Assessment of National Grid's Long-Term Capacity Report

Natural gas capacity needs and alternatives

Prepared for the Eastern Environmental Law Center

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<u>Correction notice:</u> Several numbers on page 52 were corrected for this version. See page 52A for details.

EXECUTIVE SUMMARY

National Grid's Long-Term Capacity Report projects a winter peak demand need and evaluates options to meet it. National Grid projects a peak capacity shortfall of between 265 MDth/day (Low Demand case) and 415 MDth/day (High Demand case) in the 2030s. Its analysis assumes a baseline future projection (Baseline Demand forecast), and then applies gas peak reductions to account for existing policies. However, our analysis found various errors in National Grid's assessments. In particular, we found that National Grid:

- is overly conservative in its assumptions regarding the ability to contract for peaking gas supply resources, and it did not include a planned enhancement to an existing LNG facility;
- overestimates the rate of conversion from oil to natural gas in the Baseline Demand forecast, especially in the New York City area, by assuming that past rates of conversion (which were accelerated by a now-completed policy) will continue;
- failed to include the efficiency savings that will be acquired by NYSERDA in addition to savings from the utility's programs; and
- did not properly account for the amount of electrification that will be induced by New York City's Local Law 97 and the electric utilities' New Energy New York programs.

Correcting these errors, our analysis concludes that National Grid has not shown that it faces a supply and demand gap. In fact, National Grid is expected to have a substantial surplus of supply capacity by 2034/35.

Figure ES-1. Closing the gas supply gap in 2034/35 with corrections to National Grid's forecast—High Demand scenario

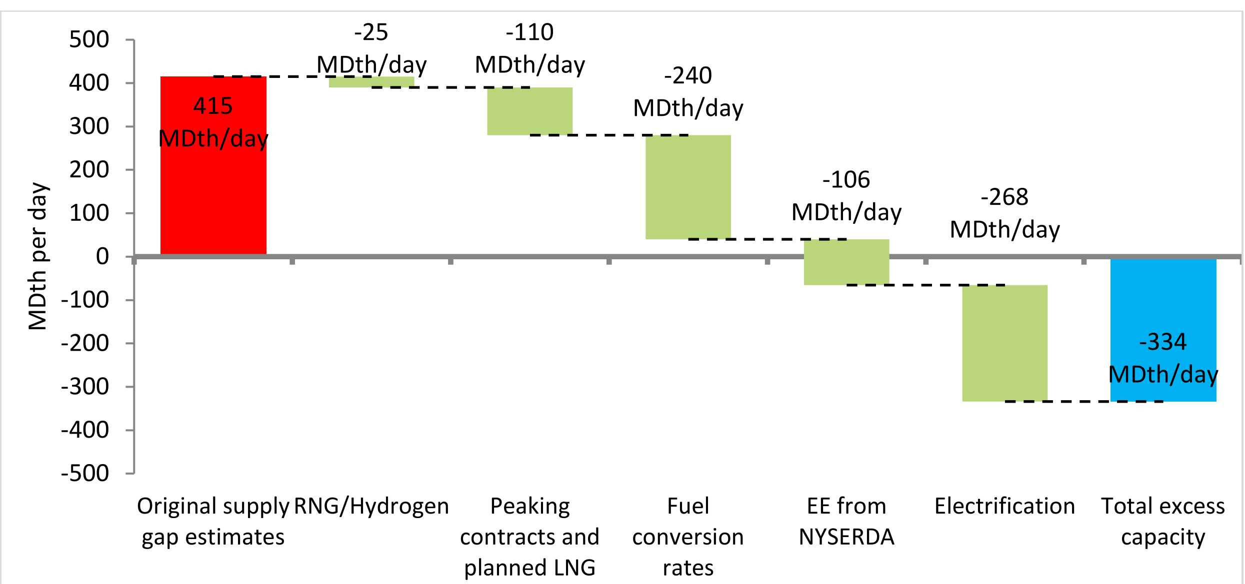
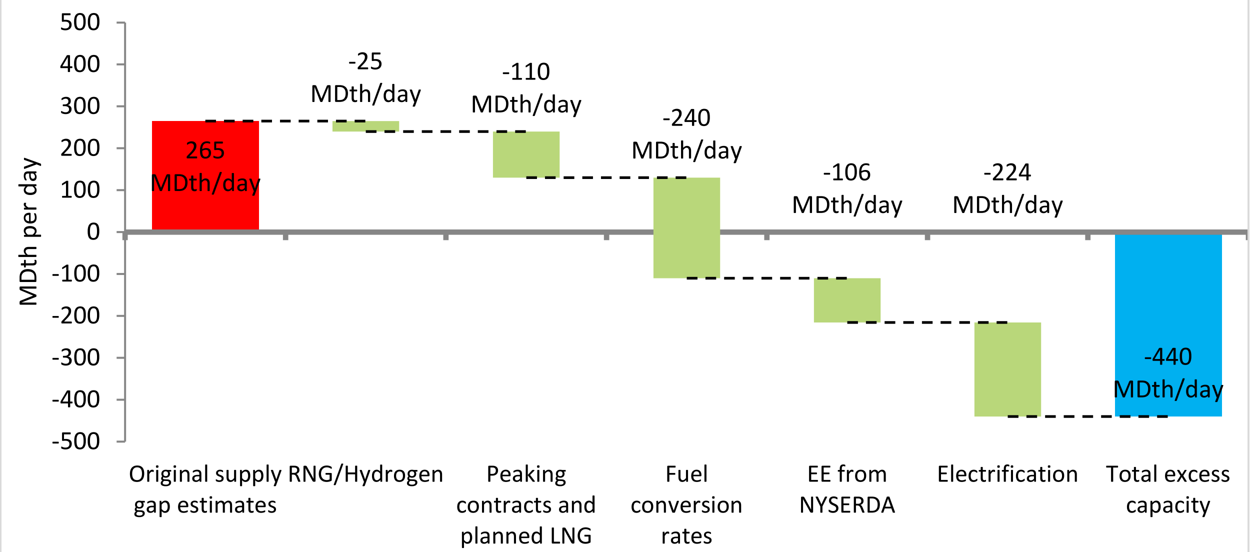


Figure ES-2. Closing the gas supply gap in 2032/33 with corrections to National Grid's forecast—Low Demand scenario



Another major finding of our analysis is that even if the supply gaps were to exist (which our analysis refuted), the No Infrastructure option is one of the least-cost solutions among all resource options analyzed by National Grid. The No Infrastructure option is certainly substantially cheaper than all of the large infrastructure options including the Northeast Supply Enhancement (NESE) pipeline and LNG terminal options. We found that National Grid significantly overestimated the cost of incremental energy efficiency and did not take into account the avoided costs of natural gas throughout and beyond the study period, or the avoided costs of carbon emissions, in its cost-benefit analysis.

1 Introduction

A recent report filed with the New York Public Service Commission (PSC) by National Grid demonstrates New York State's new challenge in reconciling its long-term natural gas planning process with its long-term climate change targets under the Climate Leadership and Community Protection Act (CLCPA). Specifically, New York faces the thorny question of whether the construction of new large natural gas infrastructure projects make sense in the context of the deep decarbonization mandated by the CLCPA (reducing greenhouse gas emissions (GHG) 85 percent by 2050, and net zero by 2050). Another, more traditional question is whether there is a need to construct large new gas facilities to meet the state's natural gas demand in the long term. This question arises in the context not only of climate goals but also of increasing options to deploy efficiency, demand response, and electrification to meet customer needs as "non-pipeline alternatives" that are cost-effective and reduce emissions of GHGs and other harmful pollutants. New York and its natural gas utilities are now facing a unique and very important opportunity to explore these questions, with direct practical import for customers.

National Grid identified future needs for firm peak gas supply capacity to serve its customers in New York City and Long Island, and signed a precedent agreement with a proposed pipeline project known as the Northeast Supply Enhancement (NESE) project to meet these needs.[1] When the NESE's pipeline project application was denied by the Department of Environmental Conservation (DEC), National Grid placed a moratorium on all new gas service connections on or about May 15, 2019, causing an undue hardship to 3,700 existing customers and potential new customers.[2] This led the New York Public Service Commission (PSC) to open a regulatory proceeding (Case 19-G-0678) that resulted in a settlement between National Grid and the Department of Public Service. On November 26, 2019, NY PSC issued an order approving the settlement and directed the Company, among other things, to develop a Long-Term Capacity Report ("Capacity Report") to address its gas capacity concerns in the long term to allow for further gas connections. This Capacity Report was issued on February 24, 2020.

On behalf of the Eastern Environmental Law Center (EELC), Synapse conducted a comprehensive assessment of National Grid's Capacity Report. The Capacity Report detailed gas peak demand forecasts through the winter of 2034/35. It showed two forecasts, called High Demand and Low Demand, based on National Grid's assessments of the impacts of recent policies and identified peak gas supply gaps of 265 to 415 thousand dekatherm per day (MDth/day) between 2020 and 2034/35. The report then assessed various long-term gas solutions to fill these gaps. These potential solutions included the NESE pipeline as well as a No Infrastructure option that solely relies on additional demand-side resources.

Our analysis found various errors in National Grid's assessments of the rate of customer conversion from oil to natural gas, expected levels and costs of energy efficiency and heat pumps under existing or expanded policies and programs, and gas supply resources. This report on Synapse's review of the Capacity Report includes our assessment of National Grid's analysis on the following issues:

a) Section 2 addresses the Baseline Demand forecast based on econometric modeling;

b) Section 3 addresses the impacts on peak demand forecasts from the implementation of energy efficiency, demand response, and electrification measures expected from recent policies and commitments including the New Efficiency New York (NENY) program and New York City's Local Law 97;

c) Section 4 addresses long-term supply resource options including contracts for peaking supplies, planned upgrades to existing liquefied natural gas (LNG) facilities, and renewable natural gas (RNG) and hydrogen; and

d) Section 5 addresses the impacts and costs of expanded demand-side measures included in the No Infrastructure option.

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[1] Balaraman, K. Nov. 25, 2019, "National Grid lifts gas moratorium following deal with New York." *UtilityDive*. Available at https://www.utilitydive.com/news/national-grid-lifts-gas-moratorium-following-deal-with-new-york/568044/

[2] Brachfeld, B. October 14, 2019. "State Orders National Grid to Immediately Connect 1,157 Customers with Gas Service, Alleges Company Violated Law." *Bklyer*. Available at https://bklyner.com/state-orders-national-grid-to-immediately-connect-1157-customers-with-gas-service-alleges-company-violated-law/

The report concludes in Section 6 by bringing the assessments together to show that appropriate treatment of demand-side measures, with or without small changes in National Grid's supply planning assumptions, eliminates the need for any of the large-scale infrastructure investments examined in the Capacity Report.

2 Baseline Demand Forecast Methodology and Assumptions

2.1 Description of National Grid's Baseline Demand Forecast

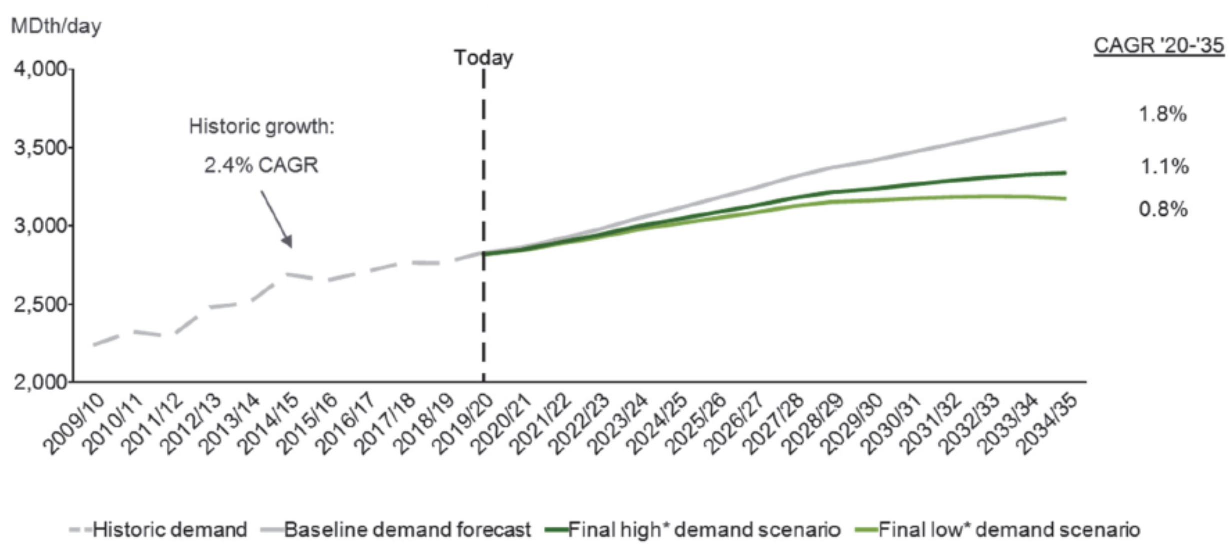
2.1.1 Forecast overview

Natural gas utilities assess expected system peak demand based on an extreme cold weather day called the design day. National Grid's Capacity Report presents three design day gas demand forecasts for the utility's jurisdiction in Long Island and New York City as follows:

1. Baseline Demand forecast
2. Final High Demand scenario
3. Final Low Demand scenario

Figure 1 below shows these forecasts as presented in the Capacity Report. The compound average growth rates (CAGR) for 2020 to 2035 for these three scenarios are 1.8 percent, 1.1 percent, and 0.8 percent, respectively, as shown in this figure.[3] The High and Low Demand scenarios are discussed in detail in Section 3 of this report. This section addresses the Baseline Demand forecast.

Figure 1. Historical and projected design day natural gas demand in Downstate New York, 2009–2035



Source: National Grid. 2020. Figure 1.

[3] National Grid. 2020. Natural Gas Long-Term Capacity Report, Figure 1, page 8.

The starting design day load in 2020 is 2,836 MDth/day.[4] Although the Capacity Report does not directly provide actual design day demand loads each subsequent year, we were able to calculate it from several values in the report, and also confirm it with Table 1 of the April 1 Technical Appendix.[5] The overall growth rate is about 1.76 percent which is rounded to 1.8 percent in Figure 1 of the report.

Table 1. Design day demand forecast increases

MDth/day	2019/20 Base	2034/35 Cases Baseline
Design Day Demand	2,836	3,687
Increase		851
Percent Increase		30%

The Baseline forecast is based on econometric modeling. The High and Low Demand forecasts are created by adjusting the Baseline forecast for factors such as energy efficiency, demand response, and electrification.[6] We discuss these adjustments in more detail in Section 3.

2.1.2 Historical perspective

The Capacity Report shows historical design day natural gas demand as explained above and shown in Figure 1. This is, however, a normalized design day value and not the actual peak demand in those years. The Capacity Report does not provide the actual peak demand in those years, nor the conditions under which they occurred. This is a shortcoming for understanding how these values relate to the actual historical peak loads.

The Capacity Report contains some general information about the historical design day demand, but it is scattered in different places.[7] We have consolidated that information to produce the following "historical" table which shows the changes from 2010 to 2019. We estimated that the annual growth rate is 2.06 percent (Table 2). This significantly is less than the 2.4 percent shown in the Capacity Report (See Figure 1 above). This inconsistency casts doubt on the accuracy of the material presented in that report.

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[4] National Grid. 2020, Table 4.

[5] Natural Gas Long-Term Capacity Report Technical Appendix to the Capacity Report issued on April 1, 2020, available at https://ngridlongtermsolutions.com/.

[6] National Grid. 2020. Section 5.2

[7] National Grid. 2020, Tables 4 and 5.

Table 2. Design day gas demand

Customers	Volume (MDth/day) 2009/10	2019/20	10-year change	% change	Annual Rate
Residential	1,458	1,709	251	17%	1.60%
C&I	593	726	133	22%	2.04%
Multi-Family	263	401	138	52%	4.31%
Total	2,314	2,836	522	23%	2.06%

Source: Synapse from Capacity Report Tables 4 and 5.

The residential customers represent about 60 percent of the current demand but had the lowest rate of increase over the past 10 years. The greatest percentage increase was seen in multi-family customers. Much of this was associated with the required conversion away from heavy fuel oils in New York City (NYC). As discussed in Section 2.2.2, that process is now mostly completed in the NYC area and will not impact the growth in the future as much as it did in the past.

Table 3 below shows the change in the number of customers over the same period. The greatest relative increase here also was for the multi-family customers. The net change in the number of residential customers represents an increase of 174,000 heating customers and a decline of 70,000 in non-heating customers (many of them switching to gas heat).[8]

Table 3. Changes in number of customers

Customers	Number (1000) 2010	2020	Change	% change
Residential	1,637	1,741	104	6%
C&I	103	112	9	8%
Multi-Family	18	23	5	28%
Total	1,758	1,877	119	7%

Source: Synapse from Capacity Report Tables 5 and 6.

Overall, the growth in demand has been driven by conversions from oil to gas, increased numbers of customers, and increased usage per customer (primarily driven by an increasing portion of gas heating customers). Historically, there has been a growth in the design day demand, but those trends may or not continue in the future depending on a variety of factors.

[8] The term “non-heating customers” refers to customers who use natural gas only for non-space heating related end-uses (e.g., cooking and water heating).

2.1.3 Baseline forecast

National Grid developed its baseline design day natural gas demand forecast based on econometric modeling. The basic approach is described as follows:

> **<u>Project "Baseline" demand growth through a statistically validated econometric forecast</u>** [is] driven by key variables under current policies and customer usage patterns. In this step, it is assumed that current energy efficiency programs continue; that there are similar rates of oil-to-gas conversions; and that any alternatives such as electrification continue at the same rate as today. The model looks at the most predictive drivers of gas customer count and usage per customer based on the last 10 years of actual data (with a higher weighting to recent activity), and then projects future customer count and usage per customer based on external forecasts of underlying macroeconomic drivers. Baseline demand growth is largely driven by expected changes in number of customers due to population, housing, and business growth; oil-to-gas conversions; and any changes in usage per customer based on existing patterns and trends.[9]

We note that the Capacity Report provides no details about the econometric model itself. Instead the Capacity Report only provides the results of the econometric modeling in terms of numbers of customers and usage per customer with no information about how these are generated (Table 4 and Table 5).

Table 4. Key drivers of baseline demand—number of customers

Driver	2010-2019		2020-2035 Baseline	
	#/yr.	%/yr.	#/yr.	%/yr.
Baseline # of Customers	11,634	0.64%	11,259	0.57%
Residential Non-heat	(7,023)	-1.0%	(7,614)	-1.3%
Residential Heat	17,436	1.8%	17,909	1.5%
Commercial & Industrial	865	0.8%	509	0.4%
Multi-family	497	2.8%	594	2.4%
Temperature Controlled	(141)	-4.4%	(140)	-13.1%

Source: National Grid. 2020. Table 9.

[9] National Grid. 2020, Section 5.2, page 32.

Table 5. Key drivers of baseline demand – usage per customer

Driver	2010-2019		2020-2035 Baseline	
	#/yr.	%/yr.	#/yr.	%/yr.
Usage Per Customer	N/A	1.7%	N/A	1.2%
Residential Non-heat		0.4%		-0.5%
Residential Heat		0.1%		0.2%
Commercial & Industrial		1.8%		0.6%
Multi-family		1.9%		1.2%
Temperature Controlled		N/A		N/A

Source: National Grid. 2020. Table 9.

An even greater gap is that these tables provide no information about the actual demand growth associated with these drivers. For example, what is the demand growth associated with the increase in commercial customers? What is the relationship between annual energy use growth and design day demand growth? This is key information that such a report should provide.

The Capacity Report issued on February 24 also did not provide design day demand load data for each customer class for 2034/35, but we were able to calculate the load based on our estimates of approximate demand growth rates we developed using the changes in the number of customers and usage per customer provided in the tables above. For example, the commercial and industrial (C&I) sector with a 0.4 percent customer growth rate combined with a 0.6 percent usage increase results in a 1.0 percent per year demand day load increase. For the multi-family sector, the overall increase is 3.7 percent per year (2.4 percent + 1.2 percent; difference due to rounding). Combining the drivers, we calculated the overall residential growth rate to be about 1.6 percent per year. We confirmed these growth rates and the resulting demand estimates for 2034/35 with the data provided in a Technical Appendix that was issued in late March and updated on April 1.[10]

The table below shows the demand increases by sector based on the Technical Appendix. The residential sector shows the greatest absolute increase, but the multi-family sector shows the greatest relative increase. Since most of the remaining fuel conversions from oil to gas have already occurred in the multi-family sector in National Grid's NYC territory (KEDNY), it is not obvious that gas usage in this sector will continue to increase at such a high rate.

[10] Natural Gas Long-Term Capacity Report Technical Appendix to the Capacity Report issued on April 1, 2020, available at https://ngridlongtermsolutions.com/.

Table 6. Baseline load increases (MDth/day)

	2019/20 Load	Growth Rate	2034/35 Load	Increase
Residential	1,704	1.6%	2,152	448
Commercial & Industrial	725	1.0%	847	122
Multi-family	400	3.7%	688	288
Total	2,829	1.8%	3687	858

Source: National Grid 2020. Technical Appendix. Table 1.

We have also done a rough calculation of what the load increases would be if the number of customers did not increase. For multi-family customers, the load would increase by only about 80 MDth—about 200 MDTh/day less than the Baseline forecast. Combined reductions for the other sectors would be about 100 MDth/day. While a moratorium may not be appropriate or feasible, slowing customer growth, especially for firm heating service, could have substantial capacity benefits.[11] Energy efficiency, demand response, and alternative energy systems such as heat pumps can play a critical role in this effort.

Table 4 above highlights another notable point: a 13.1 percent decrease per year in the temperature-controlled customers.[12] This means that this cohort of customers are essentially gone by 2035. If National Grid wishes to control design day loads, then it should retain these customers and even expand the number of such customers. By assuming in the Baseline that these customers essentially all convert to full gas service, National Grid sets up a case where demand-side adjustments are required to compensate.

2.2 Critique of the Baseline Demand Forecast

In this section, we discuss limitations of National Grid's load forecast methodology and assumptions with a focus on its econometric-based load modeling. We address two weaknesses in the Capacity Report: (1) inconsistencies between the Capacity Report and National Grid testimony regarding energy sales forecasts and (2) fuel conversion rate assumptions. We also express concern that the reliance on a zero degree Fahrenheit design day may overstate the temperature extremes that National Grid's customers face.

As mentioned above, National Grid adjusts its load forecast based on its econometric modeling for additional impacts from recent policies on demand-side measures and programs. We will discuss and provide our assessment of such additional impacts in Section 3.

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[11] Some of these benefits are likely included in the High and Low Demand scenarios, but the extent of that is not clear from the report.

[12] Temperature-controlled customers are demand response customers that are required to switch from gas to an alternate fuel when the temperature drops below a pre-set level (e.g., 16 Degrees Fahrenheit). This customer group consists of multi-family (85%) and commercial (15%) customers per the footnote to Table 4 of the Capacity Report.

2.2.1 Sales forecasts

The design day demand forecast should be consistent with the gas delivery forecast used in the National Grid rate case proceeding in 2019 (Case 19-G-0309 and 19-G-310). However, there is no discussion of that relationship in the Capacity Report. The sales forecast from the 2019 rate case has many detailed aspects not reflected in the presentation of the demand forecast in the Capacity Report. It is not clear if National Grid used the same assumptions.

Table 7 below summarizes the materials in Theodore Poe, Jr.'s testimony in the 2019 rate case. These materials assessed historical gas deliveries and forecasted future deliveries. One point of interest here is that the historical sales from 2013 through 2017 increased at an average rate of 2.9 percent, corresponding to the central period of a claimed 2.4 percent CAGR increase in the design day gas demand.[13] This implies that design day demand may not grow as quickly as energy demand. In the rate case, the projected future (2018–2024) increases in annual deliveries are much lower (0.6 to 1.0 percent). It is not clear what portion of this reduction is due to policy impacts, and what portion to different modeling tools or assumptions. Regardless, this implies a lower growth rate than historically for the design day demand. But as stated above, National Grid provides essentially no information about how these forecasts are related. National Grid's load forecast in the Capacity Report should at least make references to the sales forecast in the rate case, indicate the common and different assumptions and explain any common factors used to develop design day load forecasts.

Table 7. Annual deliveries—historical and forecast

Period	Growth Rate
Historical 2013-2017	2.9%
Rate Case Forecast (2018-2024)	
April 2019 Testimony	1.0%
January 2020 Testimony	0.6%

Note: Based on TEP-4A and TEP-4B.

The macroeconomic factors presented in Table 7 of the Capacity Report are identified as being from Moody's Analytics, but the economic scenario and underlying assumptions are not given. The Capacity Report does not provide the map between these inputs and the forecast results.

2.2.2 Fuel conversion rate assumptions

A key factor driving National Grids' projected increase in gas load is the conversion from other fuels to natural gas. In this section, we will assess the robustness of the Capacity Report's assumptions on such fuel conversion rates. As shown in the table below, the number of residential non-heating customers have declined at a rate of 7,023 per year and the number of residential heating customers have

[13] National Grid. 2020. Figure 1.

increased at an average rate of 17,436 per year, resulting in a net increase of about 10,000 residential customers per year. The total increase in residential heating customers represents non-heating customers switching to heating, new construction, and those switching from other fuels. The report indicates that there were about ~5,400 new customers per year who switched from non-gas fuels.[14] Most of those were probably residential customers, but there was also a considerable increase in multi-family customers probably also representing some fuel switching. Together the annual net customer change was about 11,600 over the past 10 years (Table 8).

Table 8. Annual change in customer count, 2010–2019

	Average Change Per Year, 2010 - 2019	
Customer type	**# of Customers**	**%**
Residential non-heat	(7,023)	-1.0%
Residential heat	17,436	1.8%
Commercial	865	0.8%
Multi-family	497	2.8%
Temperature controlled	(141)	-4.4%
Total	**11,634**	**0.6%**

Source: National Grid. 2020. Table 6.

To estimate impacts of fuel conversions for the next 15 years, the Capacity Report assumes that the historical trend over the past 10 years continues as follows:

> In the Baseline Demand scenario, this conversion trend is expected to continue, with almost 33% of building space in the Downstate NY area still heated by non-gas sources - 23% from oil heating and 10% from electric resistance, propane and other fuels.[15]

National Grid's customer conversion assumption for future customers is not warranted primarily because a large number of the buildings using other fuels in NYC have already converted to natural gas to comply with NYC's fuel oil regulation, supported under the NYC Clean Heat Program. In fact, National Grid summarizes this point in its 2018–2019 Winter Supply Review report for the fuel conversion rates in NYC area (excluding Long Island) as follows:

> Under the NYC Clean Heat program, National Grid has converted nearly all of the approximately 800 buildings in its service territory from No. 4/6 oil to natural gas. As a result, customer requirements have grown and infrastructure to support these conversions has been installed where needed.
>
> The City Clean Heat program deadline to phase out of all No. 6 heating oil was June 30th, 2015. To date, the NYC Department of Environmental Protection has achieved 99.8% compliance with the regulation. The deadline for the phase out of all No. 4

[14] National Grid. 2020. Page 30.

[15] National Grid. 2020. Page 30.

heating oil is January 1st, 2030. At this point the City has achieved it goals and is focusing on pursuing other carbon reductions options.[16]

It is also important to note that according to the company's own 2018 Winter Supply Review report, the rate of fuel conversion requests to natural gas for the entire Downstate NYC service area under National Grid jurisdiction has been declining over time. Based on this previous report, the number of requests in FY2018 were less than half of the requests National Grid received five years ago in FY2014.[17] It is possible that the conversion rate was higher in the years leading up to FY2015 because the compliance year for No. 6 fuel oil phase out was in 2015.

Based on this decreasing demand to convert to natural gas, we expect that going forward the fuel conversion rates from non-natural gas fuels to natural gas should be substantially lower than what National Grid assumes in its Capacity Report. We estimate alternative design day demand impacts using a more realistic fuel conversion rate assumption. Since we do not have any data about fuel choice by new construction buildings, this analysis conservatively assumes no change to the new construction market. We then assume the fuel conversion rate from existing buildings will be half of National Grid's assumption, based on the fall in fuel conversion rates over the past several years. This results in a 33 percent reduction in the overall customer gas connection requests over the next 15 years.[18] Properly adjusting National Grid's assumptions of customer count and usage growth analysis, we estimate that National Grid's design day demand growth is overestimated at least by **approximately 240 MDth/day**.

Table 9 and Table 10 below show our detailed analysis of design day demand impacts due to the changes in the growth rate of the number of customers and usage. Table 9 replicates National Grid's analysis of design day demand growth by 2035. Using National Grid's assumptions on the annual growth rates and the current design day demand by customer class, we estimated that the total design day growth demand by 2035 is approximately 850 MDth. (This value verifies as close to National Grid's estimate of 858 MDth/day.)[19] In Table 10, we assumed that the growth rate in the number of customers will be 30 percent less than the rates in Table 9. The resulting design day demand by 2035 grows to approximately 601 MDth/day, approximately 240 MDth/day less than the 850 MDth estimate based on National Grid's assumptions. Lastly, note that if we assume natural gas connection requests will be reduced by half instead of 30 percent (as could happen if more new construction were all-electric, for

[16] National Grid. 2018. 2018-2019 Winter Supply Review, page 32.

[17] Ibid, page 30.

[18] Based on our assessment of the growth rate in the number of households (0.3 percent) and the floor space in square footage (0.9 percent) presented in the Capacity Report in Table 7, we assumed that the growth rates in net gas usage by *new* buildings is approximately 0.6 percent. Since the overall annual growth rate assumed by National Grid is 1.8 percent, we estimated that the net usage growth rate for the *existing* buildings is 1.2 percent (1.8 percent minus 0.6 percent). This 1.2 percent represents about 67 percent of the entire annual growth rate, so cutting fuel conversions in half would reduce the overall growth rate by 33 percent.

[19] National Grid. 2020. Natural Gas Long-Term Capacity Report Technical Appendix, Table 1, page 2, April 1, 2020.

example), design day demand in 2035 would be reduced by **350 MDth/day** from the Baseline Demand forecast.

Table 9. Annual gas peak demand growth rate for 2020–2035 and expected demand growth by 2035—National Grid scenario on fuel conversion rate

	Annual Growth Rates			15 Year Impact	Current Design Day Demand (MDth/day)	Net Increase over 15 Years by 2035 (MDth)
	# of Customers	Usage	Net Rate			
Residential Non-heat	-1.30%	-0.50%	-1.8%	-24%	85	-20
Residential Heat	1.50%	0.20%	1.7%	29%	1,624	468
Commercial & Industrial	0.40%	0.60%	1.0%	16%	726	117
Multi-family	2.40%	1.20%	3.6%	71%	401	283
Total			1.8%	30%	2,836	848

Source: Synapse analysis based on National Grid's annual growth rates.

Table 10. Annual gas peak demand growth rate for 2020-2035 and expected demand growth by 2035—realistic fuel conservation rate scenario

	Annual Growth Rates			15 Year Impact	Current Design Day Demand (MDth/day)	Net Increase over 15 Years by 2035 (MDth)
	# of Customers	Usage	Net Rate			
Residential Non-heat	-0.87%	-0.50%	-1.4%	-19%	85	-16
Residential Heat	1.00%	0.20%	1.2%	20%	1,624	318
Commercial & Industrial	0.27%	0.60%	0.9%	14%	726	100
Multi-family	1.60%	1.20%	2.8%	51%	401	206
Total			1.3%	21%	2,836	601

Source: Synapse analysis based on corrected annual growth rates.

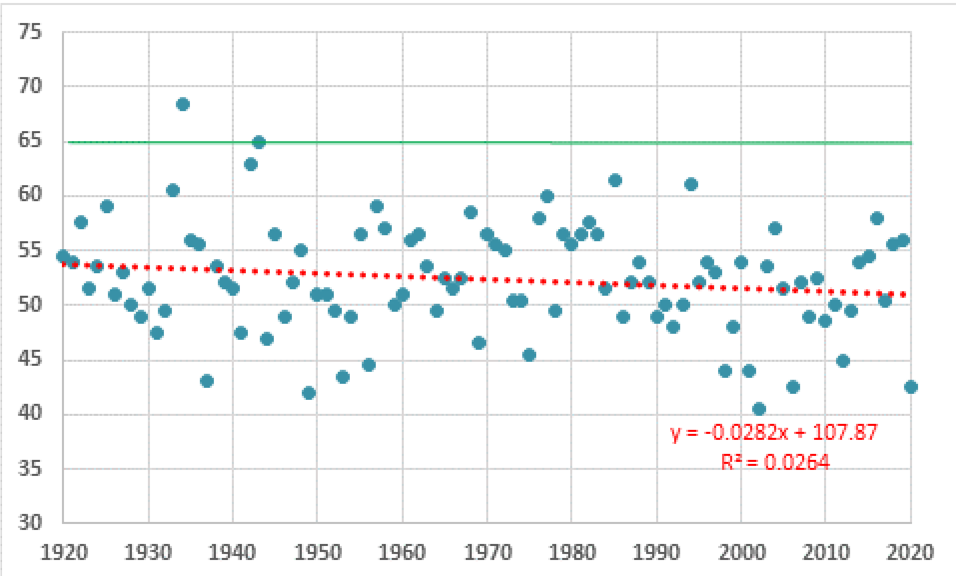
2.2.3 Design day calculation issues

The Capacity Report takes as given a design day average temperature of zero degrees Fahrenheit.[20] The Capacity Report notes that the last day that met the design day criteria was February 9, 1934—86 years ago. Much has changed since then, and the climate is getting warmer on average. The report is missing any discussion of (1) why this is an appropriate design temperature for the future and (2) what the demand implications would be of a different design temperature. Hourly load, supply, and temperature data would be required in order to perform a detailed assessment of the design temperature and reliability.

[20] National Grid 2020, Section 3.2.

Figure 2 shows the approximate heating degree days for the coldest day in Central Park in each of the last 100 winters.[21] We have added a line corresponding to the design day temperature of zero degrees. The general trend is slightly downward, perhaps reflecting impacts of ongoing climate change. The greatest HDD value in the most recent 70 years (1950 to 2020) is 61.5 (corresponding to a 3.5 degree design day), which occurred in 1985 (35 years ago).

Figure 2. Annual HDD maximums for NYC, with a simple linear regression showing slight warming over time



Source: Synapse analysis based on temperature data from the National Oceanic and Atmospheric Administration (NOAA).

In light of the actual temperatures experienced in the last 70 years, and the trend toward warmer winters, we believe that the use of a zero-degree design day may be extreme, and result in National Grid ratepayers paying for more capacity than is necessary to maintain reliability. Using a higher design day temperature would reduce the design day demand. Using National Grid's design day peak load data, we have calculated daily load levels versus HDD values for the 2019/20 season (accounting for non-heating loads). Based on these calculations, we have determined that a design day temperature of 3 degrees, for example, would reduce the design load by about 107 MDth/day for the 2019/20 season. This represents 3.8 percent of that load.

[21] We obtained historical daily high and low temperature data from the National Oceanic and Atmospheric Administration (NOAA) from 1920 to the present (National Climate Data Center, https://www.ncdc.noaa.gov/cdo-web/search; Central Park weather station). We took the simple average of the high and low to calculate the approximate HDD requirement based on 65 degrees. We then extracted the highest HDD value for each year, corresponding to the coldest average day. One thing of note is that our calculated average temperature for 1934 is lower than the daily average used for the design day calculations. We believe this is because our simple average of high and low temperatures does not correctly capture the hourly averages (hourly temperatures for the full historical period are not available).

2.2.4 National Grid's design hour issues

The natural gas industry transacts on a standard Gas Day, and gas pipeline services are scheduled as daily quantities. Pipeline operators generally accommodate hourly variations in gas deliveries by managing the gas pressure in the pipeline. At night, when the gas use is lower, the pressure is increased to be ready for the early morning ramp-up in gas use. The pipeline operator then repeats this process during the day to prepare for the evening peak. Because there are limits on the ability to manage hourly variability using pipeline pressure, pipeline operators can require shippers to take gas at uniform hourly rates if it becomes necessary to protect the operation of the system. Concerns about variable hourly flows have increased as gas consumption has expanded, and gas use for power generation has increased. However, these concerns are greater on some gas pipeline systems than on others.

Gas pipelines can be designed to provide non-uniform hourly deliveries. In some cases, firm hourly flexibility is built into the pipeline operator's standard gas transportation service. Iroquois Gas Transmission System, which supplies National Grid, allows gas to be taken at 120 percent of the uniform hourly quantity for up to three consecutive hours, two times per day.[22] Other pipeline operators offer non-standard transportation services with enhanced hourly flow rights, where the shipper contracts for both a Maximum Daily Quantity (MDQ) and a Maximum Hourly Quantity (MHQ) that is greater than 1/24th of the MDQ. Texas Eastern Transmission, another National Grid supplier, offers transportation service with a higher MHQ if the customer pays for the addition pipeline facilities needed to provide the extra hourly flexibility.[23]

Most large gas distribution utilities also address high hourly flow requirements using on-system storage and peaking. On the East Coast, where the geology does not allow gas to be stored underground, this usually involves injecting vaporized LNG, CNG, or propane into the distribution system during peak hours of the day. National Grid says that it plans to use CNG approximately four hours per day during periods of high gas demand to increase supply during the morning and evening peaks. National Grid also plans to upgrade one of its two LNG peaking facilities to increase the hourly vaporization capacity.

National Grid indicates that one reason for using a stricter design day weather standard is to account for hourly variability in gas use.[24] Inflating the design day demand forecast causes National Grid to hold more gas delivery capacity, and it provides a buffer in the event that pipeline operators put restrictions on hourly gas deliveries. However, this is a very imprecise approach to the problem and creates the risk that National Grid will contract for more gas supply capacity than it actually needs. It would be better for National Grid to quantify its Design Hour requirement and compare this to the hourly flexibility that will be available from all upstream and on-system gas supply resources.

[22] Iroquois Gas Transmission System, FERC Gas Tariff, General Terms & Conditions, Section 8.3.

[23] Texas Eastern Transmission, FERC Gas Tariff, Rate Schedule FT-1, Section 2.3.

[24] National Grid. 2020. page 19.

3 Impacts of Demand-side Resources On the Base Forecast of Capacity Needs

National Grid's baseline forecast is a purely econometric forecast, which does not account for recent changes in state and local policies or technology adoption among the company's customers. National Grid modifies the baseline forecast through explicit accounting of these incremental changes in energy efficiency, demand response, and electrification. Because the impact of these new programs and market changes is uncertain, National Grid develops Low and High Demand forecasts, reflecting higher or low impacts to reduce design day demand, respectively. This section evaluates and critiques the company's approach to accounting for the impact of incremental programs and technology adoption.

3.1 Overview of National Grid's Demand-Side Resource Analysis

To develop the Low and High Demand forecasts, the Capacity Report estimated natural gas impacts from the implementation of energy efficiency, demand response, and electrification measures expected from recent policies and commitments as follows:

- **New Efficiency New York program**: On January 16, 2020, the NY PSC established energy efficiency and electrification targets for investor-owned utilities for 2020 through 2025.[25] These targets are part of the state's overall initiative called New Efficiency New York (NENY). This order has two major components. First, the order approved increased gas savings and budget targets for gas utilities. Secondly, NENY established energy targets through heat pump installations for electric investor-owned utilities. PSEG Long Island is voluntarily complying with NENY program targets.

- **Local Law 97**: New York City has established building performance standards under Local Law 97 (LL97). Under this regulation, buildings larger than 25,000 square feet will be required to meet certain carbon dioxide (CO_2) emissions limits based on building type.

- **Recent settlement related to National Grid's moratorium**: As part of this settlement, NY PSC directed National Grid to develop an implementation and contingency plan to allow for lifting National Grid's gas moratorium for new customers on an interim basis. This plan includes an investment of $8 million to implement gas demand response and energy efficiency programs.

Further, the Capacity Report included gas impacts from the expected increase in natural/organic adoption of electric heat pumps. More specifically, National Grid anticipates that electric heat pumps in the United States will reach cost parity with natural gas by the early 2030s.[26]

[25] NY PSC. 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025.

[26] National Grid. 2020, page 33.

Table 11 below provides the total design day demand reduction estimates by National Grid for energy efficiency, demand response, and electrification measures. The combined effect in 2034/35 is to reduce the design day demand by between 346 and 511 MDth/day, which represents about 9 to 14 percent of the expected value of the baseline design day load forecast for 2034/35.

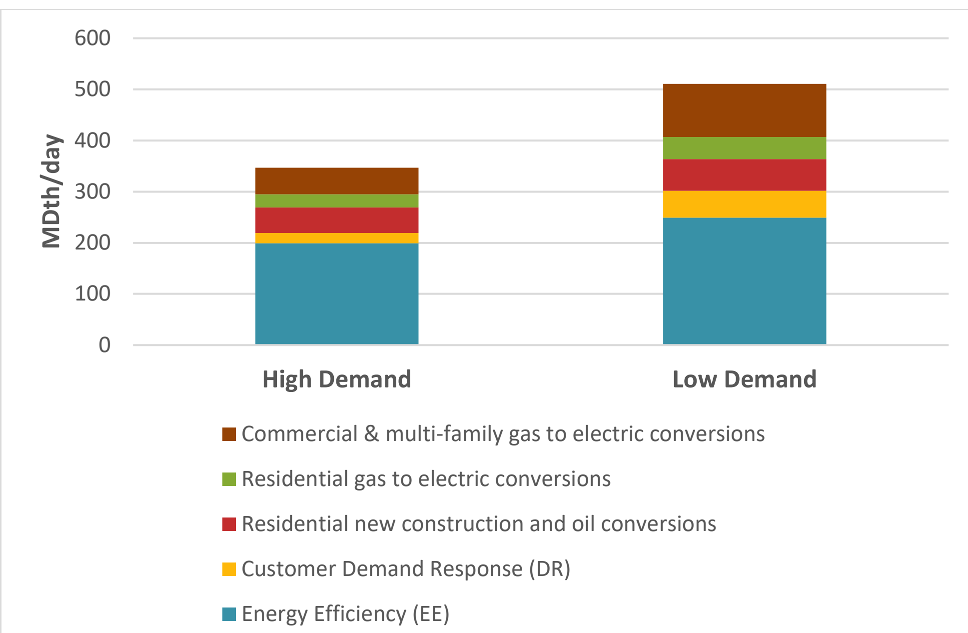
Table 11. Design day demand reduction estimates under the Low and High Demand scenarios

Program	Reduction of Design Day Demand (MDth/day)			
	2019/20	2024/25	2029/30	2034/35
Energy Efficiency (EE)	1	39-49	129-161	199-249
Customer Demand Response (DR)	9	10-36	20-47	20-53
Electrification	0	8-11	32-46	127-209
TOTAL	10	47-96	181-254	346-511

Source: National Grid 2020. Table 11 and 13.

Figure 3 below summarizes the design day load reductions presented in the report. They are 347 MDth/day for the High Demand scenario and 511 MDth/day for the Low Demand scenario. The Baseline demand increase over the same period is 870 MDth/day which results in supply gaps of 265 to 415 MDth/day, as identified in the Capacity Report. If the Baseline forecast is too high (as discussed in Section 2), the actual supply gap is smaller. Similarly, if the existing policies and programs would result in greater reductions than National Grid estimates, the actual supply gap is smaller.

Figure 3. Design day load reductions 2034/35



Source: Synapse from the National Grid Capacity Report.

3.2 Impacts from Natural Gas Energy Efficiency Policies and Programs

In the Capacity Report, National Grid assumes the level of natural gas energy efficiency investments to comply with the NENY program for 2020 to 2025, and yet neglects to account for NYSERDA's energy efficiency program targets that will affect natural gas use in National Grid's service area. In addition, the report assumes the same level of investments and savings as the 2025 levels beyond this timeframe through 2035. This creates National Grid's Low Demand scenario. For developing the High Demand scenario, the Capacity report assumes that 80 percent of NENY targets are achieved. This scenario results in 0.7 percent of sales in annual incremental gas savings by 2025, instead of 0.8 percent under the Low Demand scenario. The projected impacts of these scenarios are presented in the following table.

Table 12. National Grid's projected impact of NENY energy efficiency programs

Area of Energy Efficiency	Incremental Impact on Design Day Demand (MDth/day)			
	2019/20	2024/25	2029/30	2034/35
High Demand scenario	1	39	129	199
Low Demand scenario	1	49	161	249

Source: National Grid 2020. Table 11.

When developing these gas energy efficiency program forecasts, National Grid made at least one fundamental error: While National Grid's obligation under the NENY program is approximately 0.8 percent of sales in 2025, NY PSC set an overall gas savings target of 1.3 percent including the gas savings target by New York State Energy Research and Authority (NYSERDA). This 1.3 percent target was estimated based on adjusted 2018 sales for cumulative energy efficiency savings.[27] If the target is compared with the sales without any savings adjustment, it would be about 1.2 percent.[28] NY PSC made the following statements regarding this target:

> "This Order establishes the State's commitment to reaching nation-leading annual levels of efficiency savings by 2025 of 3% for electricity and 1.3% for gas." (NY PSC. 2020. Order p. 36)

> "These target levels are necessary and realistic, as well as ambitious" (NY PSC. 2020. Order p. 42)

To present a credible forecast of energy efficiency, National Grid must account for NYSERDA's contribution to natural gas savings under its own service territory. It failed to do so.

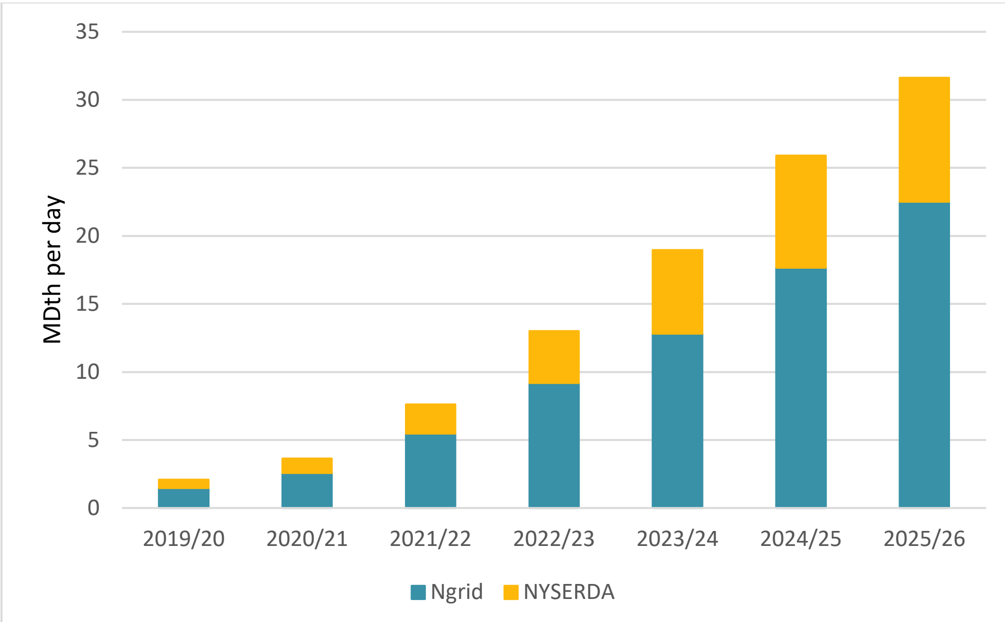
Based on the NYSERDA's contribution toward the NENY target in all the investor-owned utilities' service territories, we developed design day demand reduction estimates of the savings that would be achieved

[27] NY PSC. 2020.

[28] This can be confirmed by estimating cumulative gas savings based on the data in Appendix B to NY PSC (2020).

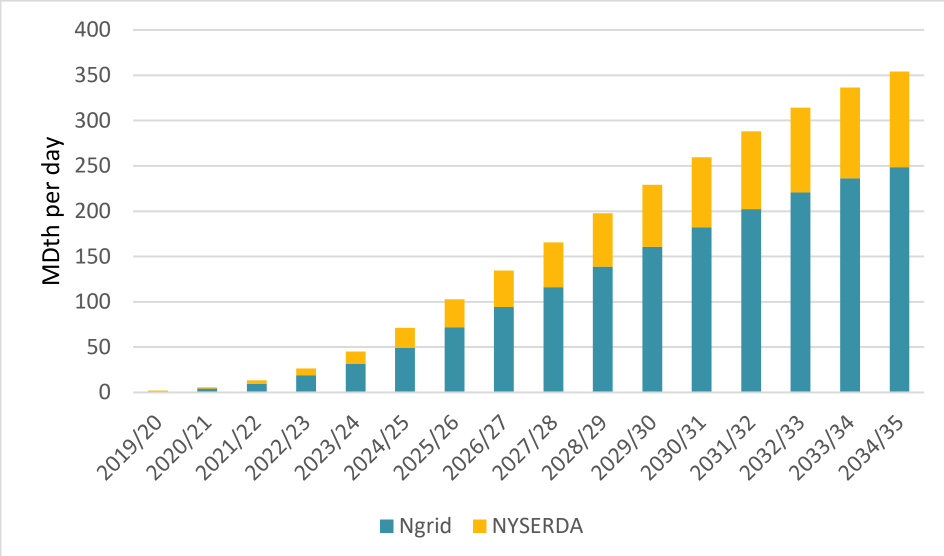
by NYSERDA in National Grid's Downtown NYC territory. Annual incremental gas demand savings by NYSERDA and National Grid through 2025 are presented in Figure 4 below.

Figure 4. Expected annual incremental design day demand reduction impacts of gas efficiency programs by NYSERDA and National Grid under the NENY program



We then estimated annual cumulative gas impacts through 2034/35, assuming that the level of savings stays at the 2025/26 level as shown in Figure 5 below. The total cumulative design day impacts from NYSERDA's gas efficiency programs will be about **110 MDth/day by 2034/35**. This incremental design day load reduction is above and beyond that which National Grid included in the Capacity Report.

Figure 5. Expected annual cumulative design day demand reduction impacts by NYSERDA and National Grid's gas efficiency programs under the NENY program



3.3 Impacts from Demand Response Programs

There is currently no regulation that sets any peak reduction targets from demand response for National Grid. However, National Grid has been testing demand response in its demand response REV (Reforming the Energy Vision) demonstration project.[29] Further, National Grid is now committed to implementing demand response programs along with incentive enhancements to its energy efficiency programs as part of the settlement agreement on its gas moratorium. National Grid agreed to invest $8 million in these programs. The company proposed the following programs in the Implementation and Contingency Plan filed to meet the settlement agreement:

- Peak Demand Response: This program will provide incentives to customers who can reduce gas usage by a predetermined amount when called upon during winter peak events. This program will mainly target large customers.
- Residential Demand Response: This program will engage residential customers to reduce their usage during peak events. The program includes calling for voluntary load reduction during peak demand periods and piloting a bring-your-own-device (BYOD) demand response program.[30]
- Non-Firm Service Offerings: The Company will offer discounts for non-firm service offerings and have a targeted marketing and outreach campaign to customers who recently switched to firm service but still maintain dual-fuel equipment.

[29] National Grid. 2019. National Grid: One-Page Summaries for Four Gas Rev Demonstration Projects. Case 16-G-0058 and Case 16-G-0059, February 15, 2019.

[30] BYOD programs typically recruit customers who already have installed smart thermostats at home and provide a small amount of financial incentive for participation (e.g., $50 per customer).

National Grid projects up to 20 MDth/day of demand reduction from its demand response programs under the High Demand scenario and 50 MDth/day under the Low Demand scenario as shown in Table 13.

Table 13. National Grid's projected impact of demand response programs

Area of Demand Response	Incremental Impact on Design Day Demand (MDth/day)			
	2019/20	2024/25	2029/30	2034/35
High Demand scenario	9	10	20	20
Low Demand scenario	9	36	47	53

Source: National Grid 2020. Table 11.

National Grid's assumptions for demand response for the Low and High Demand scenarios generally follow these proposals, but they appear to extend these programs through 2035.

Details of the assumptions are provided below.

- Commercial & Industrial and Residential Heat Programs
  - Select customers with access to other heating fuels will switch off gas during peak events
  - Select customers will participate in programs to reduce consumption during peak events
  - Reduction in design day demand ramps from 9 to 20 MDth/day
- Temperature Controlled Customers
  - Under High Demand scenario, temperature-controlled (TC) customer conversions to firm service will occur at historical rates
  - Under Low Demand scenario, assume newly proposed temperature-controlled customer tariff will go into effect and temperature-controlled customer conversion rates are 25 percent slower than historical rates[31]

With the cumulative investments of $94 million under the High Demand scenario and $109 million under the Low Demand scenario, National Grid expects to reduce design day peak demand by 20 MDth/day or 53 MDth/day by 2034/35, respectively. This results in the costs of saved peak daily gas of $4,700 per Dth/day for the High scenario and $2,057 per Dth/day for the Low scenario.

[31] National Grid. 2020. Table 10, page 36.

Table 14. National Grid's demand response peak impacts and costs by 2034/35 under the High and Low Demand scenarios

	High Demand	Low Demand
Design Day reduction by 2034/35 (MDth/day)	20	53
Cumulative investment ($ million)	$94	$109
$ per Dth/day	$4,700	$2,057

Source: National Grid. 2020. Table 11, page 36.

The Capacity Report does not provide sufficient data for us to fully examine the proposed demand response plans for these scenarios. However, the cost assumptions appear to be reasonable compared to the recent performance of large customer gas demand response programs in New York and Massachusetts and other lower cost demand response programs. The incentives for the large customer demand response programs in New York and Massachusetts are set from $300 to $400 per dekatherm (Dth) reduction with a simple average of $350 per Dth.[32] These numbers represent annual compensation. Thus, if this type of program is offered over 15 years, the total cost would be about $5,250 per Dth/day. National Grid's cost estimate for the High Demand case ($4,700 per Dth/day) is close to this value, but the cost estimate for the Low Demand case is much lower. As the portfolio of National Grid's demand response program would include the BYOD program and TC customer offerings which we expect to cost generally lower than large customer demand response programs, the cost of the entire program should be lower than these estimates. The cost for the Low Demand case is substantially lower. This is primarily because all or most of the additional demand reduction in this case beyond the Low Demand case comes from TC customers whose costs are low. Per the Technical Appendix to the Capacity Report issued on April 1, National Grid assumes $6,500 per year incentives per TC customer and 50 DTh/day of savings per customer. This results in an annual incentive level of only $13 per therm/day.

3.4 Impacts from Heat Pump Policies and Programs

National Grid estimated impacts of heat pump installations on natural gas peak day loads due to the following three factors: (a) New York City's Local Law 97, (b) NENY Heat Pump targets by ConEd and PSEG Long Island, and (c) organic adoption of heat pump technologies. We will discuss each of these factors under this section.

In Table 13 of the Capacity Report, National Grid indicates electrification impacts of 127 to 209 MDth/day in 2034/35. The utility identifies the following categories for electrification (the range of design day savings corresponds to low or high estimates for heat pump adoption within each category):

[32] Kurt Roth. March 21, 2019. "Gas Demand Response: The Next Frontier." Presented at AEE East Energy Conference. Available at https://cdn2.hubspot.net/hubfs/55819/Fraunhofer-GasDR-GlobalCon-FINAL-updated.pdf.

- NENY and continued utility heat pump programs (labeled "residential new construction and oil conversions" in the Capacity Report): 50-62 MDth/day
- Organic adoption of residential heat pumps (labeled "residential gas to electric conversions" in the Capacity Report): 26-43 MDth/day
- Commercial & multi-family gas to electric conversions driven by Local Law 97 and organic adoption: 52-104 MDth/day

Electrification savings occur overwhelmingly in the last five years of National Grid's analysis, as shown in Table 15.

Table 15. National Grid's projected impact of electrification resulting from LL97, NENY, and organic heat pump adoption

Area of Electrification	Incremental Impact on Design Day Demand (MDth/day)			
	2019/20	2020/25	2029/30	2034/35
Residential new construction and oil conversions	0	8-11	30-36	50-62
Residential gas to electric conversions	0	0	0-1	26-43
Commercial & multi-family gas to electric conversions	0	0-1	2-10	52-104
TOTAL	0	8-11	32-46	127-209

Source: National Grid Capacity Report, Table 13.

3.4.1 Local Law 97

One important driver for increased efficiency and fuel switching is New York City's Local Law 97 (LL97). Under this regulation, buildings larger than 25,000 square feet will be required to meet certain CO_2 emissions limits based on building type. The compliance period begins in 2024, and even stricter guidelines are set for 2030. For building owners who currently do not meet the targets, stepping up their energy efficiency measures will be crucial. However, certain buildings are so far past the threshold that typical efficiency measures will not be enough to ensure compliance. In these cases, switching to heat pump systems will be the most viable way to meaningfully reduce emissions. Even though the electricity provided by New York's Independent System Operator is not currently emissions-free, the recently passed CLCPA mandates that 70 percent of electric sector generation be produced by renewable energy by 2030. Therefore, CO_2 emissions resulting from electrified heating will decrease over time as the grid gets cleaner. Building owners looking ahead to 2030 compliance are likely to consider heat pump systems so that their buildings' emissions will fall without further capital investment in their buildings. We show in this section how accounting for this electrification would reduce National Grid's claimed supply gap by between 49 and 245 MDth/day by 2030, depending on adoption assumptions.

Using benchmarking data from Local Law 84 (LL84) related to energy usage in buildings,[33] Synapse analyzed the number of properties within National Grid's service area that currently emit more than the limits defined by LL97. In order to assess the magnitude of the impacts of LL97 before 2030, when the second compliance period begins with stricter emission thresholds, we selected certain building types for which we can match the right building categories in the LL84 database. These types also account for a large share of total emissions among all building types (especially multi-family buildings). For these building types, we identified the number and floor area of buildings that will be required to reduce their emissions intensities by at least 25 percent in order to meet the 2030 emission thresholds. We assume that this will be the share of buildings that will require major energy retrofits, likely to include electrification, in order to comply with the 2030 emission thresholds.

Table 16. Portion of large buildings and floor area in major categories that will require major retrofits to comply with the 2030 GHG emission limits established by Local Law 97

Benchmarking Dataset Category	Local Law 97 Category	Carbon Limit (kg CO2e/SF)	Percent of buildings that will require major retrofits	Percent of square footage that will require major retrofits
Multi-Family Housing	R-2	4.07	43%	35%
Office	B- Non Emergency	4.53	46%	39%
Hotel	R-1	5.26	38%	34%
Hospital (General Medical & Surgical)	B- Emergency	11.93	46%	33%
Weighted average			43%	35%

Source: Synapse analysis based on Local Law 84 benchmarking data.

The Capacity Report accounts for the impacts of LL97 by assuming that heat pumps' share of the HVAC replacement market will grow over time. However, the way that National Grid models the market effects of LL97 is too conservative. First, National Grid assumes that the annual HVAC replacement rate is 5 percent of the total HVAC stock (reflecting a 20-year HVAC equipment lifetime). Given that the strict 2030 compliance targets enter into force in just 10 years, and nearly one-third of building floor area will require major retrofits to comply, this additional demand will add to the underlying equipment-turnover dynamic. The result will be a faster equipment turnover rate in the coming decade. Second, National Grid assumes that the impacts of LL97 are concentrated after 2030 (with design day savings in 2034/35 10 to 25 times those assumed in 2029/30). Instead, National Grid should have assumed that heat pump share would grow earlier, and to a level sufficient to reach one-third of the building floor area by 2030. Continued heat pump installations after the 2030 compliance date are likely, reflecting both a maturing

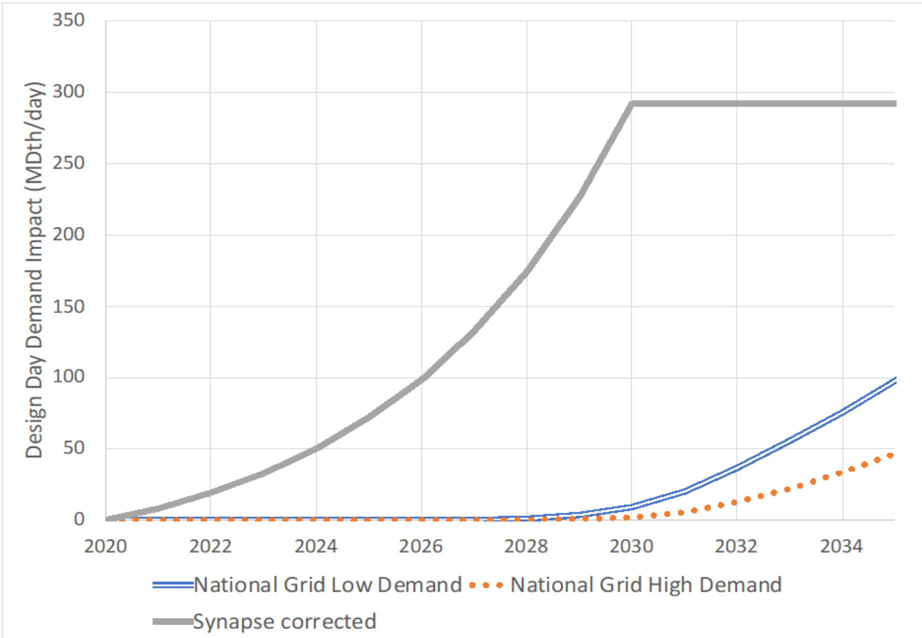
[33] 2018 Energy and Water Data Disclosure, available at https://www1.nyc.gov/html/gbee/downloads/excel/nyc_benchmarking_disclosure_2017_consumption_data.xlsx

market and likely stricter LL97 requirements for the compliance period starting 2036. However, to be conservative we assumed no further installations in our calculations.

We estimated the impact of National Grid's overly conservative LL97 assumptions and produced a comparative analysis that reflects the actual share of buildings likely to electrify before 2030. Even in the Low Demand case, National Grid assumes that just 1.2 percent of KEDNY C&I floor area uses heat pumps in 2030, and 1.1 percent of multi-family floor area.[34] (In the High Demand case the fractions are even lower: 0.3 percent for each market). Instead, we assume that one-third of C&I and multi-family floor area electrify by 2030 (conservatively based on the analysis shown in Table 16). For further conservativism, we assume that KEDNY electrification then ceases entirely after 2030, reflecting the potential that LL97 compliance may lag the start of the compliance period by a few years (and one key metric is the impact on demand in 2035). In our calculation, design day load in 2035 is **195 MDth/day lower than National Grid's Low Demand case, and 245 MDth/day lower than the High Demand case** (see Figure 6). Even if we very conservatively assume that electrification driven by LL97 is half as much (one-sixth of floor area), design day demand would still be 49 MDth/day less than the Low Demand case, and 99 MDth/day less than the High Demand case.

[34] Calculated by Synapse based on the heat pump installations and share in the Capacity Report Technical Appendix, using data from Figure 15 (page 31) of the Capacity Report and the assumptions in Table 12 on page 38.

Figure 6. Design day impact from LL97-driven electrification in KEDNY under National Grid's Low and High Demand cases, and corrected to electrify buildings that require a major retrofit to comply with LL97 by 2030



Source: Synapse analysis based on National Grid Capacity Report Technical Appendix and NYC LL84 benchmarking data.

3.4.2 NENY heat pump targets

The NENY program set targets for heat-pump-related energy savings for investor-owned utilities.[35] While the NENY program does not have any specific target for PSEG Long Island, NY PSC's January 2020 order that established the heat pump targets directed the utilities, the PSC staff, and NYSERDA to coordinate with PSEG Long Island "to facilitate and ensure that heat pump deployment on Long Island is consistent with the statewide framework."[36] National Grid's Capacity Report underestimates the effect of these programs on its design day demand.

National Grid's analysis includes gas peak savings from heat pump programs by Con Edison and PSEG Long Island under the NENY program because their service areas overlap with National Grid's service area. NENY targets are available through 2025. Thus, after 2025, National Grid assumes the same level of program-driven heat pump installations at 2025 levels through 2035. National Grid also assumes that 30 percent of the heat pump targets by these two utilities result in the loss of gas heating customers

[35] NY PSC. 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025. CASE 18-M-0084. January 16, 2020.

[36] NY PSC. 2020, page 92.

from National Grid Downtown NY utilities.[37] This ratio is informed by National Grid's assessment based on "geographic mismatches and the presence of fuel oil-heated buildings."

National Grid's assumption of the 30 percent factor to discount the impacts from Con Edison and PSEG Long Island's heat pump targets is not well supported. First of all, National Grid has failed to provide any estimate or calculations of the impact of heat pump adoption by oil-heat customers on the rate of conversion from those heat sources to natural gas. While the Capacity Report mentions this effect for oil customers, the promised discussion in Section 5.2 is not provided.[38] Instead, the only way that oil-heat customers are accounted for in the electrification discussion is to minimize the potential impact of NENY on gas customers by using the ability of NENY programs to target oil customers as a reason for the low (30 percent) overlaps between NENY heat pump programs and National Grid gas customers.

Secondly, based on geographic area matches among utility service areas, National Grid's Long Island service area (KEDLI service area) and PSEG Long Island serve the same territory, and thus their overlap area is 100 percent. Further, Con Edison's service territory overlaps with National Grid's NYC area (KEDNY) by nearly 55 percent in terms of the population (Table 17). (It is likely that overlap for single-family or small multi-family buildings is higher, given the distribution of density and building typologies within New York City.)

Table 17. Geographic match of National Grid area with Con Edison and PSEG Long Island based on population

	Population
ConEd and KEDNY overlapping area	4,913,658
ConEd only area	4,039,167
ConEd and KEDNY overlapping area (% of total)	55%

Lastly, it is not clear that National Grid has treated the presence of fuel oil heating homes appropriately when calculating the NENY program overlap factor. Our key assumptions for KEDNY and KEDLI are provided below:

- KEDNY territory has a very limited number of oil heating customers. Thus, we simply assume that 55 percent of the impact of Con Edison's NENY heat pump program will impact KEDNY's natural gas customer base.
- KEDLI still has a large portion of oil heated homes. According to National Grid's 2018-2019 Winter Supply Review report, the oil heating saturation is likely to be about 53 percent.[39] If we assume only 50 percent of such oil customers live close to gas distribution (and are thus future KEDLI customers), and further assume that 70 percent of heat pump installations under PSEG program are oil customers, we can expect about

[37] National Grid. 2020. Table 12. Page 38.

[38] See the Capacity Report in the Executive Summary on page 8 and Section 5.1 on page 30.

[39] National Grid. 2018. 2018-2019 Winter Supply Review, page 31.

19 percent of the total population (53% x 50% x 70% = 19%) are the oil heating customers who could switch to natural gas and are targeted by PSEG's heat pump program (Table 18). Using a similar logic, we estimate that about 14 percent of all customers in Long Island are gas heating customers who will be targets of PSEG's heat pump program because about 30 percent of the targets of the heat pump program may be gas customers (47% x 30% = 14%). These assumptions are provided in Table 18 below. Counting both gas and oil customers to estimate the total population whose choice of a heat pump would affect KEDLI's future growth, the total program overlap in KEDLI area is approximately 33 percent.

Table 18. Calculations of NENY heat pump program factor for KEDLI

	LI fuel mix	HP market applicability	HP program fuel target	Total match (customers selecting HP over gas)
Gas	47%	100%	30%	14%
Oil	53%	50%	70%	19%
Total	100%	74%*	100%	33%

** Weighted average value*

Finally, National Grid states that PSEG Long Island will target a similar level of heat pump installations over the same period to the targets set for Con Edison. Thus, the combined overlap factor for KEDLI and KEDNY territories is about 44 percent, which is a simple average between the 55 percent factor for KEDNY and the 33 percent for KEDLI.

We reassessed the impacts of NENY heat pump programs in National Grid territory using a 44 percent impact factor instead of National Grid's assumption of 30 percent in Table 19 below. This calculation results in total adjusted NENY program impacts of about 72 MDth/day for the High Demand scenario (an increase of about 22 MDth) and about 90 MDth/day for the Low Demand scenario (an increase of 28 MDth).

Table 19. Adjusted heat pump impacts from NENY program in National Grid territory

	2034/35	Notes
High Demand		
Total ConEd and PSEG LI HP	207	Based on NGrid's assumption
NGrid estimate on NENY heat pump	50	80% of the Low Demand scenario
Adjusted NENY heat pump	**72**	**44% overlap instead of 30%**
Difference from NGrid estimate	**22**	Calculated
Low Demand		
Total ConEd and PSEG LI HP	207	Based on NGrid's assumption
NGrid estimate on NENY heat pump	62	Based on 30% overlap with ConEd and PSEG LI programs
Adjusted NENY heat pump impact	**90**	**44% overlap instead of 30%**
Difference from NGrid estimate	**28**	Calculated

3.4.3 Organic heat pump adoption

National Grid assumed no organic adoption of heat pumps in the residential portion of the KEDNY territory, or in any portion of the KEDLI territory, until 2030. “Organic” adoption means adoption outside of participation in any utility program (utility program participants are captured in the NENY analysis). Further, heat pump adoption in commercial and multi-family buildings in KEDNY territory is assumed to be captured in the analysis of LL97 compliance. The combined effect of National Grid’s assumptions for NENY (adoption is flat after 2025 because programs are assumed to stop growing) and organic adoption (beginning in 2030) is that the overall heat pump market share for non-LL97 buildings is flat between 2025 and 2030. By failing to include expanded utility programs and delaying organic adoption, the analysis minimizes the potential cumulative design day savings that would accrue from steady market growth.

National Grid’s assumption of flat heat pump adoption for five years, followed by increased adoption only in the last few years of the analysis period, is arbitrary and unsupported in the face of reasonable expectations for a maturing market and policy reality. We expect the heat pump market will mature over the next decade, mainly driven by (a) NENY programs, (b) spillover into Long Island from installers in New York City with commercial and multi-family heat pump experience to comply with LL97, and (c) technological improvement in heat pumps. With such market maturity for heat pumps (with more experienced installers and increased economies of scale) we expect that the economics of heat pumps compared with alternatives will improve. Each building is unique and offers unique opportunities to optimize customer economic and comfort needs. As customer economics for heat pumps improve overall, more customers will find that heat pumps are the right fit for their buildings.

3.4.4 Summary of heat pump impacts

Our analysis found that National Grid failed to account for a substantial portion of the expected gas impacts from heat pump installations associated with NENY utility programs as well as LL97. Table 20 provides a summary of our estimates of adjusted design day demand impacts from electrification measures for the Low and High Demand scenarios. For the purpose of this analysis, we adopted National Grid’s assumption of the impact of organic adoption of heat pumps as we do not have any specific evidence to suggest alternative adoption rates (although as mentioned above we believe National Grid underestimates the organic adoption rates in particular prior to 2031). Taken together, our estimates of heat pump impacts from these policy and market factors result in approximately 370 to 410 MDth/day reductions, which are about 250 MDth higher for the High Demand scenario, and about 200 MDth higher for the Low Demand Scenario, than National Grid’s estimates.

Table 20. Summary of adjusted design day demand impacts from electrification for the Low and High Demand scenarios

Area of Electrification	Incremental Impact on Design Day Demand (MDth/day)			
	2019/20	2024/25	2029/30	2034/35
Residential new construction and oil conversions (NENY impacts)	0	13-16	42-53	72-90
Residential gas to electric conversions (organic heat pumps adoption)	0	0-0.5	0-1	26-43
Commercial & multi-family gas to electric conversions	0	72	292	297-300
TOTAL	***0***	**85-89**	**334-346**	**395-433**
National Grid Total	***0***	***8-11***	***32-46***	***127-209***
Difference	***0***	**77-78**	**302-300**	**268-224**

3.5 Summary of Expected Design Day Demand Impacts for Filling the Demand and Supply Gap

In its Capacity Report, National Grid identified a future demand and supply gap ranging from 265 to 415 MDth/day, which represents a 12.4 percent load increase under the Low scenario and a 17.7 percent increase under the High scenario.[40] It is this gap that National Grid uses to justify the need for various supply measures, including the NESE pipeline. Our analysis shows that the total expected impacts of recent policies on energy efficiency, demand response, and electrification are substantial and National Grid has failed to account for a large amount of the demand reductions expected from these policies.

We estimated that the total expected design day demand reductions from the recent policies range from approximately 690 MDth/day to 820 MDth/day, as shown in Table 21 below. These reduction estimates are about 340 MDth greater under the High Demand scenario and 310 MDth greater under the Low Demand scenario than National Grid's estimates. Under the Low Demand scenario, the additional demand reduction estimate in fact easily exceeds the demand and supply gap of 265 MDth/day by about 30 percent. Under the High Demand scenario, the additional demand reduction estimate is about 75 percent of the gap of 415 MDth/day. However, as we discussed in Section 2, we conclude that National Grid overestimates its peak load by more than 240 MDth/day due to outdated assumptions on fuel conversion rates. With this demand adjustment, the additional demand reduction estimates under the High Demand scenario can easily surpass the supply gap and the Low Demand case would project falling design day load.

[40] The 265 gap is equivalent to a load of 3,190 MDth/day, and the 415 gap is equivalent to a load of 3,340 MDth/day on the base supply level of 2,925 MDth/day.

Table 21. Summary of expected design day demand impacts from energy efficiency, demand response, and electrification for the Low and High Demand scenarios

Program	Reduction of Design Day Demand (MDth/day)			
	2019/20	2024/25	2029/30	2034/35
National Grid Capacity Report				
Energy Efficiency (EE)	1	39-49	129-161	199-249
Customer Demand Response (DR)	9	10-36	20-47	20-53
Electrification	0	8-11	32-46	127-209
TOTAL	10	47-96	181-254	346-511
Synapse Adjusted Estimates				
Energy Efficiency (EE)	2	57-71	183-229	283-354
Customer Demand Response (DR)	9	10-36	20-47	20-53
Electrification	0	85-89	334-346	395-433
TOTAL	10	152-196	537-621	699-841
Difference	**0**	105-100	356-367	353-330

4 Long-Term Gas Supply Resource Options

As a state-regulated natural gas utility, National Grid must plan for the current and future requirements of customers in its service area. National Grid's primary supply planning goals are: (1) to maintain a diverse portfolio of gas supply, storage, and transportation capacity contracts with varying terms and pricing provisions; (2) to dispatch the gas supply portfolio under a least-cost strategy to reliably meet projected primary firm demand; and (3) to implement a formal hedging program to mitigate price volatility.[41] National Grid also recognizes the need to support New York State's decarbonization goals.[42] This section examines how National Grid has identified and evaluated long-term resource options that would be incorporated into an updated gas supply plan.

4.1 National Grid's Existing Gas Supply Resources

National Grid's gas resource portfolio includes pipeline-delivered supplies and on-system resources.

4.1.1 Pipeline-delivered gas supplies

National Grid physically connects to three interstate pipelines at five delivery meters (often referred to as "city gates"). Through an arrangement with Con Edison, National Grid also has access to a fourth upstream pipeline and can therefore receive gas at a total of 10 city gates.[43]

[41] Cases 19-G-0309/19-G-0310, Testimony of Elizabeth D. Arangio, p. 17.

[42] National Grid. 2020, p. 7.

[43] National Grid. 2020, p. 22.

National Grid secures access to pipeline-delivered gas in two ways. First, National Grid contracts directly with pipeline operators for gas transportation service from upstream supply points to New York City and Long Island (NYC/LI) city gates. These are typically long-term contracts that give National Grid the right to continue to take service after the end of the primary term. National Grid essentially "reserves" pipeline capacity, up to the daily contract quantity, and can release capacity to another shipper when it is not needed for system supply.

Transcontinental Gas Pipe Line (Transco) is National Grid's largest pipeline supplier, and it accounts for 60 percent of the company-contracted capacity to National Grid city gates.

Table 22. National Grid long-term pipeline contracts, 2018–19

Pipeline Operator	Parent	MDth	%
Transcontinental Gas Pipe Line	Williams	1,288.5	59.6
Texas Eastern Transmission	Enbridge	406.4	18.8
Iroquois Gas Transmission System	TransCanada/ Dominion	400.7	18.5
Tennessee Gas Pipeline	Kinder Morgan	65.5	3.0
Total		**2,161.2**	**100.0**

Source: Cases 19-G-0309/19-G-0310, Testimony of Elizabeth D. Arangio, Exhibit EDA-1.

The second way that National Grid obtains pipeline-delivered gas supply is by buying gas delivered to its city gates by the seller. In most cases National Grid enters into purchase contracts that give the company a call on a defined quantity of gas during the winter heating season. National Grid currently has long-term agreements with cogeneration plant operators whose facilities are located on the National Grid distribution system. The company also has short-term agreements with gas marketers that typically have terms of one to three years.

4.1.2 On-system resources

National Grid currently has three types of on-system gas supply resources.

Liquefied Natural Gas (LNG): National Grid operates two LNG peaking facilities. The Holtsville facility on Long Island can store approximately 600 MDth, and it has daily production (vaporization) capability of 103 MDth. The daily refill (liquefaction) capability is 6 MDth. The larger Greenpoint facility in Brooklyn has a storage capacity of 1,600 MDth, daily vaporization capability of 291 MDth, and daily liquefaction capability of 7 to 8.5 MDth.

Compressed Natural Gas (CNG): National Grid operates two CNG receiving sites with a daily capacity of 16.8 MDth. The utility plans to develop two more sites by the end of 2021 to increase daily capacity to 53 MDth, based on approximately eight hours of operation per day. Injecting CNG into the distribution system during the morning and evening, when gas use is the highest, helps address peak hour concerns.

Renewable Natural Gas (RNG): National Grid receives about 1.6 MDth of RNG from the Fresh Kills landfill on Staten Island. A biogas project at the Newtown Creek wastewater treatment plant will add another 1 MDth.

4.1.3 National Grid's 2019–20 gas supply portfolio

National Grid's supply portfolio for the 2019–20 winter season is shown below.

Table 23. National Grid gas supply, 2019–20 design day

	MDth	%
Pipeline Contracts	2,102.8	70.2
Delivered Peaking – Long Term	65.1	2.2
Delivered Peaking – Short Term	415.4	13.9
LNG Peaking	394.5	13.2
Compressed Natural Gas	16.8	0.5
Renewable Natural Gas	1.6	<0.1
Total	**2,996.2**	**100.0**

Source: Case 19-M-382, November 8, 2019, Table 1a.

The city gate delivery capacity of National Grid's pipeline contracts provides 70 percent of its design day supply. For the 2019–20 winter, National Grid contracted for 480 MDth of delivered peaking supply, which is 16 percent of the total. Production from on-system LNG peaking facilities provided another 13 percent.

4.2 National Grid's Projected Gap Between Supply and Requirements

As discussed above, the Capacity Report includes a Baseline design day demand forecast that assumes current policy and customer use patterns, and High Demand and Low Demand forecasts that include the expected impact of energy efficiency, demand-side management, and electrification initiatives. The average annual growth rate for design day demand over the 15-year planning period is reduced from 1.8 percent in the Baseline case to 1.1 percent for the High Demand case, and 0.8 percent for the Low Demand case.

Even with lower demand growth rates, National Grid says that it will need to increase its gas delivery capacity to avoid a design day deficit. With currently available resources, National Grid projects that gas supplies could fall short of customer requirements under extreme winter conditions as soon as 2023. With the High Demand forecast, the gap between projected customer requirements and gas delivery capacity on the design day grows to approximately 415 MDth in the 2034–35 winter. For the Low Demand case, the gap reaches 265 MDth in 2032–33, and then starts to decline.

Table 24. Design day gas supply vs. requirements (MDth)

	2019–20	2024–25	2029–30	2034–35
Requirements				
High Demand Forecast	2,819	3,043	3,237	3,341
Low Demand Forecast	2,819	3,015	3,164	3,176
Supply				
Pipeline Contracts	2,103	2,112	2,112	2,112
Delivered Peaking Gas	480	365	365	365
LNG Peaking	395	393	393	393
Compressed Natural Gas	17	53	53	53
Renewable Natural Gas	1	3	3	3
Total	**2,996**	**2,925**	**2,925**	**2,925**
Surplus/(Deficit)	**167**	**(90)/(118)**	**(239)/(312)**	**(251)/(416)**

4.3 Gas Supply Resource Options

The Capacity Report presents several alternatives for expanding gas delivery capacity to the National Grid distribution system. The supply resource options are grouped into two categories: large-scale infrastructure options and "distributed" infrastructure options. All of the large-scale options are sized at 400 MDth, while each of the smaller distributed options would add 62 MDth to 100 MDth to design day supply. National Grid does not make any recommendations as to which option or options are best, but it gives each alternative a rating for cost, reliability, safety, environmental impact, and community impact.

4.3.1 Large-scale infrastructure options

Northeast Supply Enhancement (NESE) Pipeline Project

Expanding gas receipt capacity at a new city gate on the Rockaway Peninsula has been an element of National Grid's long-term resource plan for more than a decade. The Transco Rockaway Delivery Lateral, which connects an existing offshore pipeline to the new delivery meter in Queens, was completed in 2015. A second Transco project, the New York Bay Expansion, was placed into service in 2017.

The NESE project is the next stage of Transco's multi-year buildout plan. The 400 MDth expansion would construct 14 miles of onshore pipeline, 22 miles of offshore pipeline, and 54,000 horsepower of compression, at an estimated cost of $926.5 million. National Grid assumes that if all permits are received by mid-2020, the NESE capacity could be in service by December 2021.

LNG Deliveries by Ship

National Grid considers building an offshore or onshore terminal to receive LNG transported by ship. Both options would provide 400 MDth of design day supply. National Grid assumes that an onshore facility could be brought online in 5–6 years, and that an offshore facility would take 6–8 years to complete. The estimated capital cost is $800 million to $1,200 million.

4.3.2 Distributed infrastructure options

Enhancement by Compression (ExC) Pipeline Project

The Iroquois Gas Transmission System (IGTS) proposes to add gas compressors at three existing stations in New York and Connecticut to increase its delivery capacity to existing delivery meters in Long Island and the Bronx by 125 Dth. National Grid and Con Edison have each committed to 62.5 MDth of capacity for an initial term of 20 years. IGTS filed a certificate application with the Federal Energy Regulatory Commission for the ExC Project on January 31, 2020. The project has an estimated cost of $272 million, and a planned in-service date in late 2023.

LNG Delivered by Barge

National Grid considers building a terminal to receive LNG that would be transported by barge. The daily supply capacity would be 100 MDth with two barges off-loading simultaneously. The cost for a two-barge project is estimated to be $410 million, and the time for completion is assumed to be 5–6 years.

Clove Lakes Transmission Loop

National Grid is investigating a distribution system expansion project that would construct approximately eight miles of 30-inch diameter transmission main on Staten Island. The project would remove a bottleneck that currently limits gas receipts from Texas Eastern Transmission (TETCO) at the Goethals city gate. National Grid assumes that it would also need to contract for upstream pipeline capacity on TETCO. The project would increase pipeline-delivered gas supply by 70 MDth to 100 MDth. The estimated cost of the new transmission main is $320 million, and the upstream pipeline service is expected to cost $48 million per year. National Grid assumes that the additional capacity would be available in five years.

New LNG peaking facility

National Grid considers building a third LNG peaking facility to provide up to 100 MDth of daily supply. The company estimates that a new facility with 1,000 MDth of storage and on-site liquefaction would cost $500 million to build. The estimated time to complete the project is 5–6 years.

Table 25. National Grid supply options

Supply Option	Daily Supply (MDth)	Capital Cost ($Million)	Assumed Availability
Transco NESE Project	400	1,000	2021
Offshore LNG Port	400	800	2026
LNG Import Terminal	400	1,200	2026
IGTS ExC Project	62.5	136	2023
LNG Barges	100	410	2026
Clove Lakes Loop	70-100	320	2026
LNG Peaking Facility	100	500	2026

4.4 Critical Assessment of National Grid's Evaluation of Supply Resource Options

4.4.1 National Grid overstates the size of the design day supply shortfall with existing supply resources

National Grid's assumptions about the availability of delivered peaking supplies are overly conservative

National Grid assumes that 65 MDth of supply from peaking arrangements with cogeneration plant operators will continue to be available, and that another 300 MDth will come from short-term contracts for delivered peaking supply. The 365 MDth estimate for total delivered peaking supplies appears to be an assumption, not a hard constraint.

National Grid estimates that 700 MDth of short-term peaking supply is currently available in the market. This number is consistent with the amount of pipeline capacity with primary delivery to New York and Long Island delivery points that is held by gas producers and marketers. Table 26 shows that Transco and TETCO expansions since 2013 have increased daily delivery capacity to NYC/LI city gates by more than 1,200 MDth. Of this total, more than 800 MDth is under contract to non-LDC shippers. This includes gas producers and marketers that are potential suppliers of delivered peaking supplies to National Grid.[44]

Table 26. Recent gas pipeline expansion projects

Pipeline	Expansion Project	Start Date	Total Capacity		NYC/LI City Gates	
			LDC	Non-LDC	LDC	Non-LDC
TETCO	NJ-NY Project	2013	218	582	218	582
Transco	Northeast Supply Link	2013	-	250	-	200
Transco	Northeast Connector	2015	100	-	100	-
Transco	NY Bay Expansion	2017	115	-	115	-
Transco	Riverdale South	2019	-	190	-	50
			433	**1,022**	**433**	**832**

Source: Transco and TETCO Index of Customers Reports for January 1, 2020.

National Grid cites two reasons for limiting short-term delivered peaking supplies to 300 MDth. First, National Grid says that it is "operationally constrained" to 300 MDth. However, the fact that National Grid contracted for 415 MDth of short-term peaking supplies for the 2019–20 winter season indicates that it is able to accept more than 300 MDth of peaking supply into its system if the supply is available.

[44] National Grid's statement that only 274 MDth of capacity has been added over the last 10 years (National Grid. 2020, p. 42) is misleading because it only includes capacity that National Grid has contracted for directly under long-term agreements.

The second reason National Grid gives for capping short-term peaking supply at 300 MDth is that, of the 700 MDth that is available in the market, Con Edison relies on 400 MDth. This number appears to be high. Based on information from Con Edison's more recent rate case, Con Edison contracted for 345 MDth of delivered peaking supply for the 2018–19 winter.[45]

The supply of delivered peaking gas to the New York market for the 2019–20 winter was relatively high because of unusual operating restrictions imposed by TETCO.[46] Nonetheless, based on the available information, it appears reasonable to assume that at least 350 MDth of delivered peaking supply will be available under short-term contracts in future years.

National Grid plans to add 60 MDth from an existing on-system peaking facility

National Grid's capital plan includes investments to upgrade the Greenpoint LNG peaking facility by expanding daily vaporization capacity by 60 MDth and adding truck loading/unloading capability. The new vaporizers are expected to be completed in 2023.[47]

National Grid expects additional renewable natural gas supply to come online

The design day supply projections in Table 24 above only include the Fresh Kills and Newtown Creek RNG projects. National Grid identifies six other RNG development projects that could add 23 MDth by 2026 and observes that there are opportunities to develop additional projects within its service area.[48] For the High Demand Case, National Grid assumes that another 8 MDth of RNG supply will come online by 2035. For the Low Demand Case, National Grid assumes an increase of 18 MDth by 2033. Our analysis assumes the midpoint value of 13 MDth for additional RNG as a reasonably expected value.

Hydrogen blending and power-to-gas are emerging resource options

National Grid has proposed a hydrogen blending study to assess the opportunities to inject hydrogen into the gas system as a supplement supply resource. National Grid estimates that hydrogen could provide 4–16 MDth by 2035.[49] Our analysis assumes the midpoint value of 10 MDth.

Table 27 shows the estimated design day shortfall with the following changes: (1) short-term delivered peaking supply is increased from 300 MDth to 350 MDth; (2) supply from on-system peaking facilities increases by 60 MDth by 2029–30; (3) 13 MDth of additional RNG supply comes online by 2029–30, and (4) 10 MDth of hydrogen-based supply is available by 2034–35. The maximum design day shortfall over the 15-year planning period is reduced to approximately 130 MDth in the Low Demand case and 300

45 Case 19-G-0066, Exhibit GIOSP 3.

46 Case 19-G-0678, Implementation and Contingency Plan, October 21, 2019, p. 9.

47 Cases 19-G-0309/19-G-0310, "Second Supplemental Testimony of Gas Infrastructure and Operations Panel", December 13, 2019, pp. 12-14.

48 National Grid. 2020, p. 45.

49 National Grid. 2020, p. 47.

MDth in the High Demand case, without any of the new infrastructure projects that National Grid identifies in the Capacity Report. This table also shows the amount of gas supply resources National Grid assumed in the Capacity Report and our estimate of additional gas supply resources above the current supply limits. For additional RNG/Hydrogen, we assumed a midpoint value of the range of the estimates from 16 to 35 MDth/day provided by National Grid.

Table 27. Design day gas requirements vs. supply (MDth)

	2024–25	2029–30	2034–35	National Grid's estimate	Additional Supply
Requirements					
High Demand Forecast	3,043	3,237	3,341		
Low Demand Forecast	3,015	3,164	3,176		
Supply					
Pipeline Contracts	2,112	2,112	2,112	2,112	0
Delivered Peaking – Cogen	65	65	65	65	0
Delivered Peaking – Short-Term	350	350	350	300	50
LNG Peaking	393	453	453	393	60
Compressed Natural Gas	53	53	53	53	0
RNG/Hydrogen	3	16	26	19–38 (26 midpoint)	0
Total	**2,976**	**3,036**	**3,046**	**2,924**	**110**
Surplus/(Deficit)	**(39)/(67)**	**(128)/(201)**	**(130)/(295)**		

Note: Numbers may not align or agree exactly due to rounding.

4.4.2 All of the large-scale infrastructure projects exceed the projected need

National Grid has based its gas supply planning on econometric forecasts that assumed current policies and customer usage patterns. As recently as December 2019, National Grid filed a long-term supply-requirements forecast that shows a "net need" for design day gas supply of 385 MDth for the 2028–29 winter season.[50] Table 27 shows that when the impact of energy efficiency programs and decarbonization targets are incorporated into the demand forecast, and expected supply from existing resources is added to the resource portfolio, the projected gap between supply and requirements at the end of 10 years is roughly half of National Grid's previous estimates. The large infrastructure options examined in the Capacity Report that could provide 400 MDth/day are all at least 100 MDth/day larger than the high end of the projected need, after correcting for available additional supply.

4.4.3 National Grid does not address opportunities to coordinate with Con Edison

Under the New York Facilities System agreement, National Grid and Con Edison jointly operate the high-pressure transmission mains that supply gas to both distribution utilities. The Capacity Report does not provide any detail about how this interrelationship between the two utilities affects National Grid's

[50] Cases 19-G-0309/19-G-0310, Second Supplemental Testimony of Elizabeth D. Arangio, Exhibit EDA-6SS.

long-term gas supply planning. For example, National Grid acknowledges that the two companies transact in the same market when acquiring delivered peaking supplies, but it does not discuss how Con Edison's initiatives to increase supply from other pipe and non-pipe resources will affect the availability of delivered peaking supplies to National Grid.

5 Incremental Demand-Side Resource Options

5.1 Summary of No Infrastructure solution

Because National Grid found a supply and demand gap under its Low and High Demand scenarios, it examined the potential and the cost for additional demand-side resources beyond those included in the Low and High Demand scenarios. The company's detailed assumptions are provided in Table 28 below. Based on these assumptions, National Grid estimated the total additional design day reductions of up to 410 MDth/day (in the High Demand case) could be met with 215 MDth/day from energy efficiency, 108 MDth/day from demand response, and 86 MDth/day from electrification (Table 29). Demand-side resources also contribute in varying amounts to the design day performance of all of the infrastructure solutions other than the NESE pipeline.

National Grid calculated that the No Infrastructure solution would have a present value cost of $2.62 billion in the High Demand case (compared with a $1.83 billion cost for the NESE pipeline, for example). In the Low Demand case, National Grid estimated a cost of $1.51 billion.

Table 28. National Grid's assumptions on its No Infrastructure solution

No Infrastructure		
Incremental Energy Efficiency*	• Enhanced energy efficiency will require policies that support programs that exceed current cost tests by including value of carbon reduction and mechanisms to support increased use of renewable and clean energy sources. • Rate case approvals and incentive programs to drive behaviors and increase adoption rates will be required to implement new programs	• Estimated timeline: will need to have impact starting in 2021/22, and continue to build over time • Success will require a >3x increase in Energy Efficiency (EE) from 0.4% of total sales currently to 1.3% of total sales by 2025 (vs. 0.8% NENY target) • Success will require an incremental 20,000 – 40,000 customers per year starting in 2021 to complete energy efficiency programs (50% annual increase vs. current baseline plus NENY)
Incremental Demand Response**	• New demand response programs will require new thermostat set back programs, enhanced program for Temperature-Controlled (TC) customers, incentives for adoption and new rate structures	• Estimated timeline: starting in 2021, all TC customers will be retained; over next five years, incremental demand response will reach roughly half of all residential customers
Incremental Electrification*	• More aggressive electrification will require policies and incentives to drive behaviors to increase customer adoption	• Estimated timeline: starting in 2021, will need 5,000 to 15,000 incremental customers per year to move to electric heat/cooking/industrial use • Electric power generation and transmission/ distribution infrastructure buildout may be required to satisfy increased electric demand driven by electrification

*Source: National Grid 2020, Table 34. page 88 "*In excess of LL97, 80–100 percent of NENY and Downstate NY electric utility electrification program targets, and 25-49 percent organic electrification of heat in retrofit buildings by 2035, all of which are assumed in Demand forecasts ** In excess of planned demand response programs that are assumed to reduce Demand by up to 53 MDth by 2035."*

Table 29. National Grid's estimates of reduction of design day demand for No Infrastructure solution under the High Demand scenario (MDth/day)

Program	2034/35
Energy Efficiency (EE)	216
Customer Demand Response (DR)	108
Electrification	86
Total	**410**

Source: National Grid. 2020. Table 1, page 12.

5.2 Corrections to National Grid's Cost and Benefit Assessments for Incremental Demand-Side Measures

National Grid has overstated the net cost of demand-side solutions to meet either the High Demand or Low Demand gaps. While earlier portions of this report have shown that the supply gap may not actually exist, if we assume that the gap is as National Grid states the demand-side solutions are still highly likely to be the key to a cost-effective approach.

We have identified four major corrections: accounting for NYSERDA efficiency programs; reducing per-unit costs of saved natural gas based on experience in other jurisdictions; including avoided costs of carbon emissions; and including gas savings benefits beyond 2035. We also identified a few other benefits not considered in National Grid's benefit-cost analysis. These include co-benefits of energy efficient air-conditioning with heat pumps, avoided costs of air pollution, and avoided risk of stranded assets.

5.2.1 No incremental cost for NYSERDA programs

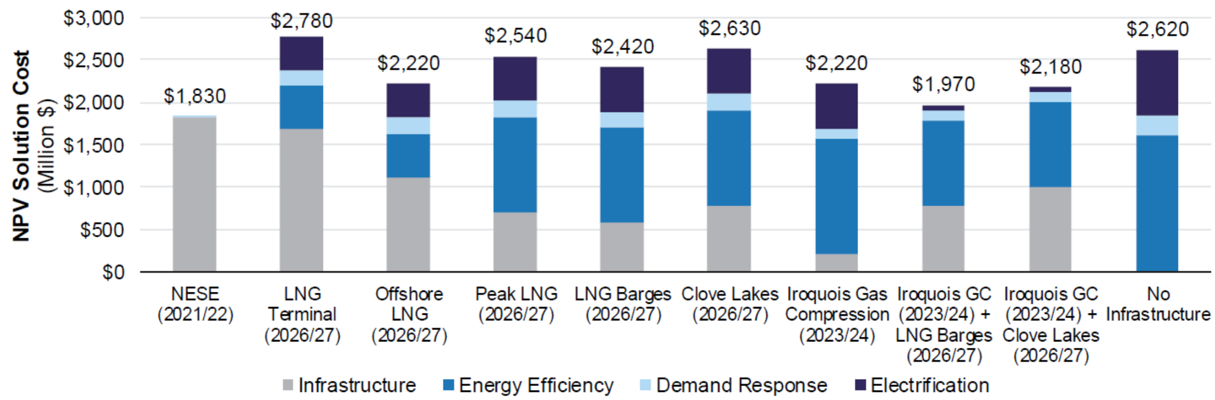
As discussed in Section 3, National Grid overlooked the portion of the gas peak reductions expected from NYSERDA's program within National Grid's Downstate NYC territory. Our estimate of the gas peak savings resulting from NYSERDA's programs is about 105 MDth/day. This means that almost half of the additional energy efficiency programs assumed by National Grid under the High Demand case (216 MDth/day) and the majority of the energy efficiency programs under the Low Demand case (110 MDth/day) result in no additional costs. This is because they are already part of the existing policy impacts. Thus, the cost of the energy efficiency in the No Infrastructure solution should also be cut accordingly.

<u>High Demand case</u>

National Grid estimates that the additional energy efficiency costs a net present value (NPV) of approximately $1,600 million under the High Demand scenario (Figure 7).[51] As NYSERDA's program contribution accounts for 49 percent of this program impact, National Grid overestimated the cost of energy efficiency at least by $780 million under this scenario. With this one adjustment to the cost estimate, the total cost of the No Infrastructure solution under the High Demand scenario would be reduced from $2,620 million to about $1,840 million, a level almost equal to the cost of the NESE pipeline option (Figure 7). With further adjustments to the costs and benefits of the No Infrastructure solution that we will discuss later in this section, it is highly likely that this option would become one of the least-cost options among the options National Grid considered.

[51] National Grid. 2020. Figure 34, page 100.

Figure 7. National Grid's estimates of net costs for different alternatives to close demand-supply gap—High Demand scenario



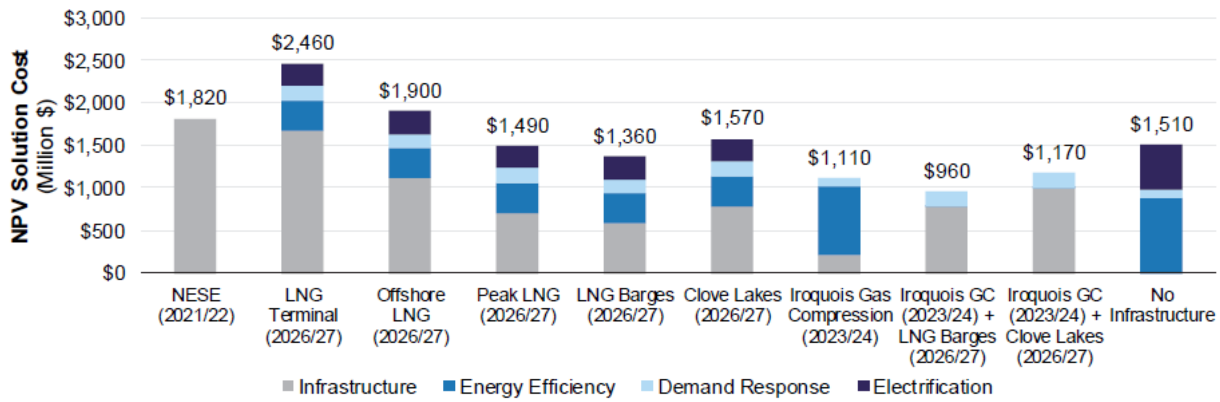
Source: National Grid. 2020. Figure 34, page 100.

<u>Low Demand case</u>

Under the Low Demand scenario, National Grid estimates the impact of additional energy efficiency is about 110 MDth/day.[52] This amount is almost equal to our estimate of NYSERDA's peak savings contribution of 106 MDth/day (or 96 percent of 110 MDth/day) under the same scenario. Since the NPV cost of additional energy efficiency is approximately $800 million as shown in Figure 8 and the savings from NYSERDA's program is $780 million, the majority of National Grid's program cost estimate is not an additional cost to the ratepayers. Taking this correction into account, the total incremental cost of the No Infrastructure solution under the Low Demand scenario would be about $728 million, which makes this scenario one of the lowest cost options among all scenarios.

[52] National Grid. 2020. Figure A-20, page 116.

Figure 8. National Grid's estimates of net costs for different alternatives to close demand-supply gap – Low Demand scenario



Source: National Grid. 2020. Figure 35, page 100.

A summary of our cost adjustments for the Low and High Demand scenarios for the No Infrastructure option is presented in Table 30 below.

Table 30. Synapse' energy efficiency cost corrections to National Grid's cost estimates for the No Infrastructure solution

	High Demand	Low Demand
NGrid total EE cost (NPV $million)	$1,600	$800
NGrid total EE Savings (MDth/day)	216	110
NYSERDA EE savings (MDth/day)	106	106
NYSERDA EE savings (%)	49%	96%
NYSERDA EE cost (NPV $million)	($782)	($782)
NGrid-only EE cost (NPV $million)	$818	$18
Total cost of No Infrastructure solution estimated by National Grid	$2,620	$1,510
Net cost of No Infrastructure solution	**$1,838**	**$728**

5.2.2 Natural gas efficiency costs are overstated

The cost of the No Infrastructure solution is likely to be even lower than the costs presented in Table 30 because National Grid's assumption on the per-unit cost of saved energy (COSE) per therm appears to be grossly overestimated. National Grid's current COSE is $3.8 per therm of first year annual savings. National Grid assumes this cost for its NENY energy efficiency program (reaching 0.8 percent savings by 2025) under the Low Demand scenario and $4.5 per therm for the High Demand scenario (which simply assumes 80 percent savings achievement with the same amount of budget).[53] However, to get to the 1.3 percent savings under the No Infrastructure solution to meet the supply gap, National Grid assumes the COSE "will increase to $9.30–$9.60 per therm on average across customer segments."[54] This cost assumption regarding energy efficiency is overestimated and not supported by any evidence.

We examined the performance of energy efficiency programs by leading gas utilities over the past several years. Figure 9 below presents our assessment of COSE in dollars per lifetime therm savings and savings as a percent of sales for five leading gas utilities' efficiency programs in Massachusetts, Rhode Island, Minnesota, and Michigan from 2010 through 2018.[55] We observe two interesting points in this graph. First, COSE are very different across utilities, even at the same savings level, but are closer to each other within the same region or state.[56] For example, the COSE data from the utilities in Massachusetts and Rhode Island (Eversource and two National Grid data points) are closer to each other than to the COSE from the two utilities in the Midwest (DTE Energy and Center Point).

Secondly, not all of these cases present a clear trend of cost increases when their savings levels were increased. For example, DTE Energy and Center Point Gas in Minnesota did not find any increases in COSE over time even though they increased savings substantially over the past several years (to 1.3 percent by DTE Energy and 1.8 percent by Center Point). On the other hand, gas efficiency programs by National Grid and Eversource in Massachusetts, as well as National Grid Rhode Island, experienced moderate increases in COSE.

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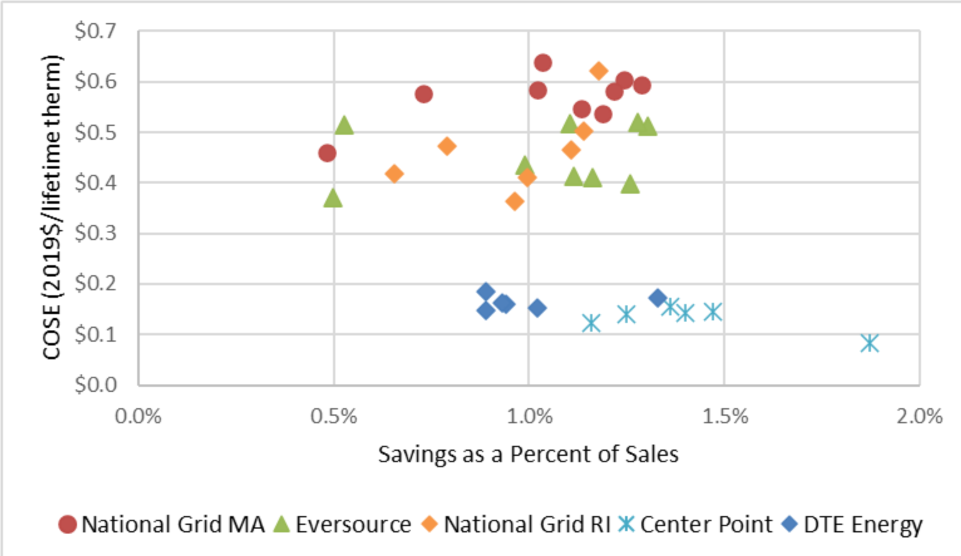
[53] National Grid. 2020. Page 35.

[54] National Grid. 2020. Page 76

[55] Data from 2010 to 2018 for National Grid MA and Eversource, from 2012 to 2018 for National Grid RI and DTE Energy, and from 2013 to 2018 for Center Point Gas in Minnesota.

[56] Levels of energy efficiency program costs generally differ by region because various aspects of energy efficiency programs differ by region and by utility, including target markets, program designs, incentive levels, program delivery mechanism, labor costs, etc. Thus, the costs in one region cannot be directly applied to another region.

Figure 9. Cost of saved energy lifetime vs. savings as a percentage of sales by leading gas utilities



Sources: Mass Save Data, Available at https://www.masssavedata.com/Public/TimeSeries*; National Grid Rhode Island's Energy Efficiency Year-End Report (from 2012-2018); DTE Energy's Annual Report on Energy Optimization (from 2012-2018); CenterPoint Energy's Conservation Improvement Program Status Report (from 2013-2018).*

We examined the COSE data for the three utilities in Massachusetts and Rhode Island in detail (Table 31) and found that their **COSE only increased by about 13 to 16 percent** when they increased efficiency savings from a level at or close to 0.8 percent (the NENY target for National Grid) to a higher level at or close to 1.3 percent (the target under the No Infrastructure option). On the other hand, National Grid in New York assumes that **the COSE will increase by 250 percent** from the current $3.8 per therm (annual savings) to about $9.5 per therm to get to the 1.3 percent savings level.

Table 31. COSE increases by leading gas utilities

	Mid savings level		High savings level		COSE % increase
	COSE lifetime	% of sales	COSE lifetime	% of sales	
National Grid MA	$0.50	0.7%	$0.58	1.3%	16%
Eversource	$0.45	0.5%	$0.51	1.3%	13%
National Grid RI	$0.43	0.8%	$0.49	1.1%	15%

If we were to conservatively assume that the COSE for the energy efficiency program under the No Infrastructure option will increase by 30 percent (which is 30 percent higher costs than experienced by the utilities in Massachusetts and Rhode Island), the COSE for National Grid in New York will be only $4.9 per therm, or about half of National Grid's cost assumption. Applying this factor to the remaining efficiency program cost for National Grid (as shown in Table 32) reduces the total net cost of the No Infrastructure solution by between $9 million and $393 million, reducing the net cost of this scenario to just $1,450 million (High Demand) to $720 million (Low Demand) as shown in Table 32. These corrected cost estimates for the No Infrastructure options are among the lowest cost options even when the same energy efficiency cost adjustments are applied to other infrastructure options that include energy efficiency programs, and they are substantially cheaper than all of the large infrastructure options. However, it is important note that, as our analysis found under Section 3, none of the additional demand-side measures included in the No Infrastructure solution are needed to close National Grid's purported supply gap. These additional measures would, however, help the state meet its long-term climate change goals while providing savings and comfort benefits to National Grid customers.

Table 32. Synapse' estimates of net cost of No Infrastructure solution adjusted for lower EE COSE

	High Demand	Low Demand
Total cost of No Infrastructure solution estimated by National Grid	$2,620	$1,510
Net cost of No Infrastructure solution	**$1,838**	**$728**
EE COSE adjustment/reduction	($393)	($9)
Net cost of No Infrastructure solution adjusted for EE COSE	**$1,445**	**$719**

5.2.3 The value of energy savings needs to be accounted for

Using the values provided in National Grid's Technical Appendix, we have evaluated the present value of the costs for the No Infrastructure options shown in Figures A-19 and A-20 of the Capacity Report. The Capacity Report states in its Figure 4 that the net present value (NPV) of net costs for the No Infrastructure scenario is $2,620 million. However, examining Table 11 of the Technical Appendix, we see that the NPV of the Net Cost, using the same 6.3 percent discount rate as National Grid, is $2,462 million. The NPV of the "Annual Cost", however, is $2,627 million – within rounding error of the value from Figure 4. Therefore, we are forced to conclude that National Grid has simply not included the savings in commodity gas when evaluating the value of the No Infrastructure solutions. The same error is repeated in the Low Demand case, where the total cost ($1,510 million) in Figure 5 of the Capacity Report does not match the NPV of $1,422 million that would be calculated from the Technical Appendix.

Furthermore, perhaps because of the underlying error, National Grid has not included the benefits from efficiency that would accrue to customers from reduced consumption after 2035. By ignoring these benefits, the utility further understates the benefits that would accrue to customers into the 2040s from the building shell improvements and other long-lasting gas efficiency measures that would be installed as part of these programs. If we assume a 15-year measure life, these savings adjust the No Infrastructure case by $81 million in the High Demand case and $29 million in the Low Demand case. Combining these two corrections, the net cost of the No Infrastructure solution should be reduced by $246 million in the High Demand case (to $1,199 million, when including the other corrections in Table 32) and $145 million in the Low Demand case (to $574 million).

5.2.4 The value of carbon emission reductions needs to be incorporated

National Grid's Capacity Report made a critical oversight in evaluating options for the state's long-term energy investments: It is silent on how the gas infrastructure investment options are incompatible with the Climate Leadership and Community Protection Act (CLCPA). The CLCPA mandates that all sectors of the economy cumulatively achieve 40 percent emissions reductions from 1990 levels by 2030 and 85 percent emissions reductions by 2050, as well as achieve net zero GHGs by 2050. While National Grid failed to address this major policy goal, it should at a minimum address the state's climate change mandate by incorporating the value of avoided carbon emissions in its benefit-cost analysis.

The NY PSC's January 21, 2016 Order, "Order Establishing the Benefit Cost Analysis Framework" established that the social cost of carbon emissions is an appropriate and relevant cost to include in benefit-costs analysis when making decisions about utility investments in energy efficiency.[57] More specifically, the Order directed the use of U.S. Environmental Protection Agency's social cost of carbon value at a 3 percent discount rate, which ranges from $46 per ton in 2020 to $76 per ton in 2050.[58] The Order also directed each investor-owned utility to develop a Benefit-Cost Analysis (BCA) handbook. In fact, National Grid's own BCA handbook appropriately includes the social cost of carbon in its analysis.[59] However, National Grid failed to consider and quantify this benefit from demand-side investments in its Capacity Report. On other hand, when Con Edison filed an application for approval of its non-pipeline solutions portfolio, it included the benefit of avoided carbon values using a $50 per ton carbon value.[60] For consistency, benefits of avoided carbon emissions should also be included when evaluating utility investments as part of a package of solutions to meet the supply gap.

National Grid has not supplied the annual fossil fuel gas combustion emissions associated with each portfolio of solutions to the supply gap, but it is logical to assume that the portfolio with the greatest investment in energy efficiency, demand response, and electrification will have the lowest emissions compared to solution portfolios that increase fossil fuel supply. The resulting value of emission reductions (or cost of emission increases) should be included in the present value calculations of the net cost of each option.

[57] NY PSC. 2016. Order Establishing the Benefit Cost Analysis Framework, January 21, 2016. CASE 14-M-0101.

[58] NY PSC. 2016. Appendix B. Table A.

[59] National Grid. 2018. Benefit-Cost Analysis Handbook Version 2.0, Case 14-M-0101 REV Proceeding, Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B95DCC733-8863-4A52-9DE5-CF5238F40BC3%7D.

[60] Con Edison. 2018. Request for Approval of Non-Pipeline Solutions Portfolio in The Smart Solutions for Natural Gas Customers Program. Case 17-G-0606. September 28, 2018, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=17-G-0606&submit=Search

5.2.5 Other benefits unaccounted for in National Grid's benefit-cost analysis

Other benefits not included in the Capacity Report include co-benefits of energy efficient air-conditioning with heat pumps, avoided costs of air pollution, and avoided risk of stranded assets.

Efficient cooling: Heat pumps that are suitable for cold-climate conditions are energy efficient heating *and* cooling systems. Thus, they can replace existing inefficient air-conditioning systems and save a substantial amount of energy, as well as the capital cost of a separate air conditioner. National Grid assumes a SEER 16 performance,[61] but modern cold-climate minisplit units commonly achieve SEER ratings of over 20.[62] National Grid has not provided the necessary calculations to evaluate whether the Capacity Report accurately accounts for capital savings, or to allow correction for the overly conservative efficiency level. These corrections could improve the calculated cost-effectiveness of heat pumps significantly.

Reduced illnesses: There are numerous studies that have found links between emissions from nitrogen oxide emissions associated with indoor natural gas appliances and serious health problems such as increased respiratory symptoms, asthma attacks, and hospital admissions in people with asthma.[63] Further, smog and toxic air contaminants from natural gas extraction processes, especially in the form of hydraulic fracturing, has been reported to be linked to various health threats such as eye, nose, and throat irritation, respiratory illnesses, central nervous system damage, birth defects, cancer, or premature death.[64] National Grid has not accounted for these non-energy health damage costs when comparing solutions.

Reduced stranded asset risk: Finally, any clean energy options, such as demand-side measures including energy efficiency and heat pumps, can help avoid stranded asset risks from large-scale gas infrastructure investments. Gas infrastructure is typically depreciated over many decades, but New York now has an ambitious CLCPA policy mandate of reaching a net zero emission economy by 2050. While some of the evaluated supply solutions would place this risk on the asset owners rather than on National Grid and its ratepayers, other options that would involve direct National Grid ownership or investment must take this short timeline of useful life into account when evaluating the cost to ratepayers. There is no evidence that National Grid has accounted for the increased burden to ratepayers from stranded assets when evaluating the cost of each option.

[61] National Grid. 2020. Natural Gas Long-Term Capacity Report Technical Appendix, p. 9

[62] See, for example, the Mitsubishi 1.5-ton wall-mounted minisplit unit MSZ-FH18NA2/MUZ-FH18NAH2, which offers a 21 SEER, 11 HSPF, and maintains rated capacity to 5 degrees. (http://meus1.mylinkdrive.com/files/MSZ-FH18NA2-MUZ-FH18NAH2_ProductDataSheet.pdf)

[63] Sierra Club. n.d. "Gas: A Major Source of Indoor Air Pollution," Available at https://www.sierraclub.org/sites/www.sierraclub.org/files/sce-authors/u6902/Gas%20appliances%20indoor%20air%20pollution.pdf.

[64] NRDC. 2014. Fracking Fumes: Air Pollution from Hydraulic Fracturing Threatens Public Health and Communities, Available at https://www.nrdc.org/sites/default/files/fracking-air-pollution-IB.pdf.

6 CONCLUSIONS

National Grid's Capacity Report projected a winter peak demand need and large amount of supply capacity shortfalls in the 2030s. It analyzed various additional supply and demand options to meet its purported supply gap. Our analysis found various errors in National Grid's load forecasts and estimates of supply resources and concludes that the supply gap most likely does not exist. Our analysis also found National Grid grossly overestimated the costs of demand-side resources, in particular energy efficiency, and grossly underestimates benefits of such resources. Finally, our analysis concludes that National Grid's analysis of long-term capacity options is not compatible with New York's climate change policies and identified the need to include the cost of avoided carbon emissions in the benefit-cost analysis.

6.1 The Supply Gap Most Likely Does Not Exist

The analysis presented in this report shows that National Grid's projected Baseline demand is too high by approximately 240 MDth/day or 6.5 percent of the Baseline demand forecast, primarily because of overly optimistic projections of the rate of fuel conversion to natural gas. National Grid has also underestimated the effects of current policies for electrification and energy efficiency in the development of policy-consistent High Demand and Low Demand cases by approximately 330 to 350 MDth/day. Together, correcting these issues with National Grid's Low Demand and High Demand cases would entirely eliminate the supply gap. Further, our analysis found that National Grid is overly conservative in its assumptions regarding the ability to contract for peaking gas supply resources, and it did not include a planned enhancement to an existing LNG facility. We estimate that National Grid has additional supply resources of approximately 110 MDth/day from peaking contracts, and planned LNG facilities.[65] A summary of these corrections to National Grid's analysis is presented in Figure 10 and Figure 11 below. We note that as these load changes from current policies are realized, the need to contract for expensive peak gas supply through compressed natural gas trucking will be eliminated.

[65] We agree that National Grid's assumptions for the availability of RNG and Hydrogen are reasonable.

Figure 10. Closing the gas supply gap with corrections to National Grid's forecast—High Demand scenario

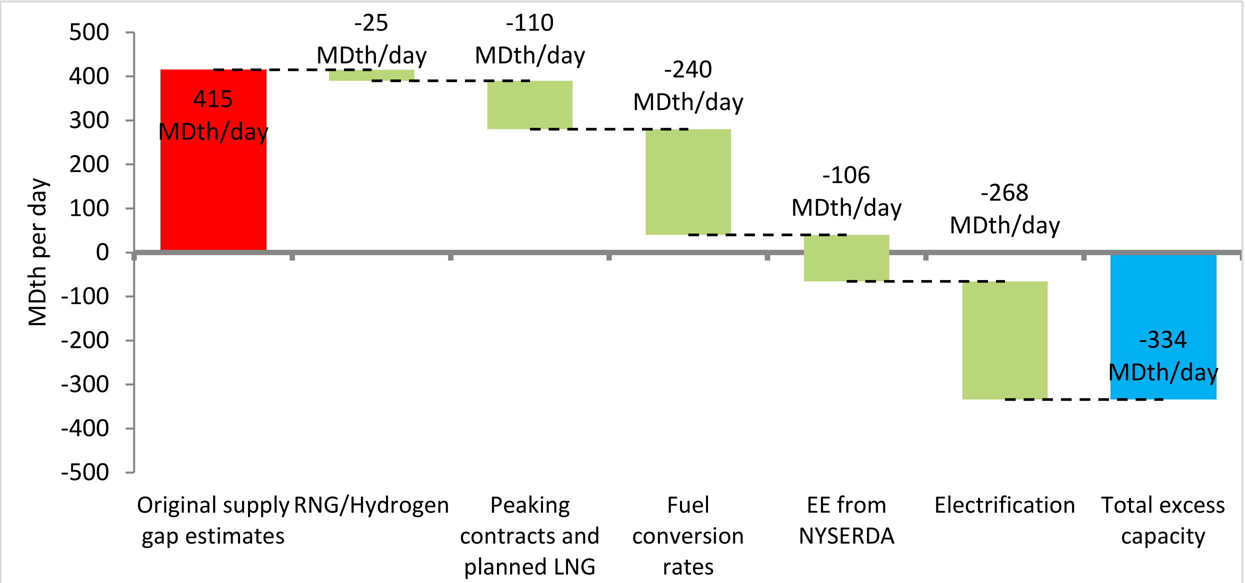
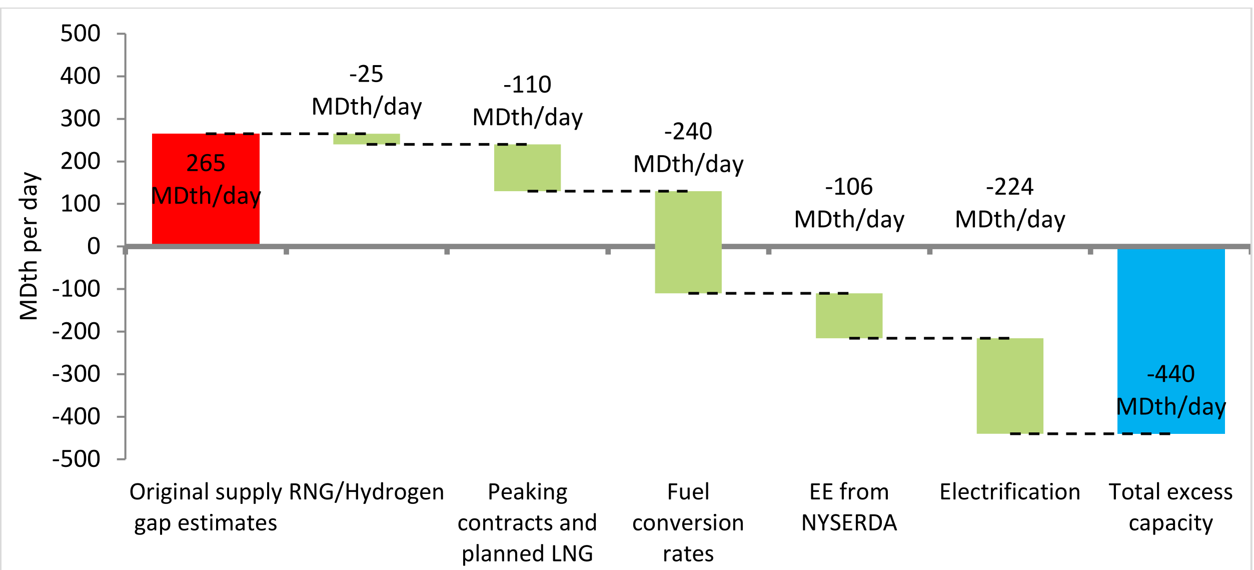


Figure 11. Closing the gas supply gap with corrections to National Grid's forecast—Low Demand scenario



6.2 National Grid has multiple cost-effective demand-side options to meet any foreseeable need

National Grid developed a portfolio of additional demand-side resources including energy efficiency, demand response, and electrification to meet its supposed supply gap. It then estimated the cost of this option along with the cost of other gas supply options. Our analysis concluded that, for this disputed supply gap, the No Infrastructure option would be one of the least-cost solutions among all resource options analyzed by National Grid. As one of its most critical errors, National Grid counted savings equivalent to NYSERDA's natural gas efficiency programs as additional energy efficiency programs even though this initiative is already state policy. Our savings estimate from accounting for NYSERDA's program is approximately $780 million, which needs to be removed from the cost of the No Infrastructure option. Further, our analysis of the COSE from leading natural gas energy efficiency programs reveals that National Grid overestimated the COSE by at least 90 percent using a COSE of $9.50 per first year therm savings. This led National Grid to overestimate the total cost by $390 million under the High Demand scenario and about $10 million under the Low Demand scenario. National Grid also neglected to include the value of energy saved through efficiency programs, which amounts to $145 million in the Low Demand case and $246 million in the High Demand case. Correcting for these factors, we estimate that the No Infrastructure option costs $1,199 million under the High Demand scenario to $574 million under the Low Demand scenario, as summarized in Table 33. This makes the No Infrastructure option one of the most economic options, if not the most, and certainly substantially lower than all of the large infrastructure options including NESE and LNG Terminal options in either the High Demand or Low Demand cases.

Table 33. Summary of cost corrections to No Infrastructure option

	High Demand	Low Demand
Original total cost of No Infra. Option	$2,620	$1,510
NYSERDA EE cost	($782)	($782)
EE COSE adjustment	($393)	($9)
Energy savings value	($246)	($145)
Corrected total cost of No Infrastructure option	**$1,199**	**$574**

6.3 National Grid's analysis of long-term capacity options is not compatible with New York's climate change policies

As stated in this report, National Grid's Capacity Report made a critical oversight dealing with the state's long-term energy investment: It is silent on how the gas infrastructure investment options are incompatible with the state's emission reduction policies. In particular, 85 percent emissions reductions and net zero GHGs by 2050 require planning for retirement, rather than expansion, of fossil fuel infrastructure. While National Grid may consider such an analysis outside of the scope of the Long-Term Capacity Report, any long-term planning that neglects this issue is lacking. Investing in large-scale natural gas infrastructure is likely to hinder more than help the state in meeting its climate policy objectives.

One way to address this issue is to incorporate the value of avoided GHG emissions in benefit-cost analysis. This is a minimum requirement of conducting an analysis of long-term energy solutions for the

Correction: Page 52 of this report was corrected as follows from the original April 6, 2020 version.

supply gap, the No Infrastructure option would be one of the least-cost solutions among all resource options analyzed by National Grid. As one of its most critical errors, National Grid counted savings equivalent to NYSERDA's natural gas efficiency programs as additional energy efficiency programs even though this initiative is already state policy. Our savings estimate from accounting for NYSERDA's program is approximately $780 million, which needs to be removed from the cost of the No Infrastructure option. Further, our analysis of the COSE from leading natural gas energy efficiency programs reveals that National Grid overestimated the COSE by at least 90 percent using a COSE of $9.50 per first year therm savings. This led National Grid to overestimate the total cost by $390 million under the High Demand scenario and about $10 million under the Low Demand scenario. National Grid also neglected to include the value of energy saved through efficiency programs, which amounts to $~~123~~ 145 million in the Low Demand case and $~~180~~ 246 million in the High Demand case. Correcting for these factors, we estimate that the No Infrastructure option costs $1,~~265~~ 199 million under the High Demand scenario to $~~596~~ 574 million under the Low Demand scenario, as summarized in Table 33. This makes the No Infrastructure option one of the most economic options, if not the most, and certainly substantially lower than all of the large infrastructure options including NESE and LNG Terminal options in either the High Demand or Low Demand cases.

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state, in particular because the NY PSC's 2016 order "Order Establishing the Benefit Cost Analysis Framework" established that the social cost of carbon emissions is an appropriate and relevant cost to include in benefit-cost analysis when making decisions about utility investments in energy efficiency.[66] Following the state's benefit-cost framework and to address the intention of the CLCPA, benefits of avoided carbon emissions must be included when evaluating utility investments in efficiency as part of a package of solutions to meet the purported gas supply gap.

In summary, the National Grid Capacity Report, and its accompanying Technical Appendix, is flawed in several critical ways. It describes a supply gap based on an unrealistic load forecast that is out of touch with current policies and market trends. Our analysis shows that this supply gap is highly unlikely to emerge, based on our corrections to various errors National Grid made in constructing its load forecasts. National Grid also overestimates the costs of the demand-side options in its No Infrastructure scenario, thereby depriving ratepayers of what would be the least-cost solution to its purported supply gap. And finally, it omits altogether any discussion of its proposed pipeline and other gas infrastructure solutions in relation to New York's climate targets, and whether such long-term infrastructure would either hinder compliance or saddle ratepayers with stranded assets. A truly comprehensive planning exercise would require remedying these flaws in order to best serve ratepayers and New York's long-term goals.

[66] NY PSC. 2016. Order Establishing the Benefit Cost Analysis Framework, January 21, 2016. CASE 14-M-0101.