STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Filing of The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid for Approval of Incremental Demand-Side Management Programs	:	**Case 19-G-0309 and Case 19-G-0310**

FILING OF THE BROOKLYN UNION GAS COMPANY D/B/A NATIONAL GRID NY AND KEYSPAN GAS EAST CORPORATION D/B/A NATIONAL GRID FOR APPROVAL OF INCREMENTAL DEMAND-SIDE MANAGEMENT PROGRAMS

The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid

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I. INTRODUCTION

This Filing by The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") (collectively, the "Companies" or "National Grid") is made pursuant to the Joint Proposal[1] recently approved by the Public Service Commission of the State of New York ("Commission") in the Companies' last rate case. The purpose of this Demand-Side Management ("DSM") Filing is to present for Commission review the proposed DSM programs that will deploy unprecedented levels of non-infrastructure solutions

[1] Case 19-G-0309, Proceeding on Motion Of The Commission As To The Rates, Charges, Rules And Regulations of The Brooklyn Union Gas Company D/B/A National Grid NY For Gas Service and Case 19-G-0310, Proceeding on Motion of The Commission As To The Rates, Charges, Rules And Regulations of KeySpan Gas East Corporation D/B/A National Grid For Gas Service, Case 18-M-0270 Petition For Approval Pursuant To Public Service Law Section 113(2), Of A Proposed Allocation Of Certain Tax Refunds Between KeySpan Gas East Corporation D/B/A National Grid And Ratepayers, Joint Proposal By and Among: The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, Department of Public Service Staff, Environmental Defense Fund, Estates NY Real Estate Services LLC, NY-Geo Bob Wyman, Long Island Power Authority, Dated: May 14, 2021 (hereinafter "Joint Proposal."); and Order Approving Joint Proposal As Modified, and Imposing Additional Requirements (issued August 12, 2021).

– specifically, expanded energy efficiency and response programs – to meet customers energy needs and address a looming gas capacity shortfall on the Companies' systems in a manner that supports New York's aggressive climate goals. This Filing further seeks the Commission's approval of the recovery of the costs of the DSM programs required to implement these non-infrastructure solutions consistent with the mechanisms adopted and approved in the Joint Proposal.

II. EXECUTIVE SUMMARY

The Filing is necessary because of the growing peak gas demand on the Companies' systems, the lack of new capacity to meet that demand, and the need for solutions that are consistent and harmonious with the goals of New York's Climate Leadership and Community Protection Act ("CLCPA"), New York City's Local Law 97, and the policies of the State and this Commission. In Case 19-G-0678, the Commission approved a settlement agreement[2] wherein the Companies agreed, *inter alia*, to identify potential solutions for addressing the gap between the Companies' supply of natural gas and the forecast of firm customer demand and to solicit public feedback and input on the identified solutions. In February 2020, National Grid published the *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island* (the "Original Report") that assessed the extent of gas supply constraints in downstate New York and identified potential options for meeting future customer demand. The report analyzed the relative risks and benefits of identified options (*e.g.*, interstate pipelines, liquified natural gas

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[2] *See* Settlement Agreement, dated November 24, 2019 ("Settlement Agreement"), between National Grid and Department of Public Service Staff; approved in Case 19-G-0678 - *Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid*, "Order Adopting and Approving Settlement," (Issued November 26, 2019).

(“LNG”), compressed natural gas (“CNG”), demand-side solutions) in terms of reliability, deliverability, cost, and environmental impacts, among other considerations. After publishing the report, as well as a reader-friendly summary and supporting data, the Companies facilitated a series of public meetings and comment sessions and received thousands of written comments from members of the public and stakeholder groups. The vast majority of these comments advocated for increased use of energy efficiency and other non-infrastructure solutions to meet customers’ energy needs. In May 2020, the Company’s published the *Long-Term Capacity Supplemental Report*[3] (“Supplemental Report”) that summarized stakeholder comments and identified a recommended option that included a portfolio of targeted infrastructure (*e.g.*, CNG and LNG) and non-infrastructure solutions (*e.g.*, energy efficiency), referred to as the “Distributed Infrastructure Solution.” The Distributed Infrastructure Solution now serves as the Companies’ roadmap for addressing supply constraints in downstate New York.

Without traditional capacity solutions to fall back on, and mindful of the imperative to meet the goals of the CLCPA, the purpose of this Filing is to present for Commission review proposed DSM (non-infrastructure) programs that are part of the Distributed Infrastructure Solution. The DSM programs described in this Filing are essential components of the Distributed Infrastructure Solution, which relies on gas demand reduction to meet three quarters of the projected demand-supply gap by the 2035-2036 winter heating season

The levels of DSM required to close the demand-supply gap in the long term are unprecedented; in peer benchmarking, the Companies have found no other utility which has attempted to implement DSM programs at this scale as rapidly as the Distributed Infrastructure

[3] The Supplemental Report and related reports are available at https://ngridsolutions.com/.

Solution. The programs and technologies that are required to deliver such aggressive energy savings are costly but -- as described in the Companies' capacity reports and validated by independent assessment -- necessary to address the gas demand capacity shortfall. These DSM programs are being implemented in lieu of traditional infrastructure, whose costs are avoided. DSM solutions are fully consistent with New York's decarbonization goals and a clean energy future. In addition to providing distribution-level benefits to all customers in the Companies' service territories, customers who directly participate in DSM programs will save energy and see direct cost savings in the form of lower energy bills.

As part of a portfolio of solutions to meet peak demand, the Companies have identified opportunities to implement non-infrastructure solutions (*i.e.*, demand response ("DR") and incremental energy efficiency ("EE") programs). The Companies propose to deploy weatherization programs for residential, commercial and industrial ("C&I") and multi-family ("MF") customers beginning in Rate Year 2 (April 1, 2021 - March 31, 2022).[4] These programs are incremental to the existing energy efficiency programs the Companies will implement in Rate Year 2 to satisfy their New Efficiency: New York ("NE:NY") targets. The incremental EE programs will expand significantly in Rate Year 3 (April 1, 2022 - March 31, 2023) to align with the demand and usage reductions necessary to achieve the goals of the Distributed Infrastructure Solution. These incremental energy efficiency programs implement measures that afford a long useful life and a very high peak coincidence value (meaning that they will reduce demand on the gas system during peak winter conditions and will do so for a period of years). These types of

[4] References to Rate Years refer to Rate Years as designated in the Joint Proposal, and correspond to the Companies' fiscal years which run April 1 – March 31.

measures require a higher investment per therm than previously employed in the Companies' NE:NY portfolio in order to secure reduction in peak demand.

With respect to Demand Response, the Companies have proposed a firm demand response budget that will enable them to continue operating and scale up the three DR programs first launched in the 2019-2020 winter heating season as part of the Settlement Agreement and described in the Companies' Implementation and Contingency Plan; namely, Daily DR, Bring Your Own Thermostat ("BYOT") and Behavioral DR.[5] As with EE, the DR programs will also expand in Rate Year 3. These Demand Response programs will provide significant daily and hourly demand reduction necessary to achieve the goals of the Distributed Infrastructure Solution. Demand Response programs can be operated as a flexible dispatchable resource that can be scaled up or down, by geography and by time, depending on system needs.

In fact, all DSM programs will expand in Rate Year 3 and in the ensuing years, adding Third Party Solutions solicitations and incremental electrification of heat ("Electrification"), in cooperation with the downstate New York electric delivery companies. The Companies, however, are requesting approval to implement the nearer-term programs in this Filing because the long-term DSM plan presented herein is expected to be adjusted to incorporate lessons learned, updates to the Companies' capacity demand forecasts in relation to available supply in future years, advances in DSM technologies, and other relevant changes. This approach helps to limit bill

[5] An Hourly DR program will also be operated for the 2021-2022 winter season and beyond. Costs of the Hourly DR program (other than labor), will be recovered though the Demand Response O&M Component of the Delivery Rate Adjustment ("DRA"), which is a separate means of recovering certain costs pursuant to the Joint Proposal.

impacts because it guards against recovering more funds than are necessary to deliver the required demand reduction.

Nevertheless, given the serious consequences of falling short of capacity on a design day, the Companies must begin to address the capacity deficiency in a significant manner and must begin that effort now. The following table shows the level of spending in Rate Year 2 and Rate Year 3 of the Joint Proposal to meet the capacity deficiency with the Distributed Infrastructure Solution.

Table 1: Incremental DSM Funding for Rate Year 2 and Rate Year 3[6]

Rate Year 2 - FY 2022	KEDNY Costs	KEDLI Costs	Total Cost
Incremental Energy Efficiency – Residential	$5,145,938	$4,210,313	$9,356,250
Incremental Energy Efficiency - Commercial and Multifamily	$3,646,662	$2,983,632	$6,630,294
Incremental Electrification	$48,125	$39,375	$87,500
Energy Efficiency and Electrification Labor Costs	$697,845	$570,964	$1,268,809
Demand Response (DCSM Non-Labor Costs only)	$4,408,250	$1,889,250	$6,297,500
Demand Response Labor	$485,940	$208,260	$694,200
Third-Party Solutions Solicitation Labor Costs	$281,429	$230,260	$511,689
Total Rate Year 2	**$14,714,188**	**$10,132,054**	**$24,846,242**

[6] The total costs for the DSM programs for Rate Years 2 and 3 presented in this table appear greater than the costs of the DSM programs for Heating Seasons 2021-22 and 2022-23 in tables showing costs for the EE programs only. This is because the Companies' rate years run from April 1 to March 31. Demand Response costs are budgeted by Heating Season corresponding to the rate year. EE programs, however, are budgeted on a calendar year basis to ensure that measures are in place by the end of December for a given heating season. The tables by Rate Year omit costs for January through March 2021 but include costs for January through March 2023. The latter are higher, because programs will ramp up by year to meet capacity demand gap. The costs of the EE programs in the last quarter of Rate Year 3, although they are not fully presented in detail in this report, are based on projections of the programs being continued similarly for the next heating season. Such costs will be updated in the next Annual DSM filing in July, 2022 as the last quarter of Rate Year 3 goals for energy efficiency and electrification programs are meant to achieve heating season 2023-2024 goals.

Rate Year 3 - FY 2023	KEDNY Costs	KEDLI Costs	Total Cost
Incremental Energy Efficiency – Residential	$29,363,421	$26,810,491	$56,173,912
Incremental Energy Efficiency – Commercial and Multifamily	$16,742,512	$13,825,461	$30,567,972
Incremental Electrification	$144,375	$118,125	$262,500
Energy Efficiency and Electrification Labor Costs	$1,132,285	$926,415	$2,058,700
Demand Response (DCSM Non-Labor Costs only)	$8,974,700	$3,846,300	$12,821,000
Demand Response Labor	$851,270	$364,830	$1,216,100
Third Party Solutions Alternatives Solicitation Labor Costs	$373,479	$305,574	$679,053
Total Rate Year 3	**$57,582,042**	**$46,197,195**	**$103,779,237**
Grand Total Rate Year 2 and 3	**$72,296,230**	**$56,329,249**	**$128,625,480**

To effectuate the recovery of the costs associated with the incremental demand response and energy efficiency programs, the Joint Proposal permits the Companies to implement a surcharge – the Demand Capacity Surcharge Mechanism (or, alternatively, "DCSM") – beginning in Rate Year 2 (April 1, 2021 – March 31, 2022). The Surcharge is to be designed to enable the Company to recover Commission-approved energy efficiency costs not already included in base rates, and certain costs to implement demand response programs and other demand-side management programs. Consistent with the Joint Proposal, the Companies will make annual filings ("Demand Side Management (DSM) filings") in Cases 19-G-0309 and 19-G-0310 that will describe the energy efficiency programs for which the Companies are seeking cost recovery and afford the Commission at least 150 days to determine whether the incremental energy efficiency programs should be undertaken and made eligible for cost recovery. Similarly, to recover demand response costs under the Surcharge, the Companies are to make annual filings describing the demand response programs the Companies will implement in the upcoming winter heating season and afford the Commission sufficient time to determine whether the incremental demand response programs should be undertaken.

In this Filing, the Companies present the incremental energy efficiency programs, with associated budgets and targets, and request Commission approval to accelerate the expenditure of funds for the incremental energy efficiency programs and to surcharge those funds using the DCSM. Timing of the surcharge mechanism is such that 50 percent of Rate Year 2 Demand Response costs will be surcharged beginning December 1, 2021, with the remaining 50 percent of Rate Year 2 DR costs, 50 percent of Rate Year 3 Demand Response costs, 50 percent of Rate Year 3 EE costs, and 100 percent of Rate Year 2 EE costs to be surcharged beginning in July of 2023.

The Companies also present their plans for incremental demand response and intended surcharge using the DCSM, consistent with the Joint Proposal. The Companies' Demand Response Implementation Plan describing the planned DR program structure and targets for the 2021-2022 Heating Season, together with proposed Tariff amendments, was filed on June 15, 2021 and approval is anticipated in October 2021.[7] Programs for the 2022-2023 Heating Season are presented in this Filing and will be updated based upon the June, 2022 demand forecast. Notably, the operation of the Demand Capacity Surcharge Mechanism – allowing 50 percent of current costs to be included in the first year, with the remainder to be included in the following year – recognizes the dynamic nature of the programs and allows for adjustments to the programs and the capture of efficiencies and experience through a true-up of the costs in the remaining surcharge recovery. This prevents the Companies from recovering more than they actually spend to deliver the required demand reduction.

This Filing will provide a comprehensive description of the programs and the reasons why the programs must be adopted by the Commission in time to meet the growing demand of

[7] Cases 20-G-0086 and 20-G-0087.

customers, and to enable the Companies to ensure that adequate gas supplies are on hand to meet anticipated Design Day requirements. Because of the critical importance of this endeavor, the Companies look forward to working expeditiously with all stakeholders – Staff, intervenors, governmental entities and agencies and customer groups – to ensure rapid and adequate consideration of our proposals, their prompt approval and expeditious adoption and implementation.

III. BACKGROUND

A. The History and Basis of the Capacity Gap

The DSM programs for which the Companies seek approval in this Filing are familiar to the Commission. On February 24, 2020, National Grid released the *Natural Gas Long-Term Capacity Report* (the "Original Report") for its downstate NY service territories. 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 National Grid 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 were denied. Since that denial, the Companies have been executing the other solution recommended by National Grid —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 EE and DR (collectively, the "Distributed Infrastructure Solution").

In June 2021, the Companies published the *Natural Gas Long Term Capacity - Second Supplemental Report* ("Second Supplemental Report"), which built on the prior reports addressing the region's gas capacity constraints. The Second Supplemental report: framed the gas capacity needs and Distributed Infrastructure Solution in the context of the Companies updated 2021 long-term demand forecast and New York's and National Grid's 'net-zero' goals; provided an update to the long-term demand forecast, supply capacity, and the projected demand-supply gap over the next 15 years; and confirmed the Distributed Infrastructure Solution remains the best viable solution to solve the demand-supply gap.[8]

The Companies' customers throughout Brooklyn, Queens, Staten Island and Long Island depend on them 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. The Companies must meet this profound energy obligation even as the Companies plan for a future where traditional natural gas demand may decline as a result of new policies to reduce greenhouse gas emissions and new sources of traditional capacity to meet that demand may no longer be available.

Downstate NY has seen dynamic economic growth, expanding residential and non-residential building space, and thousands of oil-to-gas conversions over the last 12 years. These

[8] The Second Supplemental Report recently underwent an independent review, conducted by PA Consulting ("PA") working at the direction of DPS Staff, which (i) corroborated that the Company's forecast and assessment of the supply gap is generally reasonable and (ii) concluded that the Distributed Infrastructure Solution is a similarly reasonable approach to addressing the supply gap, while acknowledging the risks to delivering the individual component. *See*, *PA Consulting's Assessment of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report* (September 10, 2021).

factors have resulted in a substantial increase in the demand for natural gas, placing stress on the Companies' existing gas network and challenging their longer-term ability to meet customers' needs when demand is at its peak.

Based on the updated Adjusted Baseline Demand Forecast, the Companies project that a gap between total downstate NY customer peak day gas demand and available gas capacity will emerge in the winter of 2022-2023 and will grow thereafter, unless it is attenuated by planned Distributed Infrastructure Solution capital projects and incremental demand reductions. Traditionally, this growth gap has been met with capital investment and supply procurement by the local delivery companies ("LDCs") to continue to provide safe and reliable natural gas service to those who request it within their respective service territories, in accordance with their statutory obligation to serve. In recent years, however, as New York State policy has evolved to meet the challenge of climate change, utilities must explore alternatives to traditional infrastructure solutions. Consequently, utilities must look to energy efficiency and other DSM programs as alternative solutions to infrastructure investment and/or supply procurement, potentially providing the LDCs with new tools to meet peak day gas demand and to manage overall gas usage.

As this Filing demonstrates, the Companies strongly support New York's goals to reduce greenhouse gas ("GHG") emissions. The Companies have also made significant corporate commitments that align with New York's ambitious climate change goals as laid out in the CLCPA. In October 2020, National Grid refined its plan to achieve New York's net zero GHG emissions by 2050 goal ("Net Zero") via its "Net Zero by 2050" plan and updated its *Responsible*

Business Charter to include those ambitions.[9] To the same end, the Joint Proposal includes a provision that the Companies will "operate their gas networks with the objective of reducing billed gas usage, normalized for temperature, in their service territories over the term of the rate plans."[10] Measured against these goals, the Companies believe that their Distributed Infrastructure Solution, which includes the DSM programs detailed herein, is consistent with the CLCPA goals, the Net Zero plan, and a clean energy future.

B. Peak Demand Design Criteria

With almost 1.9 million customers in KEDNY's and KEDLI's downstate NY service territories and with a sustained trend over the last 12 years of adding roughly 12,000 customers per year, the Companies must forecast 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.

Maintaining natural gas deliveries during several consecutive day-long cold snaps, the coldest day, and the highest use peak hour is critical to customers' health and welfare. To that end, the Companies design the gas distribution system and plan 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). During very cold weather (including but not limited

[9] National Grid has committed to achieve net zero by 2050 by reducing Scope 1 and 2 GHG emissions 80 percent by 2030, 90 percent by 2040, and to net zero by 2050 from a 1990 baseline. *See* National Grid Responsible Business Charter, at p.5. *Available at* https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf.

[10] Joint Proposal § IV.7.5.

to a Design Day), peak-hour customer demand is typically 120 percent of the average-hour customer demand. This is driven by behaviors such as thermostats calling for heat, high-usage periods of hot water (before and after the work day), and cooking loads during typical meal times. Importantly, the Companies must 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. If demand exceeds available supply, operating conditions on the system may become more challenging, including low pressure situations, which in an extreme case, may require service interruptions via customer curtailments.[11]

The downstate NY gas supply and distribution requirements are modeled based upon a Design Day average temperature of 0° Fahrenheit in Central Park (i.e., 65 Heating Degree Days). An analysis by Marquette Energy Analytics of downstate NY weather conditions (accounting for both temperature and wind that drive peak gas demand for heating) corroborates the Companies' Design Day standard as consistent with mainstream gas utility Design Day standards in terms of likelihood of occurrence.

C. The Capacity Gap

Figure 1 below shows historical and projected growth for Design Day gas demand. The historical data and forecasts of all macroeconomic variables used to develop the econometric models that generate load forecasts are obtained from a leading economic research and forecasting

[11] The scenario of a capacity shortage is discussed at more length in the Companies' Second Supplemental Long Term Capacity Report, at p. 34.

firm, Moody's Analytics.[12] The Companies forecast 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 existing energy efficiency, demand response and heat electrification programs. Based on those factors, the Companies' latest forecast projects that downstate NY Design Day gas demand will increase approximately 1.5 percent per year, from 2,766 MDth per day[13] in winter 2020-2021 to 3,430 MDth per day in winter 2034-2035.

Growth in the baseline demand forecast adjusted for the NE:NY energy efficiency targets, demand response, and the electric delivery companies' heat electrification targets ("Adjusted Baseline Demand Forecast") is significantly less than the average growth rate experienced over the historical period, which was 2.2 percent per year from winter 2007-2008 to winter 2020-2021. Design Day gas demand, however, is expected to grow much faster than even the historical rate over the next three years, averaging 3.1 percent per year from winter 2020-2021 to winter 2023-2024, due to the strong economic rebound forecast for downstate NY after the COVID-19 pandemic.

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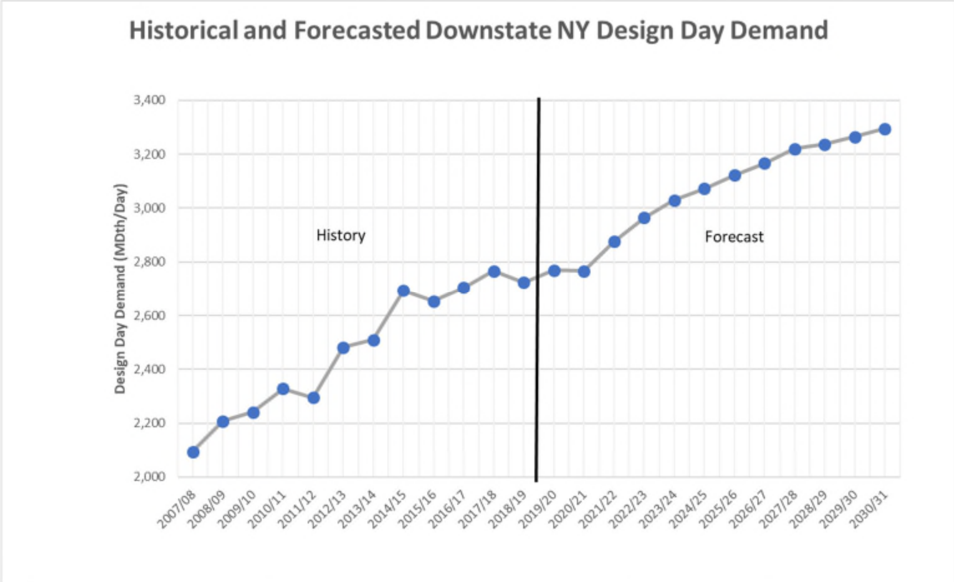
[12] Moody's Analytics Baseline Scenario (April 2021) forecast for Kings, Queens, Richmond, Nassau and Suffolk counties New York, Updated May 5, 2021. All the energy prices are from the U.S. Department of Energy, Energy Information Administration.

[13] 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.

Figure 1: Historical and Forecasted Downstate NY Design Day Gas Demand



Based on the updated Adjusted Baseline Demand Forecast, the Companies project that a gap between total downstate NY customer peak gas demand and available gas capacity (daily) will emerge in the winter of 2022-2023 and will grow thereafter, before accounting for planned gas capacity projects and incremental demand reductions under the Distributed Infrastructure Solution. The Companies have delivered every on-system supply project in our operations plan and have 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 the 2022-2023 winter heating season. Absent implementation of the Distributed Infrastructure Solution proposed in this Filing, the Companies anticipate seeing a gap emerge between peak period gas demand and Existing Capacity (the "Demand-Supply Gap") as soon as the 2022-2023 heating season and continue to grow to a gap of 518 MDth/Day in 2035-2036.[14]

D. The Distributed Infrastructure Solution

1. An Overview of the Solution

Last year, in its Long-Term Capacity Reports, 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. The Distributed Infrastructure Solution is composed of incremental DSM programs (EE, DR, Electrification, and Third Party Solutions), along with distributed infrastructure components: LNG vaporization, the Iroquois Enhancement by Compression project ("ExC Project"), and incremental portable CNG Capacity.

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 by 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 such that no additional infrastructure projects beyond the LNG Vaporization Project and

[14] The demand referenced is based upon the Adjusted Baseline Demand Forecast. Full details of the gas demand forecast and the demand-supply gap can be found in Section 4, "Planning for Reliability/Meeting Customer Needs," of the Second Supplemental Report.

ExC Project would be needed. The programs proposed in this Filing will meet near-term system needs while setting the trajectory toward these longer-term targets.

2. Existing Demand-Side Programs

National Grid's Adjusted Baseline Forecast already takes into account baseline EE, DR, and electrification, described below. The Companies, nevertheless, will face a peak demand-supply deficiency despite the existing, aggressive DSM programs currently deployed in downstate NY.

a. Existing Energy Efficiency Programs.

Although the Companies' existing energy efficiency programs under NE:NY are already incorporated into our demand forecast and are contributing to demand reduction, even more energy efficiency above the existing NE:NY targets will be required to close the gas capacity demand gap. The Companies' EE programs for the years 2019-2025, based on existing annual NE:NY budgets and targets, are contained in the latest *System Energy Efficiency Plans* ("SEEPs") filed in Case 18-M-0084. Based upon Commission-established NE:NY targets, the Companies' downstate NY gas efficiency targets increase significantly during the period 2020-2025, as illustrated in Table 2 below.

Table 2: National Grid's NE:NY EE Increase Percentages

Year	KEDNY Target Gas Savings Dth % Annual Increase	KEDLI Target Gas Savings Dth % Annual Increase
2020		
2021	16%	79%
2022	32%	39%
2023	27%	26%
2024	26%	26%
2025	24%	18%

With its Adjusted Baseline Demand Forecast, the Companies are fully accounting for the potential benefit of the above-identified EE on Design Day needs. Even these elevated levels of EE, however, do not bridge the forecast supply-demand gap.

To meet the targets established by the Commission in its January, 2020 Order in the NE:NY proceeding (Case 18-M-0084), which are already included in the demand forecast, the Companies would exhaust the entire budget allocated in the Order. The NE:NY budgets and targets were set based upon the Companies' historic energy efficiency program spend, rather than the long-useful-life, peak-coincident energy efficiency programs needed to reduce peak demand under Design Day and Design Hour conditions. Because the Companies are obligated not only to meet NE:NY metrics (measured by quarterly and annual Clean Energy Dashboard scorecard reports filed in 18-M-0084), but also to ensure customers are served safely and reliably during peak conditions consistent with the Companies' demand forecast (*e.g.*, to deploy DSM solutions which are more expensive on a dollar-per-therm basis), the Companies seek authority to accelerate spending of the previously authorized NE:NY funds. Further, the Companies request an adjustment to the Companies' targets in the NE:NY proceeding to enable a greater dollars-per-therm expended on the longer-useful-life, peak-coincident EE programs described herein. As documented in the benefit-cost analysis ("BCA") presented in this Filing, the incremental EE programs are anticipated to achieve a positive BCA in addition to supplanting the need for infrastructure projects and reducing billed energy usage.

b. Existing Demand Response Programs.

Demand Response refers to programs in which utility customers reduce or curtail usage in response to a signal from the program operator, either through an event-based or price-based signal. For over twenty years, National Grid has operated Gas Demand Response programs associated with specific service classifications and rates, collectively known as the non-firm service class. Between 2017- 2020, the Companies tested a Gas Demand Response pilot program[15] for large commercial firm service customers in the KEDNY and KEDLI service territories, to reduce their gas usage by a pre-determined amount when called upon ("event"), in exchange for a market-based credit. This pilot program, which concluded its three-year run on March 31, 2020, was one of the first offerings of firm demand response[16] (which had previously focused on electric customers) to gas customers. The initial purpose of the Demand Response Demonstration Project was to assess the effectiveness of voluntary peak reductions in terms of reducing intra-day demand and whether market-based credits will drive customer behavior to reduce consumption. This was

[15] Gas Demand Response Demonstration Project, which the Commission adopted in Cases 16-G-0058 and 16-G-0059 (the "2016 KEDNY and KEDLI Rate Cases")

[16] Firm demand response refers to programs that are offered to "firm" service customers (meaning programs for which the customer is on a "firm" rate under which utility remains obligated to provide gas service to that customer at all times). A firm customer, by enrollment in the DR program agrees to voluntarily curtail usage under stated conditions. In contrast, "non-firm" customers agree that the utility may curtail their service under agreed-upon conditions and generally receives a discounted rate.

later expanded to exploring aggregate system impacts and gaining a better understanding of how DR response can be scaled as a system management and planning tool.

Pursuant to the Order filed in Case 19-G-0678 on November 26, 2019, the Companies launched a set of three gas DR programs for the 2019-20 winter heating seasons to help reduce demand during periods of severe cold weather. These were described in the Companies' Implementation and Contingency Plan[17] and continued for the 2020-21 Winter heating season. These programs included an Expanded Demand Response ("Daily DR") program for large firm CI&MF customers, a BYOT program for residential and small commercial customers, and a Behavioral program for residential customers. An Hourly DR program was launched in 2021 for the 2021-2022 heating season.

3. Proposed Programs to Address the Capacity Gap

The Distributed Infrastructure Solution relies on the following four major Non-Gas Infrastructure Options: EE, DR, Electrification, and Third Party Solutions, all of which are presented as part of this Filing, with the focus in the initial years being EE and DR programs as the others ramp up:

- Incremental EE consists of strategies that provide savings over and above NE:NY annual targets, with programs and measures that prioritize demand reduction. The major focus of these incremental EE initiatives will be intensive weatherization programs, focused on Design Day thermal savings.

[17] 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, Implementation and Contingency Plan (filed October 19, 2019).

- Similarly, the Companies will implement expanded gas demand response programs that support Design Hour and Design Day requirements. DR programs will focus on reducing or curtailing customers' use of gas during Peak Day and Peak Hour conditions. Current programs will be refined and expanded, and new programs developed to encourage participation from all customer segments.
- In addition, the Companies will continue to promote heat Electrification as an alternative to existing natural gas customers or oil heating customers, while exploring a collaborative program with EDCs for future years.
- Beginning in 2021, the Companies will hold annual Third Party Solutions solicitations to determine whether the market can provide solutions that could assist the Company with delivering DSM more cost effectively than traditional utility program delivery.

4. *Proposed Filing Cadence*

Consistent with the Joint Proposal, the Companies will make an annual DSM filing each July presenting an evolving longer-term DSM vision and the proposed DSM programs, targets, and spending targets for the upcoming year. Each filing will contain such refinements as are necessary based on (1) changes to annual long term gas demand forecast, (2) the status of other components of the Distributed Infrastructure Solution, (3) technology advances or new business models, (4) learnings from implementing DSM in the prior years, and (5) any other relevant changes to circumstances, such as the ongoing COVID-19 pandemic. In this current annual DSM filing, the Companies present their planned programs and expenditures for the 2022-2023 heating season (corresponding with Rate Year 3).[18] (Although EE DSM programs will launch early in each calendar year to achieve the energy savings to mitigate heating season demand, DR programs are operated for the winter capability period, i.e. November 2022 – March 2023).

This annual DSM filing cadence will allow the Companies the flexibility to improve the efficacy and cost-effectiveness of their incremental DSM programs over time. An annual July DSM filing will best afford the Commission an opportunity to review the Companies' proposal reflective of the Companies' most recent (June) gas demand forecast. In Cases 20-G-0086 and 20-G-0087, the Companies were directed to submit Annual Reports detailing the operations and cost-effectiveness of their Firm DR Programs from the prior winter capability period on June 15 of each year, beginning on June 15, 2021.[19] The Companies request that this reporting obligation be subsumed within the annual DSM filing on July 1, consistent with the Joint Proposal. Costs for approved programs will be recovered through the Demand Capacity Surcharge Mechanism. Consistent with the Joint Proposal, quarterly update filings on progress and metrics toward the incremental EE and DR programs will be made in support of the Companies' recovery of the Demand Capacity Surcharge.[20]

Also consistent with the Joint Proposal, quarterly reports will be submitted following the end of each calendar quarter on the following metrics, which the Companies must meet in order to fully recover the costs of the Capital Capacity Projects (gas infrastructure projects the Companies

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[18] Program contents for 2021-2022 heating season DR programs were presented in the Companies' DR Implementation Plan filed on June 15, 2021 in Case 20-G-0086 and Case 20-G-0087, and budgets were established as part of the Joint Proposal. (See Joint Proposal, Sec. IV.3.22.2)

[19] "Order Directing Implementation Plan Filing, Annual Reporting, and Tariff Modifications" Directing Implementation Plan Filing, Annual Reporting, and Tariff Modifications submit Annual Reports.

[20] See, Joint Proposal, Section 5.3.5, page 52.

will undertake consistent with the Long-Term Capacity Report as necessary under the Plan A Scenario). The Energy Efficiency targets are based upon the programs described in this Filing, and Commission approval is requested for these incremental budgets and targets.

IV. THE PROPOSED PROGRAMS AND FUNDING LEVELS

A. Proposed Incremental Energy Efficiency

1. Incremental EE Longer-Term Strategy

Energy efficiency is and will continue to be a key component of the Companies' 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. To be clear, the Incremental EE programs are designed to achieve therm savings *over and* above the annual NE:NY targets set by the Commission on a company basis in January 2020. As discussed above, the Companies' Incremental EE programs, together with Incremental DR and the other DSM programs, are necessary to address the capacity supply-demand gap.

To achieve this level of EE, the Companies are building new program offerings beyond those designed to achieve the "base" NE:NY annual targets. This Incremental EE portfolio has been specifically tailored to reduce Design Day demand. Different programs and (generally speaking), higher incentive levels are needed to reduce peak demand than typical EE programs, which are designed to achieve year-round therm savings. The nature of these Incremental EE programs will be focused primarily on intensive weatherization measures. Budgets and targets for each program are presented below. The Companies will shift funds among programs within this EE portfolio, if necessary, to achieve Design Day goals, and to maximize cost-effectiveness of the portfolio.

2. Incremental Weatherization Programs

Weatherization is a key element of the incremental EE plan 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 the Companies do not currently offer weatherization programs in New York City or Long Island to market rate customers, weatherization programs do not conflict with the Companies existing EE portfolio. Utility peer benchmarking underscores the demand reduction value of weatherization programs.

The Companies are 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. The incentive levels for the incremental weatherization programs will be substantially higher than the typical incentive for the existing NE:NY energy efficiency programs. The NE:NY budgets and targets were based upon historic energy efficiency programs in New York which, in turn, were based on year-round therm savings, rather than peak day or peak hour savings. The capacity gap that the Incremental EE programs are designed to solve must be specifically designed with a high peak coincidence value (i.e. reducing peak energy demand on the system). The programs being proposed herein offer higher incentives, because weatherization itself requires building envelope improvements which can be quite costly -- high incentives are anticipated to be needed to enable customers to avail themselves of the programs.

- *Residential Weatherization.* The residential weatherization program will provide incentives to residential natural gas heating customers to make building envelope improvements to their 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. The Companies will encourage aggregators (“Program Partners”) 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 the Companies’ affiliate utilities’ programs in Massachusetts and Rhode Island and findings from peer benchmarking and weatherization customer survey work; however, these may evolve based on additional vendor and customer feedback after program launch. Customer education and marketing are critical elements of the program. The Companies will be using a thermal imaging technology behavioral tool vendor, MyHeat, to collect thermal imaging data to improve and personalize customer outreach. MyHeat’s technology utilizes aerial thermal imaging to reveal energy loss data for individual residential buildings across entire service territories, allowing the Companies 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 using 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 Program Partners will be selected (and provided a midstream incentive) to manage their own subset of trade allies to achieve the Companies' weatherization goals, and (4) oversee the work of, and provide quality assurance for, the Program Partners.

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 the aforementioned 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 Companies already have a robust education and marketing plan for their 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. The Companies seek to build on these efforts by leveraging experience from 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, the Companies are 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. The following programs will be ready to launch in Fall 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 set to drive customer adoption and participation. The Companies anticipate the incentives will be similar to programs launched this year. These customers represent a large portion of the C&I Sector. The Companies anticipate this program will be offered through a direct-install approach and/or prescriptive pathway to increase levels of participation. The Companies 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 the 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 the Companies' downstate NY service territories. Multifamily customers have a unique perspective and set of decision-making indicators. For example, occupant comfort is likely to be balanced against upgrade costs. The Companies 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 the 2022 portfolio.

- *Energy Efficient Connections:* Energy Efficient Connections represents strategies that focus on reducing gas demand by requiring new customers who request to convert to gas space heating to adopt energy efficiency measures prior to connection.[21] The Distributed Infrastructure Solution includes enhanced energy efficiency requirements for customers connecting to the gas system, and this program would provide incentive dollars to assist customers in achieving high levels of energy efficiency. Although current energy efficiency 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 new customers with the comfort and health benefits that the Companies' EE programs provide.

3. Low and Moderate Income Program Coordination

The Companies are not requesting accelerated funds for Low and Moderate Income ("LMI") coordination. The Companies' residential weatherization efforts, however, are anticipated to drive LMI customers to the Statewide Low- and Moderate-Income Portfolio Implementation Plan, LMI weatherization incentives, which are part of existing statewide programs in the Companies' Service Territories. For LMI owners and renters in 1-4 family buildings, the EmPower NY program delivers weatherization and home performance upgrades in the KEDNY service territory, and the HEAT program delivers weatherization and home performance upgrades in the KEDLI service territory. The US Department of Energy also offers a Weatherization

[21] Consistent with the Joint Proposal, the Companies have committed to cease actively marketing to promote new gas conversions. Customers will be referred to consider electrification prior to committing to conversion to gas heating.

Assistance Program ("WAP"). Where possible, low-income projects will be coordinated with WAP by participating contractors that are also WAP subgrantees.

For LMI Multifamily buildings, the Statewide Low- and Moderate-Income Portfolio Implementation Plan outline a transition plan to develop a new Statewide Affordable Multifamily Program. NYSERDA will focus on technical assistance offerings and discontinue incentive-based programs in service territories where utilities administer multifamily incentive programs within the consistent statewide framework. The Companies will be working with the Joint Utilities to develop this new statewide incentive-based program to be launched in 2021 and weatherization measures will be included.

MyHeat thermal imaging data collected will be provided to support the Companies' LMI program delivery teams in identifying homes of LMI customers with high heat loss and consumption. This imaging data will allow for targeted customer outreach and personalized offerings to LMI customers.

By dramatically expanding weatherization programs in downstate NY, the Companies will inherently reach numerous low- and moderate-income customers to promote and offer weatherization. The Companies intend to coordinate with existing LMI programs to maximize the uptake of weatherization programs (including LMI-specific incentives) among low- and moderate-income customers alongside the weatherization programs for non-LMI customers for which funding is proposed in this Filing. Given the existing transition phase of the Statewide LMI Portfolio, and existing statewide weatherization incentives and program funding for LMI customers through NE:NY, the Companies will not be requesting incremental targets and additional funding in this Filing specifically for LMI customers. To avoid program conflicts and overlaps, the Companies will not offer LMI-specific incentives as part of the Incremental DSM energy efficiency programs and will continue coordination with the LMI Joint Unity working group regarding LMI offerings in downstate NY Once the new statewide frameworks are finalized in 2021, the Companies will identify how they can leverage LMI funding and Incremental DSM energy efficiency funding in downstate New York collectively, to reach demand reduction goals, and to provide optimal energy efficiency programs and services for LMI customers.

4. Evaluation, Measurement and Verification ("EM&V")

To ensure accurate quantification of the energy and peak demand savings delivered by program measures, the Weatherization Programs will undergo rigorous Gross Savings Analyses.[22] At least one winter of post-installation billing data is required in order to calculate evaluated savings, and therefore the timing of the evaluation will depend on the rate at which customers enter the program in the first year. If the number of projects completed in 2021 is sufficient to produce statistically valid results, then the estimated completion of the initial Gross Savings Analysis Reports is by the fourth quarter of 2023. Additional methods will be explored to provide earlier indications of verified savings levels. The Companies will select an independent evaluator to perform the Gross Savings Analysis through a competitive bidding process. Details related to the Gross Savings Analysis methodologies will be submitted in an EM&V Plan by the second quarter of 2022. In addition to Gross Savings Analysis, the Companies will undertake one or more process evaluations. The process evaluations will enable program implementers to understand how customers are reacting to these new initiatives, identify any barriers that may be slowing adoption, and provide recommendations for improving performance.

[22] Gross Savings Analyses are evaluation studies performed by an independent evaluator to determine whether reported gross savings have been realized.

5. *Requested Incremental EE Targets and Budgets for 2021/2022 and 2022/2023 Heating Season*

The Second Supplemental Report details the savings associated with each of the proposed incremental EE programs described above in Section 5.3.4.1 "Incremental Energy Efficiency." Table 3 and Table 4 summarize the budget and targets for the incremental EE programs the Companies are proposing for heating season 2021/2022 and 2022/2023. These tables portray budgets and targets by calendar year ("CY") consistent with the Companies' SEEPs and the Long-Term Capacity Report, however the request for recovery through the Demand Capacity Surcharge Mechanism is on a rate-year basis to align with the Joint Proposal. [23]

Table 3: Incremental Energy Efficiency for Heating Season 2021-22 (CY 2021)

Calendar Year 2021 Programs	Costs			Savings	
KEDNY 2021	Non-Labor Costs	Labor Costs	Total Costs	Annual EE Savings (Dth)	Design Day Savings (Dth)
RESI Weatherization	$0	$194,521	$194,521	2,750	36
C&I and MF Weatherization	$0	$285,991	$285,991	2,750	36
RESI Energy Efficient Connections	$0	$0	$0	-	-
C&I and MF Energy Efficient Connections	$0	$0	$0	-	-
Total KEDNY	**$0**	**$480,512**	**$480,512**	**5,500**	**72**

[23] EE programs budgets and targets are listed in calendar year, given that EE must be completed by end of each calendar year to align with heating season needs. Weatherization Programs (Non-Labor Costs) for 2021 will be funded using existing NE:NY budget and incremental budget is not needed. In 2021, $1,750,833 is budgeted in KEDNY and $1,432,500 is budgeted in KEDLI for the two Weatherization Program listed launched in September 2021. Labor Costs refer to National Grid's internal labor costs and have been converted to Calendar Year.

KEDLI 2021	Non-Labor Costs	Labor Costs	Total Costs	Annual EE Savings (Dth)	Design Day Savings (Dth)
RESI Weatherization	$0	$159,154	$159,154	2,250	30
C&I and MF Weatherization	$0	$233,993	$233,993	2,250	30
RESI Energy Efficient Connections	$0	$0	$0	-	-
C&I and MF Energy Efficient Connections	$0	$0	$0	-	-
Total KEDLI	**$0**	**$393,147**	**$393,147**	**4,500**	**59**

Table 4: Incremental Energy Efficiency for Heating Season 2022-23 (CY 2022)

Calendar Year 2022 Programs	Costs			Savings	
KEDNY 2022	**Non-Labor Costs**	**Labor Costs**	**Total Costs**	**Annual EE Savings (Dth)**	**Design Day Savings (Dth)**
RESI Weatherization	$20,583,750	$333,218	$20,916,968	110,550	1,456
C&I and MF Weatherization	$14,586,647	$661,623	$15,248,270	110,550	1,456
RESI Energy Efficient Connections	$4,085,533	$0	$4,085,533	19,319	254
C&I and MF Energy Efficient Connections	$0	$0	$0	-	-
Total KEDNY	**$39,255,930**	**$994,841**	**$40,250,771**	**240,419**	**3,167**
KEDLI 2022	**Non-Labor Costs**	**Labor Costs**	**Total Costs**	**Annual EE Savings (Dth)**	**Design Day Savings (Dth)**
RESI Weatherization	$16,841,250	$272,633	$17,113,883	90,450	1,191
C&I and MF Weatherization	$11,934,529	$541,328	$12,475,857	90,450	1,191
RESI Energy Efficient Connections	$4,304,306	$0	$4,304,306	26,582	350
C&I and MF Energy Efficient Connections	$0	$0	$0	-	-
Total KEDLI	**$33,080,085**	**$813,961**	**$33,894,046**	**207,482**	**2,733**

6. *Full Time Employee ("FTE") Needs for the 2021-2022 and 2022-2023 Heating Season*

Because of the rapid pace and scale of the Distributed Infrastructure Solution, the Companies require incremental internal labor resources to develop, launch, implement and manage these additional EE programs. In the Companies' most recent Rate Case, the Joint Proposal provided for a number of FTEs for EE programs. These employees are dedicated to running "base" NE:NY programs directed in Case 18-M-0084, and therefore the Companies must request and engage *additional* employees to run the Incremental EE programs. These programs, which are nation-leading, require active oversight and creative design to ensure their success with downstate NY customers at scale. Specifically, the Companies are requesting cost recovery for FTEs that will enable program development and execution:

- Product Owners (2 FTEs beginning Rate Year 2)
- Program Manager (2 FTEs beginning Rate Year 2, and 1 FTE beginning Rate Year 3)
- Procurement Analyst (0.5 FTE beginning Rate Year 2)
- Marketing Analyst (2.5 FTEs beginning Rate Year 2)
- EMV Analyst (1 FTE beginning Rate Year 2)
- Technical Sales and Support Engineer (2 FTEs beginning Rate Year 2, and 1 FTEs beginning Rate Year 3)
- Sales Representative (1 FTEs beginning Rate Year 2, and 1 FTEs beginning Rate Year 3)

B. Proposed Incremental Demand-Response

1. Incremental DR Longer -Term Strategy

As part of an agreement to lift the gas moratorium and connect additional customers to the gas system in late 2019, the Companies launched a set of three new DR programs for the 2019-2020 and 2020-2021 winter seasons. The largest of these programs focuses on achieving verifiable reductions in gas load for an entire day, a "load-shedding" DR program, with the other two focused on "load-shifting." While still relatively novel, these programs have shown promising results for achieving Peak Day and Peak Hour gas reductions. Based on that potential, the Companies are seeking to utilize DR to address future gas system supply gaps, as described in the Long-Term Capacity Report.

2. The Proposed Programs

The Companies will deploy a suite of gas DR programs, designed to meet several distinct system needs and to maximize contributions of multiple customer classes. Three of these programs have previously been deployed for the 2020-2021 heating season and are being proposed to continue, in an expanded manner, with modifications informed by experience with past seasons' programs, research and customer feedback. The peak period ("Hourly") DR program was newly proposed in the Companies' most recent rate proceeding and is being implemented beginning in the 2021-22 heating season, consistent with the Joint Proposal. The Companies are proposing four distinct DR programs for the 2021-22 heating season and beyond:

- A Daily DR load-shedding program geared toward large, firm CI&MF customers that possess the ability to substantially curtail some or all quantities of their peak day gas loads. Although the program is geared towards peak day gas reductions, it also serves dual roles in addressing peak hour gaps based on the program's event window.
- A Peak Period DR (also referred to here and elsewhere as "Hourly DR") load-shifting program for CI&MF customers that can reduce gas consumption during the gas system's peak hours. This program is being introduced in the 2021-2022 heating season, with learning from past DR programs including the pilot Gas Demand Response Demonstration Project.
- A BYOT program for Residential and Small-to-Medium Business ("SMB") customers. In this program, customers allow the Companies to remotely dial back the temperature setpoints of wi-fi connected thermostats for a period of a few

hours coincident with KEDNY's and KEDLI's expected system peaks. Customers will retain the ability to opt out of events to override the temperature setback; doing so too often will impact their ability to receive incentives. As with the Hourly DR program, this BYOT program is primarily intended to address peak hour gaps.

- A non-incentivized Behavioral DR load-shifting program for Residential and Small Commercial customers who have not opted out of receiving communications from National Grid. This program will send messaging to a large number of customers during peak winter days ("Cold Weather Alerts") with suggestions on ways to lower gas consumption to save money and help the Companies manage their respective systems. In addition to alerting customers to incoming cold weather and offering tips on ways to reduce gas consumption during the peak event times of 6-10AM, these alerts also provide a platform for the Companies' other clean energy programs such as Energy Efficiency, BYOT DR, heat pump conversions, and weatherization programs.

The Companies also anticipate introducing new programs and pilot offerings based on learning from prior years and future customer needs.[24]

The figures shown below represent the Companies' delivered savings goals. The Companies base target enrollment on the assumption that not all customers enrolled will perform at 100 percent of the agreed-upon curtailment during an event. Therefore, the Companies'

[24] With the exception of the programs described above, at this time, the Companies are not proposing new programs and pilots as part of this filing, but envision new program offerings in future filings.

enrollment targets are greater than the delivered savings goals. The Companies apply a factor to ensure the amount of peak reduction needed is actually achieved ("reliability factor"). Predictive modeling is used to determine the reliability factor.[25] For programs that utilize period *load-shifting* programs (Hourly DR, BYOT, and Behavioral DR Programs), in addition to applying a reliability factor to customer enrollment numbers, these programs also account for customer usage patterns. Based on the data gathered during the upcoming winter capability seasons,[26] the Companies' reliability factor may be adjusted in either direction.

The DR program goals are based on the DR contributions to the Plan A Scenario in the Long-Term Capacity Report, as calculated based on Companies' June 2020 long term gas demand forecast.[27] The Companies have developed an aggressive ramp-up in DR programs that scales at a pace so that the Companies will be positioned to meet the significant Design Day long-term supply demand gap. Importantly, if any of the planned infrastructure projects outlined in the LTCR are unable to be placed into service at the scheduled dates, DR may be a critical resource called upon to help fill the gap. The Companies have planned for significant DR over the course of the next five years using the programs outlined herein to help address anticipated Peak Day and Peak Hour deficiencies. The projected peak demand reduction goals for the next five years are identified

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[25] The Companies expect that under multi-day Design Day conditions, DR resources will not be able to reliably deliver every dekatherm of gas reduction committed in the programs. For this reason, the Companies gross up their respective delivered need by a Reliability Factor to arrive at the necessary Enrolled quantity for a given season. With little history on customer performance under multi-day Design Day conditions, the Companies have estimated the Reliability Factor for commercial and industrial DR resources as 60 percent. Factors impacting reliability include but are not limited to: individual customer variability in performance, relative weather conditions of day, event fatigue, customer mix such as the presence of process loads and co-generation loads, direct load control ("DLC") and external factors (*e.g*. holidays).

[26] Mild weather conditions and lack of Design Day conditions to date have meant an absence of observed data.

[27] The gas demand forecast is continually updated and therefore, the Company's Delivered DR goals are subject to update accordingly, to align with the supply-demand gap.

in Table 5, below. Although the DR planned for each winter capability period will vary depending on multiple factors,[28] the projections in Table 5, below, portray the scale, size and urgency to ramp up the programs aggressively and build a bridge to the future with unprecedented levels of DR in downstate NY.[29]

Table 5: Projected Design Day DR Load Reduction Savings Goals ("Delivered DR")

DR Goals	Units	2021-22	2022-23	2023-24	2024-25	2025-26
Peak Period DR	MDth/Hour	0.15	0.60	0.90	1.20	1.50
BYOT	MDth/Hour	0.08	0.17	0.25	0.33	0.41
Behavioral DR	MDth/Hour	0.02	0.02	0.02	0.02	0.02
Daily DR	MDth/Day	14.40	36.00	38.25	40.50	42.75

The Companies anticipate filing an annual DR Implementation Plan and Annual Report on July 1 of each year as part of the Demand-Side Management Filing. The Annual Report will provide the results and costs of the prior winter's programs, while the Implementation Plan will focus on the aims and provide details on the operational characteristics of the programs for the following winter season.[30] The programs offered, along with the respective enrollment levels, rules and incentive rates, will be subject to adjustments as needed. To the extent possible, the Companies will strive to maintain consistency in DR program offerings, however updates and changes will be

[28] These factors include the Companies' revised gas demand forecasts, dynamic market conditions, and customer needs.

[29] At this time, the Companies are not reporting enrollment target values for future years. The Companies will use past season learning to develop enrollment values that reflect the best assumptions as to the reliability factor for upcoming seasons.

[30] On June 15, 2021, as required by the "Order Directing Implementation Plan Filing, Annual Reporting and Tariff Modifications", dated October 15, 2020 in Case 20-G-0086 and Case 20-G-0087, KEDNY and KEDLI filed an Implementation Plan for the 2021-22 winter season. Additionally, on July 8, 2021 the Companies filed their first Annual Report detailing the results from the 2020-21 prior winter season.

necessary to reflect program performance, changing technologies and system needs. The updates will be based upon the most recent demand forecast, which is available in June of each year.

In order to recover costs of the Long-Term Capital Capacity projects during the term of the rate plans, the Companies must meet specific enrollment targets. Table 6 below represents these the peak day load reduction enrollment quantities.

Table 6: Design Day DR Enrollment Targets (DR Requirements for Capacity Demand Metrics)

DR Targets (MDth/D)	2021-22	2022-23	2023-24	2024-25	2025-26
Daily DR	19.57	21.53	23.68	N/A	N/A

3. EM&V Plan

The Companies currently evaluate their programs using in-house resources, as described below, but may seek additional resources to support external program or impact evaluations in future years (meaning Rate Year 3, April 1, 2022 – March 31, 2023, and beyond). The past winters saw limited instances of colder than normal temperatures, and no periods of severe cold snaps around which Gas DR programs are designed. This has limited the Companies' ability to observe the performance of the DR resources under near-Design Day conditions. On the other hand, the winters did provide a good opportunity to engage customers, test the capabilities of the early-stage Residential programs, conduct market research, and refine program operations and administration. Even during years where an actual DR Event was not called, the Companies have called Test Events to measure an estimate of participants' likely performance in the case of an actual event. Test Events are operated, paid, and counted as Program events with the exception that such events are exempt from the DR Event Threshold temperature criteria. For the 2021-2022 winter, the Companies propose to conduct up to two Test Events at their discretion for the CI&MF segment customers. In the most recent Implementation Plan filed with the Commission detailing proposals for the 2021-2022 winter capability season, as well as the Annual Report summarizing the 2020-2021 season results, the Companies outline customer and event performance analysis methodologies, as well as results for past events.[31]

In addition to the evaluation methodologies the Companies currently use for operational purposes for calculating incentives and reporting, the Companies may undertake an external impact evaluation during Rate Year 3 (April 1, 2022 – March 31, 2023) to verify the Peak Day and Peak Hour gas reductions delivered by program interventions and validate the estimates of program impacts.[32] In addition to the impact evaluation, external process evaluation strategies may also be utilized to help understand customer acceptance of the programs, identify any barriers that may be affecting adoption, and provide recommendations for improving the performance of these newly implemented programs.

4. Requested Incremental Program Costs, FTEs and Targets

The Companies' Joint Proposal established the cost recovery mechanisms for the Companies' firm gas demand response programs.[33] A separate means of funding was approved for

[31] Case 20-G-0086 and Case 20-G-0087.

[32] The Companies would select an independent evaluator to perform the evaluations through a competitive bidding process. The funds for this third-party evaluation work are reflected in the Rate Year 3 budget in Table 8, below.

[33] Before launching the shareholder-funded DR programs in late 2019, as part of the 2019 KEDNY and KEDLI rate cases, the Companies had requested Commission approval and funding provisions to expand the Demand Response Demonstration Project. This request was approved in the Joint Proposal; the Demand Response O&M Component ("DROM") included in the Delivery Rate Adjustment provided a separate mechanism for the Companies to recover the costs of the Hourly DR program. Labor costs for the Hourly DR Program will be recovered under the Demand Capacity Surcharge Mechanism.

non-labor costs of the Hourly DR Program.[34] Costs for the remaining three DR Programs are proposed to be recovered through the Demand Capacity Surcharge Mechanism. Specifically, this Filing seeks approval to surcharge the labor and non-labor costs of the Daily DR Program, BYOT program and Behavioral program, and labor costs for the Hourly program in the manner specified herein.

For the 2021-2022 season, subject to Commission approval of the Firm DR Implementation Plan and Firm DR Tariff Amendments in Cases 20-G-0086 and 20-G-0087, the Companies will operate all four DR programs as described above and in the DR Implementation plan.[35] The Companies anticipate filing an Implementation Plan for the 2022-2023 heating season in Summer 2022. The four programs will serve as the base for designing DR products for future seasons.

As of the time of this Filing, the Companies are in the process of enrolling customers for the 2021-2022 winter heating season, while enrollment into the BYOT program is year-round. Should actual costs come in above the amounts identified here at the end of Rate Year 2 (based upon enrollment levels and factors not within the Companies' control such as weather and customer behavior), the Companies propose to request the additional amount in the subsequent annual DSM filing to be recovered through the DCSM. Similarly, if actual costs come in below the amounts presented here at the end of the season, the Companies will true-up the amounts

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[34] Case 19-G-0309, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service*, Case 19-G-*0310 Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corp. d/b/a National Grid for Gas Service*, and Case 18-M-0270, *Petition for Approval Pursuant to Public Service Law Section 113(2) of a Proposed Allocation of Certain Tax Refunds Between KeySpan Gas East Corporation d/b/a National Grid and Ratepayers*, Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements (issued and effective Aug. 12, 2021) at p.168; Joint Proposal, Sec IV.7.3.

[35] The Implementation Plan describes program offerings and options, operational characteristics, incentive payment levels, customer eligibility criteria, and such other relevant details for the 2021-2022 heating season.

requested, and the request for the "remaining 50%" of costs for the applicable rate year will reflect only actual costs spent.

Currently, the largest Demand Response program the Companies operate is the Daily DR program, both in terms of costs and load reduction commitments. At the end of a winter capability season, Daily DR program costs may depend on a variety of factors such as total load enrolled into the programs, new customer enrollments that may drive operational costs, program options chosen during enrollment, number of events called (which are also driven by temperature) and event duration, and customer performance. Given the uncertainty surrounding the cost model inputs, the Companies have used a probability-based simulation model to forecast Daily DR costs for the near term 2021-2022 winter season. Utilizing near-term enrollment trend information as inputs, the Companies analyzed the range of possible costs and their likelihood. Based on this model, the Companies are reporting 2021-2022 season costs for the Daily DR program at the 95th percentile, meaning that in 95 percent of scenarios run in the probability model, costs came in less than or equal to the values reported here. Program costs reflected in this filing reflect assumptions based on the Companies' experience with the Demand Response programs in prior seasons, potential future program design updates, as well as other relevant information such as learning from electric DR programs, customer insights, and research.[36]

In addition to program costs, the Companies will also need to increase the number of employees devoted to DR programs. Previously, KEDNY and KEDLI (in rate cases 19-G-0309 and 19-G-0310 respectively), had requested funding for a limited number of FTEs, for the purpose

[36] For Rate Year 2, the Companies have also utilized near-term enrollment trend information when modeling Daily DR program costs.

of expanding the Gas Demand Response Demonstration Project. Two FTEs were approved in the Joint Proposal and included in base rates. Since then, due to the rapid pace and scale of the Distributed Infrastructure Solution, the Companies require incremental internal labor resources. At this time, the Companies are requesting funding *only for the incremental FTEs that have been identified since the Joint Proposal as critical to the implementation of the Distributed Infrastructure Solution*. The Companies have already hired a number of the incremental FTEs for Rate Year 2 in order to create the program materials, incentives, and enroll customers in time for winter 2021-22 (Rate Year 2). The Companies seek to hire additional FTE's as they expand the Demand Response programs over the coming years. Specifically, the Companies are requesting cost recovery for the following FTEs:

- DR Program Manager (1 FTE for Rate Year 2)
- Sales & Solutions - DR Program Manager (2 new FTEs beginning Rate Year 3)
- Marketing - Marketing Support (0.5 FTE beginning Rate Year 2)
- Metering - Metering Tech (1 FTE beginning Rate Year 2 and 1 FTE beginning Rate Year 3)
- Metering – Metered Data Services Role (1 FTE beginning Rate Year 2 and 1 FTE beginning Rate Year 3)
- Metering - Meter Upgrade Team (1 FTE beginning Rate Year 2)

5. *Funding Needs and Targets for 2021-2022 and 2022-2023 Heating Season*

Tables 7 and 8 summarize the funding needs and program targets for the incremental DR programs being proposed for heating season 2021-2022 and 2022-2023 to be recovered through the Demand Capacity Surcharge Mechanism. Heating season 2021-2022 costs are based on assumptions outlined in prior sections, with savings reported here based on programmatic goals for the season, while the 2022-2023 heating season targets (and cost forecasts) are likely to be adjusted to reflect changes to the Companies' demand forecast. Actual dollars spent on DR program incentive payments each year and reductions achieved will be dependent on factors outside the Company's control as outlined above, including weather and customer behavior.

Table 7: DCSM - Demand Response for Heating Season 2021/2022

Fiscal Year 2022	Costs			Delivered Savings	
KEDNY FY 2022	**Non-Labor Costs**	**Labor Costs**	**Total Costs**	**Design Hour Savings (Dth)**	**Design Day Savings (Dth)**
Daily DR	$4,200,000			1260	10080
BYOT	$194,250			58	76
Behavioral	$14,000			11	-
Hourly DR					
Vendor (EM&V/Marketing etc.)					
Total KEDNY	**$4,408,250**	**$485,940**	**$4,894,190**	**1,328**	**10,156**
KEDLI FY 2022	**Non-Labor Costs**	**Labor Costs**	**Total Costs**	**Design Hour Savings (Dth)**	**Design Day Savings (Dth)**
Daily DR	$1,800,000			540	4320
BYOT	$83,250			25	33
Behavioral	$6,000			5	-
Hourly DR					
Vendor (EM&V/Marketing etc.)					
Total KEDLI	**$1,889,250**	**$208,260**	**$2,097,510**	**569**	**4,353**

Table 8: DCSM – Demand Response for Heating Season 2022/2023

Fiscal Year 2023	Costs			Delivered Savings	
KEDNY FY 2023	**Non-Labor Costs**	**Labor Costs**	**Total Costs**	**Design Hour Savings (Dth)**	**Design Day Savings (Dth)**
Daily DR	$8,400,000			3,150	25,200
BYOT	$420,000			116	152
Behavioral	$14,700			11	-
Vendor (EM&V/Marketing etc.)	$140,000				
Total KEDNY	**$8,974,700**	**$851,270**	**$9,825,970**	**3,276**	**25,352**
KEDLI FY 2023	**Non-Labor Costs**	**Labor Costs**	**Total Costs**	**Design Hour Savings (Dth)**	**Design Day Savings (Dth)**
Daily DR	$3,600,000			1,350	10,800
BYOT	$180,000			50	65
Behavioral	$6,300			5	-
Vendor (EM&V/Marketing etc.)	$60,000				
Total KEDLI	**$3,846,300**	**$364,830**	**$4,211,130**	**1,404**	**10,865**

C. Incremental Electrification

1. Incremental Electrification Longer-Term Vision

In March 2021, the Companies started the process to support the heat Electrification programs run by the two EDCs in their respective service territories; Consolidated Edison Company of New York, Inc. ("Con Edison") and PSEG-Long Island (which operates the system owned by the Long Island Power Authority ("LIPA") (collectively "PSEG-LI/LIPA"), through a Lead Referral process, meant to educate customers in the Companies' respective service territories of their heat electrification options. Customers who call the Companies to connect new gas service or expand existing gas service are now asked if they are interested in learning more about alternatives to gas. The Companies then direct interested customers to Con Edison's or PSEG-LI/LIPA's Electrification programs. The Companies have been working with the EDCs to ensure that interested customers are directed to the appropriate EDC resources and contacts. The

Companies' recently approved Joint Proposal contains lead generation targets the Companies must achieve for referrals to both Con Edison and PSEG-LI/LIPA 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 percent 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 KEDLI's territory. The Companies are working 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.

Electrification incremental to Con Edison's NE:NY targets and PSEG-LI/LIPA's Electrification program (which together constitute "Baseline Electrification") is a key component of the Companies' gas long-term DSM strategy, as outlined in the Second Supplemental Report. Although costly at present, Electrification is one of the most powerful strategies for advancing the pathway toward Net Zero and closing the Demand-Supply Gap. In the Companies' current long-term scenarios, after the mid-2020s, Electrification will become 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 will 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.

The Companies are requesting resources and technical support services through this DSM filing to support the ongoing work of developing the incremental Electrification program. Collaboration will be an integral part of an incremental heat electrification program's success, and the Companies are already working with the EDCs to envision program design. 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 Electrification. The Companies plan on exploring potential pilot(s) in collaboration with the EDCs and other industry partners and build upon the development and coordination efforts to date. 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 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 Electrification such as workforce development, in collaboration with existing EDC and statewide initiatives
- Pursuing studies to reveal new solutions and strategies
- Negotiating cost/savings sharing and reporting protocols with the EDCs
- Determining incentives required for accelerated Electrification of heat required for LMI customers and environmental justice zones

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

The levels of incremental energy efficiency and Electrification beyond 2025 assumed as part of the Distributed Infrastructure Solution are aspirational due to the unprecedented levels required. At this moment, the Companies 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. The Companies are committed to finding solutions, innovating and collaborating as part of our ongoing DSM efforts in downstate NY.

2. *Requested Incremental Electrification Targets and Budgets for 2022/2023 Heating Season*

For calendar year 2022, the Companies are requesting incremental funding for one full-time employee (Product Developer) to (1) manage studies conducted, (2) design an incremental electrification pilot(s) plan to launch in 2023, and (3) act as a liaison to EDCs and other industry partners throughout the initiatives in development. The Companies will also be requesting $350,000 in 2022 to perform studies required to prepare for an incremental electrification program pilot.

Tables 9 and 10 below summarize the budgets and targets for the incremental electrification initiatives proposed for heating season 2021/2022 and 2022/2023[37].

[37] No savings are listed at this time as current budget are for studies for future pilot development planned in CY 2023. Electrification programs budgets and targets will be listed in calendar year, given that Electrification must be completed by end of each calendar year to align with heating season needs.

Table 9: Incremental Electrification for Heating Season 2021/2022

Calendar Year 2021	Costs		
KEDNY 2021	Non-Labor Costs	Labor Costs[38]	Total Costs
Total KEDNY	**$0**	**$31,753**	**$31,753**
KEDLI 2021	Non-Labor Costs	Labor Costs	Total Costs
Total KEDLI	**$0**	**$25,988**	**$25,988**

Table 10: Incremental Electrification for Heating Season 2022/2023

Calendar Year 2022	Costs		
KEDNY 2022	Non-Labor Costs	Labor Costs[39]	Total Costs
Total KEDNY	**$192,500**	**$76,230**	**$268,730**
KEDLI 2022	Non-Labor Costs	Labor Costs	Total Costs
Total KEDLI	**$157,500**	**$62,370**	**$219,870**

D. Market Solicitation for Non-Pipe, Third Party Solutions

1. Program Description

Within the calendar year, the Companies are planning to solicit competitive offers from gas customers and market actors, as a further source of demand-side solutions to address the Design Day and Design Hour system constraints identified herein, through a formal Request for Proposals ("RFP") process. This Third Party Solutions RFP process will allow energy efficiency developers market to suggest innovative resources and programs that can supplement traditional approaches, accelerate scale-up, and drive down the cost of demand-side solutions to meet Design Day and Design hour needs.

[38] Market reference point.

[39] Market reference point.

This solicitation will specifically focus on the four counties of Long Island: Kings (Brooklyn), Queens, Nassau, and Suffolk. Solutions may target any demand-side customer segment. Due to parallel supply-side solicitation efforts and feedback from Staff, this exercise will exclude all supply-side resources (*e.g.*, RNG, CNG, LNG, Power-to-Gas, and Hydrogen). The Third Party Solutions may include permanent load reductions—in the form of energy efficient equipment or alternative energy sources like heat pumps; or temporary, multi-hour load reductions, including load shifting, thermal storage, fuel switching that meet the needs defined in the need statement of the RFP. Contracts and payments may last up to the life of the resource. The total scope of future Third Party Solutions solicitations is potentially quite large, limited primarily by solutions meeting relevant benefit-cost tests, and the size of the present and future system constraint.

The Companies participated in NYSERDA's REV Connect Program through a mini sprint activity to gather information about the solutions available in the market and capabilities of prospective bidders. The Companies are particularly interested in the opportunity to engage directly with some participants after they submit their responses. The Companies see this as an opportunity to understand in greater detail the potential of the offerings.

The Companies will use the REV Connect mini sprint process to prepare the capabilities, processes and tools to issue RFPs to manage system constraints, as well as to manage any solutions procured. The Companies envision further refinements to our strategy for Third Party Solutions over time, including exploring projects that could address localized, sub-system constraints and infrastructure alternatives, in addition to the initial focus on system-wide constraints. Prior to deploying Third Party Solutions, the Companies will provide the Commission the opportunity to review the proposed strategy in a future filing.

2. Requested Funding for Third Party Solutions Programs

As the Companies seek to develop their capability regarding identifying, analyzing, and implementing Third Party Solutions, they will need to hire additional FTEs that have different skillsets than existing FTEs. These employees will need to specialize in regulatory filings and compliance, procurement of solutions developed by third parties, understanding new technologies that are potentially deployed as part of a portfolio solution, and project management to implement these solutions, including the ability to work with customers who may be receiving a different solution (e.g. Electrification) in lieu of the gas service they had expected. Specifically, the Companies are requesting cost recovery for four FTEs that will develop and deploy demand-side Third Party Solutions. These four FTEs will consist of:

- Manager
- Regulatory/Reporting Lead
- Procurement Support
- Project Manager

Tables 11 and 12 summarize the budget and targets for these incremental electrification employees proposed for heating seasons 2021-2022 and 2022-2023.[40]

[40] No savings are listed for the Third Party Solutions solicitation process given that DSM solutions solicited through the Third-Party Solutions process, would fall under one or more of our existing EE, DR, or Electrification portfolios as new solutions.

Table 11: Incremental Third Party Solutions Labor for Heating Season 2021/2022

Fiscal Year 2022	Costs		
KEDNY FY 2022	Non-Labor Costs	Labor Costs	Total Costs
Total KEDNY	**$0**	**$281,429**	**$281,429**
KEDLI FY 2022	Non-Labor Costs	Labor Costs	Total Costs
Total KEDLI	**$0**	**$230,260**	**$230,260**

Table 12: Incremental Third Party Solutions FTEs for Heating Season 2022/2023

Fiscal Year 2023	Costs		
KEDNY FY 2023	Non-Labor Costs	Labor Costs	Total Costs
Total KEDNY	**$0**	**$373,479**	**$373,479**
KEDLI FY 2023	Non-Labor Costs	Labor Costs	Total Costs
Total KEDLI	**$0**	**$305,574**	**$305,574**

E. Incremental Employees Necessary for the DSM Solution

The incremental DSM programs require additional FTEs to implement. The following charts present the additional FTEs that the Companies believe are necessary to satisfy the needs of the DSM solutions being presented in this filing:

Table 13: Incremental Employees Necessary for DSM Solutions Summary

Fiscal Year Labor	Cumulative Headcount			Costs		
Total DSM Portfolio	FY 21	FY 22	FY 23	FY 21	FY 22	FY 23
Total Full-Time Employees	**8.5**	**20.5**	**23.5**	**$65,975**	**$2,578,250**	**$3,556,913**
KEDNY Portion	5.35	11.95	13.6	$36,286	$1,537,700	$2,079,176
KEDLI Portion	3.15	8.55	9.9	$29,689	$1,040,550	$1,477,737

Table 14: Incremental Employees Necessary for DSM Solutions Headcount per Program

Fiscal Year Labor	Cumulative Headcount		
RESI Weatherization	**FY 21**	**FY 22**	**FY 23**
Product Owner	1	1	1
Program Manager	1	1	2
Procurement Analyst	0.5	0.5	0.5
Marketing Analyst		1	1
EM&V Analyst	0	0.5	0.5
Total RESI Weatherization	**2.5**	**4**	**5**
KEDNY Portion (55%)	**1.375**	**2.2**	**2.75**
KEDLI Portion (45%)	**1.125**	**1.8**	**2.25**
C&I and MF Weatherization	**FY 21**	**FY 22**	**FY 23**
Product Owner	0	1	1
Program Manager	0	1	1
Marketing Analyst	0.5	1.5	1.5
EM&V Analyst	0	0.5	0.5
Technical Sales and Support Engineer	1	2	3
Sales Representative	0	1	2
Total C&I and MF Weatherization	**1.5**	**7**	**9**
KEDNY Portion (55%)	**0.825**	**3.85**	**4.95**
KEDLI Portion (45%)	**0.675**	**3.15**	**4.05**
Electrification	**FY 21**	**FY 22**	**FY 23**
Product Developer	0	1	1
Total Electrification	**0**	**1**	**1**
KEDNY Portion (55%)	**0**	**0.55**	**0.55**
KEDLI Portion (45%)	**0**	**0.45**	**0.45**
Third Party Solutions	**FY 21**	**FY 22**	**FY 23**
Manager	0	1	1
Regulatory Lead	0	1	1
Procurement	0	1	1
Project Manager	0	1	1
Total Third Party Solutions	**0**	**4**	**4**
KEDNY Portion (55%)	**0**	**2.2**	**2.2**
KEDLI Portion (45%)	**0**	**1.8**	**1.8**

Demand Response	FY 21	FY 22	FY 23
DR Program Manager - C&I	0	1	0
Sales & Solutions - DR Program Mgr	0	0	2
Marketing - Marketing Support	0	0.5	0.5
Metering - Metering Tech	0	1	2
Metering - MDS Role	0	1	2
Metering - Meter Upgrade Team	0	1	1
Total Demand Response	**0**	**4.5**	**7.5**
KEDNY Portion (70%)	**0**	**3.15**	**5.25**
KEDLI Portion (30%)	**0**	**1.35**	**2.25**

V. FIVE YEAR STRATEGY: PROJECTED INCREMENTAL DSM PROGRAM FUNDING LEVEL AND ASSOCIATED PEAK DEMAND REDUCTION

A. Overview of Programs and anticipated funding levels

In this Section, the Companies describe their longer-term vision for the DSM component of the Distributed Infrastructure Solution and the cost/benefit analysis that supports these programs.

The levels of DSM required to close the Demand-Supply Gap in the long term are unprecedented; in our peer benchmarking the Companies have found no other utility that has attempted to roll out DSM programs at this scale so rapidly. The Companies' 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. The 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. The programs, technologies, and business models that would be required to deliver such aggressive longer-term savings, however, do not yet exist. The Companies will continue to invest in the evolution of the DSM programs with the goal of maximizing their potential as non-infrastructure solutions and will use the annual DSM filing to request authority to recover for evolving DSM programs in future years.

Table 15 and 16 summarize the conceptual longer-term targets and budgets for the incremental DSM solutions. The Companies will use the Annual DSM filing to request the authority to recover for these programs in future years on an annual basis. This will provide flexibility to refine programs to improve efficacy and cost-effectiveness over time, while accounting for changes in the long-term Demand -Supply Gap.

Table 15: Incremental Demand Side Management Program Longer-Term Budgets Projections and Associated Peak Demand Reduction Projections

Costs	Heating Season				
KEDNY	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
Incremental Energy Efficiency*	$480,512	$40,519,500	$63,757,693	$76,788,261	$91,863,430
Demand Response	$4,894,190	$9,825,970	$10,587,243	$11,349,319	$12,112,223
Incremental Electrification and TPS	$313,192	$642,209	$449,709	$449,709	$449,709
Total KEDNY	**$5,687,894**	**$50,987,679**	**$74,794,645**	**$88,587,289**	**$104,425,362**
KEDLI	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
Incremental Energy Efficiency*	$393,147	$33,894,045	$59,908,289	$69,673,288	$83,505,768
Demand Response	$2,097,510	$4,211,130	$4,537,390	$4,863,994	$5,190,953
Incremental Electrification and TPS	$256,248	$525,444	$367,944	$367,944	$367,944
Total KEDLI	**$2,746,905**	**$38,630,619**	**$64,813,623**	**$74,905,225**	**$89,064,664**
Design Day Savings (MDTh)	**Heating Season**				
KEDNY	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
Incremental Energy Efficiency	0.07	3.20	5.47	6.56	7.95
Incremental Demand Response	10.16	25.35	27.00	28.65	30.31
Incremental Electrification and TPS	0.00	0.00	TBD	TBD	TBD
Total KEDNY	**10.23**	**28.55**	**32.47**	**35.22**	**38.26**
KEDLI	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
Incremental Energy Efficiency	0.06	2.75	4.83	5.82	6.96
Incremental Demand Response	4.35	10.87	11.57	12.28	12.99
Incremental Electrification and TPS	0.00	0.00	TBD	TBD	TBD
Total KEDLI	**4.41**	**13.62**	**16.41**	**18.10**	**19.95**

Table 16: Incremental Demand Side Management Budget Projections and Peak Demand Reduction Projections Summary for All Programs, By Operating Company

Costs	Heating Season				
Service Territory	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
KEDNY	$5,687,894	$50,987,679	$74,794,645	$88,587,289	$104,425,362
KEDLI	$2,746,905	$38,630,619	$64,813,623	$74,905,225	$89,064,664
Total	**$8,434,798**	**$89,618,298**	**$139,608,268**	**$163,492,515**	**$193,490,027**
Design Day Savings (MDTh)	**Heating Season**				
Heating Season	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
KEDNY	10.23	28.55	32.47	35.22	38.26
KEDLI	4.41	13.62	16.41	18.10	19.95
Annual Total	**16.64**	**42.17**	**48.88**	**53.31**	**58.21**
Cumulative Total	**14.64**	**58.61**	**107.49**	**160.80**	**219.01**

VI. BENEFIT-COST ANALYSIS ("BCA") FOR PROPOSED INCREMENTAL DSM PROGRAMS

To evaluate the proposed energy efficiency and demand response programs included in this filing, the Company engaged a third-party consultant to collaboratively develop a modeling tool. The programs were evaluated using the societal cost test ("SCT") as the BCA Order[41] positions the SCT as the primary cost-effectiveness measure for calculating benefits and costs of projects and investments because it evaluates the impact on society as a whole. Table 17 presents the resulting benefit cost ratio ("BCR") for the Companies' programs using the SCT, UCT and RIM cost-effectiveness tests. Appendix A provides definitions for each benefit and cost. Generally speaking, a BCA ratio greater than 1 indicates that the benefits exceed the costs to implement these programs; in some instances programs with a BCA lower than 1 may run where the program is the

[41] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV Proceeding)*, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (BCA Order).

best option to meet capacity constraints or for other policy-oriented reasons. Qualitative benefits not quantified in a BCA may be important drivers in this regard.

The BCA assessed the cost-effectiveness of each program, representing all benefits and costs. With respect to EE, the costs and benefits utilized to run the BCA included costs and benefits of the Companies' incremental EE programs. With respect to DR, the costs and benefits utilized to run the BCA included costs and benefits of the Companies' Daily DR Program, Hourly DR Program, BYOT Program, and Behavioral Program. Electrification was not included in the BCA because programs are still in development and costs are exclusively labor and study costs. Similarly, for Third Party Solutions, the only costs to date are labor costs to design and run solicitations. No specific projects are yet identified for which costs and benefits can be quantified, as solicitations haven't yet run.

Table 17: Portfolio BCR Results by Program Year

Benefit-Cost Test	2021/22	2022/23	2023/24	2024/25	2025/26
Societal Cost Test	3.69	1.16	1.18	1.178	1.19
Utility Cost Test	4.35	1.49	1.40	1.37	1.36
Ratepayer Impact Measure Test Ratio	3.60	0.74	0.68	0.65	0.64

VII. COST RECOVERY

A. Metrics

1. Overview

Table 18 below reflects the Capacity Demand Metrics the Company must meet in order to fully recover the costs of the Capital Capacity Projects. The Incremental EE targets are based upon the programs described in this Filing, and Commission approval is requested for these Incremental EE budgets and targets.

Table 1: Capacity Demand Metrics

<table>
<tr><th colspan="2">Capacity Demand Metrics
CY 2022-23 (EE, Electrification)
Fiscal Years 2021-23 (DR, TPS, LPP)</th><th>CY 2022 (EE, Electrification)
Fiscal Year 2021-22 (DR, TPS, LPP)</th><th>CY 2023 (EE, Electrification)
Fiscal Year 2022-23 (DR, TPS, LPP)</th><th>Weight</th></tr>
<tr><td rowspan="2">EE</td><td rowspan="2">Achieve NE:NY annual EE saving targets + achieve additional Incremental targets for Incremental EE programs</td><td>NE:NY: 866,813 Dth</td><td>NE:NY 1,149,013</td><td rowspan="2">25%</td></tr>
<tr><td>Incremental: 10,000 Dth</td><td>Incremental: 447,900</td></tr>
<tr><td>DR</td><td>Baseline of potential peak demand reduction from enrolled DR customers (17,790 Dth) + 10% escalation each year</td><td>19,569 Dth enrolled</td><td>21,562 Dth enrolled</td><td>15%</td></tr>
<tr><td rowspan="2">Electrification</td><td rowspan="2">Minimum number of prospective customers who are potential candidates for electrification referred to ConEd & PSEG-LI</td><td>DNY: 75 customers</td><td>DNY: 160 customers</td><td rowspan="2">15%</td></tr>
<tr><td>LI: 125 customers</td><td>LI: 260 customers</td></tr>
<tr><td>Non-Pipe/Third Party Solutions</td><td>At least 1 RFP each year seeking non-traditional, cost effective peak supply alternatives.</td><td>1 RFP issued</td><td>1 RFP issued</td><td>15%</td></tr>
<tr><td>Leak Prone Pipe NPAs[42]</td><td>Identify at least 5 segments of LPP that could be abandoned if all customers' natural gas loads are met with cost effective NPAs</td><td>5 segments of LPP</td><td>5 segments of LPP</td><td>15%</td></tr>
<tr><td>Failure to meet all 5 metrics</td><td></td><td></td><td></td><td>15%</td></tr>
</table>

2. *Energy Efficiency*

The Companies will meet the targets established by the Commission in the NE:NY Proceeding for energy efficiency (Case 18-M-0084) with the funding previously dedicated to meet those programs. In this Filing, the Company requests the targets to be achieved for the Incremental

[42] This workstream will be closely coordinated with the Third-Party Solutions program described in this Filing, however it will be undertaken by personnel not included in the incremental FTE request in this Filing.

EE programs be issued reflective of the proposed incremental budgets and targets for Rate Year 2 and Rate Year 3 as shown in Tables 3 and 4 above, and reflective of the associated dollar-per-therm rate for the longer-useful-life, peak-coincident programs the Companies are proposing in this filing.

3. Demand Response

The Joint Proposal establishes targets for commercial and industrial daily enrollment of 17,790 Dth which escalates by ten percent for each remaining year of the rate plans and provided authorization for budgets for the DR programs for Rate Years 2 and 3. The Companies hereby request the ability to surcharge the funding for their planned DR programs for Rate Years 2 and 3, which presently anticipate being able to achieve a higher level of peak demand reduction than these metrics in order to meet current projections of system demands and the necessary long-term ramp-up.

4. Third Party Solutions

Beginning in Rate Year 2, the Companies must annually issue at least one "RFP seeking nontraditional, cost effective peak supply alternatives. The Companies will report on the results of the RFP(s) as part of their annual Capacity Project filings with the Commission as described below. The Companies' request to surcharge funding for Third Party Solutions will enable one or more RFPs in Rate Year 2 and one or more RFPs in Rate Year 3 as part of the overall portfolio to meet the capacity demand gap.

5. Electrification

Beginning in Rate Year 2, the Companies will collaborate with Con Edison and PSEG-LI/LIPA regarding prospective customers who are potential candidates for Electrification. As set forth in the chart below, a minimum number of customers will be referred annually to Con Edison and PSEGLI/LIPA to determine if the customers are interested in electrification. The Joint Proposal directed the Companies to meet with Staff and other interested parties to develop referral materials, including any associated customer service scripts. The Companies were also directed to compile the data on the number of referrals to Con Edison and PSEG-LI/LIPA on an annual basis, and to undertake reasonable efforts to determine from customers whether Con Edison or PSEG-LI/LIPA have connected with the referred customers. The Companies were directed to make at least the number of referrals set forth below.

Table 19: Electrification Referral Targets 2

Year	Con Edison	PSEG-LI/ LIPA
2021	75	125
2022	160	260
2023	170	270
2024	180	280

B. Cost Recovery Mechanisms

1. Energy Efficiency Cost Recovery

For any Commission-approved EE costs not already included in base rates as described in the Joint Proposal, Section IV.7.1, Section IV.3.22.1 of the Joint Proposal provides that the Demand Capacity Surcharge Mechanism implemented in Rate Year 2 (fiscal year 2022) will enable the Companies to recover 50 percent of a forecast of incremental costs incurred in Rate Year 2. In all years following Rate Year 2, the Demand Capacity Surcharge Mechanism is to be designed to recover the difference between actual costs and the 50 percent of the remaining costs incurred in the previous Rate Year including carrying charges, as well as 50 percent of the costs forecast to be incurred in the year in which the Demand Capacity Surcharge Mechanism will be in effect. Given that this Filing is being made during Rate Year 2, this filing seeks EE cost recovery for both the Second and Third Rate Years pursuant to the Demand Capacity Surcharge Mechanism. As noted previously, the mechanism adopted in the Joint Proposal permitting 50 percent of anticipated costs to be recovered currently with the remaining 50 percent to be recovered in the following year, provides for the recognition of program experience, efficiency, cost savings and changes to the program.

With respect to EE, the Joint Proposal allows the Companies to recover the funds authorized for the entire NE:NY period more rapidly to assist with addressing the capacity issues identified herein and in Case 19-G-0678. Therefore, pursuant to the Joint Proposal, recovery of incremental EE program costs through the Demand Capacity Surcharge Mechanism is to be capped at the cumulative 2019-2025 budget, as adopted by the Commission in the NE: NY Proceeding, less previously recovered amounts and less the base NE:NY budget that is being recovered through base rates.[43] The Joint Proposal further provides that if, following the interim review scheduled to take place in the NE:NY Proceeding, the Commission authorizes additional budgets, the cap for the recovery of energy efficiency costs through the Demand Capacity Surcharge Mechanism will be updated accordingly.[44] Finally, the Joint Proposal provides that the Companies' annual Demand Side Management filings may seek to recover through the Demand Capacity Surcharge Mechanism incremental resources, including incremental internal labor and/or contractors, needed to implement Commission-approved energy efficiency programs.[45] The budgets and targets for these incremental energy efficiency programs presented above are therefore made pursuant to the

[43] Joint Proposal, Sec. IV.3.22.1.

[44] Id.

[45] Id.

Joint Proposal and, if approved, are authorized to be recovered by the Demand Capacity Surcharge Mechanism.

2. *Demand Response Cost Recovery Mechanisms*

With respect to DR costs, the Companies are permitted to recover through the Demand Capacity Surcharge Mechanism actual annual demand response spending in a manner similar to the EE recovery discussed above. The Joint Proposal provides that the Companies will be permitted to recover demand response program costs through two cost recovery mechanisms: the Demand Capacity Surcharge Mechanism[46] and the Demand Response O&M Component.[47] The Companies propose that the incentive costs associated with the following programs be recovered through the Demand Capacity Surcharge Mechanism:

- Daily DR
- BYOT
- Behavioral DR

In addition, as set forth above, the Companies also propose that the labor costs of the Daily DR, BYOT, Behavioral DR, and Hourly DR programs be recovered through the DCSM. The Joint Proposal established the amount of demand response spending eligible for recovery through the Demand Capacity Surcharge Mechanism for each Rate Year at the following levels:

[46] Joint Proposal, Sec. IV.3.22.2.

[47] Joint Proposal, Sec. IV.7.3.

Table 20: DR Demand Capacity Surcharge Mechanism Cap Amounts (in $ MM)

Year	Rate Year Two 21-22	Rate Year Three 22-23	Stayout Period 23-24
KEDNY	$ 4.90	$ 11.50	$ 13.50
KEDLI	$ 2.10	$ 4.90	$ 5.80
Total	**$ 7.00**	**$ 16.40**	**$ 19.30**

Demand Response programs and costs to be effective for the 2021-2022 Heating Season (Rate Year 2) were filed for approval with the Commission on June 15, 2021. These programs are expected to be addressed by the Commission in October 2021. Upon approval, the first 50 percent of the costs for this program in Rate Year 2 will be subject to the recovery through the Demand Capacity Surcharge Mechanism commencing December 1, 2021, based on the forecast of Rate Year 2 costs presented in this filing. The remaining 50 percent of the cost of the Demand Response program in Rate Year 2, which will be trued-up to actual costs at season end, with applicable carrying charges, and 50 percent of costs of the Rate Year 3 DR programs described herein for the following year, will be subject to Commission approval, and will be contained in the Demand Capacity Surcharge Mechanism commencing July 1, 2022. Although the Joint Proposal does not address them specifically, the costs presented above for Electrification and Third Party Solutions, if approved by the Commission as part of this Filing, should also be collected pursuant to the Demand Capacity Surcharge Mechanism in the same manner as the costs approved for Rate Year 3, *i.e.*, 50 percent of the costs recovered commencing July 1, 2022 with the remainder recovered in the surcharge for the following year.

3. Operation of the Demand Capacity Surcharge

The new Demand Capacity Surcharge Mechanism will be included in the DRA and will be supported by a statement setting forth the costs being collected and their relationship to specific

Long-Term Capital Capacity Projects. In addition, the Demand Capacity Surcharge Mechanism will be allocated among each Company's service classifications as follows:

(i) DR costs and the costs of Long-Term Capital Capacity Projects will be allocated based on peak daily sendout to all firm service classifications; and

(ii) EE costs will be allocated based on gas deliveries to all firm and non-firm service classifications. Residential programs will be allocated to residential customers and commercial and industrial programs will be allocated to all firm and non-firm, non-residential classes.

The first Demand Capacity Surcharge Mechanism statement will be filed to become effective 90 days after the issuance of a Commission order adopting the terms of this Joint Proposal, to be recovered through June 30, 2022. For subsequent years until the Commission next sets rates, the Demand Capacity Surcharge Mechanism will be filed to become effective on July 1, to be recovered over a twelve-month period ending June 30.

C. Total Cost and Customer Bill Impact

The bill impacts for the DSM programs, as surcharged via the DCSM, for Rate Year 2 (FY 2022-April 2021 - March 2022) and Rate Year 3 (FY 2023 April 2022 – March 2023) are presented below. The Companies' respective DCSM, effective December 1, 2021, assumes fifty-percent recovery of the Companies' FY 2022 Demand Response costs. The Companies' DSCM, effective July 1, 2022, assumes fifty-percent of FY 2022 Demand Response costs, fifty-percent of FY 2023 Demand Response costs, one hundred percent of FY 2022 Energy Efficiency costs and fifty-percent of FY 2023 Energy Efficiency, electrification and third party solution costs.

KEDNY Bill Impacts:

Table 21: KEDNY Fiscal Year 2022 (Rate Year 2) Costs – Bill Impact

Fiscal Year 2022 Costs Surcharge Effective December 1, 2021	Average Usage Per Customer	Delivery Bill	Delivery $ Change	Delivery Change %	Total Bill Change %
SC 1A - Residential Non Heat	9	$31	$0.01	0.05%	0.04%
SC 1AR - Residential Non Heat Reduced Rate (Tier 1)	7	$24	$0.01	0.05%	0.00%
SC 1B - Residential Heat	102	$107	$0.22	0.20%	0.13%
SC 1 BR - Residential Heat Reduced Rate (Tier 1)	96	$66	$0.20	0.31%	0.16%
SC 1B-DG - Residential Heat Distributed Generation	199	$76	$0.42	0.56%	0.21%
SC 2-1 - Non Residential Non Heat	680	$392	$1.16	0.30%	0.14%
SC 2-2 - Non Residential Heat	365	$292	$1.03	0.36%	0.20%
SC 3 - Heating and/or Water Heating Service (Multi-Family Buildings)	1,599	$807	$2.99	0.37%	0.17%
SC 4A - High Load Factor Service	34,750	$10,218	$32.70	0.32%	0.13%
SC 4A-CNG - Compressed Natural Gas Service	50,297	$14,232	$46.79	0.33%	0.13%
SC 4B - Year-Round Air Conditioning Service	1,374	$842	$2.65	0.32%	0.18%
SC 7 - Seasonal Off-Peak Service	299	$110	$-	0.00%	0.00%
SC21 - Baseload DG - Rate 1 Apr-Oct	32,553	$3,745	$16.77	0.45%	0.07%
SC21 - Baseload DG - Rate 1 Nov-Mar	32,553	$4,657	$16.77	0.36%	0.07%
SC21 - Baseload DG - Rate 2 Apr-Oct	32,553	$3,845	$16.77	0.44%	0.07%
SC21 - Baseload DG - Rate 2 Nov-Mar	32,553	$4,757	$16.77	0.35%	0.07%
SC21 - Baseload DG - Rate 3 Apr-Oct	1,365,662	$115,306	$703.69	0.61%	0.07%
SC21 - Baseload DG - Rate 3 Nov-Mar	1,365,662	$127,780	$703.69	0.55%	0.07%
Non-Firm Demand Response: Commercial / Government Tier 1	6,938	$1,538	$-	0.00%	0.00%
Non-Firm Demand Response: Commercial / Government Tier 2	6,938	$1,348	$-	0.00%	0.00%
Non-Firm Demand Response: MultiFamily Tier 1	6,938	$917	$-	0.00%	0.00%
Non-Firm Demand Response: MultiFamily Tier 2	6,938	$831	$-	0.00%	0.00%

Table 22: KEDNY Fiscal Year 2023 (Rate Year 3) Costs – Bill Impact

Fiscal Year 2023 Costs Surcharge Effective July 1, 2022	Average Usage Per Customer	Delivery Bill	Delivery $ Change	Delivery Change %	Total Bill Change %
SC 1A - Residential Non Heat	9	$32	$0.26	0.84%	0.71%
SC 1AR - Residential Non Heat Reduced Rate (Tier 1)	7	$24	$0.20	0.85%	0.00%
SC 1B - Residential Heat	102	$113	$3.17	2.89%	1.83%
SC 1 BR - Residential Heat Reduced Rate (Tier 1)	96	$72	$2.98	4.33%	2.32%
SC 1B-DG - Residential Heat Distributed Generation	199	$83	$6.18	8.09%	3.08%
SC 2-1 - Non Residential Non Heat	680	$409	$12.13	3.06%	1.48%
SC 2-2 - Non Residential Heat	365	$305	$7.99	2.69%	1.53%
SC 3 - Heating and/or Water Heating Service (Multi-Family Buildings)	1,599	$848	$31.22	3.82%	1.72%
SC 4A - High Load Factor Service	34,750	$10,682	$574.61	5.69%	2.27%
SC 4A-CNG - Compressed Natural Gas Service	50,297	$15,064	$822.04	5.77%	2.27%
SC 4B - Year-Round Air Conditioning Service	1,374	$882	$25.50	2.98%	1.71%
SC 7 - Seasonal Off-Peak Service	299	$111	$4.45	4.17%	2.05%
SC21 - Baseload DG - Rate 1 Apr-Oct	32,553	$4,309	$513.73	13.54%	2.13%
SC21 - Baseload DG - Rate 1 Nov-Mar	32,553	$5,237	$513.73	10.88%	2.06%
SC21 - Baseload DG - Rate 2 Apr-Oct	32,553	$4,409	$513.73	13.19%	2.13%
SC21 - Baseload DG - Rate 2 Nov-Mar	32,553	$5,337	$513.73	10.65%	2.05%
SC21 - Baseload DG - Rate 3 Apr-Oct	1,365,662	$137,650	$21,551.28	18.56%	2.23%
SC21 - Baseload DG - Rate 3 Nov-Mar	1,365,662	$150,264	$21,551.28	16.74%	2.20%
Non-Firm Demand Response: Commercial / Government Tier 1	6,938	$2,148	$103.37	5.06%	2.19%
Non-Firm Demand Response: Commercial / Government Tier 2	6,938	$1,869	$103.37	5.85%	2.33%
Non-Firm Demand Response: MultiFamily Tier 1	6,938	$1,205	$58.64	5.11%	2.23%
Non-Firm Demand Response: MultiFamily Tier 2	6,938	$1,079	$58.64	5.75%	2.34%

KEDLI Bill Impacts:

Table 23: KEDLI Fiscal Year 2022 (Rate Year 2)   Costs – Bill Impact

Fiscal Year 2022 Costs Surcharge Effective December 1, 2021	Average Usage Per Customer	Delivery Bill	Delivery $ Change	Delivery Change %	Total Bill Change %
SC 1A - Residential Non Heat	16	$42.85	$0.02	0.04%	0.03%
SC 1AR - Non Heat Reduced Rate (Tier 1)	11	$31.67	$0.01	0.04%	0.03%
SC 1B - Residential Heat	102	$102.19	$0.14	0.14%	0.09%
SC 1 BR - Heat Reduced Rate (Tier 1)	86	$56.14	$0.12	0.21%	0.11%
SC 1B DG - Residential Heat Distributed Generation	161	$65.56	$0.22	0.34%	0.14%
SC 2-A - Non-Residential Non Heat	522	$361.34	$0.31	0.08%	0.05%
SC 2-B - Non Residential Heat	461	$367.74	$0.62	0.17%	0.10%
SC 3 - Multiple Dwelling Service	2,615	$1,147.92	$3.33	0.29%	0.12%
SC 15 - High Load Factor Service for Cogeneration	11,522	$2,842.47	$6.10	0.21%	0.08%
SC 16 -Non Residential Year-Round Space Conditioning Service	45,931	$14,774.99	$34.71	0.24%	0.10%
SC 9 - Uncompressed Natural Gas Vehicle Service	29,283	$17,022.17	$11.22	0.07%	0.04%
SC 17 - Baseload DG - Rate 1- Apr - Oct	3,479	$733.78	$2.22	0.30%	0.08%
SC 17 - Baseload DG - Rate 1 - Nov - Mar	3,479	$884.38	$2.22	0.25%	0.08%
SC 17 - Baseload DG - Rate 2- Apr - Oct	3,479	$883.16	$2.22	0.25%	0.08%
SC 17 - Baseload DG - Rate 2 - Nov - Mar	3,479	$1,033.76	$2.22	0.22%	0.07%
SC 17 - Baseload DG - Rate 3- Apr - Oct	3,479	$96,016.40	$2.22	0.00%	0.00%
SC 17 - Baseload DG - Rate 3 - Nov - Mar	3,479	$96,064.15	$2.22	0.00%	0.00%
Non-Firm Demand Response: Tier 1	4,875	$752.08	$-	0.00%	0.00%
Non-Firm Demand Response: Tier 2	4,875	$990.51	$-	0.00%	0.00%

Table 24: KEDLI Fiscal Year 2023 (Rate Year 3) Costs – Bill Impact

Fiscal Year 2023 Costs – Bill Impact Surcharge Effective July 1, 2022	Average Usage Per Customer	Delivery Bill	Delivery $ Change	Delivery Change %	Total Bill Change %
SC 1A - Residential Non Heat	16	$44.22	$0.54	1.24%	1.02%
SC 1AR - Non Heat Reduced Rate (Tier 1)	11	$32.55	$0.37	1.16%	0.96%
SC 1B - Residential Heat	102	$108.63	$3.55	3.37%	2.14%
SC 1 BR - Heat Reduced Rate (Tier 1)	86	$61.85	$2.99	5.08%	2.71%
SC 1B DG - Residential Heat Distributed Generation	161	$71.16	$5.60	8.53%	3.46%
SC 2-A - Non-Residential Non Heat	522	$378.05	$11.26	3.07%	1.66%
SC 2-B - Non Residential Heat	461	$387.98	$11.00	2.92%	1.69%
SC 3 - Multiple Dwelling Service	2,615	$1,228.27	$62.63	5.37%	2.30%
SC 15 - High Load Factor Service for Cogeneration	11,522	$3,065.35	$247.61	8.79%	3.23%
SC 16 -Non Residential Year-Round Space Conditioning Service	45,931	$15,994.96	$1,009.96	6.74%	2.86%
SC 9 - Uncompressed Natural Gas Vehicle Service	29,283	$19,077.48	$620.57	3.36%	2.02%
SC 17 - Baseload DG - Rate 1- Apr - Oct	3,479	$807.54	$75.98	10.39%	2.71%
SC 17 - Baseload DG - Rate 1 - Nov - Mar	3,479	$957.79	$75.98	8.62%	2.57%
SC 17 - Baseload DG - Rate 2- Apr - Oct	3,479	$956.92	$75.98	8.63%	2.57%
SC 17 - Baseload DG - Rate 2 - Nov - Mar	3,479	$1,107.17	$75.98	7.37%	2.45%
SC 17 - Baseload DG - Rate 3- Apr - Oct	3,479	$96,090.16	$75.98	0.08%	0.08%
SC 17 - Baseload DG - Rate 3 - Nov - Mar	3,479	$96,137.91	$75.98	0.08%	0.08%
Non-Firm Demand Response: Tier 1	4,875	$1,275.23	$100.26	8.53%	3.33%
Non-Firm Demand Response: Tier 2	4,875	$1,885.67	$204.97	12.20%	3.77%

The costs displayed in Tables 21-24, above, reflect all the previously described DSM costs by rate year. In this regard, however, it should be recognized that these are projected costs at this time and that the actual timing of the surcharge aligns with the directives in the Joint Proposal, such that only 50 percent of the projected costs will be surcharged, with the remaining 50 percent of the costs surcharged in the year following the implementation of the programs. This process will ensure that only the actual costs of the programs (and not more) are surcharged to customers. This will also permit any efficiencies, new technologies and methods and savings from amounts projected to be reflected in the remaining, actual 50 percent of the total costs for any 12-month period.

Furthermore, although the Companies acknowledge that the costs of the programs and the associated bill impacts are not insignificant, it must also be acknowledged that the EE, DR and other programs are vitally important and, moreover and for a number of reasons, bring with them tangible and significant benefits to our customers, the State of New York and the larger community generally.

First, as noted, the EE, DR and other programs are critically important, because of the growing peak gas demand on the Companies' systems and the gas capacity shortfall currently projected to meet that projected demand. In light of the Long-Term Capacity Report, there is simply no other way to continue to serve customers on the coldest winter day without these programs. If these programs are not initiated and funded, given the projected gas capacity shortfall and the lack of reserve margins; as early as next winter customers could begin to experience negative consequences, including curtailments during extreme winter conditions or in event of contingencies.

Second, the Distributed Infrastructure Solution and the associated costs described in this Filing have not materialized out of thin air. The programs and their costs have been well known to the Commission and the Companies' stakeholders, having been outlined in National Grid's various capacity reports, in Case 19-G-0678 and in many other fora. In fact, the Joint Proposal explicitly recognized the need for the Distributed Infrastructure Solution and includes mechanisms for the recovery of its associated costs.

Third, the costs that are being sought are not without offsets and future savings. The DSM programs discussed in the Filing are replacing traditional infrastructure, whose costs are avoided.

Fourth, the programs offered by the Company will produce tangible benefits for customers who participate in them. For example, customers who directly participate in the envisioned weatherization programs will save energy, improve the value of their homes and see direct cost savings in the form of lower energy bills. Weatherization can be expensive and EE Programs offer significant financial incentives to mitigate that barrier. Building improvements result in a more comfortable home that may also improve the safety and health of occupants. Weatherization work, moreover, improves a building's resiliency against volatile weather conditions and temperature swings. Upgrading a customer's building envelope through an EE program is a sustainable practice where improvements last for 20 to 30 years into the future. With home heating costs constituting the most significant portion of a customer's bill, weatherization results in significant energy savings. Deep retrofit weatherization projects may provide up to 30% in energy savings. Weatherization installs physical measures such as attic and wall insulation that have long useful lives. These measures will reduce both gas and electric consumption in homes, allowing customers to save money and enjoy more comfort able homes.

Finally, and significantly, unlike traditional capacity that would have been used to meet the gas capacity shortfall, the programs that the Companies have proposed to meet the growing capacity shortfall are fully consistent with the goals of the CLCPA, New York City's Local Law 97 and the policies of the State and this Commission. Although the reductions in therms that flow from successful DR programs are more limited than the reductions from EE, (given that DR targets reduction during specific peak events), the DR programs serve the goal of averting the need for hard gas infrastructure by reducing demand in targeted locations. The environmental benefit potential from EE, on the other hand, can be stunning.

For example,

- The greenhouse gas emissions avoided from 5,000 weatherized homes is the equivalent of that from a car traveling around the world over 11,300 times

- The greenhouse gas emissions avoided from 10,000 weatherized homes is equivalent to avoiding emissions from 22,600 cars traveling around the world

- The greenhouse gas emissions avoided from 20,000 weatherized homes is equivalent to avoiding CO2 emissions from a year of 81,700 homes' electricity use for one year

- In fact, every home weatherized is equivalent to Carbon sequestered by an nearly 30 acres of US forests for a year.

The benefits in energy saved and CO2 not emitted from the EE programs for which the Companies are seeking approval are real and they are long lasting. When a home is weatherized, the benefits continue for 20-30 years, or more. Moreover, the tangible, environmental benefits from the EE programs are simply too big be ignored. The table below represents the emission savings equivalents for the lifetime impact of programs as shown in Table 3 & 4: Incremental Energy Efficiency for Heating Seasons 2021-2022 (CY 2021) & 2022-2023 (CY 2022)

Table 25: CO_2 Emission Savings from Incremental EE Programs

Equivalences	Heating Season 2021-22 (CY 2021)	Heating Season 2022-23 (CY 2022)
Lifetime Metric Tons of CO2 Avoided	**13,000**	**592,000**
Greenhouse gas emissions from		
Passenger vehicles driven for one year	3,000	129,000
Miles driven by an average passenger vehicle	33,000,000	1,500,000,000
CO2 emissions from		
homes' energy use for one year	1,600	71,000
homes' electricity use for one year	2,400	108,000
Pounds of coal burned	15,000,000	650,000,000
Carbon sequestered by		
acres of U.S. forests in one year	16,000	730,000
tree seedlings grown for 10 years	219,000	9,800,000

Moreover, these potential benefits are neither fanciful nor illusory. In fact, within the first few days of the enrollment period for the Company's 2021-22 heating season Weatherization program, over 300 customers applied. In short, although the programs proposed in this Filing will increase bills in the short run, in the long run they will save money for customers who enroll in them. Further, any such rate increases arising from the programs must be viewed in the larger context of the significant environmental and health benefits to New York State and the nation, and the contribution to the ability of our customers to reduce their gas usage and avoid costs in the future. Viewed in that context, the programs and their associated benefits are more than cost-justified.

VIII. RELIEF REQUESTED

For the foregoing reasons, the Company respectfully requests that the Commission:

- Approve the Incremental Demand-Side Management programs described herein;
- Authorize the expenditures described herein for 2021-2022;
- Direct the Companies to submit an annual Demand Side Management filing beginning in July, 2022 and continuing through July, 2024 that will outline, among other things, program timelines, milestones, and detailed budgets;
- Confirm that the Companies' annual Demand Response Implementation Plan filings will be subsumed by the annual DSM filing in this proceeding;
- Direct the filing of quarterly reports regarding the programs and expenditures consistent with the quarterly filings required in the Joint Proposal (of which the second quarterly filing may be a part of the annual filing, and of which the EE components will be due no sooner than the Company's EE savings and spend information is required to be filed for the Clean Energy Dashboard Scorecard filed in Case 18-M-0084);
- Affirm that the applicable metrics for recovery of the Capital Capacity Projects remain unchanged from those in the Joint Proposal, other than metrics for the Incremental EE Programs;
- Direct that the Capacity Demand Metrics for Energy Efficiency are to be as shown in Table 19 above, and that the EE metrics for future rate years may be updated on an annual basis as part of the Annual DSM filing in this proceeding;

- Authorize the Company to recover through a surcharge the costs of implementing the Incremental Demand-Side Management programs consistent with the costs and timing described herein;
- Authorize the Company to adjust the rate of energy savings to be achieved (dollars per therm) and associated targets for the accelerated NE:NY funds to be expended on the Incremental EE programs described herein; and
- Provide any other approvals or grants of authority as may be needed to implement the Incremental Demand-Side Management programs.

CONCLUSION

Based on the above, the Companies respectfully request that the Commission approve the Incremental Demand-Side Management Programs discussed above, as these programs will benefit customers and facilitate safe and reliable operations while advancing the State's energy and climate goals. The Companies further request that the Commission approve the funding for such programs in the manner requested herein and grant such other and further relief as the Commission deems appropriate.

Respectfully submitted,

KeySpan Gas East Corporation d/b/a National Grid
and
The Brooklyn Union Gas Company
d/b/a National Grid NY

/s/ *Philip DeCicco*

Dated: October 4, 2021

Appendix A. Additional Benefit-Cost Analysis Information

I. Benefit-Cost Analysis Overview

Methodology

The Company has worked with a consultant, Guidehouse, to develop an Excel-based modeling tool for calculating benefit-cost ratios ("BCRs") for individual and portfolios of the incremental demand side management programs. To determine the relevant benefits and costs the Company referenced ConEdison's Gas Benefit-Cost Analysis Handbook which was developed by ConEdison. The resulting tool was used to evaluate each program individually and as a portfolio solution. The Company is looking to develop and expand the modeling tool to evaluate a broader solution of programs. The definitions below describe the components on the benefit and costs side, respectively, for the various tests indicated in Table 17, above *(Portfolio BCR Results by Program Year*).

Definitions of Benefits

Avoided Peaking Services include (1) a fixed reservation fee for the right to call upon the supply and (2) a variable commodity charge for when the supply is called upon. Peaking services are currently considered the marginal source of supply during peak days

Avoided Pipeline & Storage Costs includes the firm contractual rights to interstate pipeline and storage that may be used to transport baseload gas from producing regions to city-gate. For a fixed annual cost to hold firm capacity rights, these assets supply firm supply to city-gate.

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 O&M includes variable operation and maintenance benefits on the transmission, regulator, and/or distribution systems realized from a proposed program or project. Generally, these benefits are commodity related and will be included in Avoided On-System Capacity Infrastructure cost.

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).

Reliability/Resiliency includes the qualitative impact of a project or program on overall system reliability and ability to maintain system standards and recover from system outages.

Economic Impacts quantifies the macroeconomic impacts of energy efficiency programs using REMI analysis. This analysis includes the program life and average annual impact of jobs, GDP, personal income and state tax revenue.

Thermal Comfort accounts for the greater participant-perceived comfort in their home and is specific to energy efficiency weatherization programs.

Other Non-Energy Benefits covers all other benefits (or reduced costs) accruing to the utility related to other non-commodity aspects of a proposed project or program.

Avoided Electric Benefits includes avoided electric commodity costs and avoided electric capacity costs.

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).

Lost Utility Revenue includes the distribution and other non-bypass able revenues that are shifted on to non-participating customers due to the normal process of establishing rates during a utility rate filing or the presence of revenue decoupling mechanisms,

Shareholder Incentives include the annual costs to customers of utility shareholder incentives that are tied to the projects or programs being evaluated.

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.

II. Benefit Cost Analysis Results

Tables A1, A2 and A3, below, provide the benefits, costs and net benefits under each of the tests (SCT, UCT, and RIM) for the Incremental DSM portfolio. Table A4, below, shows costs and benefits by portfolio under the Societal Cost Test ("SCT").

Table A1: Societal Cost Test (SCT) for the Incremental DSM Programs

Heating Season	SCT Benefits	SCT Costs	SCT Net Benefits	SCT BCR
2021/22	$54,204,676	-$14,704,795	$39,499,881	3.69
2022/23	$234,049,771	-$200,987,771	$33,061,999	1.16
2023/24	$294,670,280	-$249,373,207	$45,297,073	1.18
2024/25	$332,502,233	-$282,916,840	$49,585,393	1.18
2025/26	$380,203,376	-$318,805,506	$61,397,871	1.19
5-Yr Total	**$1,295,630,335**	**-$1,066,788,119**	**$228,842,216**	**1.21**

Table A2: Utility Cost Test (UCT) for Incremental DSM Programs

Heating Season	UCT Benefits	UCT Costs	UCT Net Benefits	UCT BCR
2021/22	$52,288,135	-$12,010,331	$40,277,804	4.35
2022/23	$148,556,237	-$99,464,750	$49,091,487	1.49
2023/24	$178,587,485	-$127,121,290	$51,466,195	1.4
2024/25	$196,810,348	-$143,656,297	$53,154,051	1.37
2025/26	$221,244,176	-$162,581,807	$58,662,369	1.36
5-Yr Total	**$797,486,381**	**-$544,834,476**	**$252,651,906**	**1.46**

Table A3: Ratepayer Impact Measure Test (RIM) for Incremental DSM Programs

Heating Season	RIM Benefits	RIM Costs	RIM Net Benefits	RIM BCR
2021/22	$52,288,135	-$14,508,719	$37,779,416	3.6
2022/23	$148,556,237	-$200,280,330	-$51,724,093	0.74
2023/24	$178,587,485	-$264,451,911	-$85,864,426	0.68
2024/25	$196,810,348	-$302,454,778	-$105,644,429	0.65
2025/26	$221,244,176	-$347,038,826	-$125,794,650	0.64
5-Yr Total	**$797,486,381**	**-$1,128,734,564**	**-$331,248,183**	**0.71**

Table A4: Societal Cost Test (SCT) per Portfolio

Program	Value	2021/22	2022/23	2023/24	2024/25	2025/26	5-Year Total
EE Portfolio	SCT Benefits	$3,636,488	$187,590,142	$254,381,983	$297,086,550	$348,785,981	$1,091,481,144
EE Portfolio	SCT Costs	-$5,361,391	-$181,591,142	-$229,191,632	-$261,730,920	-$296,726,978	-$974,602,063
EE Portfolio	**SCT BC Ratio**	**0.68**	**1.03**	**1.11**	**1.14**	**1.18**	**1.12**
DR Portfolio	SCT Benefits	$50,568,188	$46,459,629	$40,288,297	$35,415,682	$31,417,396	$204,149,192
DR Portfolio	SCT Costs	-$8,773,964	-$18,298,178	-$19,457,969	-$20,505,199	-$21,438,150	-$88,473,461
DR Portfolio	**SCT BC Ratio**	**5.76**	**2.54**	**2.07**	**2.07**	**2.07**	**2.07**
TPS + EH Portfolio	SCT Benefits	$0	$0	$0	$0	$0	$0
TPS + EH Portfolio	SCT Costs	-$569,439	-$1,098,450	-$723,606	-$680,721	-$640,377	-$3,712,594
TPS + EH Portfolio	**SCT BC Ratio**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Appendix B. Reference to Contingency Scenario

This Filing focuses on the need to address the Companies' gap in gross demand day and demand hour capacity. The Filing assumes the Plan A Scenario set forth in the LTCR (and Supplements), which is premised on the timely completion of all pending infrastructure projects. For reference here, a brief summary is provided on the contingency scenario where the Greenpoint LNG Vaporization Project and ExC components of the Distributed Infrastructure Solution are delayed. If these solutions are delayed, the size and acceleration rate of the DSM programs must increase to fill the gap and maintain reliability. The program scopes and budgets identified in this Filing do not include the additional program budgets that would be needed in this contingency scenario.

Table B1 illustrates a case where the LNG Project is delayed to the winter of 2024-25 and ExC is delayed to 2025-26. In such a scenario, DSM programs must provide additional, incremental reductions in peak demand by 2023-24 to prevent a capacity shortfall. The table below shows the incremental gap that would need to be met by Demand Side resources and the corresponding increase in DSM to address the gap.

Table B1: Required DSM Contributions In the Event of Delays to ExC and LNG

Total Supply Stack		Design Day [MDth/day]				
Supply Type	Resource	2021-22	2022-23	2023-24	2024-25	2025-26
Total Fixed Pipeline & Storage		2,377.0	2,377.0	2,377.0	2,377.0	2,439.5
LNG		394.5	394.5	394.5	453.3	453.3
Cogen + Contracted Peaking		105.1	123.1	123.1	123.1	123.1
CNG		61.6	79.2	79.2	79.2	79.2
RNG/H2		0.8	0.8	0.8	0.8	0.8
Total		2,938.9	2,974.5	2,974.5	3,033.3	3,095.8

Demand Forecast	Design Day [MDth/day]				
Forecast	2021-22	2022-23	2023-24	2024-25	2025-26
June 2021 Adj. Baseline (S05)	2,876.86	2,965.90	3,031.37	3,073.83	3,123.43

Gap to be Met via DSM	Design Day [MDth/day]				
	2021-22	2022-23	2023-24	2024-25	2025-26
Inc. Gap to be Met via DSM	-62.0	-8.6	56.9	40.5	27.6
Inc. in DSM Required	0.0	58.8	58.8	62.5	0.0

In addition to the need to meet the Design Day Gap, the Company must also meet the Design Hour need. As illustrated in Table B2, the gap in Design *Hour*, absent additional DSM beyond those proposed in the Filing, would appear earlier than in the Design *Day* scenario summarized by Table B1 above. Demand Response, which can target short durations, is a particularly useful tool to solve Design Hour gaps. The increase in DSM required if LNG and ExC are delayed is demonstrated in the last row of Table B2.

Table B2: DSM Contributions to the Design Hour in the Distributed Infrastructure Solution

Total Supply Stack		Design Hour [MDth/hr]				
Supply Type	**Resource**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**
Total Fixed Pipeline & Storage		114.0	114.0	114.0	114.0	117.1
LNG		16.4	16.4	16.4	18.9	18.9
Cogen + Contracted Peaking		5.3	6.2	6.2	6.2	6.2
CNG		7.7	9.9	9.9	9.9	9.9
RNG/H2		0.0	0.0	0.0	0.0	0.0
Total		143.37	146.47	146.47	148.92	152.05

Demand Forecast		Design Hour [MDth/hr]				
Forecast		**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**
June 2021 Adj. Baseline (S05)		143.84	148.30	151.57	153.69	156.17

Gap to be Met via DSM		Design Hour [MDth/hr]				
		2021-22	**2022-23**	**2023-24**	**2024-25**	**2025-26**
Inc. Gap to be Met via DSM		0.47	1.82	5.10	4.77	4.13
Inc. in DSM Required		0.0	2.5	2.5	3.1	0.0