary)	50 MDth/day per barge	109%	
Micro-LNG Tank	2025-26	18 MDth/day	109%	

A.3.2. Incremental Demand Side Options

As discussed in Sections 5 and 6, much of the available demand-side management potential is already being pursued currently and as part of the Distributed Infrastructure solution. The following parameterization assumptions are made for demand side options that may be necessary as a component of a solution to a contingency scenario.

Incremental Demand Response

Section 6.2.3 of the main report discusses the various incremental demand response options that merit further exploration. For the modeling, it is assumed that in response to a contingency scenario National Grid would be able to retain more Non-Firm DR customers and potentially convert some large firm customers to the Non-Firm DR service class. While the actual mechanics of such programs would need to be developed, the assumptions used in this model are discussed below.

While the Non-Firm DR value proposition should improve as discussed in Sections 5.4.3.2. and 6.2.3, the adjusted baseline demand forecast still forecasts that roughly half of current Non-Firm DR customers will switch to firm rates by 2035, as is shown in Table A-4. That is because the full impact of the rate change remains to be seen. In the case that these customers still leave this rate class, as a contingency scenario option it is assumed that all Non-Firm DR customers could be provided an additional annual incentive, as discussed in Section 6.2.3. The assumed parameters of such a program for modeling are shown in Table A-5.

Table A-4. Cumulative (from 2022) Forecasted Lost Non-Firm DR Customers by Year

OpCo	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
KEDNY	119	194	268	335	407	482	555	640	717	788	850	912	968
KEDLI	3	6	9	12	14	17	20	21	25	27	30	31	34

Table A-5. Assumed Parameters of a Non-Firm Retention Program

Parameter	Value	Notes
Assumed percentage of Non-Firm DR customers forecasted to leave that could be retained	50%	
Assumed design day savings per retained Non-Firm DR customer	48 Dth/day average per retained cust	Based on National Grid analysis of current Non-Firm DR customers and those identified as getting the least value from the current Non-Firm DR rate
Assumed design day savings per Non-Firm DR customer	$4,000/yr average per cust	Assumed to be provided to all current Non-Firm DR customers in a given year, not just those who may ask to switch to firm service in a given year

It is assumed that these customers would participate in 10 effective full load days worth of events per year, and that during this time these customers would use fuel oil at a 95:75 ratio given the lower efficiency of fuel oil equipment. Given the average design day savings per customer of 48 Dth then, it is assumed that each year a single retained customer saves 480 MMBtu of gas but consumes an additional 608 MMBtu of fuel oil. This is then used to calculate the net commodity costs and net emissions impact when comparing solutions.

There are also large firm customers that could be incentivized to become Non-Firm DR customers to increase the savings from this program. Based on an analysis of billing data, National Grid identified the current number of large firm customers as the population that could be incentivized.

Table A-6. Estimated Population of Large Firm Customers for Non-Firm DR Service

OpCo	Heating/ Non-Heating	Number of Customers	Assumed Number that could be Incentized to Join Non-Firm DR	Annual Usage per Customer (Dth/yr)	Estimated Design Day Usage Per Customer (Dth/day)
KEDNY	Heating	90	14	26,800	268
KEDNY	Non-Heating	16	2	38,600	193
KEDLI	Heating	297	45	28,900	289
KEDLI	Non-Heating	99	15	46,800	234

It was assumed that these customers would need to receive an upfront incentive in order to switch to Non-Firm DR service, plus the additional annual incentive that they would now receive as Non-Firm DR customers. The necessary costs were estimated based on the average size of the customers, and are listed below.

Table A-7. Estimated Population of Large Firm Customers for Non-Firm DR Service

OpCo	Heating/ Non-Heating	Assumed Average Upfront Cost ($/cust)	Assumed Average Annual Incentive ($/cust/yr)
KEDNY	Heating	$720,000	$81,000
KEDNY	Non-Heating	$1,015,000	$115,000
KEDLI	Heating	$775,000	$88,000
KEDLI	Non-Heating	$1,220,000	$139,000

As with the non-firm retention, it is assumed that these customers would participate in 10 effective full load days worth of events per year, and that during this time these customers would use fuel oil at a 95:75 ratio given the lower efficiency of fuel oil equipment.

Incremental Electrification

Programmatic electrification is parameterized as part of the Distributed Infrastructure solution. For some contingency scenario solutions, this programmatic electrification may need to begin sooner or its magnitude may differ. To that effect, the modeling assumes a single "electrification program" incremental to that included in the adjusted baseline demand forecast as part of the Distributed Infrastructure Solution and the contingency scenario solutions. The "incremental electrification" for a solution is then the difference in size/cost between the solution's program and Distributed Infrastructure Solution's program. The parameterization of electrification is discussed at length in Appendix B.

A.4. Contingency Scenario Analysis

As discussed in Sections 6 and 7 of the Report, National Grid analyzed 7 different contingency scenarios concerning some portion of the Distributed Infrastructure Solution not contributing in full to the design day demand. The resulting apparent design day gap in each scenario would then be met with some combination of additional options as defined in Section 6 to form "solutions". These solutions are then compared. These steps are described below.

A.4.1. Assembling Solutions

First, a solution comprised entirely of demand-side management options was developed for each contingency scenario, referred to as the "No Infrastructure" solution. Because the incremental demand response option is cheaper than incremental electrification, that solution is comprised first of as much demand response as is necessary up to it's maximum potential. At that point, additional electrification is added to meet the need. As discussed in Appendix B, the "levers" for adding electrification are the year that incentives begin and the assumed incentive level (which impacts the estimated customer payback period and therefore how much of the population chooses to electrify).

Then, additional solutions were developed based on some combination of applicable distributed infrastructure options along with incremental DSM options. At this point, an additional consideration was made for the locational benefit that the infrastructure option would provide. For example, the LNG Vaporization Project and the Clove Lakes Transmission Loop Project would both provide supply to the eastern side of the downstate New York service territory, while the ExC Project provides supply to the western side of the downstate New York service territory. Therefore the Clove Lakes TL Project would provide more benefit to the system if the LNG Vaporization Project was rejected than if the ExC Project was rejected. Similar considerations were made for LNG Barges and micro-LNG; an LNG Barge in theory could be tied to the system wherever necessary while micro-

LNG was assumed to be deployable in the western portion of the service territory. These considerations left the following solutions for analysis for each contingency scenario.

Table A-8. Analyzed Solutions for Each Contingency Scenario

ExC Rejected (LNG Vap. on-time)	LNG Vap. Delayed (ExC on-time)	LNG Vap. Rejected (ExC on-Time)	ExC & LNG Vap. Delayed	ExC & LNG Vap. Rejected	80% of DSM in DI Sol'n
No Infrastructure	No Infrastructure	No Infrastructure	No Infrastructure	No Infrastructure	No Infrastructure
Micro-LNG + DSM	LNG Barge + DSM	LNG Barge + DSM	LNG Barge + DSM	Clove Lakes TL + LNG Barge + DSM	Clove Lakes TL + LNG Barge + DSM
LNG Barge + DSM	Clove Lakes TL + DSM	Clove Lakes TL + DSM	Clove Lakes TL + DSM	Micro-LNG + Clove Lakes TL + DSM	Micro-LNG + Clove Lakes TL + DSM
				2 LNG Barges + DSM	2 LNG Barges + DSM
				LNG Barge + DSM	LNG Barge + DSM
				Clove Lakes TL + DSM	

The annual composition of each of the developed solutions listed above is shown in Appendix C.

A.4.2. Comparing Solutions

The analyzed solutions are compared in the following ways, listed along with the appendix that provides a further explanation of the approach and comprehensive results for each:

- Appendix D – Annual Cost to the Utility
- Appendix E – Net Present Value Cost to the Utility
- Appendix F – Net Present Value Cost to Society
- Appendix G – Global Warming Potential
- Appendix H – Customer Cost Impact

To summarize, the following tables provide select key outputs for the analyzed solutions to each contingency scenario, with the solutions recommended for each contingency scenario in Section 7 of the Report highlighted. In general, the primary criteria for selection were cost and feasibility. On cost, more consideration was made for reducing costs over the short-term; recommended solutions do not necessarily have the lowest 15-year net present value if other solutions are cheaper primarily because electrification is reduced in later years. For that reason, the No Infrastructure solution was recommended in the cases where distributed infrastructure is delayed; the same amount of demand-side management needs to be pursued regardless. This, as well as feasibility considerations, was also the reason the LNG Barge + DSM solution is recommended under the contingency scenario in which 80% of demand-side management targets in the Distributed Infrastructure Solution are met;

though it has a higher net present value cost, much of the cost savings for the other solutions come from avoiding electrification in the later years, and a single distributed infrastructure option would be more feasible at that point in time.

Table A-9. Key Analysis Outputs for Solutions under ExC Rejected (LNG Vap. on-time)

Solution	Distrib. Infra. Option Count (#)	Electrification Savings by 2025 (MDth/day)	NPV Cost to Utility (Million $)	NPV Cost to Society (Million $)	Customer Cost Impact over next 5 Years (%)	20-yr GWP Savings (Million tons CO2e)
LNG Barge + DSM	1	21.9	$350	$415	3.3%	0.7
Micro-LNG + DSM	1	21.9	$450	$495	3.4%	1.8
No Infrastructure	0	32.9	$645	$710	4.9%	3.0

Table A-10. Key Analysis Outputs for Solutions under LNG Vap Delayed (ExC on-time)

Solution	Distrib. Infra. Option Count (#)	Electrification Savings by 2025 (MDth/day)	NPV Cost to Utility (Million $)	NPV Cost to Society (Million $)	Customer Cost Impact over next 5 Years (%)	20-yr GWP Savings (Million tons CO2e)
Clove Lakes TL + DSM	1	11.0	-$385	-$290	1.6%	-2.5
LNG Barge + DSM	1	11.0	-$180	-$110	1.6%	-1.8
No Infrastructure	0	11.0	$50	$70	1.6%	0.1

Table A-11. Key Analysis Outputs for Solutions under LNG Vap. Rejected (ExC on-time)

Solution	Distrib. Infra. Option Count (#)	Electrification Savings by 2025 (MDth/day)	NPV Cost to Utility (Million $)	NPV Cost to Society (Million $)	Customer Cost Impact over next 5 Years (%)	20-yr GWP Savings (Million tons CO2e)
Clove Lakes TL + DSM	1	11.0	$95	$155	1.7%	-0.5
LNG Barge + DSM	1	21.9	$285	$365	3.2%	0.0
No Infrastructure	0	42.1	$610	$690	4.8%	2.5

Table A-12. Key Analysis Outputs for Solutions under ExC & LNG Vap. Delayed

Solution	Distrib. Infra. Option Count (#)	Electrification Savings by 2025 (MDth/day)	NPV Cost to Utility (Million $)	NPV Cost to Society (Million $)	Customer Cost Impact over next 5 Years (%)	20-yr GWP Savings (Million tons CO2e)
Clove Lakes TL + DSM	1	11.0	-$405	-$310	1.5%	-2.5
LNG Barge + DSM	1	11.0	-$195	-$130	1.5%	-1.8
No Infrastructure	0	11.0	$30	$50	1.5%	0.1

Table A-13. Key Analysis Outputs for Solutions under ExC & LNG Vap. Rejected

Solution	Distrib. Infra. Option Count (#)	Electrification Savings by 2025 (MDth/day)	NPV Cost to Utility (Million $)	NPV Cost to Society (Million $)	Customer Cost Impact over next 5 Years (%)	20-yr GWP Savings (Million tons CO2e)
Clove Lakes TL + DSM	1	43.9	$575	$735	6.6%	1.7
LNG Barge + DSM	1	54.8	$955	$1,110	8.2%	3.3
2 LNG Barges + DSM	2	54.8	$940	$1,100	8.2%	2.6
Micro-LNG + Clove Lakes TL	2	32.9	$590	$705	5.1%	1.6
Clove Lakes TL + LNG Barge	2	43.9	$555	$725	6.6%	1.0
No Infrastructure	0	65.8	$1,230	$1,370	9.9%	5.5

Table A-14. Key Analysis Outputs for Solutions under 80% of DSM in DI Sol'n

Solution	Distrib. Infra. Option Count (#)	Electrification Savings by 2025 (MDth/day)	NPV Cost to Utility (Million $)	NPV Cost to Society (Million $)	Customer Cost Impact over next 5 Years (%)	20-yr GWP Savings (Million tons CO2e)
LNG Barge + DSM	1	0.0	$335	$560	0.2%	-2.7
2 LNG Barges	2	0.0	$150	$370	0.0%	-3.8
Micro-LNG + Clove Lakes TL	2	0.0	$30	$245	0.0%	-3.8
Clove Lakes TL + LNG Barge	2	0.0	-$155	$75	0.0%	-5.1
No Infrastructure	0	0.0	$495	$695	0.8%	-2.2

Appendix B. Electrification Parameterization

B.1. Overview

Although incentivizing electrification is not normally within the purview of a gas utility, it is assumed to be necessary here to help address the demand gap in Downstate New York as energy efficiency and demand response reach their limits of achievability. While some amount of electrification is assumed within the adjusted baseline demand forecast, it is assumed that National Grid would need to provide a separate incentive to drive enough customers to adopt electric heating and reduce gas consumption on the design day. National Grid includes significant heat electrification to close the design-supply gap in the Distributed Infrastructure Solution, as discussed in Section 5 of the Report.

Note that the scale of electrification discussed here will require significant investment across a range of areas – workforce development, collaboration with PSEG-LI and ConEdison, among others. Further consideration is warranted for how the electric grid would be impacted.

For this analysis, National Grid has made assumptions that an electrification program will be necessary. The assumptions surrounding this program are discussed below. National Grid is continuing to refine the assumptions presented in this section. This began with assumptions about base heating and cooling equipment and their associated replacement equipment, including assumed installed costs and operating costs. This required developing estimates for typical equipment, efficiencies, heating and cooling loads, and applying assumed energy rates. These equipment parameterization assumptions then formed the basis for estimating the necessary level of customer adoption and the incentive levels assumed to be necessary to drive that adoption. The results of the analysis are summarized in the sections and tables that follow.

B.2. Baseline and Replacement Equipment Parameterization

For each electrification option, a baseline efficiency and replacement efficiency were defined for three different types of customers – residential, small commercial, and multifamily. For each measure considered in this study, the model calculates the incremental measure costs, annual consumption savings (of electricity and natural gas), peak demand savings, and annual energy cost savings.

The analysis assumes heating could occur when outdoor temperatures are below 65°F. The basis for outdoor temperatures in Downstate NY is the typical meteorological year (TMY) data provided by the National Renewable Energy Laboratory (NREL) for LaGuardia Airport (weather station #725030). In addition, because of the current technology attributes, for homes or businesses that have both air source heat pumps and a gas furnace we assume design day gas consumption is not reduced because most dual fuel systems will meet their heating loads using gas-fired systems when outdoor air temperatures are below 32°F.

B.2.1. Size and Efficiency of Heating and Cooling Equipment

Each electrification activity considered in the analysis is defined by a baseline equipment type and a replacement equipment type. Table B-1 presents the full list of baseline equipment and Table B-2 presents replacement equipment.

Table B-1. Baseline Heating, Cooling, and Water Heating Equipment

Customer Type	Equipment	Size	Efficiency
Residential	Gas Boiler	110,000 Btu/hr	80% AFUE
Residential	Gas Furnace	80,000 Btu/hr	85% AFUE
Residential	Room AC	36,000 Btu/hr (3 units @ 12,000 Btu/hr)	10 EER
Residential	Ducted AC	36,000 Btu/hr	13 SEER / 11 EER
Residential	No AC	N/A	N/A
Residential	Storage Water Heater	50 gallon	0.55 UEF
Small Commercial	Gas Boiler	320,000 Btu/hr	85% AFUE
Small Commercial	Gas Furnace	230,000 Btu/hr	85% AFUE
Small Commercial	Room AC	132,000 Btu/hr (11 units @ 12,000 Btu/hr)	10 EER
Small Commercial	Ducted AC	170,000 Btu/hr	13 SEER / 11 EER
Small Commercial	No AC	N/A	N/A
Large Multifamily	Gas Boiler	1,250,000 Btu/h	85% AFUE
Large Multifamily	Gas Furnace	900,000 Btu/hr	85% AFUE
Large Multifamily	Room AC	156,000 Btu/hr (13 units @ 12,000 Btu/hr)	10 EER
Large Multifamily	Ducted AC	200,000 Btu/hr	13 SEER / 11 EER
Large Multifamily	No AC	N/A	N/A

Table B-2. Replacement Heating, Cooling, and Water Heating Equipment

Customer Type	Equipment	Size	Efficiency
Residential	Ductless Minisplit HP	48,000 Btu/hr	15 SEER / 10.0 HSPF
Residential	Central HP	60,000 Btu/hr	15 SEER / 9.0 HSPF
Residential	Heat Pump Water Heater	50 gal	2.45 UEF
Small Commercial	Central HP	280,000 Btu/hr	15 SEER / 9.0 HSPF
Small Commercial	Ductless Minisplit HP	220,000 Btu/hr	20 SEER / 9.0 HSPF
Large Multifamily	Central HP	330,000 Btu/hr	15 SEER / 9.0 HSPF
Large Multifamily	Ductless Minisplit HP	270,000 Btu/hr	20 SEER / 9.0 HSPF

For several measures, the baseline cooling component is described as a "blend." These blended baselines are calculated as weighted averages that represent the mix of air conditioning technologies that customers use. The assumed values are shown in Table B-4. The residential and multifamily values are based on NYSERDA's Residential Baseline Study, and the commercial values are based on NYSERDA's Commercial Baseline Study.[1,2] We assume that all residential gas heating customers are eligible for conversion to electric heat pump water heaters.

[1] NYSERDA Residential Baseline Study, Volume 1, Table 27, available at: https://www.nyserda.ny.gov/-/media/Files/Publications/building-stock-potential-studies/residential-baseline-study/Vol-1-Single-Family-Res-Baseline.pdf

[2] NYSERDA Commercial Baseline Study,Vol. 1, pp.43-44. https://www.nyserda.ny.gov/-/media/Statewide-Commercial-Baseline-Study-Report/NYSERDA-CBS-Vol-1-Commercial-Baseline-Study.pdf

Table B-3. Replacement Heating, Cooling, and Water Heating Equipment

A/C Technology	Residential	Small Commercial	Large Multifamily
Central A/C	36%	39%	12%
Packaged A/C	0%	31%	3%
Room A/C	48%	29%	54%
No A/C	16%	1%	31%

B.2.2. Installed Cost of Equipment, including Connection Costs

The installed cost of residential natural gas measures includes a gas line connection cost ($5,600 per residence). The installed cost of residential heat pump measures includes an average electric system upgrade cost ($500).[3] For both natural gas and electric, the installed costs do not include the cost of potential upgrades on the gas or electric distribution networks.

Table B-4. Baseline Equipment Installed Costs

Customer Type	Equipment	Installed Cost
Residential	Gas Boiler	$6,042
Residential	Gas Furnace	$3,966
Residential	Room AC	$900
Residential	Ducted AC	$3,514
Residential	No AC	$0
Residential	Storage Water Heater	$1,653
Small Commercial	Gas Boiler	$17,550
Small Commercial	Gas Furnace	$11,520
Small Commercial	Room AC	$3,400
Small Commercial	Ducted AC	$19,755
Small Commercial	No AC	$0
Large Multifamily	Gas Boiler	$69,000
Large Multifamily	Gas Furnace	$45,300
Large Multifamily	Room AC	$9,900
Large Multifamily	Ducted AC	$25,900
Large Multifamily	No AC	$0

Table B-5. Replacement Equipment Installed Costs

Customer Type	Equipment	Installed Cost
Residential	Ductless Minisplit HP	$13,015
Residential	Central HP	$21,829
Residential	Heat Pump Water Heater	$2,110
Small Commercial	Central HP	$38,965
Small Commercial	Ductless Minisplit HP	$61,891
Large Multifamily	Central HP	$153,204
Large Multifamily	Ductless Minisplit HP	$243,343

[3] The assumed electrical system upgrade cost includes the cost of service panel upgrades and the addition of a new circuit. This average cost figure assumes that some portion of residences will need electrical upgrades and some portion of residences will not.

Costs of residential equipment are taken from cost studies conducted by the Massachusetts Energy Efficiency Advisory Council (EEAC) cost studies;[4] these costs are comparable to residential installation costs reported in NYSERDA (2019). Installation costs for commercial and large multifamily customers are estimated based on ratios of commercial and residential system capacities.

B.2.3. Heating, Cooling, and Water Heating Loads

Electrification measures are charachterized using engineering calculations that use the load and efficiency of a given piece of equipment as inputs. As such, the results calculated for each measure depend on estimates of heating, cooling, and water heating loads.

Higher load values lead to higher consumption estimates and, in turn, to greater savings potential from measures that improve energy efficiency. The estimates for heating, cooling, and water heating loads are based on recently measured and reported values in Downstate New York.

Table B-6. Annual Heating, Cooling, and Water Heating Loads

Customer Type	Load	Unit	MMBtu
Residential	Space Heating	Per home	68.0
Residential	Space Cooling	Per home	14.0
Residential	Water Heating	Per home	9.5
Small Commercial	Space Heating	Per sq ft	0.049
Small Commercial	Space Cooling	Per sq ft	0.016
Large Multifamily	Space Heating	Per sq ft	0.067
Large Multifamily	Space Cooling	Per sq ft	0.007

Heating Load. The model specifies separate heating load values for single family households, multifamily buildings, and small commercial buildings. For single-family households in downstate New York, the space heating load is based on values reported in NYSERDA (2019).[5] The Energy Information Administration's 2015 Residential Energy Consumption Survey (RECS) reports end use energy consumption by fuel type for households in the Mid-Atlantic region. The space heating load assumptions for small commercial and multifamily buildings are estimated as the product of the natural gas energy use intensity (EUI, from B. Howard (2012)), the portion of natural gas used for space heating (disaggregated using EIA RECS and CBECS), and the baseline equipment energy efficiency.

Cooling Load. The model specifies separate space cooling load values for single family households, multifamily buildings, and small commercial buildings. For single-family households the cooling load is based on values reported in NYSERDA (2019). The cooling load assumptions for small commercial and multi-family buildings are estimated as the product of the electrical EUI (from B. Howard (2012)), the portion of electricity used for space cooling in buildings with space cooling (disaggregated using EIA RECS and CBECS), and the baseline equipment energy efficiency.

Water Heating Load. The E3 *Pathways* study shows water heating load of 9.52 MMBtu/year for average single-family households in downstate New York.

[4] See RES 19 Water Heating, Boiler, and Furnace Cost Study, available at: https://ma-eeac.org/wp-content/uploads/RES19_Assembled_Report_2018-09-27.pdf
and RES 28 Ductless Mini-Split Heat Pump Cost Study, available at: https://ma-eeac.org/wp-content/uploads/RES28_Assembled_Report_2018-10-05.pdf
[5] NYSERDA (2019). "New Efficiency: New York Analysis of Residential Heat Pump Potential and Economics" Table 4-6.

Table B-7. Baseline Equipment Annual Energy Consumption

Customer Type	Equipment	Electricity (kWh/yr)	Electric Peak (kW/yr)	Natural Gas (therm/yr)
Residential	Gas Boiler	311	0.00	879
Residential	Gas Furnace	500	0.00	800
Residential	Room AC / No AC Blend	982	0.81	0
Residential	Ducted AC	1,017	1.33	0
Residential	Storage Water Heater	0	0.00	173
Small Commercial	Gas Boiler	903	0.00	2,324
Small Commercial	Gas Furnace	1,452	0.00	2,324
Small Commercial	Room AC / No AC Blend	6,367	4.91	0
Small Commercial	Ducted AC	4,655	9.86	0
Large Multifamily	Gas Boiler	3,552	0.00	9,137
Large Multifamily	Gas Furnace	5,710	0.00	9,137
Large Multifamily	Room AC / No AC Blend	7,717	5.95	0
Large Multifamily	Ducted AC	7,289	7.76	0

Table B-8. Replacement Equipment Annual Energy Consumption

Customer Type	Equipment	Electricity (kWh/yr)	Electric Peak (kW/yr)	Natural Gas (therm/yr)
Residential	Ductless Minisplit HP	8,079	2.76	0
Residential	Central HP	7,847	3.51	0
Residential	Heat Pump Water Heater	1,139	0.18	0
Small Commercial	Central HP	26,323	19.10	0
Small Commercial	Ductless Minisplit HP	24,428	14.90	0
Large Multifamily	Central HP	94,558	22.72	0
Large Multifamily	Ductless Minisplit HP	84,132	17.72	0

B.2.4. Annual Energy Costs

Average rates for residential and commercial customers of the electric and gas utilities in Downstate NY were derived from analysis of EIA Form 861 (electric) and EIA Form 176 (natural gas) data. As a simplifying assumption we use the average rates, rather than modeling demand charges, time of use rates, block rates, or other rate electric and gas designs. We also assume rates increase at inflation.

Table B-9. Assumed Energy Rates

Customer Type	PSEG-LI and KEDLI		ConEd and KEDNY	
	Electric ($/kWh)	Gas ($/therm)	Electric ($/kWh)	Gas ($/therm)
Residential	$0.2039	$1.394	$0.2530	$1.415
Commercial/Multifamily	$0.1827	$1.049	$0.1870	$1.171

Annual energy costs then are the product of the heating, cooling, and water heating consumption and the associated energy rates.

Table B-10. Baseline Equipment Annual Energy Costs by Region

Customer Type	Equipment	PSEG-LI and KEDLI		ConEd and KEDNY	
		Electricity ($/yr)	Natural Gas ($/yr)	Electricity ($/yr)	Natural Gas ($/yr)
Residential	Gas Boiler	$63	$1,225	$79	$1,244
Residential	Gas Furnace	$102	$1,115	$127	$1,132
Residential	Room AC / No AC Blend	$250	$0	$311	$0
Residential	Ducted AC	$263	$0	$326	$0
Residential	Storage Water Heater	$0	$241	$0	$245
Small Commercial	Gas Boiler	$165	$2,438	$169	$2,721
Small Commercial	Gas Furnace	$265	$2,438	$272	$2,721
Small Commercial	Room AC / No AC Blend	$1,163	$0	$1,191	$0
Small Commercial	Ducted AC	$850	$0	$870	$0
Large Multifamily	Gas Boiler	$649	$9,585	$664	$10,699
Large Multifamily	Gas Furnace	$1,043	$9,585	$1,068	$10,699
Large Multifamily	Room AC / No AC Blend	$1,410	$0	$1,443	$0
Large Multifamily	Ducted AC	$1,332	$0	$1,363	$0

Table B-11. Replacement Equipment Annual Energy Costs by Region

Customer Type	Equipment	PSEG-LI and KEDLI		ConEd and KEDNY	
		Electricity ($/yr)	Natural Gas ($/yr)	Electricity ($/yr)	Natural Gas ($/yr)
Residential	Ductless Minisplit HP	$1,647	$0	$2,044	$0
Residential	Central HP	$1,600	$0	$1,985	$0
Residential	Heat Pump Water Heater	$232	$0	$288	$0
Small Commercial	Central HP	$4,809	$0	$4,922	$0
Small Commercial	Ductless Minisplit HP	$4,463	$0	$4,568	$0
Large Multifamily	Central HP	$17,276	$0	$17,682	$0
Large Multifamily	Ductless Minisplit HP	$15,371	$0	$15,733	$0

B.2.5. Baseline Equipment and Preferred Replacement Technology

Building baselines are assumed to either not provide space cooling or provide space cooling using either a central A/C system or room/window A/C units. For measures in this analysis that include a cooling function, the baseline cooling characteristics are calculated as a blend of these A/C types (Room A/C, Central A/C, and No A/C).

The customers most likely to install a Central HP system are assumed to be customers who already have ductwork in place from an existing furnace and/or central A/C installation. Customers using a natural gas boiler with room A/Cs or no cooling are more likely to install a DMSHP than a central HP.

To characterize these baseline A/C blends, the consumption and costs associated with the baseline efficiency level of each separate A/C equipment type (Room A/C, Central A/C, and No A/C) were esimated. Then, the consumption and costs of the separate A/C types were combined into weighted averages, using the saturation of the different A/C types as weights within Downstate NY.Baseline A/C saturation describes the percent of households that are equipped with central A/C, window/room A/C, or no A/C. Baseline saturations are reported in the NYSERDA's residential and commercial baseline studies and are summarized in Section B.2.1.

For measures with furnace equipment in the baseline, the blended A/C baseline is a weighted average of all three cooling types (Room A/C, Central A/C, and No A/C).

For measures with boiler equipment in the baseline, customers with a boiler and central A/C are assumed to more likely upgrade to a central HP (since they already have ductwork in place), and customers with a boiler and room A/C or no A/C would most likely upgrade to a DMSHP to avoid the cost of installing new ductwork. Based on this assumption:

- Measures that upgrade from a boiler baseline to a DMSHP use a blended baseline that is a weighted average of two cooling types (Room A/C and No A/C).
- Measures that upgrade from a boiler baseline to a central HP use a central A/C baseline without any blending.

The table below summarizes the replacement equipment assumed for different baseline configurations.

Table B-12. Typical Baseline and Replacement Configurations

Customer Type	Short Name	Baseline			Replacement	
		Heating	Cooling	Water Heating	Heating & Cooling	Water Heating
Residential	Boiler/AC → DMSHP Storage WH→HPWH	Gas Boiler	AC Blend	Gas Storage WH	Ductless Mini-Split HP	HPWH
Residential	Furnace/AC → CHP Storage WH→HPWH	Gas Furnace	Ducted AC	Gas Storage WH	Central HP	HPWH
Small Commercial	Boiler/AC → DMSHP	Gas Boiler	AC Blend	N/A	Ductless Mini-Split HP	N/A
Small Commercial	Furnace/AC → CHP	Gas Furnace	Ducted AC	N/A	Central HP	N/A
Large Multifamily	Boiler/AC → DMSHP	Gas Boiler	AC Blend	N/A	Ductless Mini-Split HP	N/A
Large Multifamily	Furnace/AC → CHP	Gas Furnace	Ducted AC	N/A	Central HP	N/A

B.2.6. *Incremental Savings and Costs*

The difference between the baseline equipment parameters and the preferred replacement equipment parameters are the “incremental” parameters. The resulting incremental energy savings by electrification measure are shown below. Negative values imply a net increase (e.g., more annual electric consumption).

Table B-13. Incremental Energy Savings by Electrification Measure

Customer Type	Short Name	Annual Electric Savings (kWh/yr)	Summer Peak Savings (kW/yr)	Annual Gas Savings (therm/yr)
Residential	Boiler/AC → DMSHP Storage WH→HPWH	-7,925	-2.1	1,030
Residential	Furnace/AC → CHP Storage WH→HPWH	-7,470	-2.4	970
Small Commercial	Boiler/AC → DMSHP	-19,050	-10.0	2,320
Small Commercial	Furnace/AC → CHP	-17,715	-9.2	2,320
Large Multifamily	Boiler/AC → DMSHP	-83,290	-11.8	9,140
Large Multifamily	Furnace/AC → CHP	-71,130	-15.0	9,140

To estimate the design day savings associated with these annual gas savings, the annual gas savings were multiplied by the implied design day factors (the ratio of wholesale design day usage per customer to retail annual usage per customers implicit in the adjusted baseline forecast). Those values are shown in the table below.

Table B-14. Assumed Ratio of Design Day Savings to Annual Gas Savings per Electrification

Customer Type	KEDNY	KEDLI
Residential	1.20%	1.21%
Small Commercial	1.04%	0.88%
Large Multifamily	0.87%	1.02%

The total incremental costs are shown below for a heat pump assumed to be installed in KEDNY and KEDLI, assuming a 20-year equipment lifetime.

Table B-15. Incremental Costs of Electrification, KEDNY

Customer Type	Short Name	Incremental Installed Cost ($)	Incremental Annual Operating Cost ($/yr)	Incremental Lifetime Cost ($)
Residential	Boiler/AC → DMSHP Storage WH→HPWH	$6,755	$554	$17,815
Residential	Furnace/AC → CHP Storage WH→HPWH	$16,618	$520	$27,018
Small Commercial	Boiler/AC → DMSHP	$19,683	$1,482	$49,323
Small Commercial	Furnace/AC → CHP	$39,504	$841	$56,324
Large Multifamily	Boiler/AC → DMSHP	$87,936	$6,378	$215,496
Large Multifamily	Furnace/AC → CHP	$207,097	$3,416	$275,417

Note: Lifetime cost is not discounted

Table B-16. Incremental Costs of Electrification, KEDLI

Customer Type	Short Name	Incremental Installed Cost ($)	Incremental Annual Operating Cost ($/yr)	Incremental Lifetime Cost ($)
Residential	Boiler/AC → DMSHP Storage WH→HPWH	$6,755	$186	$10,475
Residential	Furnace/AC → CHP Storage WH→HPWH	$16,618	$174	$20,098
Small Commercial	Boiler/AC → DMSHP	$19,683	$1,708	$53,843
Small Commercial	Furnace/AC → CHP	$39,504	$1,081	$61,124
Large Multifamily	Boiler/AC → DMSHP	$87,936	$7,253	$232,996
Large Multifamily	Furnace/AC → CHP	$207,097	$4,359	$294,277

Note: Lifetime cost is not discounted

B.2.7. Referenced Data Sources for Parameterization

Below are additional links and descriptions of key data sources used throughout this parameterization:

- **New York Technical Reference Manual (TRM)**
  - https://www3.dps.ny.gov/W/PSCWeb.nsf/All/72C23DECFF52920A85257F1100671BDD
  - The New York TRM describes the efficiency of different residential equipment at the baseline and replacement levels of performance. The TRM was referenced to

determine equipment performance at the different efficiency levels considered in this study.

- **Energy Information Administration (EIA) Fuel Price Data**
  - https://www.eia.gov/dnav/pet/pet_pri_wfr_dcus_SNY_w.htm
  - The EIA publishes residential price data for a variety of fuel types by U.S. state on a weekly basis. This data was used to estimate the annual energy costs associated with different measures.
- **EIA 2015 Residential Energy Consumption Survey (RECS)**
  - https://www.eia.gov/consumption/residential/data/2015/index.php
  - The EIA RECS reports energy consumption by end use, fuel type, and geographic region. Water heating load for New York households was estimated using RECS data for natural gas--fired water heater energy consumption for the Mid-Atlantic region.
- **New Efficiency: New York Analysis of Residential Heat Pump Potential and Economics (NENY)**
  - https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf
  - The NENY study from NYSERDA examined the total installed costs and annual loads of various types of residential heating and cooling equipment. This study was referenced to estimate the total installed costs of different equipment types at different efficiency levels. Specifically, typical equipment costs of replacement heat pump were referenced.
- **National Renewable Energy Laboratory (NREL) – Typical Meteorological Year Data**
  - https://nsrdb.nrel.gov/about/tmy.html
  - For weather stations across the U.S., NREL provides hourly weather data that represent a Typical Meteorological Year (TMY) for building energy simulations. TMYs contain one year of hourly data that best represents median weather conditions over a multiyear period. The data are considered "typical" because the entirety of the original solar radiation and meteorological data is condensed into one year's worth of the most usual conditions. Hourly temperature data was used for weather stations in downstate New York to estimate the typical annual performance of heat pump equipment in this location.
- **U.S. Department of Energy (DOE) Appliance Standards Technical Support Documents**
  - Link: https://www.energy.gov/eere/buildings/standards-and-test-procedures
  - The DOE publishes detailed analyses of the energy consumption of various residential equipment at different efficiency levels. These analyses were referenced to estimate the electrical consumption associated with the furnace, boiler, and water heating equipment considered in this study.
- **Northeast Energy Efficiency Partnerships (NEEP) Cold Climate Air-Source Heat Pump Database**
  - https://neep.org/high-performance-air-source-heat-pumps/ccashp-specification-product-list
  - NEEP hosts the Cold Climate Air-Source Heat Pump (ccASHP) Specification and a database of products that meet the specification. The ccASHP Specification was

developed to address concerns regarding the HSPF metric, especially in cold temperature conditions. The ccASHP database provides performance data for approved products at outdoor test temperatures of 47 °F, 17 °F and 5 °F.

B.3. Adoption Assumptions

The assumed population for participation in programmatic electrification are residential, small commercial, and large multifamily customers forecasted to switch to or replace their natural gas heating equipment. That would include net new forecasted gas customers (as by definition they are forecasted to join gas heating), and current customers replacing their existing natural gas heating equipment. Of the latter population, we assumed that the average gas equipment replacement cycle is 20 years, leading to 5% of current customers planning to replace their natural gas equipment each year. These total populations are shown in Table B-17 Of this population, it was assumed that 40% have existing ductwork and would therefore opt for the central heat pump. The remaining 60% were assumed to opt for the ductless minisplit.

Table B-17. Assumed Populations Eligible for Electrification

Population[1]	KEDNY - RH	KEDNY - COM	KEDNY - MF	KEDLI - RH	KEDLI - COM	KEDLI - MF
Existing Customer Base Replacing Equipment Each Year	31,675	2,571	958	23,270	2,996	87
Net Additions in 2021-22	7,021	164	86	5,215	0	30
Net Additions in 2022-23	8,347	346	48	7,210	181	26
Net Additions in 2023-24	6,361	200	266	8,593	310	26
Net Additions in 2024-25	7,513	120	140	9,220	257	28
Net Additions in 2025-26	7,727	67	143	9,591	240	31
Net Additions in 2026-27	7,427	71	110	9,457	235	31
Net Additions in 2027-28	7,300	59	121	8,633	250	28
Net Additions in 2028-29	7,017	41	135	7,730	245	26
Net Additions in 2029-30	6,865	31	148	6,918	242	26
Net Additions in 2030-31	6,953	27	168	6,486	230	25
Net Additions in 2031-32	6,997	26	155	6,247	206	24
Net Additions in 2032-33	6,978	23	135	6,020	162	24
Net Additions in 2033-34	6,885	19	116	5,681	50	19
Net Additions in 2034-35	6,783	19	93	5,364	0	12
Net Additions in 2035-36	6,706	24	96	5,169	0	11

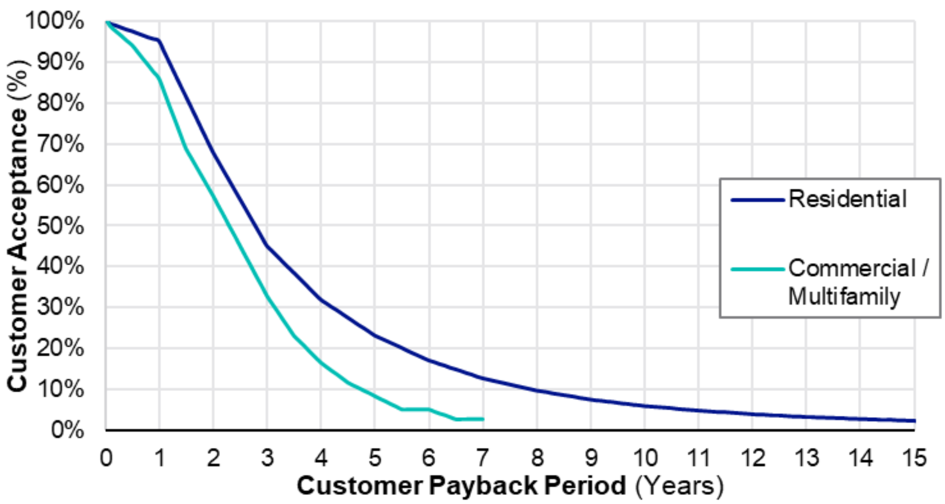
[1] Note that the “Existing Customer Base Replacing Equipment each Year” is the population available for electrification *each year* (e.g., ~2,000 existing commercial gas customers in KEDLI replace their gas equipment in 2021-22, then another ~2,000 replace their gas equipment in 2022-23, and so on), whereas the “Net Additions” are listed in this table by year, and are only able to be “electrified” in the year they’re forecasted to be added to gas service

The portion of this population that would need to electrify was then calculated based on the gap in a particular scenario divided by the assumed design day savings per electrification identified in Section B.2.6. This percentage of the population that would be needed to electrify then went to estimate incentive costs.

B.4. Estimating Incentive Costs

Customer payback analysis was used to estimate the incentives necessary to drive the level of adoption identified for each solution. This assumes that customers are motivated only by costs, and that they follow an assumed curve of payback acceptance, shown in Figure B-1 below. The payback period is the number of years until an investment pays off, calculated in this case as the incremental cost of a the technology divided by the annual savings from that technology. Applying that to the figure then, if a technology pays for itself immediately (i.e., it is cheaper than a competing technology) then 100% of customers will purchase it. But if, for example, a technology pays for itself over 2 years (if, say, a technology is $100 more expensive, but it saves $50 per year) then we would expect ~70% of residential customers and ~60% of commercial customers to opt for that technology.

Figure B-1. Contribution of No Infrastructure Solution to Design Day Gap if ExC Rejected (LNG Vap. On-Time)



The issue with heat pump technology in downstate New York is that it is more expensive both upfront and annually. In the 2020 Supplemental Report this was addressed by assuming that a five-year ongoing incentive program would cover the additional cost of operation. Given the difficulties with managing ongoing incentive payments, for this Report that assumption has been changed so that a single incentive would be provided upfront that exceeds the incremental cost of the heat pump and thereby pays for some of the ongoing operation cost. Note that the incremental cost is not the full cost of the heat pump, just the difference between the cost of the heat pump and the typical gas baseline equipment (see Section B.2.6).

For setting this single incentive, it was assumed that the only alternative for the payback acceptance curve shown in Figure B-1 would be to install the typical gas baseline equipment. That is, the heat pump would be incentivized at such a level that the gas baseline equipment became more expensive upfront, but would then pay for itself over time given its lower annual operating cost. If then, for example, 70% of customers would choose to install the gas equipment, then the remaining 30% would be choosing to electrify.

Using the assumed upfront and ongoing costs of electric heat pumps, incentives could then be set based on the payback acceptance necessary by this logic to drive the level of adoption identified for each solution.

Note that this approach carries with it an implicit inequity, wherein customers who may have less money available upfront opt for the cheaper technology, even though it costs them more in the long-term. In developing an actual electrification program, this would be thoroughly considered along with alternative incentive methods.

B.5. Estimating Non-Incentive Costs

In addition to these incentive costs, program and administrative costs were applied to account for the cost to ramp-up and manage this program. This may include such activities as engaging with customers via marketing, training contractors, and coordinating with manufacturers. The added non-incentive costs over time as a percentage of incentive costs is shown below.

Table B-18. Assumed Non-Incentive Cost Adder, as a Percent of Annual Incentive Costs

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
103%	91%	86%	60%	57%	39%	20%	20%	20%	20%	20%	20%	20%

National Grid will be further assessing and refining these planning-level estimates as the planning for heat electrification progresses.

Appendix C. Design Day Savings vs. Gap

C.1. Approach

Multiple plausible contingencies are identified where an infrastructure component associated with the distributed infrastructure solution is delayed or rejected or the demand-side management goals are not achieved. The analysis of outcomes for these contingencies assumes the adjusted baseline forecast and existing supply remain the same as for the distributed infrastructure solution. In selected permutations, a design day gap for Downstate NY emerges. Where a gap emerges, the approach is to test combinations of alternative infrastructure and non-infrastructure options to fill the gap. The no infrastructure alternative is composed of incremental DR, with heat electrification to fill any remaining demand-supply gap.

Illustrations below depict the gaps and the components of recommended solutions to fill those gaps.

C.2. Design Day Savings vs. Gap for No Infrastructure Solutions

Figure C-1. Contribution of No Infrastructure Solution to Design Day Gap if ExC Rejected (LNG Vap. On-Time)

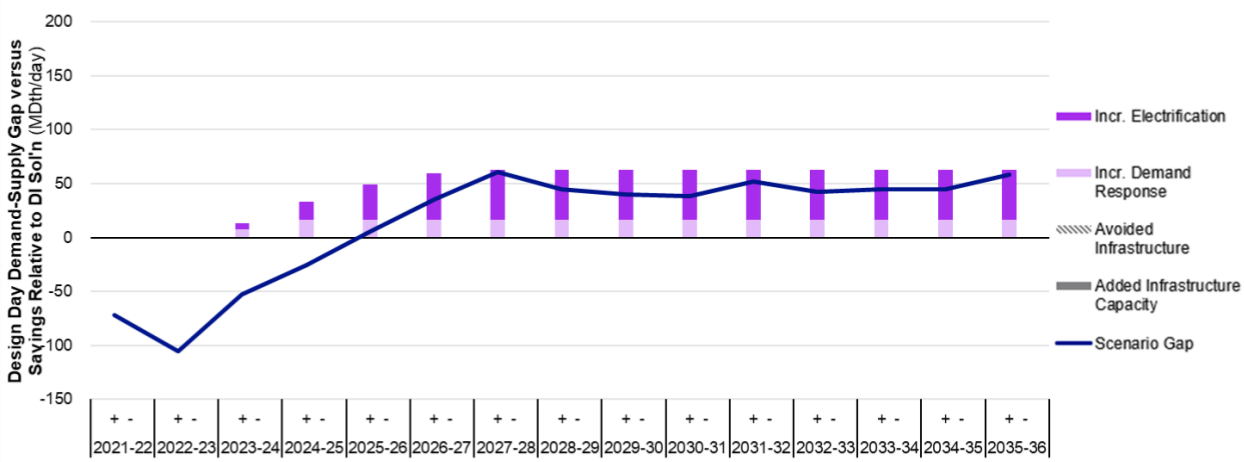


Figure C-2. Contribution of No Infrastructure Solution to Design Day Gap if LNG Vap. Delayed (ExC On-Time)

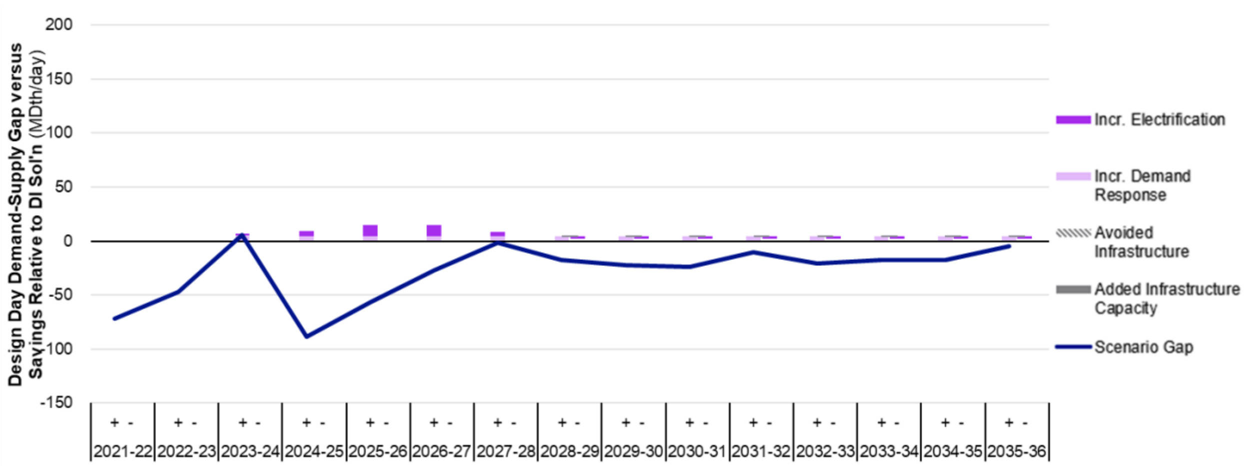


Figure C-3. Contribution of No Infrastructure Solution to Design Day Gap if LNG Vap. Rejected (ExC On-Time)

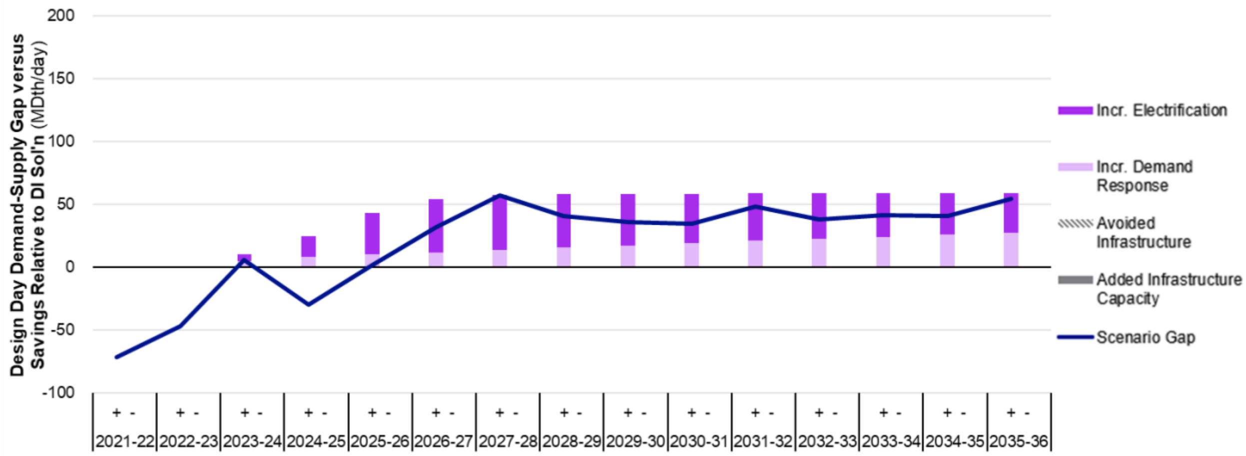


Figure C-4. Contribution of No Infrastructure Solution to Design Day Gap if ExC & LNG Vap. Delayed

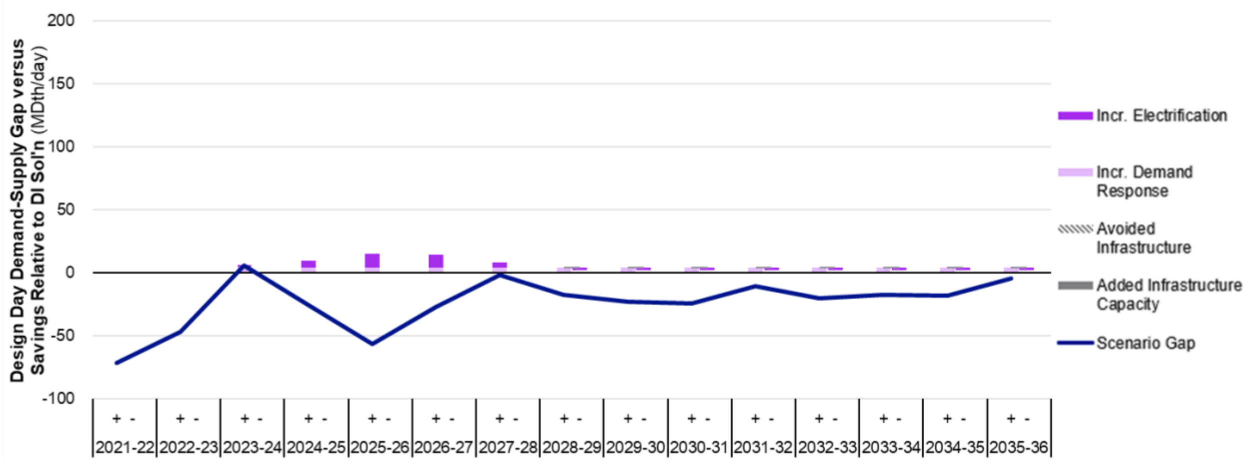


Figure C-5. Contribution of No Infrastructure Solution to Design Day Gap if ExC & LNG Vap. Rejected

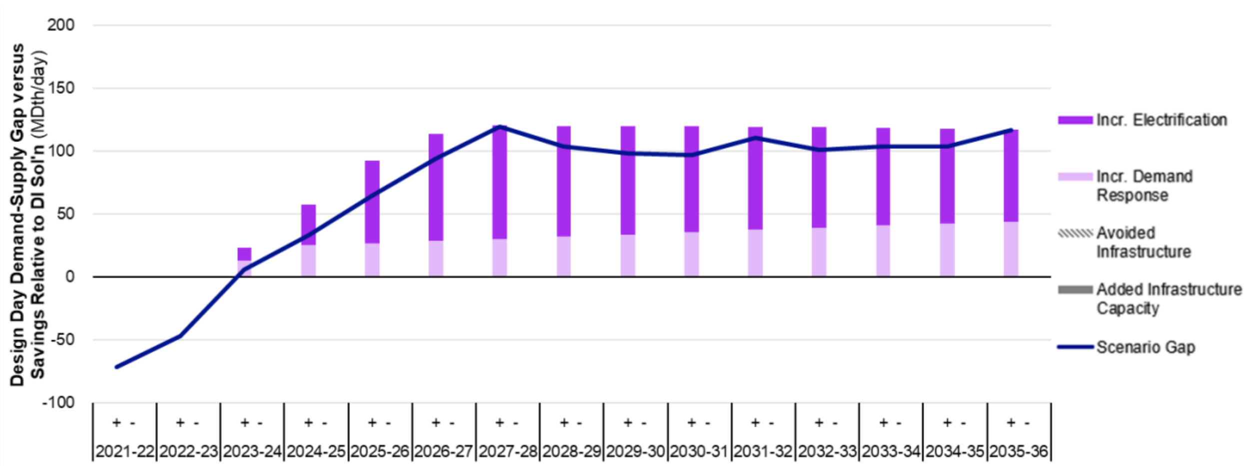
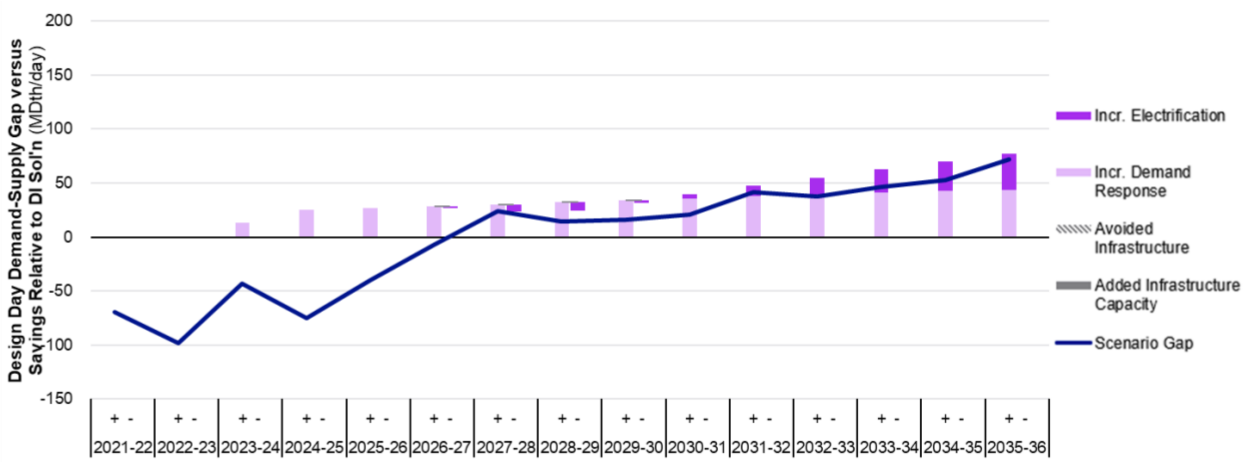


Figure C-6. Contribution of No Infrastructure Solution to Design Day Gap if 80% of DSM Savings in DI Sol'n



C.3. Design Day Savings vs. Gap for Recommended Solutions

Figure C-7. Contribution of LNG Barge Solution to Design Day Gap if ExC Rejected (LNG Vap. On-Time)

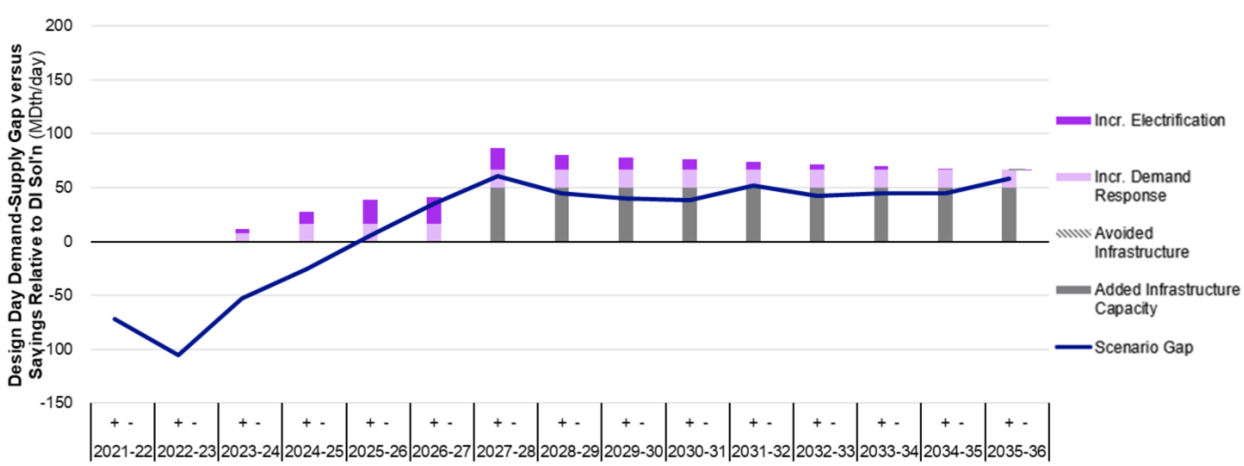


Figure C-8. Contribution of No Infrastructure Solution to Design Day Gap if LNG Vap. Delayed (ExC On-Time)

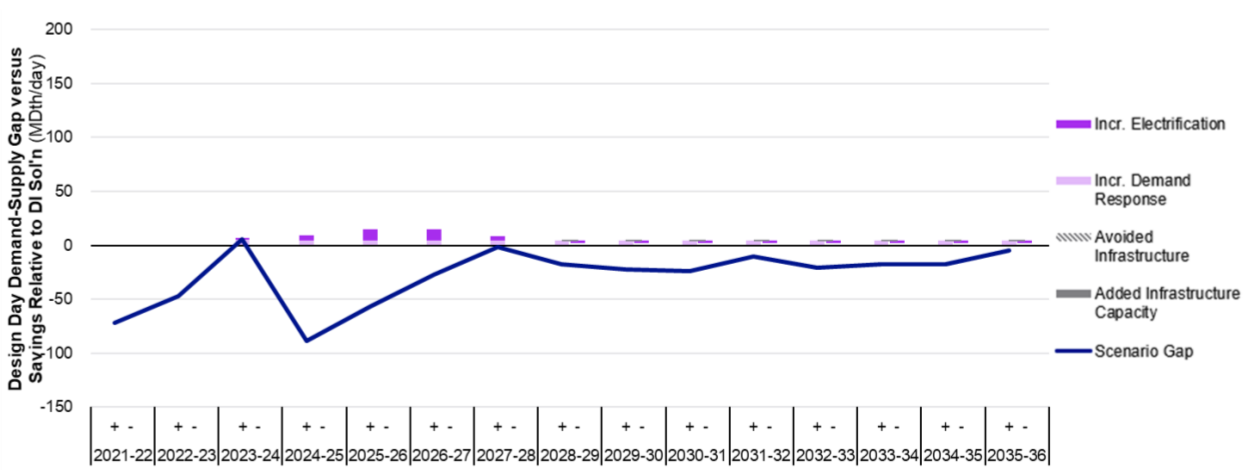


Figure C-9. Contribution of Clove Lakes TL Solution to Design Day Gap if LNG Vap. Rejected (ExC On-Time)

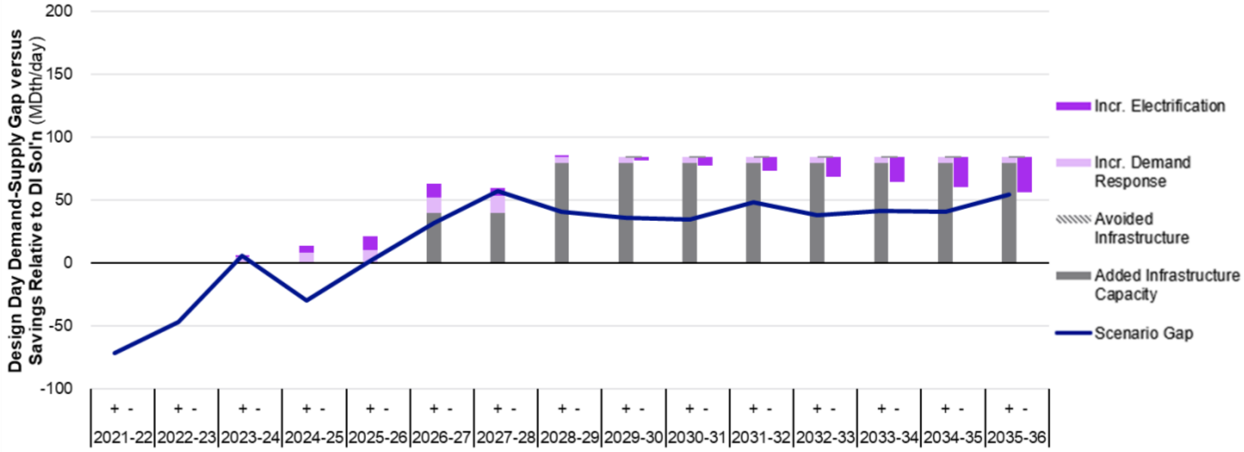


Figure C-10. Contribution of No Infrastructure Solution to Design Day Gap if ExC & LNG Vap. Delayed

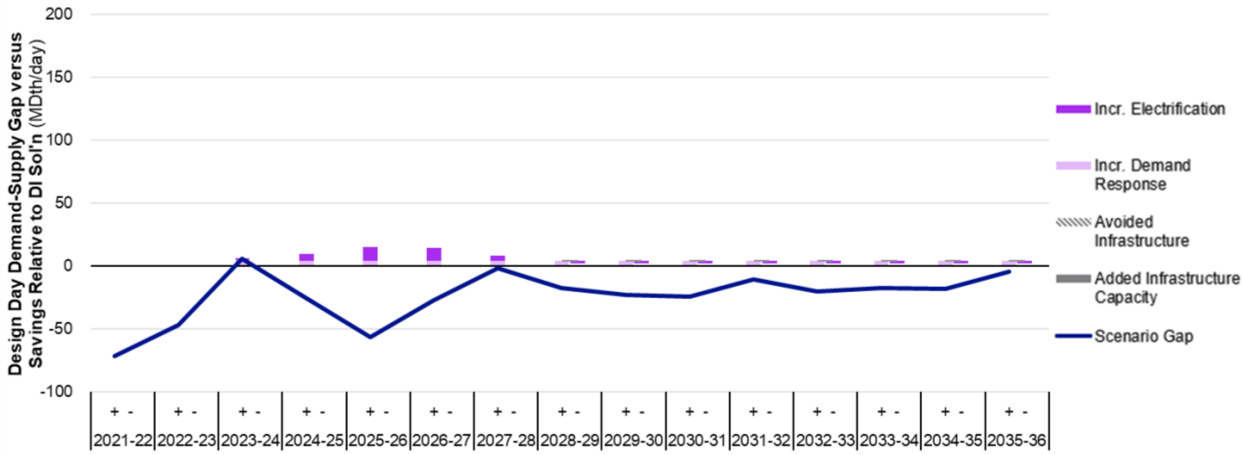


Figure C-11. Contribution of Clove Lakes TL + LNG Barge Solution to Design Day Gap if ExC & LNG Vap. Rejected

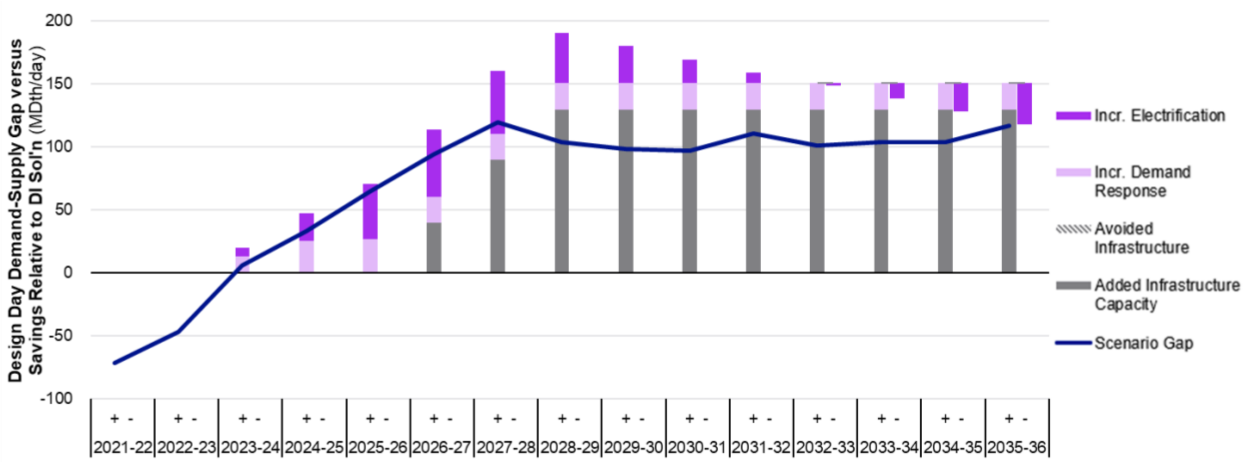
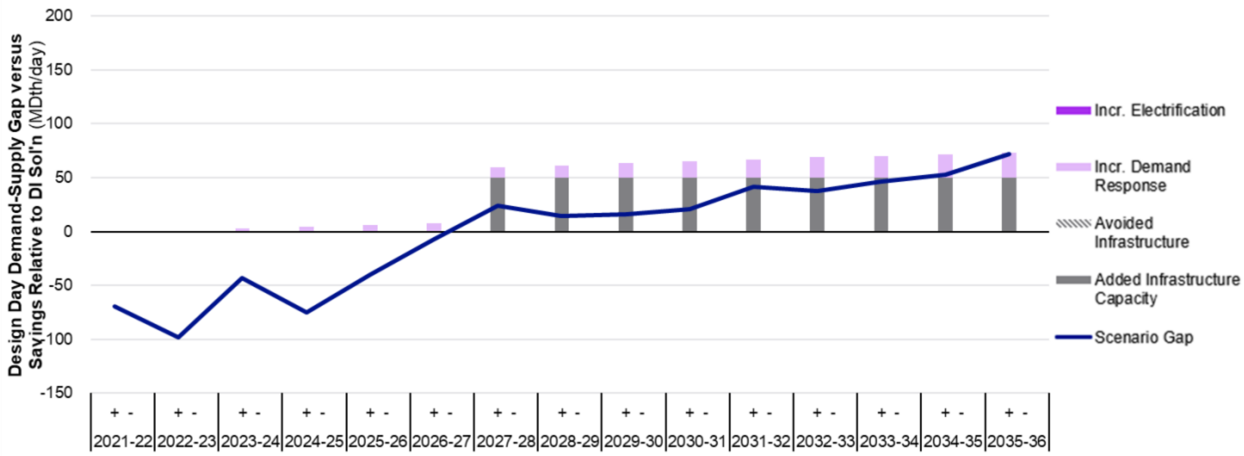


Figure C-12. Contribution of LNG Barge Solution to Design Day Gap if 80% of DSM Savings in DI Sol'n



C.4. Design Day Savings vs. Gap for All Solutions

Table C-1. Design Day Savings by Analyzed Solution Compared to Demand-Supply Gap under ExC Rejected (LNG Vap. on-time) [MDth/day]

Solution	Parameter	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
LNG Barge	Demand Gap	-71.6	-105.5	-53.0	-25.7	5.9	35.5	61.1	45.0	40.0	38.4	52.3	42.2	45.0	44.9	58.0
LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
LNG Barge	Demand Response	0.0	0.0	8.0	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
LNG Barge	Electrification	0.0	0.0	3.6	10.9	21.9	25.0	20.2	13.8	11.7	9.6	7.5	5.4	3.3	1.2	-0.8
Micro-LNG	Demand Gap	-71.6	-105.5	-53.0	-25.7	5.9	35.5	61.1	45.0	40.0	38.4	52.3	42.2	45.0	44.9	58.0
Micro-LNG	Infrastructure	0.0	0.0	0.0	0.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Micro-LNG	Demand Response	0.0	0.0	8.0	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
Micro-LNG	Electrification	0.0	0.0	3.6	10.9	21.9	27.2	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8
No Infrastructure	Demand Gap	-71.6	-105.5	-53.0	-25.7	5.9	35.5	61.1	45.0	40.0	38.4	52.3	42.2	45.0	44.9	58.0
No Infrastructure	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No Infrastructure	Demand Response	0.0	0.0	8.0	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
No Infrastructure	Electrification	0.0	0.0	5.4	16.4	32.9	42.7	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0

Table C-2. Design Day Savings by Analyzed Solution Compared to Demand-Supply Gap under LNG Vap Delayed (ExC on-time) [MDth/day]

Solution	Parameter	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Demand Gap	-71.6	-46.7	5.8	-88.2	-56.6	-27.0	-1.4	-17.5	-22.5	-24.1	-10.2	-20.3	-17.5	-17.6	-4.5
Clove Lakes TL	Infrastructure	0.0	0.0	0.0	0.0	0.0	40.0	40.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Clove Lakes TL	Demand Response	0.0	0.0	4.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Clove Lakes TL	Electrification	0.0	0.0	1.8	5.5	11.0	7.5	-4.9	-19.8	-31.5	-39.9	-48.3	-56.7	-64.9	-73.2	-81.3
LNG Barge	Demand Gap	-71.6	-46.7	5.8	-88.2	-56.6	-27.0	-1.4	-17.5	-22.5	-24.1	-10.2	-20.3	-17.5	-17.6	-4.5
LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
LNG Barge	Demand Response	0.0	0.0	4.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
LNG Barge	Electrification	0.0	0.0	1.8	5.5	11.0	8.2	-2.9	-15.9	-25.0	-30.3	-35.6	-40.8	-46.0	-51.1	-56.3
No Infrastructure	Demand Gap	-71.6	-46.7	5.8	-88.2	-56.6	-27.0	-1.4	-17.5	-22.5	-24.1	-10.2	-20.3	-17.5	-17.6	-4.5
No Infrastructure	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No Infrastructure	Demand Response	0.0	0.0	4.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
No Infrastructure	Electrification	0.0	0.0	1.8	5.5	11.0	10.5	4.1	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0

Table C-3. Design Day Savings by Analyzed Solution Compared to Demand-Supply Gap under LNG Vap. Rejected (ExC on-time) [MDth/day]

Solution	Parameter	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Demand Gap	-71.6	-46.7	5.8	-29.4	2.2	31.8	57.4	41.3	36.3	34.7	48.6	38.5	41.3	41.2	54.3
Clove Lakes TL	Infrastructure	0.0	0.0	0.0	0.0	0.0	40.0	40.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Clove Lakes TL	Demand Response	0.0	0.0	4.9	8.8	10.6	12.2	13.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Clove Lakes TL	Electrification	0.0	0.0	1.8	5.5	11.0	11.1	6.0	1.7	-2.5	-6.7	-11.0	-15.2	-19.3	-23.4	-27.5
LNG Barge	Demand Gap	-71.6	-46.7	5.8	-29.4	2.2	31.8	57.4	41.3	36.3	34.7	48.6	38.5	41.3	41.2	54.3
LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
LNG Barge	Demand Response	0.0	0.0	4.9	8.8	10.6	12.2	13.9	15.7	17.5	19.5	21.3	23.1	24.5	26.0	27.4
LNG Barge	Electrification	0.0	0.0	3.6	10.9	21.9	23.9	17.0	7.4	1.0	-2.1	-5.3	-8.4	-11.5	-14.6	-17.6
No Infrastructure	Demand Gap	-71.6	-46.7	5.8	-29.4	2.2	31.8	57.4	41.3	36.3	34.7	48.6	38.5	41.3	41.2	54.3
No Infrastructure	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No Infrastructure	Demand Response	0.0	0.0	4.9	8.8	10.6	12.2	13.9	15.7	17.5	19.5	21.3	23.1	24.5	26.0	27.4
No Infrastructure	Electrification	0.0	0.0	5.4	16.4	32.9	42.1	44.0	42.4	40.8	39.3	37.7	36.1	34.6	33.0	31.5

Table C-4. Design Day Savings by Analyzed Solution Compared to Demand-Supply Gap under ExC & LNG Vap. Delayed [MDth/day]

Solution	Parameter	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Demand Gap	-71.6	-46.7	5.8	-25.7	-56.6	-27.0	-1.4	-17.5	-22.5	-24.1	-10.2	-20.3	-17.5	-17.6	-4.5
Clove Lakes TL	Infrastructure	0.0	0.0	0.0	0.0	0.0	40.0	40.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Clove Lakes TL	Demand Response	0.0	0.0	4.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Clove Lakes TL	Electrification	0.0	0.0	1.8	5.5	11.0	7.5	-4.9	-19.8	-31.5	-39.9	-48.3	-56.7	-64.9	-73.2	-81.3
LNG Barge	Demand Gap	-71.6	-46.7	5.8	-25.7	-56.6	-27.0	-1.4	-17.5	-22.5	-24.1	-10.2	-20.3	-17.5	-17.6	-4.5
LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
LNG Barge	Demand Response	0.0	0.0	4.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
LNG Barge	Electrification	0.0	0.0	1.8	5.5	11.0	8.2	-2.9	-15.9	-25.0	-30.3	-35.6	-40.8	-46.0	-51.1	-56.3
No Infrastructure	Demand Gap	-71.6	-46.7	5.8	-25.7	-56.6	-27.0	-1.4	-17.5	-22.5	-24.1	-10.2	-20.3	-17.5	-17.6	-4.5
No Infrastructure	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No Infrastructure	Demand Response	0.0	0.0	4.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
No Infrastructure	Electrification	0.0	0.0	1.8	5.5	11.0	10.5	4.1	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0

Table C-5. Design Day Savings by Analyzed Solution Compared to Demand-Supply Gap under ExC & LNG Vap. Rejected [MDth/day]

Solution	Parameter	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Demand Gap	-71.6	-46.7	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
Clove Lakes TL	Infrastructure	0.0	0.0	0.0	0.0	0.0	40.0	40.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Clove Lakes TL	Demand Response	0.0	0.0	13.0	25.3	27.1	28.7	30.5	32.2	34.0	36.0	37.9	39.6	41.1	42.6	43.9
Clove Lakes TL	Electrification	0.0	0.0	7.2	21.8	43.9	53.9	52.0	44.5	37.1	29.7	22.3	15.0	7.7	0.6	-6.6
LNG Barge	Demand Gap	-71.6	-46.7	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
LNG Barge	Demand Response	0.0	0.0	13.0	25.3	27.1	28.7	30.5	32.2	34.0	36.0	37.9	39.6	41.1	42.6	43.9
LNG Barge	Electrification	0.0	0.0	9.1	27.3	54.8	67.8	68.4	63.0	57.8	52.5	47.2	42.0	36.8	31.7	26.5
2 LNG Barges	Demand Gap	-71.6	-46.7	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
2 LNG Barges	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
2 LNG Barges	Demand Response	0.0	0.0	13.0	25.3	27.1	28.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
2 LNG Barges	Electrification	0.0	0.0	9.1	27.3	54.8	65.6	64.0	56.5	49.1	41.7	34.4	27.1	19.8	12.6	5.5
Micro-LNG+Clove Lakes TL	Demand Gap	-71.6	-46.7	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
Micro-LNG+Clove Lakes TL	Infrastructure	0.0	0.0	0.0	0.0	18.0	58.0	58.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Micro-LNG+Clove Lakes TL	Demand Response	0.0	0.0	13.0	25.3	27.1	28.7	30.5	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Micro-LNG+Clove Lakes TL	Electrification	0.0	0.0	5.4	16.4	32.9	41.4	42.1	36.7	31.4	26.1	20.9	15.6	10.5	5.3	0.2
Clove Lakes TL+LNG Barge	Demand Gap	-71.6	-46.7	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
Clove Lakes TL+LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	40.0	90.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Clove Lakes TL+LNG Barge	Demand Response	0.0	0.0	13.0	25.3	27.1	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Clove Lakes TL+LNG Barge	Electrification	0.0	0.0	7.2	21.8	43.9	53.1	49.6	39.7	29.6	19.0	8.5	-1.9	-12.3	-22.6	-32.8
No Infrastructure	Demand Gap	-71.6	-46.7	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
No Infrastructure	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No Infrastructure	Demand Response	0.0	0.0	13.0	25.3	27.1	28.7	30.5	32.2	34.0	36.0	37.9	39.6	41.1	42.6	43.9
No Infrastructure	Electrification	0.0	0.0	10.9	32.8	65.8	84.9	90.2	88.1	86.0	83.9	81.8	79.7	77.6	75.6	73.5

Table C-6. Design Day Savings by Analyzed Solution Compared to Demand-Supply Gap under 80% of DSM in DI Sol'n [MDth/day]

Solution	Parameter	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
LNG Barge	Demand Gap	-69.7	-97.8	-42.8	-74.9	-39.7	-7.1	24.0	14.4	16.0	20.9	41.3	37.6	46.8	52.9	72.3
LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
LNG Barge	Demand Response	0.0	0.0	2.9	4.7	6.4	8.0	9.8	11.6	13.3	15.4	17.2	18.9	20.4	21.9	23.2
LNG Barge	Electrification	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2 LNG Barges	Demand Gap	-69.7	-97.8	-42.8	-74.9	-39.7	-7.1	24.0	14.4	16.0	20.9	41.3	37.6	46.8	52.9	72.3
2 LNG Barges	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	50.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
2 LNG Barges	Demand Response	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2 LNG Barges	Electrification	0.0	0.0	0.0	0.0	0.0	-3.9	-11.6	-18.2	-19.1	-19.9	-20.8	-21.6	-22.5	-23.3	-24.1
Micro-LNG+Clove Lakes TL	Demand Gap	-69.7	-97.8	-42.8	-74.9	-39.7	-7.1	24.0	14.4	16.0	20.9	41.3	37.6	46.8	52.9	72.3
Micro-LNG+Clove Lakes TL	Infrastructure	0.0	0.0	0.0	0.0	18.0	58.0	58.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Micro-LNG+Clove Lakes TL	Demand Response	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro-LNG+Clove Lakes TL	Electrification	0.0	0.0	0.0	0.0	0.0	-3.9	-11.6	-18.2	-19.1	-19.9	-20.8	-21.6	-22.5	-23.3	-24.1
Clove Lakes TL+LNG Barge	Demand Gap	-69.7	-97.8	-42.8	-74.9	-39.7	-7.1	24.0	14.4	16.0	20.9	41.3	37.6	46.8	52.9	72.3
Clove Lakes TL+LNG Barge	Infrastructure	0.0	0.0	0.0	0.0	0.0	40.0	90.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Clove Lakes TL+LNG Barge	Demand Response	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Clove Lakes TL+LNG Barge	Electrification	0.0	0.0	0.0	0.0	0.0	-6.0	-17.9	-30.7	-39.7	-45.1	-46.8	-48.4	-50.1	-51.7	-53.4
No Infrastructure	Demand Gap	-69.7	-97.8	-42.8	-74.9	-39.7	-7.1	24.0	14.4	16.0	20.9	41.3	37.6	46.8	52.9	72.3
No Infrastructure	Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No Infrastructure	Demand Response	0.0	0.0	12.9	25.3	27.1	28.7	30.4	32.2	34.0	36.0	37.9	39.6	41.1	42.6	43.9
No Infrastructure	Electrification	0.0	0.0	0.0	0.0	0.0	-2.1	-6.4	-7.9	-2.0	3.9	9.8	15.6	21.4	27.2	32.9

Appendix D. Annual Cost to Utility

D.1. Approach

The annual cost to the utility is comprised of the following components:

- Additional annualized infrastructure costs
- Avoided annualized infrastructure costs
- Net costs of gas commodity associated with the implementation of the solution
- Annual implementation costs of incremental demand side management options

The additional and avoided annualized infrastructure costs refer to the cost of added infrastructure as part of a solution and the avoided cost associated with avoided infrastructure in a given contingency scenario. The assumed costs are listed in Sections A.2.1 and A.3.1.

The net commodity costs captures the difference in the cost of gas commodity from different sources. For example, gas from an LNG barge is typically more expensive than gas from a pipeline. To calculate this value, a simplified dispatch modeling was performed for the design day in each year under the Distributed Infrastructure Solution and then each of the contingency scenario solutions. The design day demand net of incremental demand-side management was compared to the supply stack in each year. Then supply stack resources were dispatched up to their maximum daily capacity in order of increasing commodity costs until the demand is met. The difference in the amount of each resource that was dispatched between the Distributed Infrastructure Solution and each of the contingency solutions is then the net commodity cost. Note that this is a very simplified application of an analysis that National Grid typically performs for all days of the year, which also accounts for resource availability and locational requirements. This more complete study would likely yield different results. However, the overall magnitude of this cost component is small (typically <1%) compard to the total solution cost, and is therefore well within the error of other cost estimates in this Report.

The annual implementation costs of demand side management options is the incentive and non-incentive costs associated with incremental demand response and incremental electrification pursued as part of a contingency scenario solution.

Summaries of total costs for each solution are provided below.

D.2. Annual Cost to the Utility of No Infrastructure Solutions

Figure D-1. Annual Cost to Utility of No Infrastructure Solution if ExC Rejected (LNG Vap. On-Time)

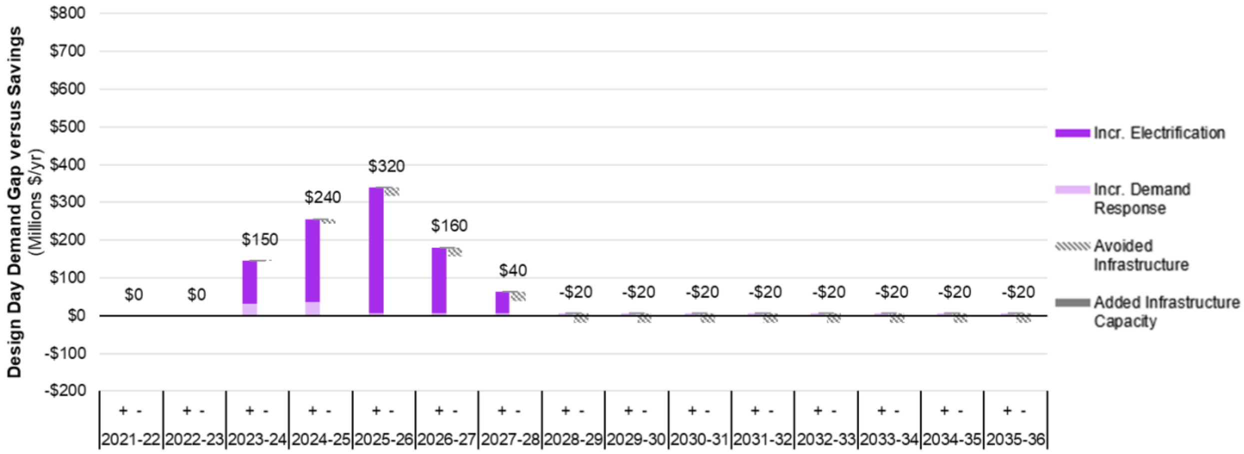


Figure D-2. Annual Cost to Utility of No Infrastructure Solution if LNG Vap. Delayed (ExC On-Time)

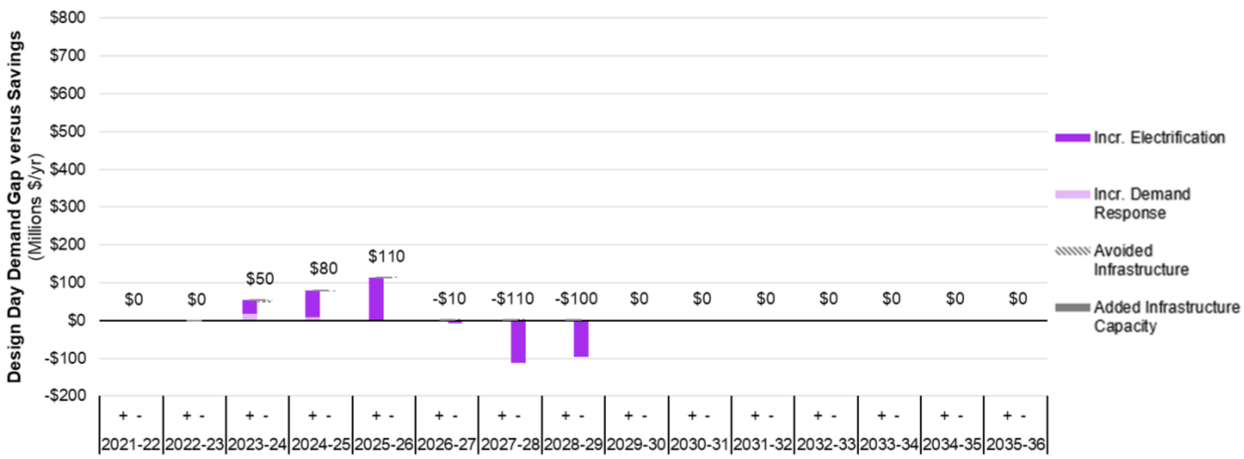


Figure D-3. Annual Cost to Utility of No Infrastructure Solution if LNG Vap. Rejected (ExC On-Time)

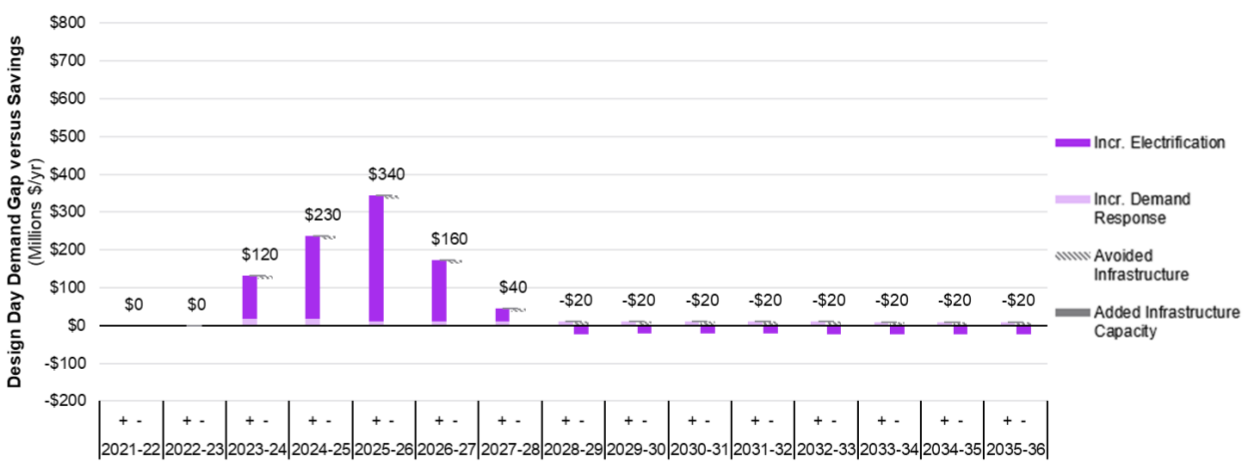


Figure D-4. Annual Cost to Utility of No Infrastructure Solution if ExC & LNG Vap. Delayed

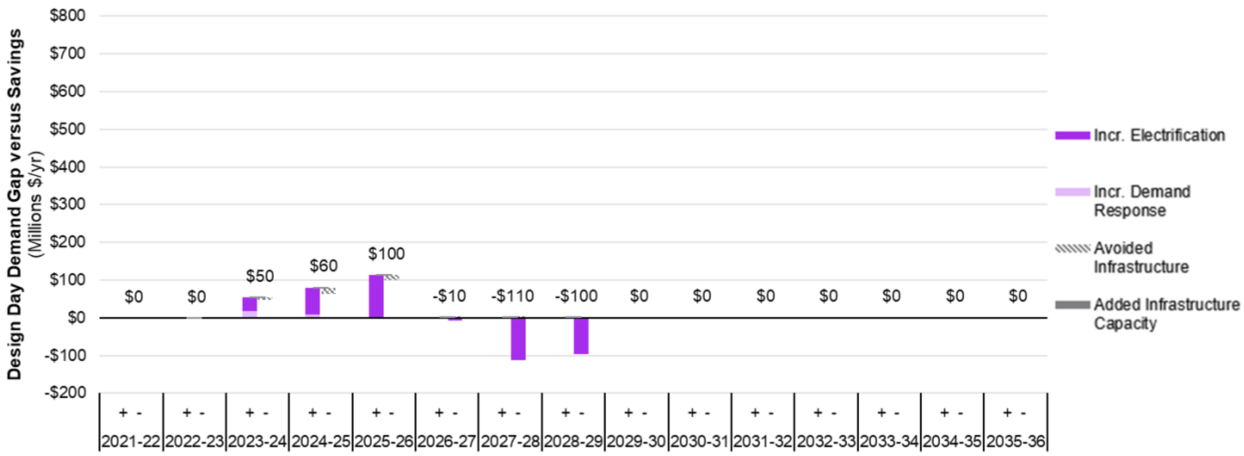


Figure D-5. Annual Cost to Utility of No Infrastructure Solution if ExC & LNG Vap. Rejected

Figure D-6. Annual Cost to Utility of No Infrastructure Solution if 80% of DSM Savings in DI Sol'n

D.3. Annual Cost to the Utility for Recommended Solutions

Figure D-7. Annual Cost to Utility of LNG Barge Solution if ExC Rejected (LNG Vap. On-Time)

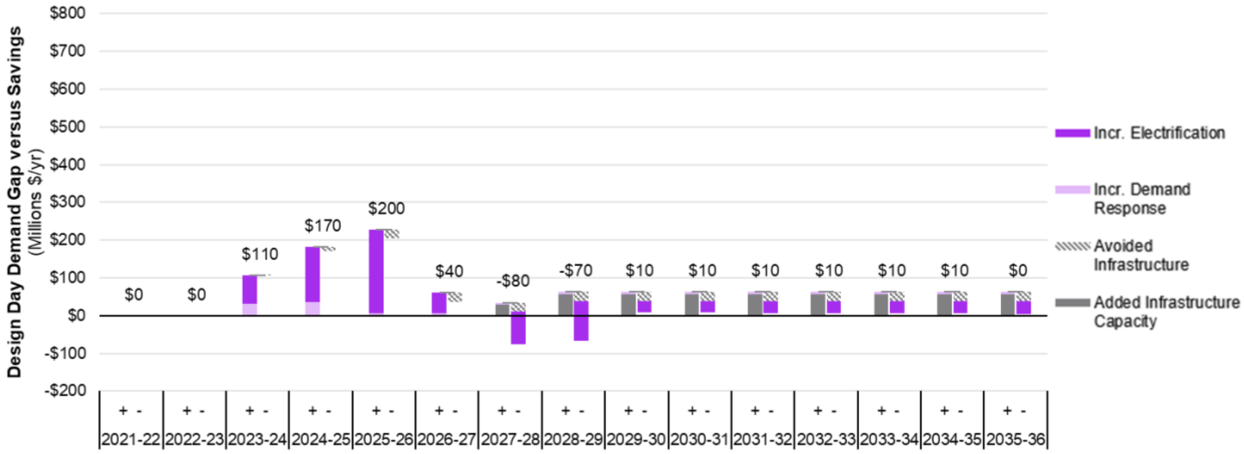


Figure D-8. Annual Cost to Utility of No Infrastructure Solution if LNG Vap. Delayed (ExC On-Time)

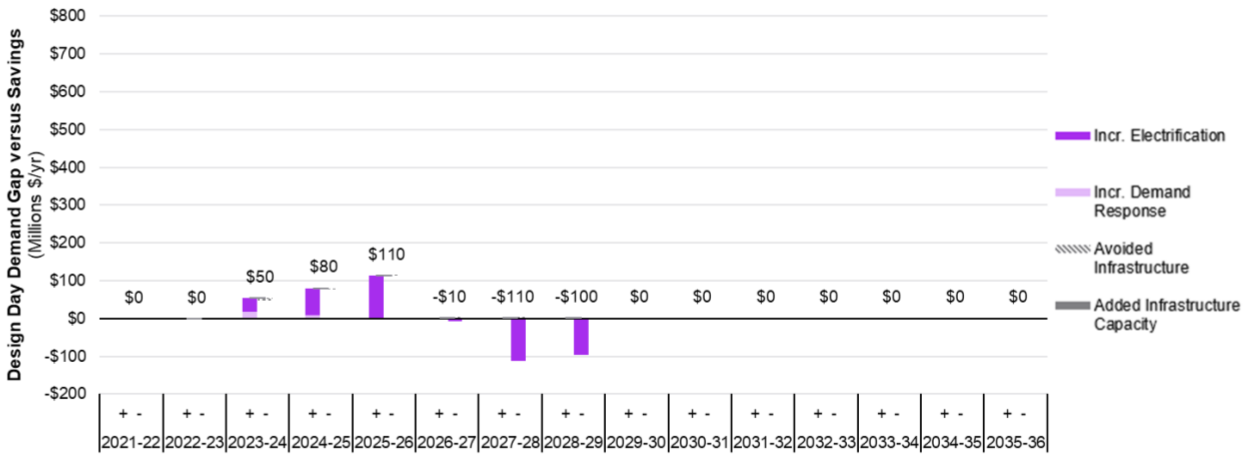


Figure D-9. Annual Cost to Utility of Clove Lakes TL Solution if LNG Vap. Rejected (ExC On-Time)

Figure D-10. Annual Cost to Utility of No Infrastructure Solution if ExC & LNG Vap. Delayed

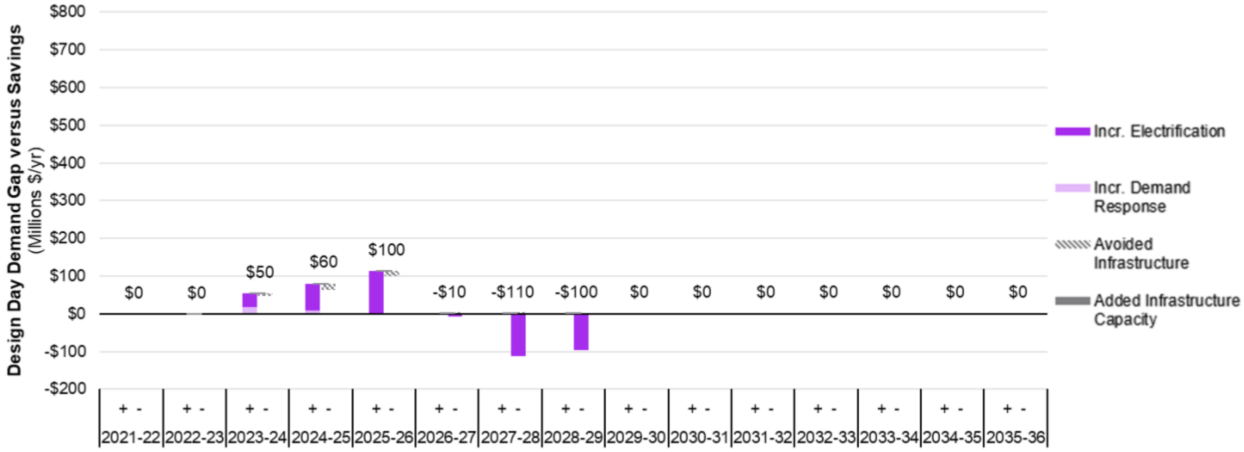


Figure D-11. Annual Cost to Utility of Clove Lakes TL + LNG Barge Solution if ExC & LNG Vap. Rejected

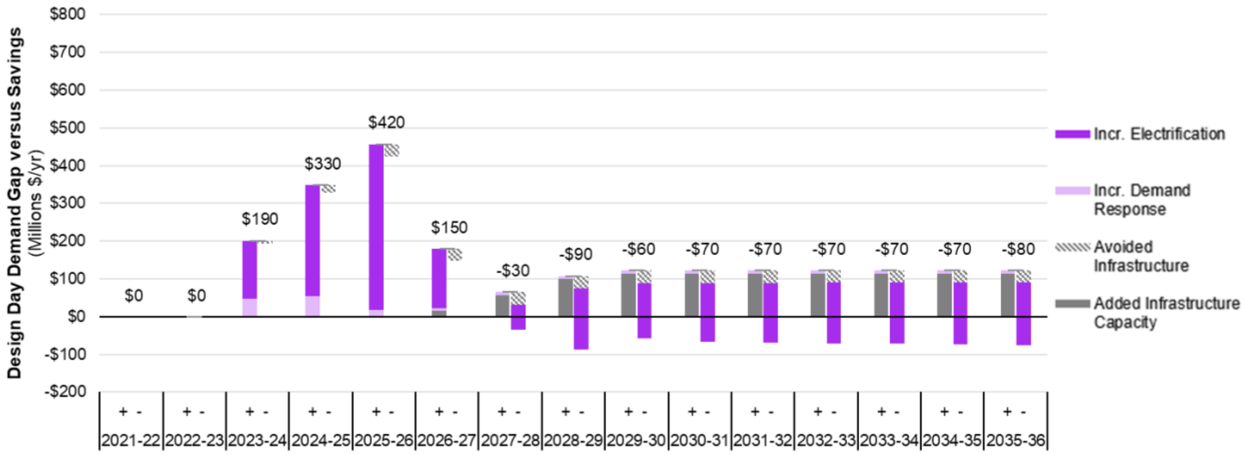
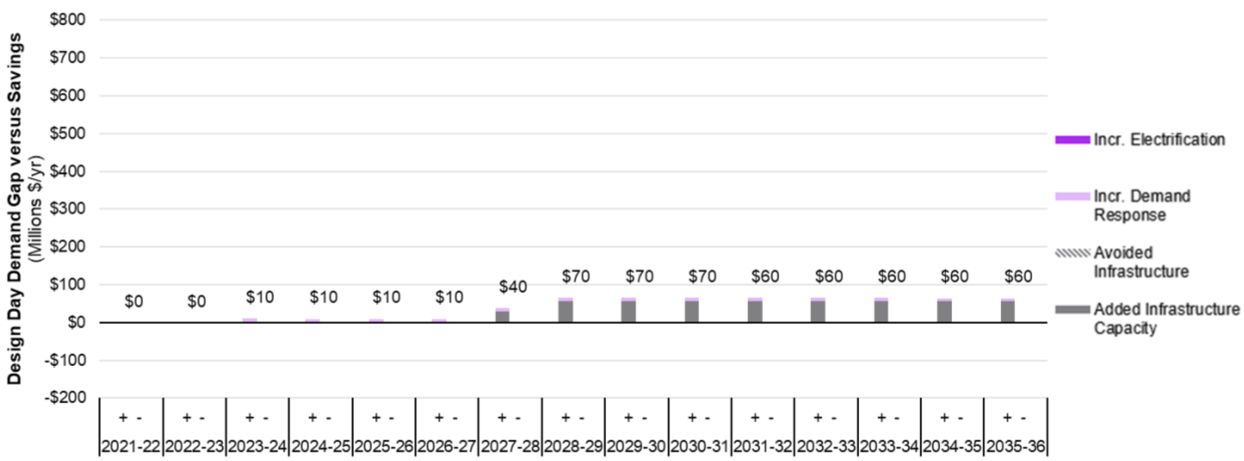


Figure D-12. Annual Cost to Uility of LNG Barge Solution to if 80% of DSM Savings in DI Sol'n



D.4. Annual Cost to the Utility by Category for All Solutions

Table D-1. Annual Cost to Utility by Category Relative to Distributed Infrastructure Solution under ExC Rejected (LNG Vap. on-time) [Million$/yr]

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4
LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	-$12.1	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3
LNG Barge	Net Commodity Costs	$0.0	$0.0	-$0.1	$0.4	$0.3	$0.1	-$0.1	$0.0	$0.1	$0.1	$0.1	$0.2	$0.2	$0.2	$0.1
LNG Barge	Demand Response	$0.0	$0.0	$31.3	$37.0	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6
LNG Barge	Electrification	$0.0	$0.0	$75.4	$145.2	$221.6	$53.5	-$86.3	-$105.2	-$30.8	-$31.3	-$33.6	-$33.2	-$32.7	-$33.4	-$34.2
Micro-LNG	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$7.2	$14.4	$14.4	$14.4	$14.4	$14.4	$14.4	$14.4	$14.4	$14.4	$14.4
Micro-LNG	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	-$12.1	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3
Micro-LNG	Net Commodity Costs	$0.0	$0.0	-$0.1	$0.4	$0.3	$0.2	-$0.1	$0.2	$0.2	$0.2	$0.1	$0.2	$0.2	$0.2	$0.0
Micro-LNG	Demand Response	$0.0	$0.0	$31.3	$37.0	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6
Micro-LNG	Electrification	$0.0	$0.0	$75.4	$145.2	$222.1	$93.0	-$8.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	-$12.1	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3	-$24.3
No Infrastructure	Net Commodity Costs	$0.0	$0.0	-$0.1	$0.3	$0.1	-$0.1	-$0.4	-$0.1	-$0.1	-$0.1	-$0.2	-$0.1	-$0.1	-$0.1	-$0.3
No Infrastructure	Demand Response	$0.0	$0.0	$31.3	$37.0	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6	$6.6
No Infrastructure	Electrification	$0.0	$0.0	$113.9	$218.8	$333.5	$174.2	$57.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table D-2. Annual Cost to Utility by Category Relative to Distributed Infrastructure Solution under LNG Vap Delayed (ExC on-time) [Million$/yr]

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$14.4	$28.8	$43.2	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6
Clove Lakes TL	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Clove Lakes TL	Net Commodity Costs	$0.0	$0.4	$0.6	$0.0	-$0.2	-$0.6	-$0.4	-$0.6	-$0.4	-$0.2	-$0.1	$0.0	$0.2	$0.3	$0.5
Clove Lakes TL	Demand Response	$0.0	$0.0	$17.2	$8.2	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
Clove Lakes TL	Electrification	$0.0	$0.0	$37.5	$72.0	$110.3	-$63.2	-$222.0	-$243.3	-$166.6	-$125.1	-$127.4	-$128.6	-$130.0	-$131.4	-$133.8
LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4
LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
LNG Barge	Net Commodity Costs	$0.0	$0.4	$0.6	$0.0	-$0.2	-$0.1	-$0.3	-$0.1	$0.0	$0.1	$0.2	$0.3	$0.4	$0.5	$0.5
LNG Barge	Demand Response	$0.0	$0.0	$17.2	$8.2	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
LNG Barge	Electrification	$0.0	$0.0	$37.5	$72.0	$110.8	-$51.3	-$198.3	-$211.5	-$130.7	-$78.7	-$80.8	-$80.9	-$80.7	-$82.6	-$84.2
No Infrastructure	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Net Commodity Costs	$0.0	$0.4	$0.6	$0.0	-$0.2	-$0.2	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Demand Response	$0.0	$0.0	$17.2	$8.2	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
No Infrastructure	Electrification	$0.0	$0.0	$37.5	$72.0	$111.4	-$8.5	-$113.5	-$99.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table D-3. Annual Cost to Utility by Category Relative to Distributed Infrastructure Solution under LNG Vap. Rejected (ExC on-time) [Million$/yr]

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$14.4	$28.8	$43.2	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6
Clove Lakes TL	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2
Clove Lakes TL	Net Commodity Costs	$0.0	$0.4	$0.6	$0.5	$0.5	$0.0	-$0.1	-$0.3	-$0.2	-$0.1	$0.0	$0.0	$0.1	$0.2	$0.2
Clove Lakes TL	Demand Response	$0.0	$0.0	$17.2	$17.8	$11.0	$10.9	$10.7	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
Clove Lakes TL	Electrification	$0.0	$0.0	$37.5	$72.0	$111.1	$1.5	-$92.5	-$71.4	-$61.2	-$62.2	-$64.8	-$64.9	-$64.6	-$65.9	-$67.1
LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4
LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2
LNG Barge	Net Commodity Costs	$0.0	$0.4	$0.6	$0.4	$0.3	$0.1	$0.0	$0.2	$0.3	$0.3	$0.3	$0.4	$0.4	$0.4	$0.2
LNG Barge	Demand Response	$0.0	$0.0	$17.2	$17.8	$11.0	$10.9	$10.7	$10.5	$10.4	$10.2	$10.0	$9.9	$9.7	$9.6	$9.5
LNG Barge	Electrification	$0.0	$0.0	$75.4	$145.2	$221.6	$34.6	-$124.2	-$156.4	-$90.6	-$46.2	-$48.7	-$48.6	-$48.3	-$49.5	-$50.2
No Infrastructure	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2	-$8.2
No Infrastructure	Net Commodity Costs	$0.0	$0.4	$0.6	$0.3	$0.1	$0.0	-$0.3	$0.0	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	-$0.2
No Infrastructure	Demand Response	$0.0	$0.0	$17.2	$17.8	$11.0	$10.9	$10.7	$10.5	$10.4	$10.2	$10.0	$9.9	$9.7	$9.6	$9.5
No Infrastructure	Electrification	$0.0	$0.0	$113.9	$218.8	$333.2	$162.2	$34.1	-$26.3	-$22.7	-$23.1	-$23.5	-$24.0	-$24.2	-$24.2	-$25.0

Table D-4. Annual Cost to Utility by Category Relative to Distributed Infrastructure Solution under ExC & LNG Vap. Delayed [Million$/yr]

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$14.4	$28.8	$43.2	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6
Clove Lakes TL	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$16.2	-$12.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Clove Lakes TL	Net Commodity Costs	$0.0	$0.4	$0.6	$0.5	-$0.2	-$0.6	-$0.4	-$0.6	-$0.4	-$0.2	-$0.1	$0.0	$0.2	$0.3	$0.5
Clove Lakes TL	Demand Response	$0.0	$0.0	$17.2	$8.2	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
Clove Lakes TL	Electrification	$0.0	$0.0	$37.5	$72.0	$110.3	-$63.2	-$222.0	-$243.3	-$166.6	-$125.1	-$127.4	-$128.6	-$130.0	-$131.4	-$133.8
LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4
LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$16.2	-$12.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
LNG Barge	Net Commodity Costs	$0.0	$0.4	$0.6	$0.5	-$0.2	-$0.1	-$0.3	-$0.1	$0.0	$0.1	$0.2	$0.3	$0.4	$0.5	$0.5
LNG Barge	Demand Response	$0.0	$0.0	$17.2	$8.2	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
LNG Barge	Electrification	$0.0	$0.0	$37.5	$72.0	$110.8	-$51.3	-$198.3	-$211.5	-$130.7	-$78.7	-$80.8	-$80.9	-$80.7	-$82.6	-$84.2
No Infrastructure	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$16.2	-$12.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Net Commodity Costs	$0.0	$0.4	$0.6	$0.5	-$0.2	-$0.2	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Demand Response	$0.0	$0.0	$17.2	$8.2	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
No Infrastructure	Electrification	$0.0	$0.0	$37.5	$72.0	$111.4	-$8.5	-$113.5	-$99.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table D-5. Annual Cost to Utility by Category Relative to Distributed Infrastructure Solution under ExC & LNG Vap. Rejected [Million$/yr]

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$14.4	$28.8	$43.2	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6	$57.6
Clove Lakes TL	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$20.3	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4
Clove Lakes TL	Net Commodity Costs	$0.0	$0.4	$0.6	$0.7	$0.2	$0.0	-$0.5	-$0.3	-$0.2	-$0.1	-$0.1	$0.1	$0.0	$0.0	-$0.2
Clove Lakes TL	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$17.5	$17.3	$17.2	$17.0	$16.8	$16.7	$16.5	$16.4	$16.2	$16.1
Clove Lakes TL	Electrification	$0.0	$0.0	$152.8	$293.6	$442.2	$174.0	-$36.4	-$123.6	-$107.0	-$108.9	-$111.4	-$112.1	-$112.5	-$114.5	-$116.8
LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4
LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$20.3	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4
LNG Barge	Net Commodity Costs	$0.0	$0.4	$0.5	$0.7	$0.2	-$0.2	-$0.2	-$0.1	$0.0	$0.1	-$0.1	$0.1	$0.0	$0.0	-$0.2
LNG Barge	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$17.5	$17.3	$17.2	$17.0	$16.8	$16.7	$16.5	$16.4	$16.2	$16.1
LNG Barge	Electrification	$0.0	$0.0	$192.4	$370.2	$553.1	$224.8	$8.5	-$89.3	-$77.0	-$78.7	-$80.8	-$80.9	-$80.7	-$82.6	-$84.2
2 LNG Barges	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$83.9	$111.4	$111.4	$111.4	$111.4	$111.4	$111.4	$111.4
2 LNG Barges	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$20.3	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4
2 LNG Barges	Net Commodity Costs	$0.0	$0.4	$0.5	$0.7	$0.2	-$0.2	-$0.2	-$0.4	-$0.3	-$0.1	$0.0	$0.1	$0.2	$0.3	$0.3
2 LNG Barges	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$17.5	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2
2 LNG Barges	Electrification	$0.0	$0.0	$192.4	$370.2	$553.1	$186.5	-$30.1	-$123.6	-$107.0	-$108.9	-$111.4	-$112.1	-$112.5	-$114.5	-$116.8
Micro-LNG + Clove Lakes TL	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$7.2	$28.8	$43.2	$57.6	$72.0	$72.0	$72.0	$72.0	$72.0	$72.0	$72.0
Micro-LNG + Clove Lakes TL	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$20.3	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4
Micro-LNG + Clove Lakes TL	Net Commodity Costs	$0.0	$0.4	$0.6	$0.7	$0.5	$0.2	-$0.2	-$0.2	-$0.1	$0.0	$0.1	$0.2	$0.2	$0.3	$0.1
Micro-LNG + Clove Lakes TL	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$17.5	$17.3	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2
Micro-LNG + Clove Lakes TL	Electrification	$0.0	$0.0	$113.9	$218.8	$331.7	$148.2	$8.5	-$89.3	-$77.0	-$78.7	-$80.8	-$80.9	-$80.7	-$82.6	-$84.2

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Clove Lakes TL + LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$14.4	$57.0	$99.6	$114.0	$114.0	$114.0	$114.0	$114.0	$114.0	$114.0
Clove Lakes TL + LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$20.3	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4
Clove Lakes TL + LNG Barge	Net Commodity Costs	$0.0	$0.4	$0.6	$0.7	$0.2	$0.0	-$0.3	-$0.6	-$0.5	-$0.3	-$0.1	$0.1	$0.2	$0.4	$0.3
Clove Lakes TL + LNG Barge	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2	$8.2
Clove Lakes TL + LNG Barge	Electrification	$0.0	$0.0	$152.8	$293.6	$439.1	$157.1	-$66.3	-$162.4	-$147.0	-$155.6	-$159.0	-$161.0	-$162.3	-$164.3	-$166.9
No Infrastructure	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Avoided Fixed Infrastructure Costs	$0.0	-$4.1	-$8.2	-$20.3	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4	-$32.4
No Infrastructure	Net Commodity Costs	$0.0	$0.4	$0.5	$0.7	$0.2	-$0.2	-$0.7	-$0.4	-$0.3	-$0.3	-$0.5	-$0.4	-$0.4	-$0.4	-$0.6
No Infrastructure	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$17.5	$17.3	$17.2	$17.0	$16.8	$16.7	$16.5	$16.4	$16.2	$16.1
No Infrastructure	Electrification	$0.0	$0.0	$231.5	$446.4	$665.6	$336.2	$93.0	-$36.6	-$30.8	-$31.3	-$33.6	-$33.2	-$32.7	-$33.4	-$34.2

Table D-6. Annual Cost to Utility by Category Relative to Distributed Infrastructure Solution under 80% of DSM in DI Sol'n [Million$/yr]

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4	$56.4
LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
LNG Barge	Net Commodity Costs	$0.0	$0.1	$0.2	$0.1	$0.3	$0.3	$0.0	$0.1	$0.3	$0.4	$0.5	$0.6	$0.7	$0.7	$0.5
LNG Barge	Demand Response	$0.0	$0.0	$9.8	$9.7	$9.5	$9.3	$9.2	$9.0	$8.9	$8.7	$8.5	$8.3	$8.2	$8.1	$8.0
LNG Barge	Electrification	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
2 LNG Barges	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.2	$83.9	$111.4	$111.4	$111.4	$111.4	$111.4	$111.4	$111.4
2 LNG Barges	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
2 LNG Barges	Net Commodity Costs	$0.0	$0.1	$0.2	$0.1	$0.3	$0.4	$0.2	$0.1	$0.2	$0.3	$0.4	$0.6	$0.7	$0.8	$0.9
2 LNG Barges	Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
2 LNG Barges	Electrification	$0.0	$0.0	$0.0	$0.0	$0.0	-$86.1	-$171.3	-$133.7	-$15.8	-$15.9	-$16.0	-$16.3	-$16.3	-$16.6	-$17.2
Micro-LNG + Clove Lakes TL	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$7.2	$28.8	$43.2	$57.6	$72.0	$72.0	$72.0	$72.0	$72.0	$72.0	$72.0
Micro-LNG + Clove Lakes TL	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Micro-LNG + Clove Lakes TL	Net Commodity Costs	$0.0	$0.1	$0.2	$0.1	$0.3	-$0.1	$0.2	-$0.1	$0.1	$0.2	$0.3	$0.4	$0.5	$0.7	$0.8
Micro-LNG + Clove Lakes TL	Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Micro-LNG + Clove Lakes TL	Electrification	$0.0	$0.0	$0.0	$0.0	$0.0	-$86.1	-$171.3	-$133.7	-$15.8	-$15.9	-$16.0	-$16.3	-$16.3	-$16.6	-$17.2
Clove Lakes TL + LNG Barge	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$14.4	$57.0	$99.6	$114.0	$114.0	$114.0	$114.0	$114.0	$114.0	$114.0
Clove Lakes TL + LNG Barge	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Clove Lakes TL + LNG Barge	Net Commodity Costs	$0.0	$0.1	$0.2	$0.1	$0.3	$0.0	-$0.1	-$0.2	$0.0	$0.2	$0.4	$0.5	$0.6	$0.8	$1.0
Clove Lakes TL + LNG Barge	Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Clove Lakes TL + LNG Barge	Electrification	$0.0	$0.0	$0.0	$0.0	$0.0	-$132.4	-$265.3	-$258.9	-$160.3	-$97.1	-$33.6	-$33.2	-$32.7	-$33.4	-$34.2

Solution	Category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
No Infrastructure	Added Annual Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Avoided Fixed Infrastructure Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
No Infrastructure	Net Commodity Costs	$0.0	$0.1	$0.2	$0.1	$0.3	$0.4	$0.0	$0.3	$0.4	$0.4	$0.2	$0.3	$0.3	$0.3	$0.1
No Infrastructure	Demand Response	$0.0	$0.0	$48.5	$54.8	$17.6	$17.5	$17.3	$17.2	$17.0	$16.8	$16.7	$16.5	$16.4	$16.2	$16.1
No Infrastructure	Electrification	$0.0	$0.0	$0.0	$0.0	$0.0	-$45.5	-$91.3	-$26.4	$109.4	$111.5	$112.6	$114.5	$116.3	$117.8	$118.8

Appendix E. Net Present Value to Utility

E.1. Approach

The net present value to the utility is the present value of the annual costs listed in Appendix D over the 15 year time horizon for the analysis, 2021/22 to 2035/36, using a discount rate of 6.3%, the average weighted-average cost of capital (WACC) across KEDNY and KEDLI. The net present value by cost component and in total are presented below.

E.2. Net Present Value to Utility for All Solutions

In the charts below, a positive value indicates a net increase in the cost to the utility compared to the Distributed Infrastructure solution, while a negative value indicates a net decrease in the cost to the utility compared to the Distributed Infrastructure Solution.

Figure E-1. Net Present Cost to Utility of Analyzed Solutions if ExC Rejected (LNG Vap. On-Time)

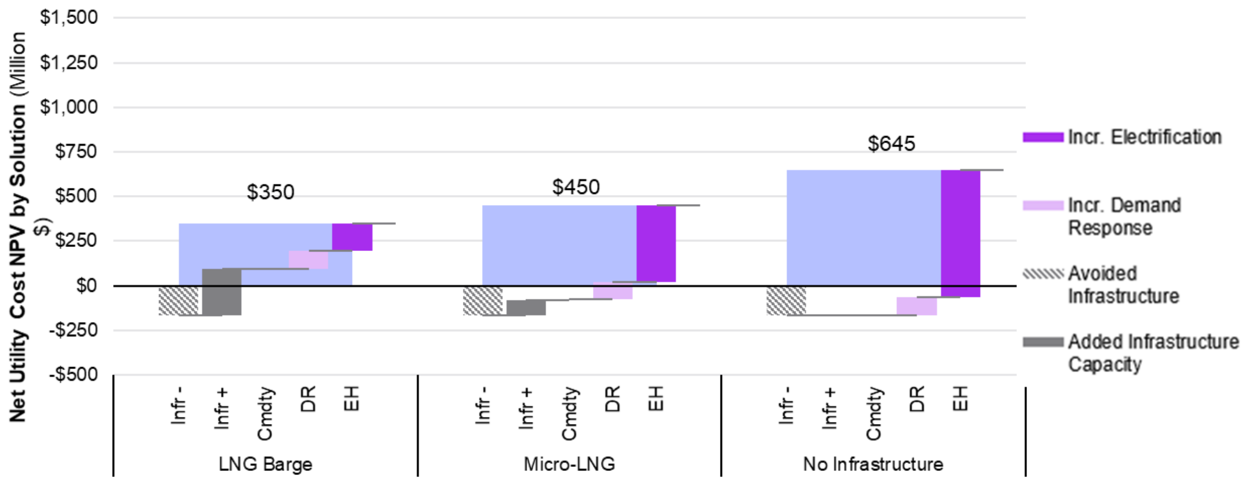


Figure E-2. Net Present Cost to Utility of Analyzed Solutions if LNG Vap. Delayed (ExC On-Time)

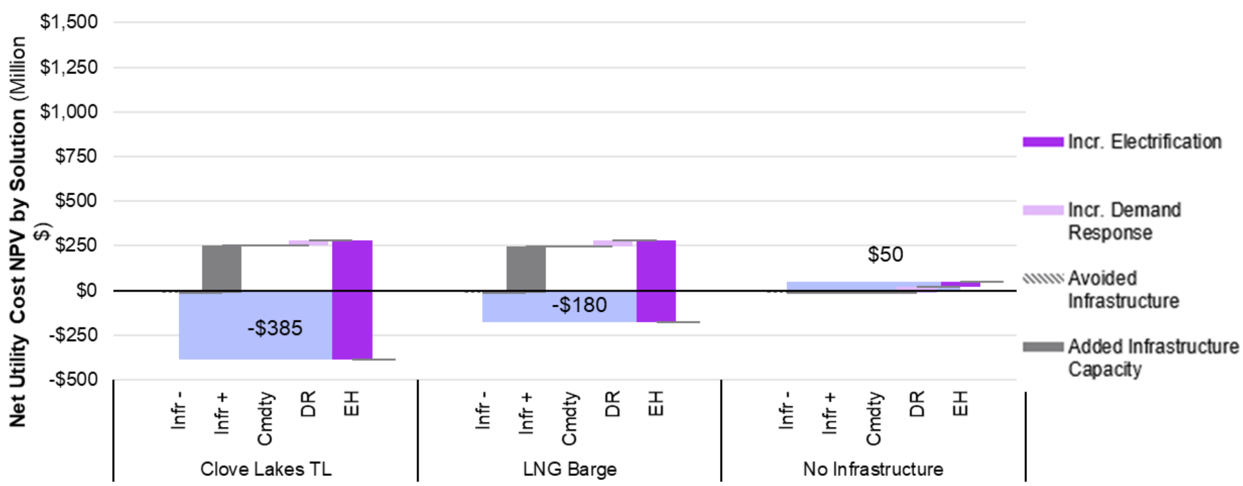


Figure E-3. Net Present Cost to Utility of Analyzed Solutions if LNG Vap. Rejected (ExC On-Time)

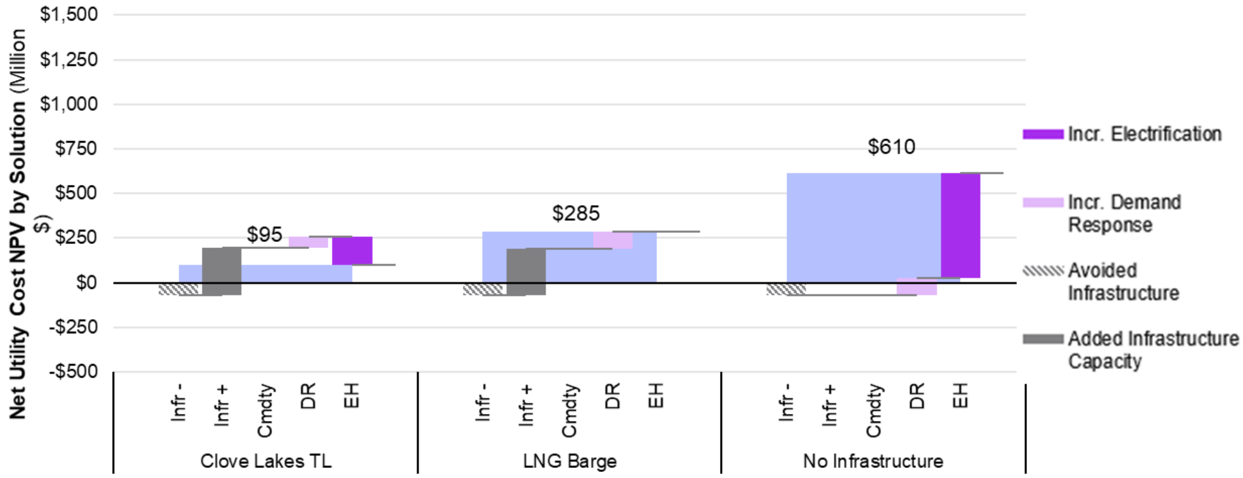


Figure E-4. Net Present Cost to Utility of Analyzed Solutions if ExC & LNG Vap. Delayed

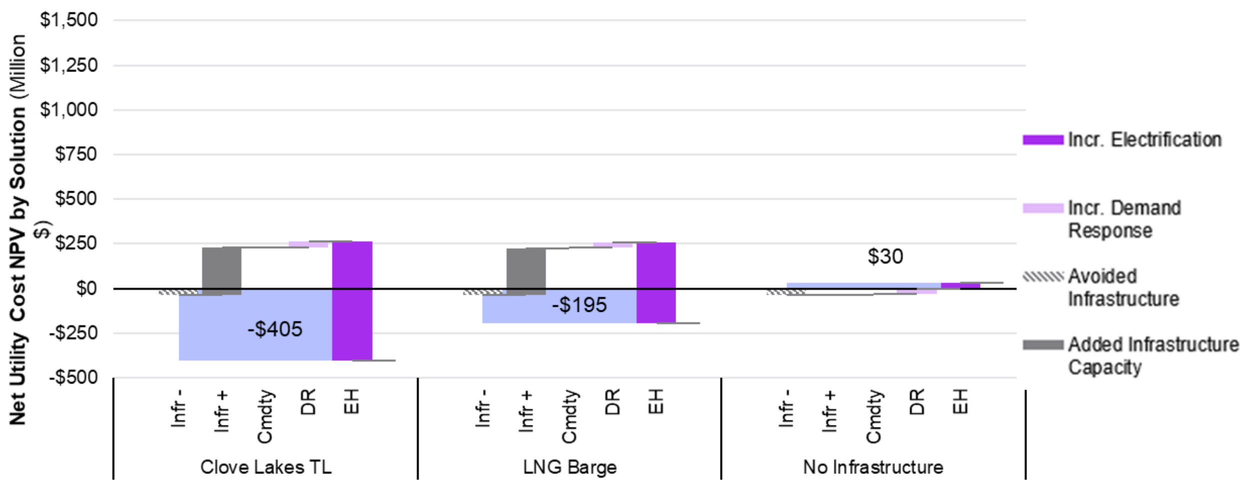


Figure E-5. Net Present Cost to Utility of Analyzed Solutions if ExC & LNG Vap. Rejected

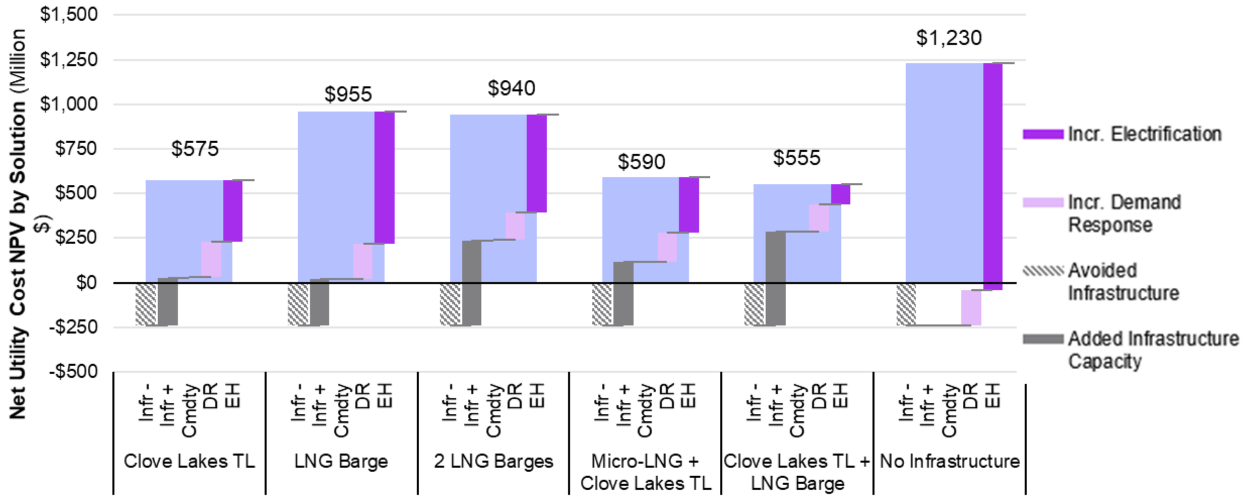
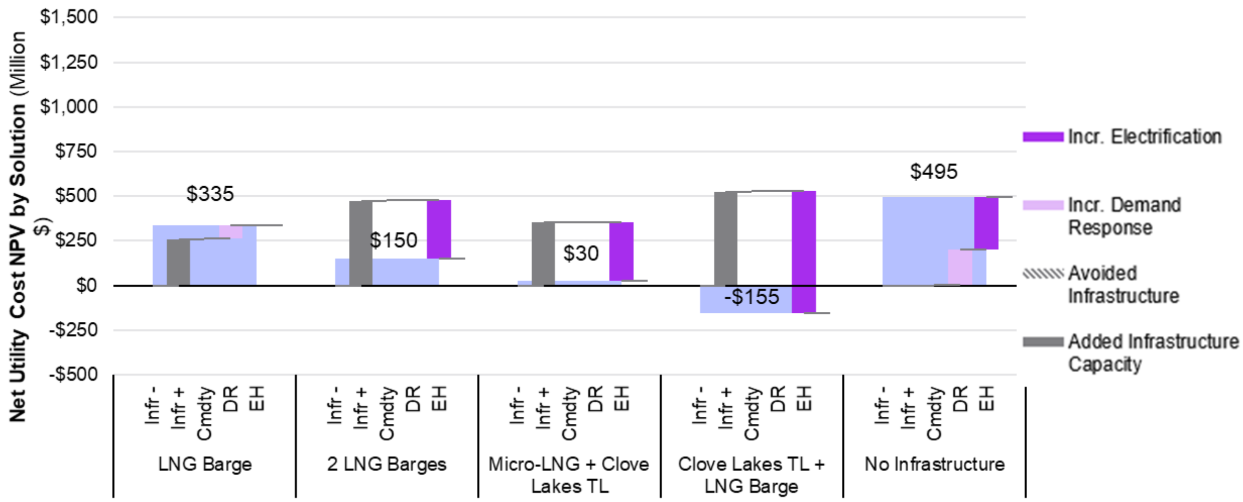


Figure E-6. Net Present Cost to Utility of Analyzed Solutions if 80% of DSM Savings in DI Sol'n



Appendix F. Net Present Value to Society

F.1. The Societal Cost Test (SCT)

Current guidance from NY Department of Public Service (DPS) specifies that the Societal Cost Test (SCT) should be used for benefit-cost analyses (BCAs). This test assesses the impact of initiatives from a broad perspective and encompasses customer impacts, utility system impacts, and impacts on society as a whole.

A non-pipe alternatives BCA Handbook will be developed by the New York Joint Utilities. In the absence of such a consistent framework, this analysis follows guidance previously issued by the NY DPS and best industry practices. Because this analysis compares both distributed infrastructure and non-infrastructure alternatives, not all avoided infrastructure costs are monetized in the analysis. Instead, it compares the net present value of net costs across all solutions for a given contingency scenario.

This Appendix contains a description of benefits and costs included in the analysis along with the sources of values used to monetize them. The net present values of costs and benefits for each contingency scenarioare presented along with a comparison to the results of the net present cost to the utility.

F.2. Definitions of Benefits Included

Avoided Gas Commodity Costs includes the commodity component, associated with the physical molecules of natural gas that are delivered to city-gate by pipeline and storage capacity.

Avoided On-System Infrastructure benefits result from on-system load reductions or supply resources that are valued at the marginal cost of transmission, regulator, or distribution system infrastructure that is avoided or deferred by a Gas BCA project or program. The project or program must be coincident with the on-system equipment peak or otherwise defer or avoid the need for incremental transmission, regulator or distribution infrastructure based on the characteristics of the specific project or program.

Avoided CO2 Emissions accounts for avoided CO2 emissions at the customer site due to a net reduction in natural gas use or replacement of gas normally delivered by pipeline with an alternative fuel.

Avoided Other Emissions accounts for the value of avoided pollutant emissions (excluding CO2 emissions).

F.3. Definitions of Costs

Program Administration Costs include the cost to administer and measure a Gas BCA program or project. This may include the cost of incentives, measurement and verification, and other program administration costs to start and maintain a specific program. These costs may include one-time or annual incentives such as rebates, one-time or annual payments to suppliers, and program administration costs related to marketing, evaluation, measurement and verification.

Incremental On-System Investments include those costs incurred by the utility to support the project or program. These are distinct from Program Administration costs and can include incremental transmission, regulator, or distribution system infrastructure costs. In addition, this can include O&M, any capital or other direct expenses (e.g., special meters, monitoring systems, and/or upgrades), opportunity costs associated with any utility owned land or infrastructure granted or dedicated to the project, and indirect administrative costs related to the program (i.e., its impact on broader administrative costs).

Incremental Participant Costs are costs that would be incurred by providers of Gas BCA services, less incentives recognized by Program Administration Costs with a floor of zero. This includes the equipment and participation costs assumed by Gas BCA providers, which need to be considered when evaluating the societal costs of a project or program. For the purpose of performing the BCA, Incremental Participant Costs are applied net of rebates and incentives that have been accounted for under Program Administration costs.

Alternative Fuel Commodity Costs include the cost of using an energy source other than gas.

Alternative Fuel CO2 Emissions include the emissions generated from the alternative fuel used by the consumer.

Alternative Fuel Other Emissions include emissions other than CO2 associated with using an energy source other than gas to replace the service provided by gas.

F.4. Avoided Cost Values for Monetizing Costs and Benefits

Avoided cost values are used to monetize some of the benefits and costs listed above. For example, the social cost of carbon is an avoided cost, which, when multiplied by the amount of CO2 avoided by a solution, provides a dollar value for the benefit that that solution provides. These avoided costs and other associated assumptions for analysis are listed below.

Table F-1. Assumptions that are fixed over the analysis period

Input	Description	Source	Value
Nominal inflation rate	Inflation rate applied if forecasted data is not available	Utiltity BCA Handbooks[1]	2%
Discount rate	Utility weighted annual cost of capital (WACC) applied to calculate present value of benefits and costs	KEDNY and KEDLI rate caes	6.3%
Company-retained gas	Gas lost between send-out and point of consumption; includes lost and unaccounted for gas (LAUF)	Assumed for KEDNY and KEDLI	1.3%
Electric loss rate	Electricity lost between wholesale and retail	Utility BCA Handbooks based on Electric Loss Reports[1]	6.64%

[1] Based on loss percentages provided in ConEd's BCA Handbook v3.0, published to Case 16-M-0412

Table F-2. Avoided gas supply and capacity benefits

Input	Description	Source
Gas Commodity Costs	Gas commodity costs in non-winter season	2019 CARIS 1 Natural Gas Hub Prices
Gas Marginal Cost of Service (Avoided On-System Infrastructure)	Marginal cost of maintaining system capacity	Marginal cost of service studies[1]
Social Cost of Carbon (Avoided CO2 Emissions)	Social cost of carbon ($/ton) used for gas and fuel oil emissions	NY DEC Social Cost of Carbon at 2% discount rate[2]
Social Cost of Pollutants (Avoided Other Emissions)	Social cost of pollutants ($/ton) used for gas and fuel oil emissions	NY DEC Social Cost of Carbon at 2% discount rate

[1] Most recent source for KEDNY/KEDLI is 2017 Marginal Cost Studies, Appendix A pgs. 1-2, sum of transmission and distribution marginal cost, less LAUF.

[2] Available at: https://www.dec.ny.gov/regulations/56552.html

Table F-3. Avoided electric supply and capacity benefits

Input	Description	Source
Electric summer peak LBMP	Electric commodity costs for 7AM-11PM, June through September	2019 CARIS 1 LBMPs[1]
Electric summer off-peak LBMP	Electric commodity costs for 11PM-7AM, June through September	2019 CARIS 1 LBMPs
Electric winter peak LBMP	Electric commodity costs for 7AM-11PM, October through May	2019 CARIS 1 LBMPs
Electric winter off-peak LBMP	Electric commodity costs for 11PM-7AM, October through May	2019 CARIS 1 LBMPs
Avoided cost of generation capacity (AGCC)	Avoided cost of capacity associated with generation	ICAP spreadsheet from DPS Staff, published in 14-M-00581
Marginal cost of transmission	Avoided cost of capacity associated with transmission	Utility BCA Handbooks based on marginal cost studies[2]
Marginal cost of distribution	Avoided cost of capacity associated with distribution	Utility BCA Handbooks based on marginal cost studies[2]
Electric net marginal damage cost of carbon	Cost of carbon ($/kWh) used for electric emissions	NY DEC Social Cost of Carbon at 2% discount rate net of forecasted RGGI,[3] multiplied by assumed electric emissions rate

[1] CARIS study data available at: https://www.nyiso.com/espwg?meetingDate=2020-05-22

[2] For KEDNY this is based on ConEd's most recent BCA Handbook. For KEDLI, because PSEG-LI does not publish their BCA Handbook, values for NMPC in upstate New York are used as a proxy

[3] The cost of carbon via RGGI is already captured in LBMPs, so to avoid double counting the forecasted cost of RGGI in the LBMP values are subtracted for the social cost of carbon

As noted in the tables above, the avoided greenhouse gas emissions are monetized using the NY Department of Environmental Conservation's Social Cost of Pollutants from December of 2020. To monetize the net emissions associated with net natural gas and fuel oil consumption, the emissions rates listed in Table F-4 were used. Note that gas savings from demand-side management resources is assumed to emit at the levels of pipeline gas, and that emissions associated with net commodity (as discussed in Section E.1) is based on the relative emissions rate of a resource type.

Table F-4. Assumed Emissions Rate of Pipeline Natural Gas and Fuel Oil

Greenhouse Gas	Pipeline Gas [lb per MMBtu]	Fuel Oil [lb per MMBtu]
CO2	117	205
N2O	0.00022	0.0013
CH4	0.44	0

To monetize the net emissions associated with electricity, the emissions rate of the electric grid needed to be assumed to develop a $/kWh value. The assumed electric grid emissions rate aligning with CLCPA targets is shown in Table F-5 below.

Table F-5. Assumed Electric Grid Emissions Rate

Year	Electric Emissions Rate [lb CO2/MWh]
2020	375
2025	282
2030	188
2035	94
2040, and on	0

F.5. Net Present Value to Society for All Solutions

In the charts below, a positive value indicates a net increase in the cost to society compared to the Distributed Infrastructure solution, while a negative value indicates a net decrease in the cost to society compared to the Distributed Infrastructure Solution.

Figure F-1. Net Present Cost to Utility of Analyzed Solutions if ExC Rejected (LNG Vap. On-Time)

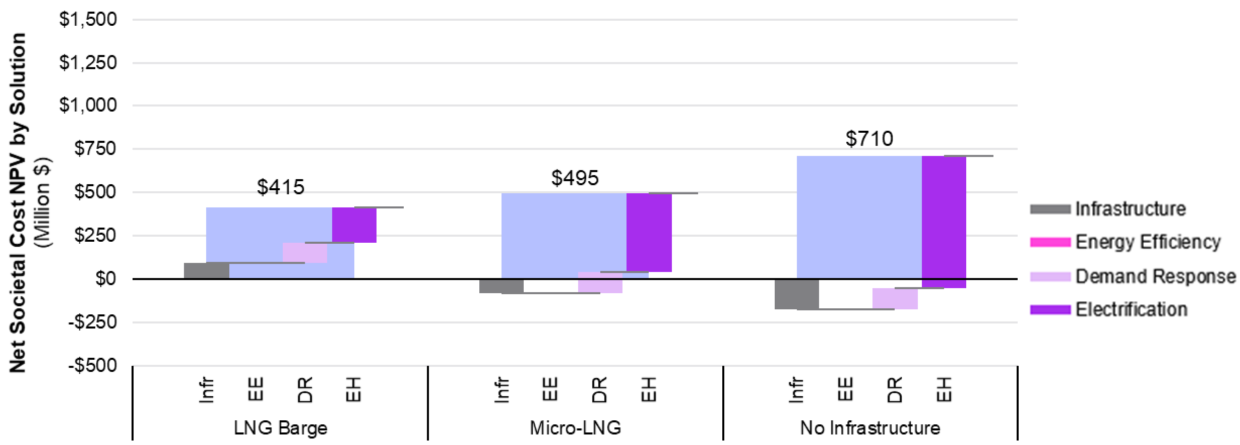


Figure F-2. Net Present Cost to Utility of Analyzed Solutions if LNG Vap. Delayed (ExC On-Time)

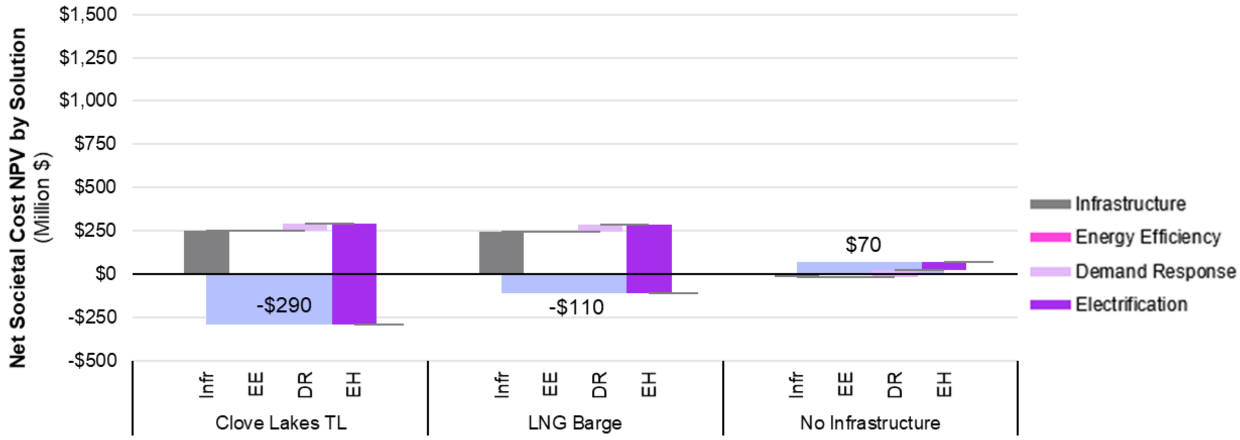


Figure F-3. Net Present Cost to Utility of Analyzed Solutions if LNG Vap. Rejected (ExC On-Time)

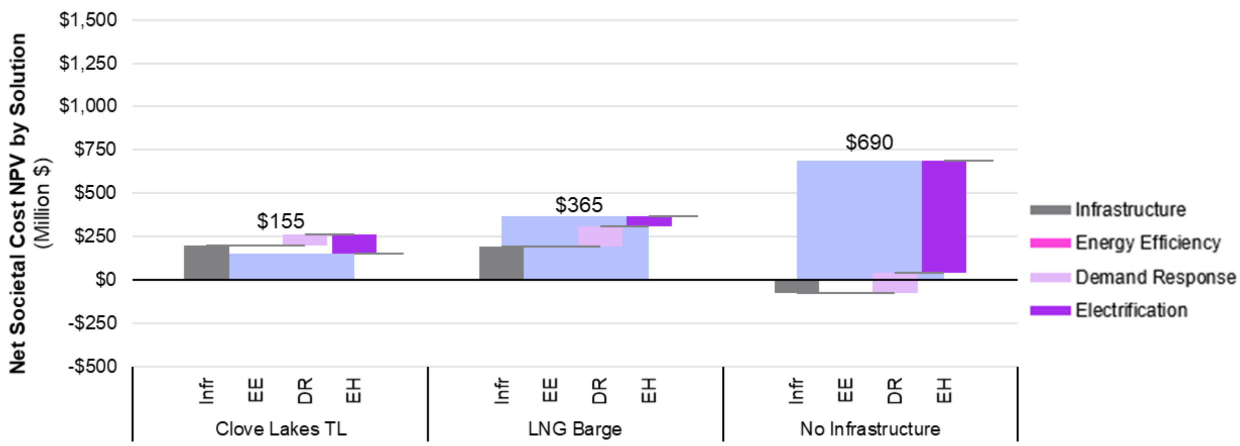


Figure F-4. Net Present Cost to Utility of Analyzed Solutions if ExC & LNG Vap. Delayed

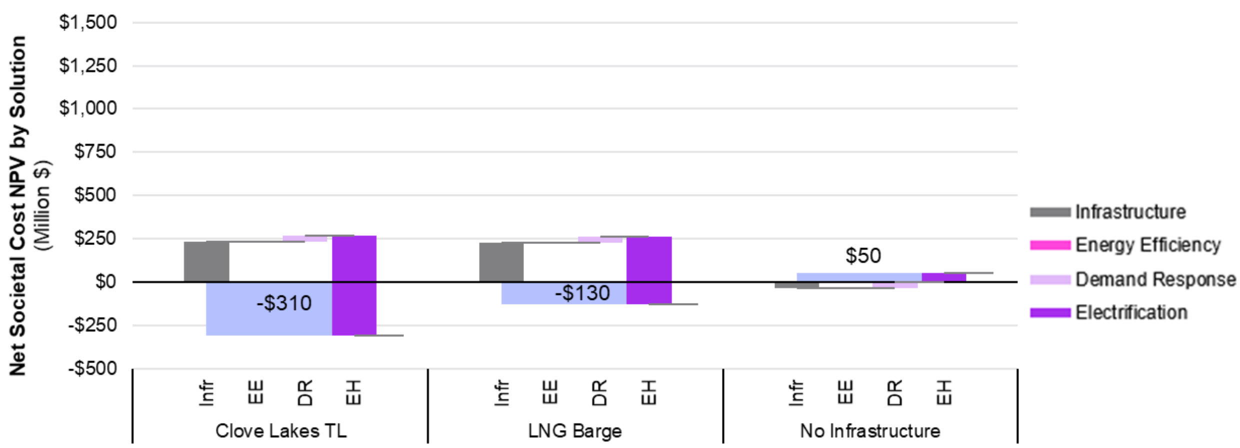


Figure F-5. Net Present Cost to Utility of Analyzed Solutions if ExC & LNG Vap. Rejected

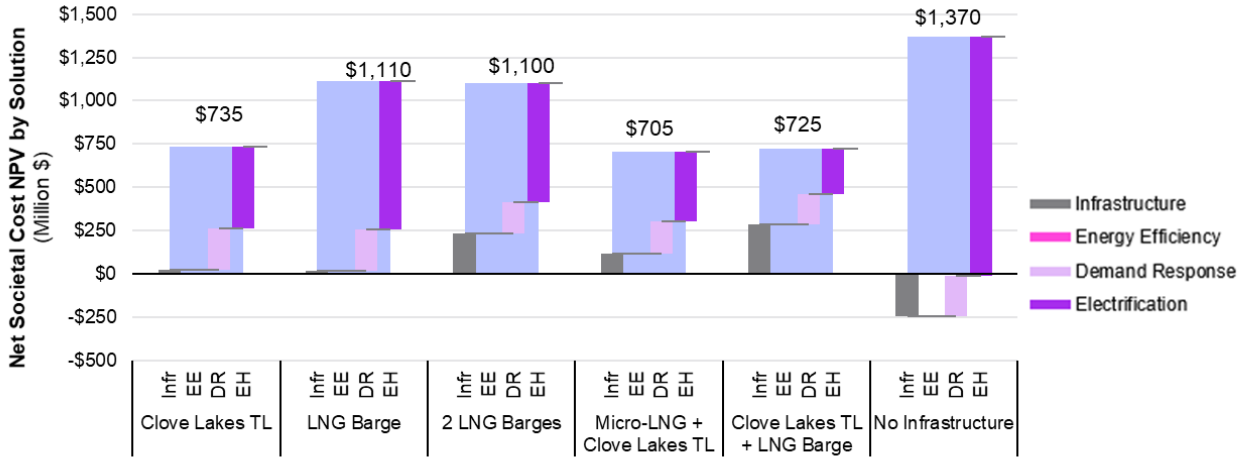
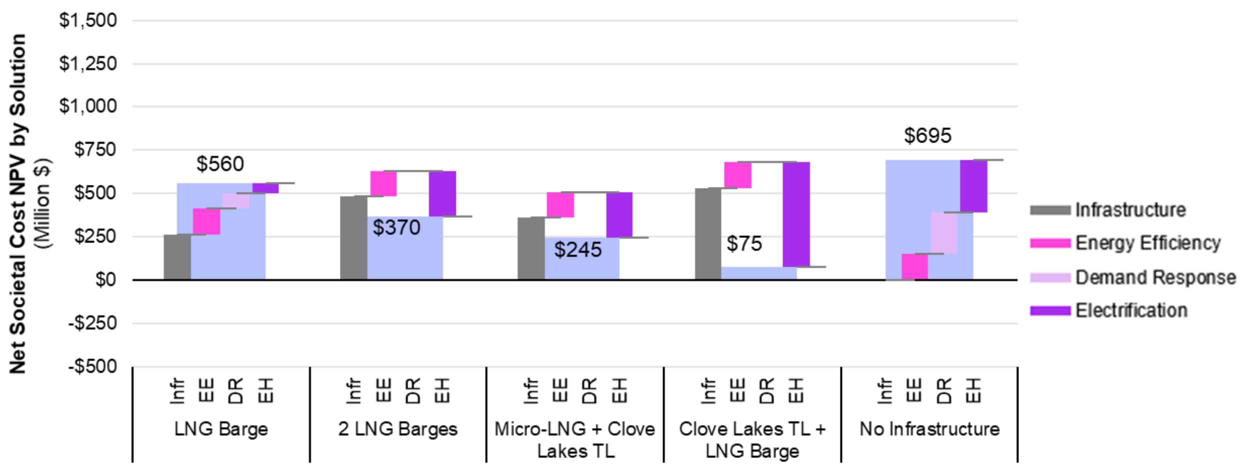


Figure F-6. Net Present Cost to Utility of Analyzed Solutions if 80% of DSM Savings in DI Sol'n



F.6. Utility Cost to Societal Cost Comparison

What has been discussed in this report as the cost to the utility is often referrd to as the Utility Cost Test (UCT), also known as the program administrator cost test. It assesses the impact of initiatives on the utility system – thus, it only includes costs and benefits to the utility. It is used as a secondary test to the SCT in New York to assess and compare initiatives solely from the utility's revenue requirement perspective. The UCT can provide benefit cost ratios or a NPV of net benefits over the life of a project.

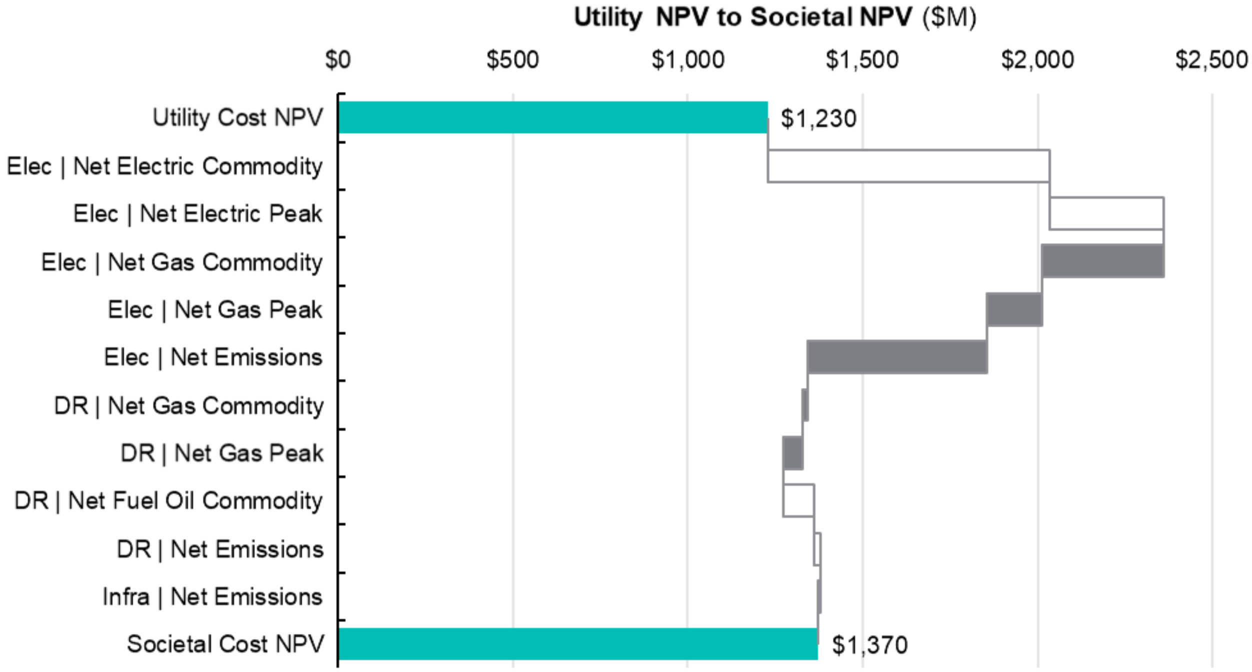
The table below compares the components included in each test. Because National Grid operates only as the gas utility in downstate New York, only gas utility costs and benefits are included in the utility cost in this report.

Table F-6. BCA Test Comparison of Benefits and Costs

Type	Component	SCT	UCT
Benefit	Avoided Gas Commodity Costs / Gas non-peaking service commodity costs	Yes	Yes
Benefit	Avoided On-System Infrastructure / Gas marginal cost of service	Yes	Yes
Benefit	Avoided CO2 Emissions / Gas social cost of carbon	Yes	No
Benefit	Avoided Other Emissions	Yes	No
Benefit	Electric summer peak LBMP	Yes	No
Benefit	Electric summer off-peak LBMP	Yes	No
Benefit	Electric winter peak LBMP	Yes	No
Benefit	Electric winter off-peak LBMP	Yes	No
Benefit	Avoided cost of generation capacity (AGCC)	Yes	No
Benefit	Marginal cost of transmission	Yes	No
Benefit	Marginal cost of distribution	Yes	No
Benefit	Electric net marginal damage cost of carbon	Yes	No
Cost	Program Administration Costs	Yes	Yes
Cost	Incremental On-System Investments	Yes	Yes
Cost	Incremental Participant Costs	Yes	No
Cost	Alternative Fuel Commodity Costs	Yes	No
Cost	Alternative Fuel CO2 Emissions	Yes	No
Cost	Alternative Fuel Other Emissions	Yes	No

The inclusion of different benefits and costs leads to different net present values to the utility versus to society for each solution. In general, the societal cost is higher due to the added cost of electricity outweighing the avoided cost of gas and reduced emissions from electrification, and due to the added cost of fuel oil and its associated emissions outweighing the avoided cost of gas and its associated avoided emissions from demand response. This is illustrated for a single contingency scenario solution in Figure F-7.

Figure F-7. Cross-walk from Utility Cost NPV to Societal Cost NPV for the No Infrastructure Solution if ExC & LNG Vap. Rejected



Appendix G. Global Warming Potential

G.1. Approach

The atmospheric impact of each solution in global warming potential equivalent tons is estimated for each contingency solution. This accounts for the net emissions from distributed infrastructure resources with slightly different emissions rates and the net emissions from demand side reduction measures. The same assumed emissions rates as shown in Table F-4 and Table F-5 are used here. The global warming potential factors used to convert the greenhouse gases into CO2 equivalents are shown in Table G-1.

Table G-1. Global Warming Potential Factors

Greenhouse Gas	20-Year GWP Factor	100-Year GWP Factor
CO2	1	1
N2O	264	265
CH4	84	28

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

G.2. Global Warming Potential for All Solutions

In the charts below, a positive value indicates a net savings of total CO2e compared to the Distributed Infrastructure Solution, while a negative value indicates a net increase in total CO2e compared to the Distributed Infrastructure Solution.

Figure G-1. Net Global Warming Potential Savings of Analyzed Solutions if ExC Rejected (LNG Vap. On-Time)

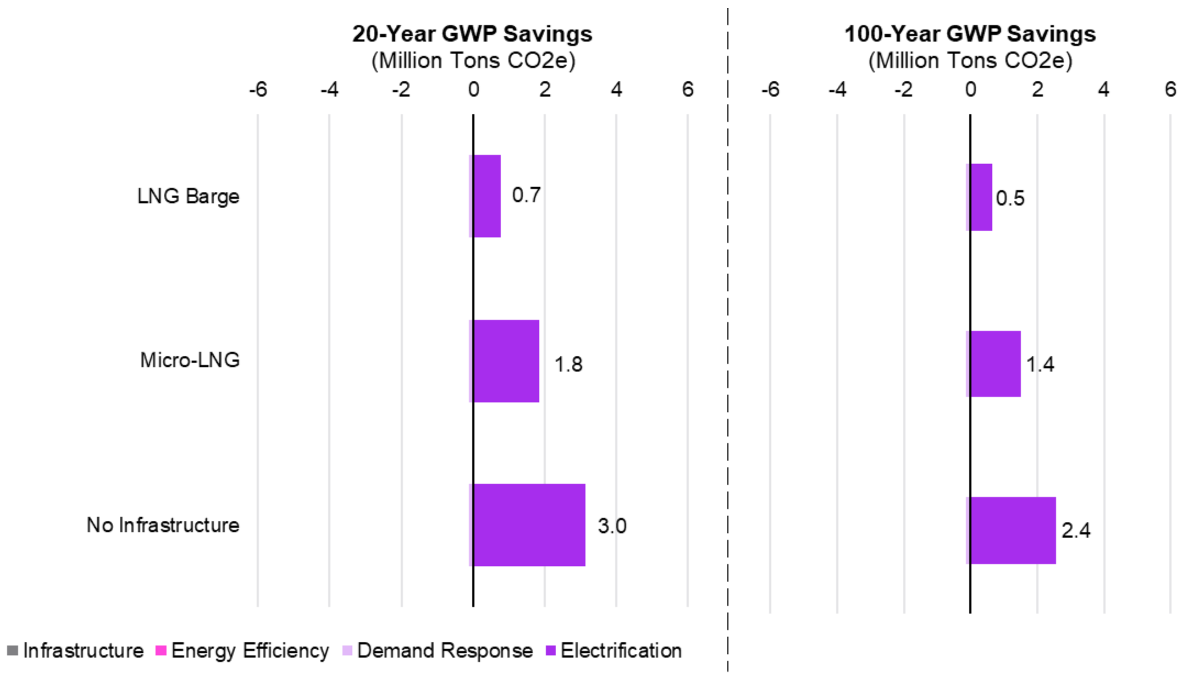


Figure G-2. Net Global Warming Potential Savings of Analyzed Solutions if LNG Vap. Delayed (ExC On-Time)

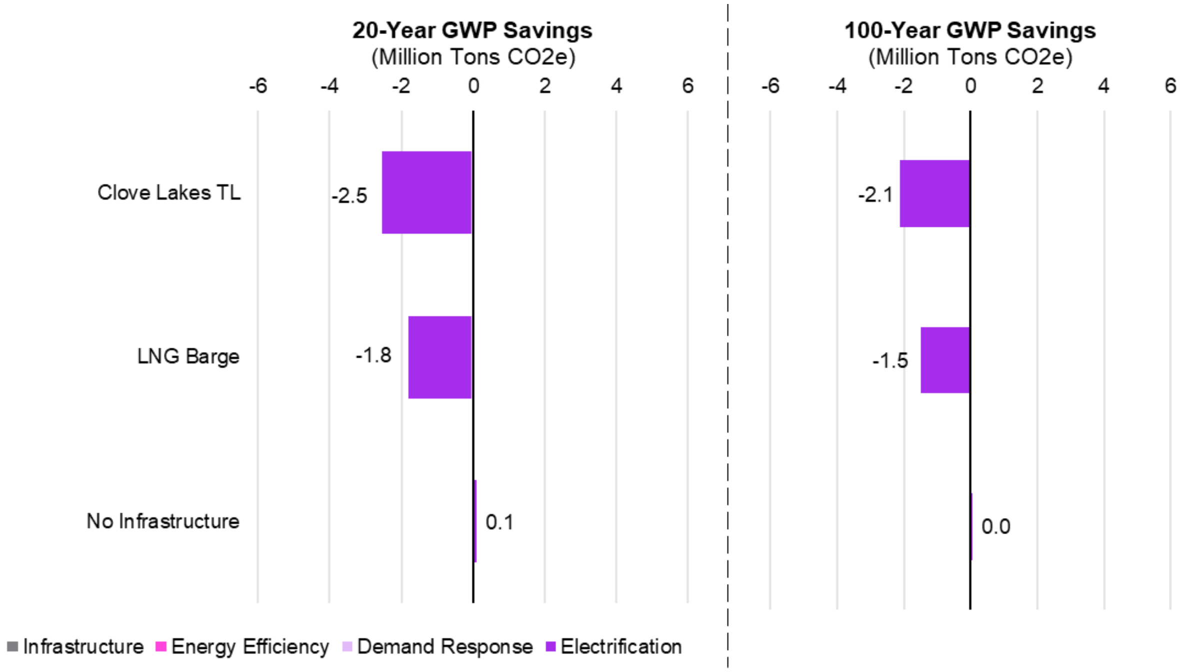


Figure G-3. Net Global Warming Potential Savings of Analyzed Solutions if LNG Vap. Rejected (ExC On-Time)

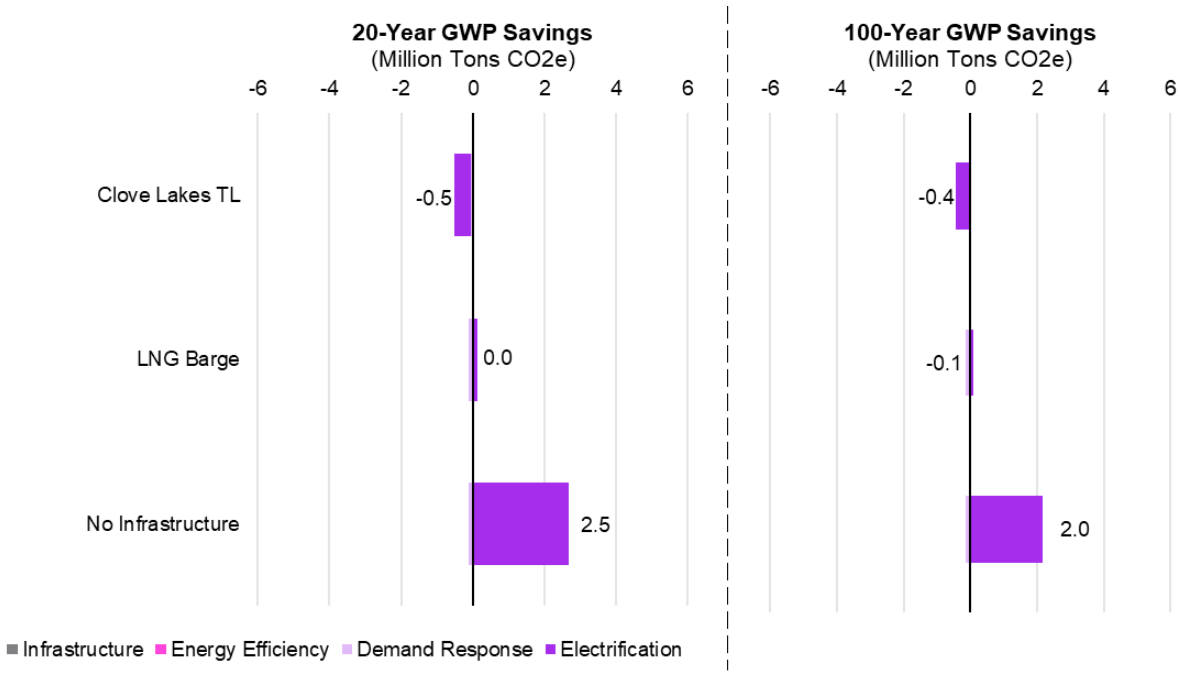


Figure G-4. Net Global Warming Potential Savings of Analyzed Solutions if ExC & LNG Vap. Delayed

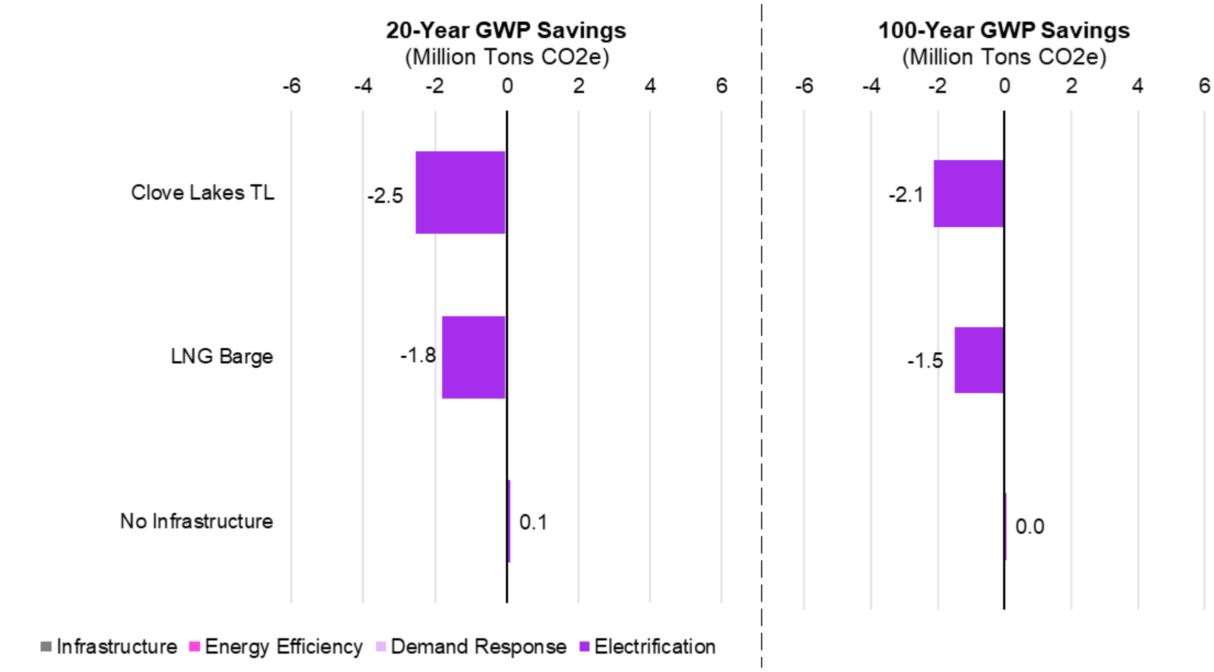


Figure G-5. Net Global Warming Potential Savings of Analyzed Solutions if ExC & LNG Vap. Rejected

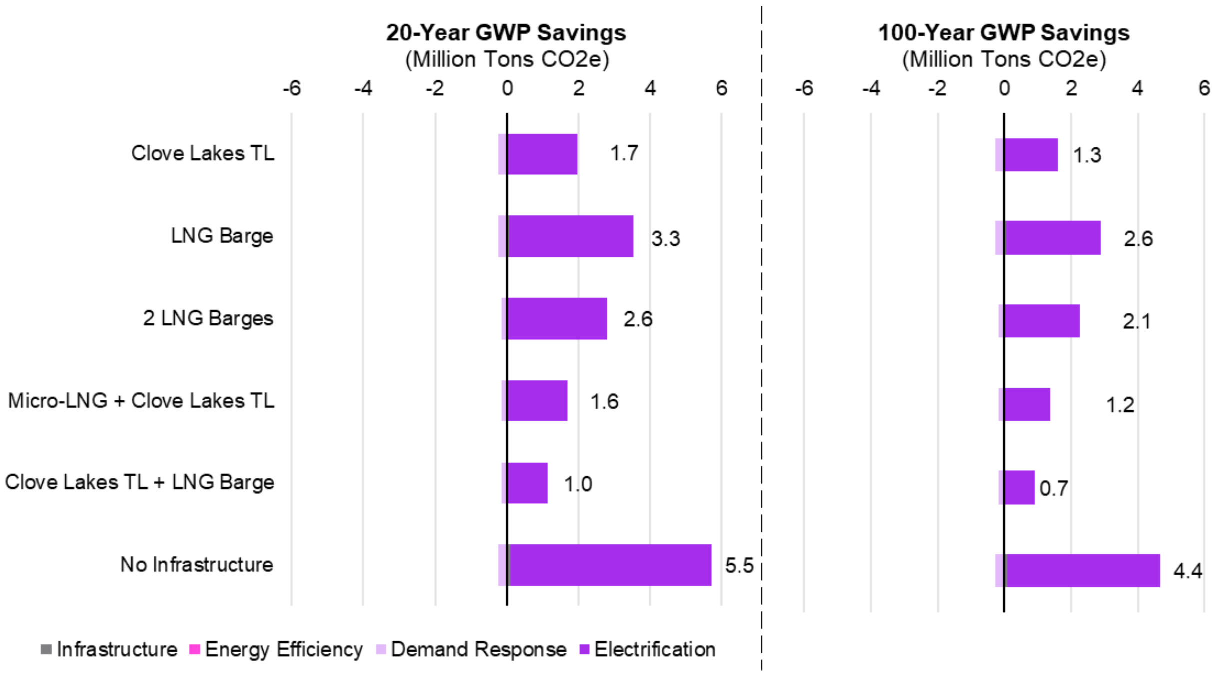
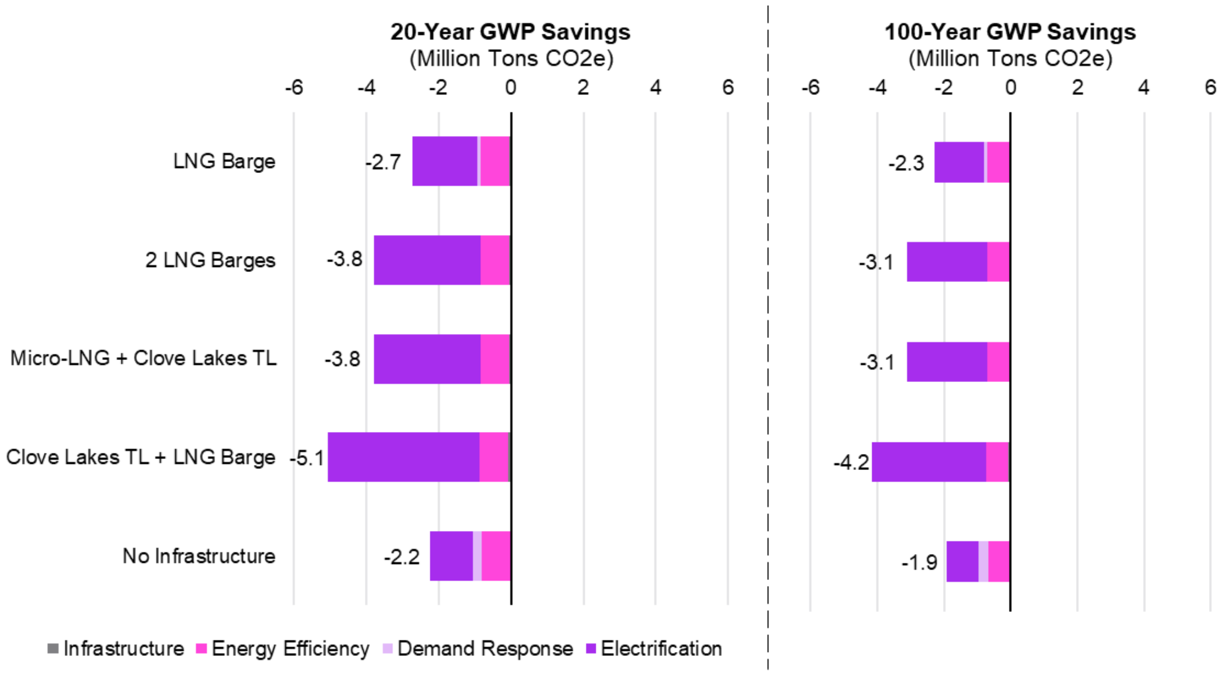


Figure G-6. Net Global Warming Potential Savings of Analyzed Solutions if 80% of DSM Savings in DI Sol’n



Appendix H. Customer Cost Impact

H.1. Approach

In addition to the total cost analysis shown elsewhere, National Grid also completed an analysis for each of the analyzed solutions to each of the contingency scenarios to estimate the customer cost impact. These costs were evaluated in isolation from any other network and program costs, while taking into account forecast changes in number of customers over time. So, to the extent that % growth in number of customers is greater than the net % growth in the cost of the solution, cost impacts could in fact be negative in this analysis.

It is important to note that this analysis is not equivalent to an expected bill increase for any customer. This analysis isolates the incremental cost of these solutions across a projected uniform customer base (i.e. it does not evaluate potentially different impacts by customer type and usage of Residential Heat, Multifamily, etc.). Other potential changes that could impact costs and customer bills, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, inflation, etc. are also not included in this analysis.

H.2. Cost Increase Percentages Over Time

In the first step, we looked at the average annual non-discounted cost of each option in five-year time periods (2021/2022 – 2025/2026, 2026/2076 – 2030/2031, and 2031/2032 – 2035/2036), and compared that to the baseline 2018 revenue for Downstate NY (Baseline revenue from 2018 annual reports: KEDNY $1.85B, KEDLI $1.24B, Downstate NY total $3.1B) to calculate the total cost increase % resulting from each option.

Further, we assume the distributed infrastructure solution is the baseline and compare the cost of the recommended solutions for each contingency scenario relative to the Distributed Infrastructure Solution cost. The results of this analysis for each of the different options is presented in the following tables.

Table H-1. Percent Change in Total Revenue Requirement for Solutions under ExC Rejected (LNG Vap. on-time) [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
LNG Barge	3.1%	-0.6%	0.2%	0.9%
Micro-LNG	3.2%	0.4%	-0.1%	1.2%
No Infrastructure	4.6%	0.9%	-0.6%	1.6%

Table H-2. Percent Change in Total Revenue Requirement for Solutions under LNG Vap Delayed (ExC on-time) [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	1.5%	-4.0%	-2.3%	-1.6%
LNG Barge	1.5%	-3.0%	-0.8%	-0.8%
No Infrastructure	1.5%	-1.4%	0.0%	0.1%

Table H-3. Percent Change in Total Revenue Requirement for Solutions under LNG Vap. Rejected (ExC on-time) [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	1.6%	-0.6%	-0.5%	0.1%
LNG Barge	3.0%	-1.1%	0.3%	0.7%
No Infrastructure	4.4%	0.9%	-0.7%	1.5%

Table H-4. Percent Change in Total Revenue Requirement for Solutions under ExC & LNG Vap. Delayed [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	1.3%	-4.0%	-2.3%	-1.6%
LNG Barge	1.3%	-3.0%	-0.8%	-0.8%
No Infrastructure	1.3%	-1.4%	0.0%	0.0%

Table H-5. Percent Change in Total Revenue Requirement for Solutions under ExC & LNG Vap. Rejected [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	6.1%	-0.5%	-2.3%	1.1%
LNG Barge	7.6%	0.7%	-1.3%	2.3%
2 LNG Barges	7.6%	0.2%	-0.8%	2.3%
Micro-LNG + Clove Lakes TL	4.7%	0.5%	-1.1%	1.4%
Clove Lakes TL + LNG Barge	6.1%	-0.6%	-2.4%	1.0%
No Infrastructure	9.1%	1.6%	-1.6%	3.0%

Table H-6. Percent Change in Total Revenue Requirement for Solutions under 80% of DSM in DI Sol'n [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
LNG Barge	0.2%	1.6%	2.1%	1.3%
2 LNG Barges	0.0%	-0.6%	3.1%	0.8%
Micro-LNG + Clove Lakes TL	0.1%	-1.0%	1.8%	0.3%
Clove Lakes TL + LNG Barge	0.0%	-3.3%	2.6%	-0.2%
No Infrastructure	0.8%	0.9%	4.3%	2.0%

The percentage increases above are all calculated as percent changes in total revenue requirements compared to the Distributed Infrastructure Solution. For example, if we are looking at the No Infrastructure solution in the ExC & LNG Vap. Rejected contingency scenario (bottom row of Table H-5), it indicates that costs would be 9% higher over the next five years, but ten years from now costs would be about 1.5% lower as the high level of demand side reduction measures pursued earlier on means that less are necessary later.

This analysis isolates the cost impact of each alternative and does not consider other potential changes that could impact costs and customer bills, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, etc.

H.3. Average Cost Increase Percentage Per Customer

Having calculated the total cost changes over the five-year time periods for each of the different options, we then factor in the changes in the number of customers over time to derive an average estimated customer cost impact. Again, we are using the same data on the cost of each option, but now take into account the expected change in number of customers over time in each scenario and solution combination. The results of this analysis for each of the different options is included in the following tables.

Table H-7. Percent Change in Cost per Customer for Solutions under ExC Rejected (LNG Vap. on-time) [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
LNG Barge	3.3%	0.0%	0.3%	1.2%
Micro-LNG	3.4%	1.4%	0.9%	1.9%
No Infrastructure	4.9%	2.6%	1.1%	2.9%

Table H-8. Percent Change in Cost per Customer for Solutions under LNG Vap Delayed (ExC on-time) [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	1.6%	-4.4%	-4.4%	-2.4%
LNG Barge	1.6%	-3.4%	-2.3%	-1.4%
No Infrastructure	1.6%	-1.3%	0.0%	0.1%

Table H-9. Percent Change in Cost per Customer for Solutions under LNG Vap. Rejected (ExC on-time) [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	1.7%	-0.5%	-1.1%	0.0%
LNG Barge	3.2%	-0.7%	-0.1%	0.8%
No Infrastructure	4.8%	2.4%	0.6%	2.6%

Table H-10. Percent Change in Cost per Customer for Solutions under ExC & LNG Vap. Delayed [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	1.5%	-4.4%	-4.4%	-2.5%
LNG Barge	1.5%	-3.4%	-2.3%	-1.4%
No Infrastructure	1.5%	-1.3%	0.0%	0.1%

Table H-11. Percent Change in Cost per Customer for Solutions under ExC & LNG Vap. Rejected [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
Clove Lakes TL	6.6%	1.2%	-1.9%	2.0%
LNG Barge	8.2%	3.1%	0.1%	3.8%
2 LNG Barges	8.2%	2.3%	-0.1%	3.5%
Micro-LNG + Clove Lakes TL	5.1%	1.9%	-0.7%	2.1%
Clove Lakes TL + LNG Barge	6.6%	0.8%	-2.6%	1.6%
No Infrastructure	9.9%	4.9%	1.3%	5.4%

Table H-12. Percent Change in Cost per Customer for Solutions under 80% of DSM in DI Sol'n [%]

Solution	5 yr avg - 25/26	5 yr avg - 30/31	5 yr avg - 35/36	15 Year Avg Total
LNG Barge	0.2%	1.5%	2.0%	1.2%
2 LNG Barges	0.0%	-1.2%	1.9%	0.2%
Micro-LNG + Clove Lakes TL	0.0%	-1.6%	0.7%	-0.3%
Clove Lakes TL + LNG Barge	0.0%	-4.4%	0.2%	-1.4%
No Infrastructure	0.8%	0.8%	5.1%	2.2%

In some cases, higher levels of heat electrification means fewer customers to spread costs across, which drives the cost impact on a per-customer basis higher when compared to the total cost impact (i.e. the percentages are higher in the tables in Section H.3 than they are in the tables in Section H.2 for solutions with more heat electrification). Taking again for example the No Infrastructure solution in the ExC & LNG Vap. Rejected contingency scenario (bottom row of Table H-11), the cost per customer is now 1% higher on average between 2031/32 and 2035/36 than in the Distributed Infrastructure solution even though the total cost in that period is 1.5% lower as identified in Table H-5, because there are fewer remaining gas customers in those years compared to the Distributed Infrastructure solution.

This analysis does not consider changes in customer mix or any other changes to cost such as changes in capital investment, operating cost increases, etc. It is an attempt to isolate to overall average impact to costs of the different options.

This analysis aggregates all customer types. Further segmented analysis accounting for multiple other factors would have to be conducted to arrive at projected customer bill impacts by customer class and across KEDNY and KEDLI.

Appendix I. Gaps in Terms of Number of Customers

I.1. Approach

The size of an emergent design day gap is listed for a number of situations. In some cases these are scenario gaps without any solution to address them. In one case the No Infrastructure solution to a contingency scenario is assumed to meet 80% of it's DSM savings targets, resulting in a net gap.

This gap is then shown in terms of a number of representative customers. To do this, the average design day usage per aggregate customer (that is, total firm volume divided by total firm customers, including residential non-heating, residential heating, commercial, and large multifamily customers) are calculated. These are estimated as the annual usage per customer from the adjusted baseline forecast multiplied by an implied design day factor from that forecast. The emergent gap in each situation is then divided by the usage per customer to get the gap in terms of number of representative customers.

Note that these tables are only shown to contextualize the magnitude of these gaps in a tangible way. See Section 7.4 for a more complete discussion of the potential risk for customer connection pauses and curtailments.

I.2. Gap in Terms of Number of Customers

Table I-1. Remaining Design Day Gap by Situation [MDth/day]

Situation	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
ExC Rejected (LNG Vap. on-time) with No Solution	0.0	0.0	0.0	0.0	5.9	35.5	61.1	45.0	40.0	38.4	52.3	42.2	45.0	44.9	58.0
LNG Vap. Rejected (ExC on-time) with No Solution	0.0	0.0	5.8	0.0	2.2	31.8	57.4	41.3	36.3	34.7	48.6	38.5	41.3	41.2	54.3
ExC & LNG Vap. Rejected with No Solution	0.0	0.0	5.8	33.1	64.7	94.3	119.9	103.8	98.8	97.2	111.1	101.0	103.8	103.7	116.8
80% of DI Sol'n DSM with No Solution	0.0	0.0	0.0	0.0	0.0	0.0	24.0	14.4	16.0	20.9	41.3	37.6	46.8	52.9	72.3

Table I-2. Remaining Design Day Gap by Situation in Terms of Number of "Aggregate" Customers [# Customers]

Situation	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
ExC Rejected (LNG Vap. on-time) with No Solution	0	0	0	0	3,900	23,100	39,600	28,800	25,600	24,400	33,000	26,300	28,000	27,700	35,600
LNG Vap. Rejected (ExC on-time) with No Solution	0	0	3,900	0	1,500	20,700	37,200	26,400	23,200	22,000	30,700	24,000	25,700	25,400	33,300
ExC & LNG Vap. Rejected with No Solution	0	0	3,900	21,900	42,600	61,500	77,600	66,500	63,200	61,700	70,100	63,000	64,600	64,000	71,700
80% of DI Sol'n DSM with No Solution	0	0	0	0	0	0	15,600	9,300	10,300	13,300	26,000	23,500	29,100	32,700	44,300

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