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April 29, 2022

New York State Department of Environmental Conservation
Division of Environmental Permits
625 Broadway
Albany, NY 12233-1750
Attention: Christopher Hogan, Chief, Bureau of Energy Project Management
chris.hogan@dec.ny.gov

Re: Iroquois Gas Transmission System, LP
Enhancement By Compression (ExC) Project
Air State Facility Permit ID Nos. 3-1326-00211 and 4-1922-00049

Dear Mr. Hogan:

Enclosed please find Iroquois Gas Transmission System, L.P.'s response to the New York State Department of Environmental Conservation's January 13, 2022, Request for Additional Information related to the above-referenced Air State Facility permit modification applications for the Enhancement by Compression ("ExC") Project.

Feel free to contact me if you have any questions or require additional information.

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.
By its Agent
Iroquois Pipeline Operating Company

By: Michael Kinik
Name: Michael Kinik
Title: Director, Engineering Services

<u>Response to NYSDEC January 13, 2022 Request for Additional Information</u>
Iroquois Gas Transmission System, LP
Enhancement By Compression (ExC) Project
Air State Facility Permit ID Nos. 3-1326-00211 and 4-1922-00049

Below are Iroquois Gas Transmission System, L.P.'s ("Iroquois") responses to the New York State Department of Environmental Conservation's ("DEC") January 13, 2022, Request for Additional Information ("RFAI") associated with Iroquois' applications for minor modifications to the Air State Facility Permits (the "Applications")[1] for Iroquois' Athens Compressor Station (DEC ID No. 4-1922-00049) and Dover Compressor Station (DEC ID No. 3-1326-00211) related to the proposed Enhancement by Compression Project (the "ExC Project" or the "Project").

For convenience, set forth below are Question Nos. 1 through 4 of the RFAI followed by Iroquois' responses.

Question No. 1:

1) GHG Emissions

The first prong requires an initial determination as to whether a project would be inconsistent with or would interfere with the Statewide GHG emission limits set forth in the Act. Based on a review of the current record, including Iroquois' initial CLCPA assessment and October 13, 2021 supplement, DEC has determined additional information is required in order to complete the analysis required by the first prong of CLCPA.

In particular, Iroquois needs to further supplement the record to include the following:

- *a. The GHG potential to emit (PTE) of the ExC Project (direct emissions) in both tons per year (tpy) and carbon dioxide equivalents (CO2e) need to be calculated and provided as part of the record. This can be done using any appropriate emission factor, and should include CO2, Methane, and N2O emissions from each emission source associated with the project. Note that CO2e must be calculated using the 20-year global warming potentials found in 6 NYCRR 496.5.*
- *b. The projected actual direct GHG emissions from the ExC Project, again in both tpy and total CO2e, need to be calculated and reported.*
- *c. the upstream GHG emissions associated with the ExC Project in both tpy and CO2e need to be calculated and reported. (Attached are the emission factors developed by DEC and can be used for this analysis. Alternative emission factors can be used, but a justification for using those alternative emission factors must also be provided.)*
- *d. the downstream emissions associated with the ExC Project need to be calculated and reported. (Attached are downstream emission factors that can be used for this analysis.*

[1] The Applications, as supplemented, and this RFAI response have been filed with DEC without prejudice to any rights that Iroquois now has, may have, or which it seeks to assert in the future under the Natural Gas Act (15 U.S.C. §§ 717–717z) or any other federal or state law or regulation, all of which are hereby expressly reserved.

Alternative downstream emission factors can be used, but a justification for using alternative downstream emission factors must also be provided.)

e. *the projected total emissions from the ExC Project, including upstream and downstream GHG emissions, in the years 2030 and 2050 need to be calculated and reported, if possible.*

Response:

Iroquois maintains that the development and operation of the ExC Project will be consistent with the statewide greenhouse gas ("GHG") emissions limits established by the Climate Leadership and Community Protection Act ("CLCPA"). The "Life Cycle Greenhouse Gas Analysis of the Enhancement by Compression (ExC) Project" prepared by M.J. Bradley and Associates, filed with DEC on October 13, 2021 ("Life Cycle Analysis") demonstrates that life cycle GHG emissions resulting from the Project would be less than the GHG emissions that would result from viable alternative energy sources that would be required to meet the energy demand satisfied by the Project. Based on the results of the Life Cycle Analysis, the Federal Energy Regulatory Commission ("FERC") found, as part of its National Environmental Policy Act ("NEPA")[2] environmental review, that the Project would result in a net reduction of GHG emissions.[3] Accordingly, DEC should determine that the Project is consistent with the CLCPA.

Responses to the specific questions set forth in subsections (a) through (e) of DEC's question are provided below.

a.

Table 1 below provides estimates of direct ExC Project GHG PTE for the Athens and Dover, New York and Brookfield, Connecticut compressor stations. Estimates represent GHG emissions in units of metric tons per year. Emissions are presented for the individual GHG pollutant constituents including carbon dioxide ("CO_2"), methane ("CH_4"), and nitrous oxide ("N_2O"), as well as combined GHG emissions presented as carbon dioxide equivalent (CO_2e). Emissions estimates are based on 20-year global warming potentials as set forth in 6 NYCRR 496.5. Turbine PTE are conservatively based on operating sources at peak load every hour of the year and at a worst case average ambient temperature of zero degrees Fahrenheit. For purposes of this estimate, the Dover emergency engine PTE are based on peak load operation for no more than the 500 operating hours per year in accordance with the air permit exemption limit set forth in 6 NYCRR 201-3.2. The Brookfield emergency engine PTE are based on 8,760 hours of operation per year, since the Brookfield engine criteria pollutant PTE are less than CT's air permit exemption threshold of 15 tons per year.

b.

Table 1 below also provides estimates for projected actual direct ExC Project GHG emissions for the Athens and Dover, New York and Brookfield, Connecticut compressor stations. Projected

[2] 42 U.S.C. §§ 4321–4370m.
[3] Order Issuing Certificate, 178 FERC ¶ 61,200 at P 56.

actual emissions are based on a twenty-five percent (25%) expected "load factor," based on information provided by Con Edison Company of New York, Inc. ("Con Edison") and KeySpan Gas East Corporation d/b/a National Grid ("National Grid" and collectively with Con Edison, the "Project Shippers"). For purposes of this estimate, projected actual emissions from the Dover and Brookfield emergency engines are conservatively estimated based on substantially greater than the annual average actual historic operating hours of either station (i.e., 100 hours per year). There are no proposed modifications to, or additions of, an emergency engine for the Athens or Milford stations.

Table 1				
ExC Project GHG Emissions (20-Year Global Warming Potentials)				
Potential to Emit (PTE) Metric Tons/Year				
	CO2	**CH4**	**N2O**	**GHG (CO2e)**
Athens CS	39,589	1,133	19.7	40,742
Dover CS	39,234	1,314	19.5	40,568
Brookfield CS	74,367	2,788	37	77,192
Milford CS	-3.39	-29,115	0.00	-29,118
Combined Project Emissions	**153,187**	**23,880**	**76.2**	**129,384**
Projected Actual Emissions Metric Tons/Year				
	CO2	**CH4**	**N2O**	**GHG (CO2e)**
Athens CS	9,525	496	4.7	10,025
Dover CS	9,460	473	4.7	9,938
Brookfield CS	19,405	1,269	9.7	20,684
Milford CS	-1.21	-10,429	0.00	-10,430
Combined Project Emissions	**38,389**	**-8,191**	**19.1**	**30,217**
Notes				

- CO2 = carbon monoxide, CH4 = methane and N2O = nitrous oxide.
- GHG estimates include only proposed ExC Project emission sources and modifications.
- Included GHG emissions from the proposed second Brookfield emergency generator and the Dover replacement emergency generator.
- The Athens and Dover air permit applications reported turbine GHG CO2e values in short tons per year and are based on Solar Turbines, Inc. 2019 model which are greater than shown above. Values used above are based on EPA GHG reporting calculation methods.
- CT DEEP air permit application required Iroquois to estimate the Brookfield ExC turbine GHG emissions using the CT DEEP's "CO2 Equivalents Calculator" and 100-year global warming potentials in units of short tons per year. For consistency with this response, Brookfield turbine GHG values above were modified using the same EPA GHG reporting calculation method.
- The Milford CS emissions are negative values because the Project does not propose any new emissions source at Milford but does propose to install a Vent Recovery System at that compressor station.

c. – e.

The upstream, downstream and total lifecycle GHG emissions from the Project were estimated using the “Life Cycle Greenhouse Gas Analysis of the Enhancement by Compression (ExC) Project” prepared by M.J. Bradley and Associates, which Iroquois filed with DEC on October 13, 2021 (“Life Cycle Analysis”). The Life Cycle Analysis estimated Project lifecycle emissions for the entire 20-year period of the Project Shippers’ contract terms. Included in Tables 2 and 3 below are the estimated upstream and downstream GHG emissions for the year 2023 as presented in the Life Cycle Analysis. Included in Table 4 below are the estimated total lifecycle GHG emissions of the ExC Project in the years 2030 and 2050. The estimated 2030 total lifecycle GHG emissions reflect the emission reduction improvements set forth in the Life Cycle Analysis. Estimated GHG emissions in the year 2050 are zero because 2050 is seven years after the anticipated expiration date of the Project Shipper’s 20-year contract terms.

All values in the following tables represent actual emissions provided in annual metric tons per year and the CO_2e values are calculated using IPCC AR5 20-year global warming potential values (CH_4 = 84 and N_2O = 264).

Table 2				
Upstream Anticipated Actual ExC Project GHG Emission (CO2e with 20-Year Global Warming Potentials)				
Annual Emissions	**CO2**	**CH4**	**N2O**	**GHG (CO2e)**
2023	125,491	226,627	274	352,392

Table 3				
Downstream Anticipated Actual ExC Project GHG Emission (CO2e with 20-Year Global Warming Potentials)				
Annual Emissions	**CO2**	**CH4**	**N2O**	**GHG (CO2e)**
2023	581,936	121,287	2,993	706,146

Table 4				
Total Lifecycle Anticipated Actual ExC Project GHG Emission (CO2e with 20-Year Global Warming Potentials)				
Annual Emissions	**CO2**	**CH4**	**N2O**	**Total CO2e**
2030	715,217	142,225	1,615	859,057
2050	0	0	0	0

The Life Cycle Analysis used in the preparation of responses to RFAI Question 1 (c) - (e) used alternative emissions factors from those developed by DEC. An explanation and justification for the use of those emissions factors is provided in Attachment A.

Question No. 2:

2) Justification

As described above, if the issuance of ASF permit modifications for the ExC Project would be inconsistent with or would interfere with the Statewide GHG emission limits, then the second element of the three-pronged analysis set forth in CLCPA Section 7(2) requires that DEC must also provide a detailed statement of justification for the ExC Project notwithstanding the inconsistency. While Iroquois may assert that the ExC Project would be consistent with the Statewide GHG emission limits, Iroquois should nevertheless supplement the record to provide DEC with a justification regarding the potential need for the ExC Project, in the event DEC determines that the ExC Project would be inconsistent with or interfere with the Statewide GHG emission limits.

Response:

As discussed above, Iroquois maintains that, based on the results of the Life Cycle Analysis, the development and operation of the ExC Project will be consistent with the statewide GHG emissions limits established by the CLCPA. Additionally, since filing the Life Cycle Analysis with DEC in October 2021, the New York State Climate Action Council issued its Draft Scoping Plan ("Scoping Plan").[4] The Scoping Plan recognizes that utility companies have a continuing obligation "to provide safe and reliable service . . . ."[5] The Scoping Plan provides that the transition of the natural gas system must be "equitable and cost effective for consumers without compromising reliability and safety."[6] The Scoping Plan further recognizes that "investment in traditional infrastructure may . . . be necessary to maintain reliability and safety for . . . customers." [7] As explained further below, the ExC Project is needed to ensure safe, reliable and affordable natural gas service to customers within the Project Shippers service territories and, as such, the Project is not only consistent with the statewide GHG emissions limits, but it also conforms to the Scoping Plan.

However, in the event that DEC was to determine, contrary to the record established in this proceeding, that the ExC Project would be inconsistent or interferes with the CLCPA's statewide emissions limits, as explained further below, the administrative records before the FERC and the New York State Public Service Commission ("PSC") clearly establish that the Project is justified notwithstanding such purported inconsistency.

I. FERC Certificate Proceeding

On February 3, 2020, Iroquois filed with the FERC an abbreviated application for a Certificate of Public Convenience and Necessity ("Certificate") pursuant to Section 7 of the Natural Gas Act

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[4] The Scoping Plan, https://climate.ny.gov/Our-Climate-Act/Draft-Scoping-Plan.
[5] Scoping Plan at 266; *see also* Public Service Law § 65 ("Every gas corporation . . . shall furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable.")
[6] Scoping Plan at 264.
[7] Scoping Plan at 264–265.

("NGA") for the Project ("FERC Application").[8] As further detailed in the FERC Application, Con Edison and National Grid each entered into binding precedent agreements with Iroquois for 62,500 dekatherms per day of incremental firm natural gas transportation service to serve each of their respective local distribution company service territories.[9]

On March 3, 2020, Con Edison filed comments with FERC requesting that FERC issue a Certificate for the ExC Project. Con Edison explained that it requires "sufficient pipeline capacity be available to meet our customers' demand on the coldest expected winter day ("design day")."[10] Con Edison's comments acknowledged the requirements of the CLCPA, discussed Con Edison's efforts to implement demand side management solutions to reduce demand, but nevertheless noted that implementation of those solutions "have not been adequate to offset customer requests for additional gas supply or curtail the requirement for additional capacity to meet demand."[11] Notwithstanding the requirements of the CLCPA, Con Edison advised FERC of its continuing legal obligation to serve customers in the region seeking gas service.[12] Con Edison also noted that the increase in gas demand to be addressed by the Project is, in part, due to conversions of buildings from fuel oil to cleaner-burning natural gas.[13] A copy of Con Edison's March 3, 2020, comments is attached hereto as Attachment B.

On April 20, 2021, Con Edison filed a letter with FERC reaffirming its March 3, 2020, comments and reiterating the need for the Project, stating that the Project would assist Con Edison in delivering "natural gas to support our customers' critical heating needs and other essential uses."[14] A copy of Con Edison's April 20, 2021 letter is attached hereto as Attachment C.

On January 28, 2022, Con Edison again filed comments with FERC further reiterating the need for the Project.[15] Con Edison's comments state that notwithstanding (i) the actions undertaken by Con Edison to reduce demand for natural gas in its service territory, (ii) the effects of the COVID-19 pandemic, and (iii) New York City's recent ban on certain new natural gas service connections, Con Edison estimates continued firm customer demand growth in its service territory for the next several years. As a result, the ExC Project remains necessary for Con Edison to safely and reliably serve Con Edison's customers on peak winter days. Con Edison further explained that it had weighed the ExC Project against other supply options and determined that ExC would "be a key component of safely, reliably, affordably and sustainably meeting existing customers' needs."[16] A copy of Con Edison's January 28, 2022 comments are attached as Attachment D.

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[8] Iroquois Gas Transmission Sys., L.P., Abbreviated Application for a Certificate of Public Convenience and Necessity, Docket No. CP20-48-000 (filed February 3, 2020).
[9] FERC Application at 2.
[10] Consolidated Edison, Comments in Support of Consolidated Edison Company of New York, Inc., Docket No. CP20-48-000, at 3 (filed March 3, 2020).
[11] *Id.*
[12] *Id.* at 3–5.
[13] *Id.* at 5.
[14] Consolidated Edison, Letter of Consolidated Edison Company of New York, Inc., Docket No. CP20-48-000 (filed April 20, 2021).
[15] Con Edison, Motion for Leave to Answer and Limited Answer of Consolidated Edison Company of New York, Inc., Docket CP20-48 (filed January 28, 2022).
[16] *Id.* at 5.

National Grid also filed comments in the FERC Certificate proceeding emphasizing the need for the Project. Beginning on March 4, 2020, National Grid filed comments with FERC,[17] requesting that FERC issue the Certificate, stating the following:

> after accounting for its own demand-reduction efforts as well as emerging trends such as electrification, National Grid LI is still projecting consistent peak demand growth. National Grid LI has a statutory obligation to serve customer requests for new gas connections and will require incremental supplies of natural gas to meet forecast demand levels. The ExC Project is designed to help alleviate these concerns.[18]

National Grid further explained that it supports the ExC Project not only because it would aid in meeting the supply needs of the region but also provides a "design that minimizes environmental impacts and complements greenhouse gas reduction and other pollution-control efforts underway within New York."[19] A copy of National Grid's March 4, 2020 comments are attached hereto as Attachment E.

On April 9, 2021, National Grid filed a letter with FERC reaffirming its March 4, 2020 comments and reiterating the need for the Project. The April 9th letter states that the Project is "a key component of National Grid's current portfolio of supply solution to deliver reliable and affordable service in the downstate New York while also complying with and facilitating New York State's clean energy priorities."[20] A copy of National Grid's April 9, 2021 letter is attached as Attachment F.

On December 17, 2021, National Grid filed supplemental comments with FERC again supporting and reiterating the need for the Project. The December 17 letter states:

> [National Grid's] long-term supply planning contemplates that public policy and electrification efforts in New York State will eventually lead to some level of demand destruction, but such proposals, including the New York City Council's proposed ban on the use of natural gas in new buildings, do not eliminate the near-term need for the ExC Project.

Thus, even when considering the potential effects of electrification efforts and the enactment of local laws restricting future natural gas use, the need for the Project persists. A copy of National Grid's December 17, 2021 comments are attached as Attachment G.

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[17] National Grid Gas Delivery Companies, Motion to Intervene and Comments in Support of the National Grid Gas Delivery Companies, Docket No. CP20- 48 (filed March 4, 2020).
[18] *Id.*
[19] *Id.*
[20] National Grid Gas Delivery Companies, Supplemental Comments of the National Grid Gas Delivery Companies, Docket No. CP20- 48 (filed April 9, 2021).

On January 27, 2022, National Grid again filed comments with FERC. [21] National Grid requested that FERC not delay approval of the Project and reiterated the need for the Project to meet National Grid's obligations under the New York Public Service Law to "serve its customers in a manner that is reliable, cost effective and equitable."[22] National Grid explained that revitalization projects, new construction and conversion of fuel oil and propane to natural gas have resulted in continued customer peak day demand. Despite the COVID-19 pandemic, New York City's gas service connection ban, and application of demand side management programs, National Grid reiterated that it still requires additional gas capacity. National Grid also weighed the ExC Project against other supply solutions and found that "the ExC Project was the best option for reliably meeting customer demand and in accordance with the goals of the Climate Law."[23] A copy of National Grid's January 27, 2022 comments are attached as Attachment H.

On March 25, 2022, FERC issued an Order pursuant to Section 7 of the Natural Gas Act ("Certificate Order") finding that "the public convenience and necessity requires approval of the Enhancement by Compression Project."[24] The Certificate Order acknowledged that notwithstanding New York City's enactment of a natural gas service connection ban and implementation of demand side management programs, both Project Shippers' anticipate "continued firm customer peak day gas demand growth in their service territories for the next several years."[25]

Based upon all of the foregoing, it is clear that notwithstanding the other measures implemented by the Project Shippers to reduce the need for additional supply, New York City's ban on certain new natural gas connections, and the State's efforts to electrify building heating, both Con Edison and National Grid require the Project to provide safe, reliable, and affordable gas service to their customers.

II. <u>PSC Proceedings</u>

In addition to the FERC proceeding discussed above, the record before the PSC in Case Nos. 19-G-0678 and 20-G-0131 also provide justification for the Project.

A. <u>Case No. 20-G-0131</u>

On July 17, 2020, Con Edison filed with the PSC an analysis of supply and demand for areas

[21] National Grid Delivery Companies, Limited Answer of the National Grid Gas Delivery Companies to Comments of the U.S. Environmental Protection Agency of Final Environmental Impact Statement, CP20-48 (filed January 28, 2022) ("National Grid Limited Answer").
[22] *Id.* at 2.
[23] *Id.* at 8-9.
[24] Order Issuing Certificate, 178 FERC ¶ 61,200 at P 95. The Certificate Order can be found at the following website and is hereby incorporated by reference into this response:
https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220325-3078&optimized=false .
[25] *Id.* at P 16.

within its service territory with potential future supply constraints.[26] As part of that analysis, Con Edison explained that the capacity to be supplied by the ExC Project "will allow [Con Edison] to continue meeting the needs of NYC customers safely and reliably by decreasing reliance on delivered services."[27] Con Edison further stated that if the ExC Project "encounter[s] permitting challenges or construction delays, [Con Edison] may not be able to procure sufficient delivered services at the Iroquois Hunts Point city gate."[28]

B. Case No. 19-G-0678

On February 24, 2020, National Grid filed with the PSC its Natural Gas Long-Term Capacity Report for Downstate New York ("LTCR").[29] National Grid forecasted an approximately 1.5% per annum increase in design day demand between winter 2021-22 and 2034-35.[30] The LTCR provided an analysis of National Grid's natural gas capacity constraints and options to meet long term customer demand. The ExC Project was among the options analyzed by National Grid to meet forecasted demand in the region.

On May 8, 2020, National Grid filed with the PSC its Natural Gas Long-Term Capacity Supplemental Report ("LTCSR").[31] The LTCSR presented National Grid's Distributed Infrastructure Solution, a combination of incremental energy efficiency and demand response programs and enhancement projects intended to close the gap between its projected design day demand and supply. The ExC Project is one component of National Grid's Distributed Infrastructure Solution.

On June 30, 2021, and August 25, 2021, National Grid filed with PSC its Second and Third LTCSR,[32] which updated National Grid's natural gas demand forecast and reiterated the need for the Distributed Infrastructure Solution, including the ExC Project. Notably, the Third LTCSR included customer survey results that indicated that customers within National Grid's natural gas service territory were most concerned with heating affordability and maintaining service reliability.[33] Moreover, survey respondents indicating that they understood the demand-supply gap were much more supportive of the Distributed Infrastructure solution, including the ExC Project.[34]

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[26] Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to gas planning Procedures – Supply/Demand Analysis for Vulnerable Locations,* Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Supply and Demand Analysis for Regions Vulnerable to Supply Constraints (filed July 17, 2020).
[27] *Id.* at 16.
[28] *Id.* at 45.
[29] The LTCR can be found at https://ngridsolutions.com/ and is hereby incorporated by reference into this response.
[30] LTCR at 9.
[31] The LTCSR can be found at https://ngridsolutions.com/ and is hereby incorporated by reference into this response.
[32] The Second and Third LTCSRs can be found at https://ngridsolutions.com/ and are hereby incorporated by reference into this response.
[33] Third LTCSR at Section 5.2.
[34] *Id.*

On September 10, 2021, PA Consulting Group, Inc. filed with the PSC its Assessment of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report (the "PA Assessment"). The PA Assessment confirmed National Grid's assertion that if the ExC Project is not constructed, customer energy demand in the region may not be met, finding that "delays in the permitting and implementation of these infrastructure projects exposes National Grid to significant curtailment and moratorium risk . . . ."[35] A copy of the PA Assessment is attached hereto as Attachment I.

On September 14, 2021, the independent monitor assigned in PSC Case No. 19-G-0678, filed its National Grid Monitorship, Closing Report (the "Closing Report"). The Closing Report noted that the ExC project is a "critical component of the Distributed Infrastructure Solution."[36] The Closing Report further stated that "National Grid has taken substantial efforts consistent with the Settlement Agreement and with the Monitor's recommendations in order to develop its long-term plan" but noted that permitting risks remain and, as a result, "additional focus on these developing projects should be given by" all stakeholders.[37] The Monitor further noted its "significant concerns that National Grid may not timely implement key components of the Distributed Infrastructure Solution and that National Grid may be unable to meet . . . future supply needs."[38] A copy of the Closing Report is attached as Attachment J.

On December 29, 2021, National Grid filed with the PSC its Long-Term Capacity Status Report for Brooklyn, Queens, Staten Island and Long Island ("Status Report"). The Status Report further underscores the need for the Distributed Infrastructure Solution, including the ExC Project, and emphasizes that the key risk to ExC is the timely receipt of federal and state permits.[39] National Grid explained that if any component of its Distributed Infrastructure Solution is not timely implemented, "there is substantial risk that National Grid will not be able to meet projected customer demand" as early as Winter 2023-24.[40] The Status Report further clarifies the need for the ExC Project notwithstanding New York City's recent enactment of a local law banning the use of natural gas in certain buildings.[41] A copy of the Status Report is attached as Attachment K.

III. <u>Conclusion</u>

The records in both the FERC and PSC proceedings clearly establish, and reiterate on several occasions, that the Project Shippers require the development of the ExC Project to meet their customers' demand for a safe, reliable and affordable supply of natural gas. The urgent need for the Project has not only been verified by the filings of the Project's Shippers but also by the independent third parties, including PA Consulting and the independent monitor assigned to PSC Case No. 19-G-0678. As such, there is significant evidence supporting the need and justification for the Project. Accordingly, even if DEC were to find the Project to be inconsistent with the CLCPA, it should find that there is justification for the Project notwithstanding such purported inconsistency.

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[35] PA Assessment at 6.
[36] Closing Report at 15.
[37] Closing Report at 18.
[38] Closing Report at 13.
[39] Status Report at Section 2.2.
[40] Status Report at Section 4.
[41] Status Report at Section 2.1.

Question No. 3:

3) Alternatives and GHG Mitigation

In the event the ExC Project is inconsistent with the Statewide GHG emission limits but a justification is available notwithstanding the inconsistency, then the third prong of the analysis set forth by CLCPA Section 7(2) requires an evaluation of alternatives and GHG mitigation. The 12/23/2020 analysis submitted by Iroquois includes a discussion of "mitigation measures" that will be implemented at the ExC Project. While dry low NOx combustion and an oxidation catalyst are welcome additions to the ExC project from a criteria pollutant emissions reduction standpoint, they are not mitigation measures for GHG emissions. As such, the record does not currently include an analysis of alternatives to the ExC project as proposed and/or GHG mitigation measures for the resulting GHG increase. The record needs to be supplemented to include potential alternatives and/or GHG mitigation measures for the GHG increase resulting from this ExC project. If any identified alternatives/mitigation measures are found to be infeasible, the analysis needs to discuss that as well.

DEC did note that both Iroquois' 12/23/2020 analysis and 10/13/2021 supplement include a supplemental analysis that attempts to predict the lifecycle GHG emissions from the ExC Project based on demand forecasts and other information. This appears to rely on the actions of entities other than Iroquois and actions at locations other than the ExC Project compressor stations. Further, if some (or all) of the assumptions made in this analysis do not come to pass, any GHG emission benefit shown could change. Accordingly, the alternative and GHG mitigation analysis should focus on measures that are within Iroquois' direct control to reduce GHG emissions to the extent practicable.

Response:

As stated above, the record in this proceeding clearly establishes that the ExC Project is consistent with the CLCPA and, thus, an evaluation of alternatives and mitigation is not required pursuant to CLCPA Section 7(2).[42] Nevertheless, to be responsive to DEC's request, provided below is a discussion of Project alternatives and GHG mitigation measures that Iroquois evaluated.

I. PROJECT ALTERNATIVES

Project alternatives were evaluated as part of the FERC NEPA review, by the Project Shippers, and further by Iroquois in the Life Cycle Analysis filed with DEC in October 2021. Those evaluations revealed that there is no feasible alternative that would achieve the Project's

[42] Specifically, FERC's NEPA review concluded that the Project would result in a net reduction of GHG emissions. That conclusion was based on the findings presented in the Life Cycle Analysis, which relied on a number of conservative modeling assumptions regarding future heat pump installation rates in the Project Shippers' service territories. If those conservative heat pump installation rates are not realized, the Project could result in further net reductions in GHG emissions when compared to reasonable alternative energy sources to meet the energy demand met by the Project. *See* Order Issuing Certificate, 178 FERC ¶ 61,200 at P 56.

objective[43] while minimizing potential environmental impacts to the extent achieved by the proposed Project.

A. ***<u>FERC NEPA Alternatives Analysis</u>***

As part of the Project's required NEPA review, the FERC performed an alternatives analysis.[44] The FERC alternatives analysis considered the no action alternative, pipeline system alternatives and compressor station alternatives. The FERC evaluation considered the following criteria to assess those alternatives: (i) ability to meet the Project's objective; (ii) technical and economic feasibility and practicality; and (iii) potential environmental impacts.[45] A brief discussion of these alternatives and conclusions follows.

i. <u>No Action Alternative</u>

Under the no-action alternative the Project would not be developed and, as a result, the Project's objectives would not be met unless another project was constructed. Therefore, the potential impacts of the Project would not be alleviated, but simply transferred to another location. Since the Project's facilities are proposed to be sited at existing compressor stations, the impacts of any replacement project are likely to be greater. Since the environmental impacts would not be lessened, and the purpose and need of the Project would remain, the no-action alternative was not considered a viable alternative.[46]

ii. <u>System Alternatives</u>

System alternatives would generally use existing, modified, or proposed pipeline systems to meet the purpose and need of the Project. Possible system modifications that could be used to transport the additional throughput provided by the Project include replacing the current pipeline with a larger diameter pipeline, looping the existing pipeline, adding compression, or some combination of looping and adding compression.[47] Installation of a larger diameter pipeline or looping the existing pipeline would increase the Project's construction footprint, result in additional impact to environmental resources, and would require the acquisition of additional third-party owned property rights to expand Iroquois' ROW and for Project contractor staging areas. Additionally, pipeline replacement would require temporarily removing Iroquois' existing pipeline from service, preventing Iroquois from delivering gas to existing customers during the period of construction.[48] For these reasons, replacement of the existing pipeline with a larger diameter pipeline or pipeline looping were dismissed from further consideration.

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[43] The purpose of the Project is to provide up to 125,000 dekatherms per day of firm natural gas transportation service to delivery points at South Commack and Hunts Point, New York.
[44] FERC, Enhancement by Compression Project Environmental Assessment, CP20-48 (filed September 30, 2020) at Section C.
[45] *Id.*
[46] *Id.* at Section C.2.
[47] *Id.* at Section C.3.
[48] *Id.*

In addition to Iroquois system alternatives, third-party system alternatives were evaluated. Tennessee Gas Transmission, Transcontinental Gas Pipe Line Corporation (Transco), and Texas Eastern Transmission operate natural gas transmission pipeline systems in the Project area that serve New York City and Long Island. However, the existing pipeline systems are fully subscribed to existing contract commitments and cannot provide the additional capacity proposed by the Project. Therefore, for these existing systems to provide the additional natural gas proposed by the Project, each would require new compression, new pipeline construction, and/or pipeline looping to expand current capacity. Expansion of these systems would likely require similar or greater environmental impact and, thus, were not considered preferable alternatives to the Project.[49]

iii. <u>Compressor Station Alternatives</u>

Alternative compressor station sites were also evaluated but it was determined that utilizing Iroquois' existing sites would result in less overall impacts on the environment, compared to constructing the proposed Project at new locations, which would require construction of additional support buildings, pipe to connect to Iroquois' mainline, and new electric service. Therefore, alternatives sites were dismissed from further evaluation.[50]

The feasibility of using electric motor-driven compressor units in lieu of the proposed natural gas-fired compressor units at the Athens, Dover, and Brookfield Compressor Stations was also assessed.[51] As explained further below, this potential alternative was rejected after considering environmental, cost, reliability and Project schedule impacts that would result if it was implemented.

Although technically feasible, use of electric-powered compressor units would increase the overall Project footprint and associated environmental impacts. Electric-powered compressors would require the installation of electric transmission, distribution and substation improvements. Installing electric-driven compressors at the three Project compressor stations would result in approximately 39 acres of environmental impacts (disturbance of soils, wetlands, waterbodies, land use, and visual) and would result in impacts on new landowners from construction and operation of the power lines.[52] The additional Project footprint may also require the acquisition of third-party owned property rights.

Additionally, the work by the respective New York and Connecticut local distribution companies to bring additional electric service to the compressor stations would require between approximately two to four years to complete, which would be inconsistent with the Project's planned in-service date. Iroquois estimated that electric motor-driven compression would cost between \$25 - \$30 million[53] for the required electric service improvements at each compressor station, rendering this alternative cost prohibitive for the Project. In fact, on March 30, 2022,

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[49] *Id.*
[50] *Id.* at Section C.4.
[51] *Id.* at Section C.5.
[52] *Id.*
[53] Iroquois, Resource Report 10: Alternatives, CP20-48 (filed Feb. 3, 2020) at Section 10.6.1.

Eversource Energy advised Iroquois that electric transmission and distribution upgrades that would be required for electric-driven compressors at the Brookfield compressor station would cost significantly more than what Iroquois had estimated – approximately $45 - $50 million[54] - further evidencing that this alternative would be cost prohibitive for the Project. Electric motor-driven compression would also result in a less reliable power source to the Project compressors, which could interfere with Iroquois' ability to provide service during electric service interruptions.[55]

For all of the foregoing reasons, electric motor-driven compressors were determined not to be a viable alternative for the Project.

B. Anchor Shipper's Alternatives Analysis

The ExC Project Shippers both fully assessed options and alternatives to meet the anticipated energy demand in the region. Based on those evaluations, even when implementing initiatives intended to reduce future natural gas demand such as gas demand response programs, pursuing non-pipeline alternatives, and new programs to transition to energy-efficient electrified space and water heating, both Project Shippers concluded that there would be no suitable alternative to the Project.[56] Notwithstanding the other options being pursued to reduce gas demand, both Project Shippers require the Project to be able to continue to meet the increasing need for natural gas in their service territories.

National Grid's weighing of the ExC Project against possible alternatives has been ongoing for approximately two years. In its February 2020 LTCR, National Grid outlined several possible solutions to address the need for increased natural gas demand in the region. The LTCR evaluated large scale infrastructure projects such as an offshore LNG port, an LNG import terminal and the Northeast Supply Enhancement project ("NESE"), distributed infrastructure projects such as a peak LNG facility, LNG barges, the Cloves Lakes Distribution Loop, and the ExC Project, and no infrastructure solutions such as incremental energy efficiency, incremental demand response and incremental electrification.[57] Based on the LTCR's initial evaluation and public comments received in response to the LTCR, in May 2020, National Grid published its LTCSR, which provided a further assessment of possible energy solutions and recommended two options that would meet the region's long term supply needs: (i) the Distributed Infrastructure Solution, which includes the ExC Project, and (ii) the NESE project. Shortly after the LTCSR was issued, state permits for the NESE project were denied. As such, National Grid thereafter refined the Distributed Infrastructure Solution to include more aggressive incremental demand side management programs. In January 2022, National Grid requested that FERC issue a Certificate for the Project, explaining that it "weighed the ExC Project against other supply solutions and considers it to be a key component of reliably, affordably, and sustainably meeting the needs of our customers."[58]

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[54] *See* Eversource Energy Letter to Iroquois, March 30, 2022, attached as Attachment L.
[55] Iroquois, Resource Report 10: Alternatives, CP20-48 (filed Feb. 3, 2020) at Section 10.6.1.
[56] *See e.g.*, Con Edison, Motion for Leave to Answer and Limited Answer of Consolidated Edison Company of New York, Inc., Docket CP20-48 (filed January 28, 2022) at 7.
[57] LTCR at Section 2.5.
[58] National Grid Limited Answer at 5.

Similar to National Grid, Con Edison has been weighing the ExC Project against viable alternatives since 2020. In its July 17, 2020, *Supply and Demand Analysis for Regions Vulnerable to Supply Constraints*,[59] Con Edison explained that the ExC Project would allow it to "continue meeting the needs of NYC customers safely and reliably by decreasing reliance on delivered services"[60] and that delays in developing the ExC Project could result in Con Edison being unable to procure sufficient delivered services to the Iroquois Hunts Point city gate.[61] If this were to occur, Con Edison would be required to evaluate several other alternatives.[62] In January 2022, Con Edison explained to FERC that it had "thoroughly reviewed a number of alternative projects and determined that the ExC Project was the best option for safely and reliably meeting customer demand and in accordance with the goals of the Climate Law."[63]

Accordingly, in addition to the FERC's NEPA alternative analysis, the Project Shippers have undergone a thorough alternatives analysis and concluded that the ExC Project is the optimum solution or, in the case of National Grid, is a critical element of the solution, required to meet the natural gas demand needs of the region.

C. ***Greenhouse Gas Emissions Alternatives Analysis***

In addition to the above-discussed alternatives that were evaluated during the FERC NEPA review and those that were assessed by the Project Shippers, Iroquois compared the potential lifecycle greenhouse gas emissions that would result from the Project to those that would result from alternative energy sources. This comparison was included in the Life Cycle Analysis, which Iroquois filed with DEC on October 13, 2021. The Life Cycle Analysis estimates lifecycle GHG emissions from the ExC-transported natural gas and compares those emissions, for the 20-year term of the Project Shippers transportation service agreements, to the lifecycle GHG emissions that would be associated with alternative energy sources needed to meet the same anticipated energy needs of the Project Shippers' customers. The results of that analysis demonstrate that life cycle GHG emissions resulting from the Project would be less than the GHG emissions that would result from viable alternative energy sources that would be required to meet the energy demand satisfied by the Project. As FERC concluded as part of its NEPA review, the Life Cycle Analysis revealed that, when compared to viable energy alternatives, the ExC Project results in a net reduction in GHG emissions.[64] For those reasons, the ExC Project is superior from a GHG emissions perspective to alternative energy sources.

D. ***Conclusion***

As discussed above, through the various state and federal proceedings, the Project has undergone a through alternatives analysis. That assessment has consistently revealed and reiterated that there

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[59] Con Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., Supply and Demand Analysis for Regions Vulnerable to Supply Constraints, PSC Case No. 20-G-0131 (filed July 17, 2020).
[60] *Id.* at 16.
[61] *Id.* at 45.
[62] *Id.*
[63] Con Edison, Motion for Leave to Answer and Limited Answer of Consolidated Edison Company of New York, Inc., Docket CP20-48, at 9 (filed January 28, 2022) ("Con Edison January 28, 2022 FERC Filing").
[64] Order Issuing Certificate, 178 FERC ¶ 61,200 at P 56.

is currently no viable alternative to the Project that would meet the energy supply needs of the region while minimizing environmental impacts to the extent achieved by the ExC Project.

II. PROJECT MITIGATION

The following sections provide a discussion of the GHG mitigation associated with the Project, as well as Iroquois' evaluation of additional potential GHG mitigation.

A. Project Shipper GHG Mitigation

In addition to the GHG mitigation planned by Iroquois (discussed below), the Project Shippers propose technological mitigation that will result in reduced Project end use GHG emissions.

For example, National Grid is in the process of commissioning an RNG project from the largest sewage treatment facility operated by the New York City Department of Environmental Protection and is collaborating with the Town of Hempstead, New York, to build a clean hydrogen ("H_2") facility to demonstrate the feasibility of blending green hydrogen into National Grid's local gas distribution system.[65] Moreover, on April 19, 2022, National Grid released its *Our Clean Energy* Vision, in which it proposes to transition to a fossil-free gas system by 2050 through the incorporation of RNG and green H_2 into its distribution systems.[66] Con Edison is also exploring the integration of green H_2 and RNG into its natural gas distribution system, having recently executed an agreement with a RNG project developer that will locate its facility in Con Edison's service territory.[67] These actions of the Project Shippers and other efforts to incorporate RNG and green H_2 into the natural gas mix will, throughout the twenty-year Project contracts terms, reduce the carbon intensity of the natural gas consumed in the region, resulting in lower Project end-use GHG emissions.

Although Iroquois does not have direct control over the Project Shippers' mitigation, those measures, and future actions that will reduce the carbon intensity of pipeline gas, will result in lower end use GHG emissions and, thus, are an important consideration when assessing the Project's anticipated future lifecycle emissions and the Project's alignment with the CLCPA's emissions reduction goals.

B. Iroquois GHG Mitigation

The ExC Project, as proposed, includes significant GHG mitigation. However, as further discussed below, Iroquois has considered the implementation of further GHG mitigation in the event that DEC determines, contrary to the record set forth in this proceeding, that the Project is inconsistent with the CLCPA statewide GHG emissions limits.

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[65] National Grid January 28, 2022 FERC filing at 7.
[66] National Grid's *Our Clean Energy Vision*, https://www.nationalgrid.com/document/146251/download?bcs-agent-scanner=ed71c8c3-7835-c046-a06c-005f6fedf498.
[67] Con Edison January 28, 2022 FERC Filing at fn 17.

i. Current Planned GHG Mitigation

As proposed, the Project would include Vent Recovery Systems ("VRS") at each of the Project compressor stations, which would capture and reinject into the pipeline methane emissions from planned blowdowns and dry compressor seal gas leakage. Installation of the VRS is expected to reduce compressor station methane emissions by approximately seventy percent (70%) below historical levels. As such, installation of the VRS is anticipated to reduce methane emissions at each of the Project compressor stations as set forth in Table 5 below:

Table 5[68]		
Compressor Station	**Annual GHG (CO2e – 20 Yr GWP) Actual Emissions Reductions Due to VRS (Metric Tons Per Year)**	**Annual GHG (CO2e – 20 Yr GWP) PTE Emissions Reductions Due to VRS (Metric Tons Per Year)**
Athens, NY	4,327	9,634
Dover, NY	3,907	11,270
Brookfield, CT	6,560	24,032
Milford, CT	10,430	29,118
Total	25,224	74,054

This reduction in GHG emissions equals approximately 45% of the Project's direct total annual anticipated GHG emissions and approximately 35% of the Project's direct annual GHG PTE, in each case assuming that VRS was not installed as part of the Project.

Also, the proposed ExC Project facilities have been designed to incorporate the use of non-methane actuators (air or electric) for the compressor unit valves. This will eliminate the venting of methane when the valves are required to move during a start/stop or ESD condition.[69]

Additionally, the Project as proposed includes a fuel use limit on the proposed turbines to be installed at the Brookfield, CT compressor station equal to ninety-one and one-half percent (91.5%) of the total fuel Btu heat value that could be consumed at the worst-case full load conditions assumed to estimate potential emissions. This mitigation measure is anticipated to reduce the Project's direct annual GHG (CO2e – 20 Yr GWP) PTE by approximately 6,682 metric tons per year.

Additionally, in January 2022, Iroquois was certified by the Center for Resource Solutions as utilizing one hundred percent (100%) renewable electricity at all of its facilities. Iroquois consumes approximately 5,000,000 kilowatt-hours (kwh) of electricity annually from all its

[68] With regard to potential vs. actual reductions in Table 5, since PTE assumes 100% runtime, compressor station venting and/or emergency shutdowns ("ESD") are assumed to be zero. Any venting would result in downtime thereby reducing GHG emissions from combustion. Therefore, annual PTE emissions only represent seal gas recovered from the VRS. Actual annual GHG emissions represent seal gas leakage and venting recovered from the VRS.

[69] While this measure reduces actual anticipated emissions, it would not affect annual PTE due to the assumption the units would be running 100% of the time.

facilities, including compressor stations, metering stations, Shelton and Oxford offices, and mainline valve sites. As such, according to EPA guidelines, the GHG offset associated with this certification is equal to 3,906 tons of CO2e annually. Provided that the market price for renewable electricity remains at or below 125% of that of the electric distribution company's standard offer rate for electricity, Iroquois will continue to procure 100% renewable electricity throughout the 20-year Project Shipper contract terms.

Collectively, Iroquois' current planned mitigation would result in following GHG reductions:

Table 6

Current Proposed Mitigation	**Annual GHG (CO2e – 20 Yr GWP) Actual Emissions Reductions Due to VRS (Metric Tons Per Year)**	**Annual GHG (CO2e – 20 Yr GWP) PTE Emissions Reductions Due to VRS (Metric Tons Per Year)**
VRS	25,224	74,054
Non-Methane Valve Actuators	588	--
Brookfield Fuel use Restriction	--	6,682
Center for Resource Solutions Renewable Energy Certification	3,906	3,906
Annual Total	29,718	84,642

The current proposed mitigation reduces approximately 54% of the Project's actual anticipated annual direct GHG emissions and approximately 40% of the Project GHG PTE, in each case assuming that no GHG mitigation had been proposed for the Project.

Also noteworthy is that Iroquois is a member of the EPA Natural Gas STAR Program and has committed to reduce pipeline venting by fifty percent (50%) during or before 2025 through the EPA's Methane Challenge Program, which it entered in March 2020.

The foregoing clearly demonstrates that the Project, as proposed, includes a significant amount of GHG mitigation.

ii. *Evaluation of Additional Project GHG Mitigation*

Since receiving DEC's January 13, 2022 RFAI, Iroquois further considered additional mitigation including (i) use of RNG and/or hydrogen (H_2) to power Project turbines, (ii) injection of RNG and/or H_2 into Iroquois' pipeline system, and (iii) operational restrictions on the Project's turbines. A discussion of each of the mitigation measures evaluated is provided below.

a. Use of RNG and/or Hydrogen to Power Project Turbines

Iroquois evaluated the feasibility of using RNG and/or H_2 to power the Project's turbines at the Athens, Dover and Brookfield compressor stations. While Iroquois foresees that the use of RNG and H_2 will play a significant role in the decarbonization of natural gas and achievement of the State's GHG emissions reduction goals, this mitigation measure was determined to be *currently* unfeasible. As discussed above, the Project Shippers are beginning to develop and evaluate projects that would introduce RNG and/or H_2 into their natural gas distribution systems. However, it is currently unclear whether there would be sufficient sources to supply RNG and/or H_2 to power the Project's turbines on a timeline that is consistent with the Project's planned in-service date. Additionally, the use of RNG and/or H_2 to power the compressor stations would require additional equipment or infrastructure to deliver and store those alternative fuels, which would expand the Project footprint and likely increase potential environmental impacts. This mitigation measure would also add significant unbudgeted capital costs to the Project, estimated to be approximately $100 million, and would also increase Project operational costs. For all of the foregoing reasons, powering the Project's turbines using RNG and/or H_2 is not currently considered to be a viable option. However, as the supplies of RNG and green H_2 become widely available, costs decrease, and operational compatibility with compressor station equipment is further tested, Iroquois will continue to monitor the efficacy of introducing these alternatives fuels to power the Project's turbines.

b. Incorporation of RNG and/or Hydrogen into Iroquois' Pipeline

For many of the same reasons discussed above in subsection (ii)(a), while Iroquois anticipates that that the integration of RNG and H_2 will play a significant role in the decarbonization of the natural gas that it transports and Iroquois will continue to assess the feasibility of incorporating RNG and/or H_2 into its pipeline gas mixture, *currently* this mitigation measure is not deemed to be feasible and thus could not be implemented on a timeframe consistent with Iroquois' anticipated Project in-service date. Incorporation of RNG and H_2 into Iroquois' pipeline gas mix would require further source assessment of those alternative fuel gases to ensure that there is a continuous available supply. Also, the operational implication of those alternative fuel gases on Project compressor stations, pipeline equipment, and LDC distribution systems requires further evaluation. Additionally, this mitigation measure would require amendment of Iroquois' FERC natural gas tariff. Thus, while Iroquois foresees that the introduction of RNG and H_2 into its pipeline will likely be an important measure in reducing the future carbon intensity of natural gas, this mitigation measure could not be implemented in the timeframe required to achieve the desired Project in-service date. However, as the supplies of RNG and green H_2 become widely available and operational compatibility with compressor station equipment is further studied, Iroquois will continue to assess the efficacy of introducing these alternative fuels into its pipeline system.

c. Reduce Project Contract Terms

Iroquois also evaluated the implementation of certain operational restrictions at the Project's compressor stations to mitigate potential GHG emissions. For example, Iroquois considered reducing the Project's 20-year contracts terms with the Project Shippers. Implementation of this measure would reduce actual anticipated Project direct emissions and PTE GHG emissions for each year that the contract terms were reduced. However, this measure would result in the inability of Iroquois to provide the Project's firm capacity to the Project Shippers during those lost years. The Project Shippers advised Iroquois that they anticipate that Project need will continue throughout the entire 20-year contract terms and, thus, this mitigation measure is not practicable without negatively affecting supply to the region and the reliability of service to the Project Shipper's customers. For that reason, this mitigation measure was eliminated from further consideration.

d. Fuel Use Restrictions

As discussed above, Iroquois has proposed a maximum annual fuel use limit of ninety-one and one-half percent (91.5%) for the Brookfield compressor station's proposed Project turbines. This fuel restriction limits potential NOx emissions to less than the major source threshold and also results in a reduction of GHG PTE. Iroquois evaluated implementing the 91.5% maximum annual fuel use limit for the Project's turbines at Dover and Athens. The implementation of a fuel use limitation at the Project's compressor stations introduces the potential risk that Iroquois would be unable to fulfill its contractual obligations to provide firm transportation service to the Project Shippers. However, the 91.5% maximum annual fuel use restriction achieves the appropriate balance between the resulting GHG PTE reduction benefits and the risk assumed by Iroquois that it will be unable to satisfy its contractual obligations. A larger fuel restriction presents too great a risk that, during the 20-year contract period, Iroquois will be unable to satisfy its obligations to the Project Shippers, potentially negatively affecting supply to the region and reliability on the Project Shipper's distributions systems. However, as detailed in Table 7, below, the GHG PTE reductions that would result from this mitigation measure are significant. This mitigation measure, along with the fuel use restriction at Brookfield, would result in the reduction of GHG emissions as follows:

Table 7

Compressor Station	**Annual Direct GHG (CO2e – 20 Yr GWP) PTE Emissions Reductions From 91.5% Fuel Use Restriction**
Athens, NY	3,372
Dover, NY	3,336
Brookfield, CT	6,682
Annual Total	13,391
20-Year Total	267,800

Additionally, this mitigation measure would not (i) affect the Project footprint, (ii) increase environmental impacts, (iii) increase Project cost, or (iv) negatively impact the planned in-service date.

Project air permit conditions memorializing this operational restriction must include sufficient flexibility for Iroquois to modify operations in the event of unforeseen circumstances, emergencies, service interruptions at other pipelines and other conditions that would require Iroquois to alter operations to maintain safe and reliable service to the region.

iii. Evaluation of Additional GHG Mitigation

In addition to the GHG mitigation described above, and consistent with its other ongoing efforts pursuant to EPA's Methane Challenge Program, Iroquois proposes to install VRS at its three other New York compressor stations (Wright, Boonville and Croghan) subject to its completion of a thorough feasibility assessment. The feasibility study will include an assessment of the engineering, environmental, procurement, and financial requirements related to the installation of VRS at those three stations. Iroquois will complete the feasibility study within one year following the Project's in-service date. If installation of VRS at these stations is determined to be feasible, Iroquois will provide DEC with a proposed schedule for installation of VRS at those stations. Iroquois anticipates that the GHG emissions reductions realized from VRS at those stations will be similar to those discussed above for the Project's compressor stations.

C. Conclusion

The ExC Project is consistent with the CLCPA because when compared to viable alternative energy sources, the Project results in a net reduction of GHG emissions. However, in the event that DEC determines that the Project is inconsistent with the CLCPA, the foregoing provides a thorough evaluation of alternatives and mitigation measures that have been considered by Iroquois. The alternatives evaluation reveals that no viable Project exists that would meet the energy supply needs of the Project while minimizing environmental impact to the degree achieved by the Project. Iroquois' evaluation of mitigation measures reveals that Iroquois is currently proposing to implement significant GHG mitigation as part of the Project and, in the event that DEC determines that the Project is inconsistent with the CLCPA, Iroquois would be willing to implement the fuel use restriction and install VRS at its three other compressor stations following a feasibility study, as discussed above in Sections II.B.ii.d and II.B.iii, to reduce actual GHG emissions and GHG PTE to the extent practicable.

Question No. 4:

4) Disadvantaged Communities

The 3/5/2021 RFAI asks the applicant to provide a map indicating whether the project is located in a potential environmental justice area (PEJA) pursuant to DEC's Commissioner's Policy 29 (CP-29). In addition, as noted above, CLCPA Section 7(3) requires that DEC not disproportionately burden Disadvantaged Communities as part of relevant permitting actions, and that DEC prioritize reductions of GHG emissions and co-pollutants in such Disadvantaged Communities.

Please provide additional information regarding the ExC Project's compliance with CP-29 and CLCPA Section 7(3). This should include a discussion of each compressor station's proximity to both PEJAs and Disadvantaged Communities, and whether the ExC Project will potentially impact a PEJA or Disadvantaged Community, including due to co-pollutant emissions.

Response:

On May 14, 2021, Iroquois submitted maps to DEC identifying the location of potential environmental justice areas ("PEJA") in relation to the Project's Athens and Dover, New York compressor stations.[70] Following that submission, New York issued updated PEJA mapping. In response to DEC's request that Iroquois provide additional information regarding the Project's compliance with CP-29[71] and CLCPA Section 7(3), attached as Attachment M are updated maps showing the locations of PEJAs and Disadvantaged Communities ("DAC")[72] in relation to the Athens and Dover compressor stations.

None of the Project facilities or workspaces are proposed to be sited within PEJAs. For the Athens Compressor Station, the closest PEJA is approximately 0.9 miles to the west. For the Dover Compressor Station, the closest PEJA is located to the west, across Dover Furnace Road, approximately 700 feet west of the nearest Project facilities.

None of the Project facilities or workspaces are proposed to be sited within DACs as designated on NYSERDA's interim DAC maps.[73] For the Athens Compressor Station, the closest DAC is approximately 2.3 miles to the south. For the Dover Compressor Station, the closest DAC is located approximately 3.2 miles to the north.

[70] The May 14, 2021, submission was made in response to DEC's March 5, 2021, Request for Additional Information.

[71] DEC Commissioner's Policy CP-29, Section V.A.2 provides that it does not apply to permit applications for minor modifications, such as the ExC Project State Air Facility permit modification applications. Nevertheless, Iroquois is providing this response for information purposes and to be responsive to DEC's request.

[72] The Disadvantages Communities maps depict the areas that meet the interim criteria for disadvantaged communities as published by NYSERDA at the following site: https://www.nyserda.ny.gov/ny/disadvantaged-communities.

[73] On March 9, 2022, draft Criteria for the identification of Disadvantaged Communities was released by the Climate Justice Working Group. The draft DAC criteria is currently subject to a 120-day public comment period before the criteria can be finalized. NYSERDA guidance indicates that the interim DAC criteria is to be used until the final DAC criteria is established.

FERC Environmental Justice Review

FERC thoroughly evaluated environmental justice considerations as part of its NEPA review of the Project. FERC specifically evaluated potential construction related dust, traffic, noise and visual impacts, as well as Project operational impacts to noise and air quality.[74] Based on that review, FERC concluded that impacts to environmental justice communities as a result of Project construction and operation would not be significant.[75]

With respect to potential traffic impacts to environmental justice communities, FERC explained that Iroquois will implement mitigation measures such as avoiding peak commute times and periods associated with school traffic, as well as coordinating its construction with local transportation authorities.[76] As a result, FERC determined that traffic impact to environmental justice communities would be minor and short term.[77]

With regard to noise impact on environmental justice communities, construction noise would be temporary, and Iroquois has committed to implementing mitigation during operations such that noise levels at both the Dover and Athens compressor stations would not exceed day-night noise levels of 55 dBA at the nearest receptors located within environmental justice communities. Thus, the Project will not significantly impact noise in environmental justice communities.[78]

FERC's NEPA review also concluded that visual impacts to environmental justice communities would not be significant since Project facilities would either not be visible or only partially visible from surrounding environmental justice areas and would be partially obscured by existing compressor station facilities.[79]

During construction, Iroquois would mitigate potential dust and exhaust emissions using dust suppressants, reducing vehicle speeds on unpaved roadways, removing debris from paved roads, and complying with federal, state and local emissions standards.[80] Project operational air emissions, when considered with existing and background concentrations, would be below National Ambient Air Quality Standards ("NAAQS"), which are designed to be protective of human health and welfare.[81] FERC also concluded that the Project would result in a net reduction of GHG emissions and, therefore, would not disproportionately impact environmental justice communities from a climate change perspective.[82] Accordingly, FERC's NEPA review concluded that the Project would not significantly impact air quality in environmental justice communities.[83]

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[74] Order Issuing Certificate, 178 FERC ¶ 61,200 at P 71. The FERC Certificate Order further explained that environmental justice concerns were not present for other resources such as geology, groundwater, wildlife, or cultural resources due the minimal impact from the Project. *Id.* at 74.
[75] Order Issuing Certificate, 178 FERC ¶ 61,200 at P 83.
[76] Order Issuing Certificate, 178 FERC ¶ 61,200 at PP 75 and 80.
[77] *Id.*
[78] *Id.* at PP 76 and 81.
[79] *Id.* at PP 77 and 82.
[80] *Id.* at PP 78 and 83.
[81] *Id.*
[82] *Id.* at P 86.
[83] *Id.* at PP 89, 91.

Furthermore, FERC concluded that the human health risk assessment prepared for the Project (discussed in further detail below) demonstrated that emissions of hazardous air pollutants ("HAPs") would be well below a level of health concern and would not pose a chronic or acute risk to humans in nearby communities, including environmental justice communities.[84]

Human Health Risk Assessment

DEC's RFAI requests additional information regarding the potential impact of Project co-pollutant emissions on PEJAs and DACs. The FERC NEPA review concluded that criteria pollutant air emissions from the Project would be below NAAQS.[85] Additionally, Iroquois commissioned a Human Health Risk Assessment ("HHRA") as part of the FERC NEPA review. For convenience, the HHRA report is provided as Attachment N to this response. The following discussion provides a summary of the findings of the HHRA and specifically how they relate to the PEJAs or DACs located nearest to the Project.

The HHRA evaluated potential exposures and human health risks associated with current and future operational emissions at each of the Project's compressor stations. For the purposes of the HHRA, emissions were broadly characterized as HAPs. Due to the volatile nature of these chemical compounds, the only exposure pathway of significant concern is through inhalation. The human receptors evaluated in the HHRA were hypothetical residents because residential receptors, including children, are considered the most sensitive human receptors. The methods employed to assess health risks in the HHRA explicitly consider exposure and risk to sensitive subpopulations of residents such as children.

The HHRA provided upper-bound estimates of individual cancer and noncancer risk for the theoretical Reasonable Maximum Exposure ("RME") for adult and child receptors based on direct exposures to potential emissions from natural gas combustion. The RME approach is consistent with current USEPA (2005) guidance and is a conservative measure that overestimates potential risks, thus ensuring the protection of public health. The HHRA was conducted following standardized risk assessment methods consistent with USEPA risk assessment guidance, including, but not limited to, the following guidance documents, as applicable:

- The Risk Assessment Guidelines of 1986 (USEPA 1987);
- Risk Assessment Guidance for Superfund, Volume I, Health Evaluation Manual, Part A (USEPA 1989); and
- Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities (USEPA 2005).

Iroquois purposefully selected a conservative approach to err on the side of the protection of human health. When completing human health risk assessments, key areas of uncertainty generally include (1) exposure assumptions and (2) toxicity data extrapolations. For chronic exposures, it was assumed that an individual resident may be exposed to maximum five-year average air concentrations at a compressor station fence or property line over the course of their entire

[84] *Id.* at 93.
[85] FERC FEIS at 53.

residential tenure (30 years for an adult and 6 years for a child) (USEPA 2005). This assumption is highly conservative since residential receptors are more realistically exposed to average concentrations over their entire exposure duration, not continuous exposure to maximum concentrations (USEPA 1989). The chronic toxicity data used to characterize cancer and chronic noncancer risks were derived almost entirely from studies of laboratory animals whereby conservative dose response models are applied to calculate upper-bound estimates of cancer potency and noncancer thresholds. It is generally recognized that these uncertainties result in the over-estimation of health risk, thus ensuring the protection of human health. Many of the Acute Inhalation Exposure Criteria (AIEC) values used to assess potential acute noncancer risks are based on either very mild health effects (e.g., discomfort) or non-health related effects (e.g., odors) rather than overt toxic effects. For these chemicals of potential concern (COPCs), the acute noncancer Hazard Quotient are considered highly conservative, and their contribution to the cumulative acute noncancer Hazard Index (HI) in turn renders the cumulative acute noncancer HIs to be very conservative.

The HHRA showed that modeled HAP emissions from the Project compressor stations are well below a level of health concern. The analysis utilized highly conservative assumptions for receptor exposure (e.g., an individual would be exposed to the maximum concentrations from full-capacity facility operation for 24 hours per day for 350 days per year). Specifically, potential total excess lifetime cancer risk and noncancer hazard indices were calculated based on a theoretical RME adult and child from long-term exposures to the highest predicted maximum five-year average HAP concentrations emitted during normal operations at the facility fence line or property line. This is a very conservative assumption since concentrations will decrease substantially with distance from the compressor station fence or property line, further reducing exposure and risk. Cumulative cancer risks were below 1 in one million and noncancer hazard indices were at or below the target HI of 1 (e.g., the level at which sensitive individuals can be exposed without risk of chronic noncancer health effects).

The HHRA's acute exposure evaluations were based on short-term maximum concentrations using conservative meteorological conditions. The potential for short-term health effects due to exposures to the highest predicted 1-hour HAP concentrations emitted during normal operations was assessed to account for periods of high exposures. Air concentrations were evaluated against the AIEC, which are protective of the general public, including sensitive subpopulations, for a variety of toxic endpoints. The AIEC that were used also protect against discomfort, mild health effects, and objectionable odors. The results of the analysis indicate that acute exposures to the highest predicted 1-hour emissions during normal operations of the proposed Project would be at or below the benchmark criteria (e.g., the level at which sensitive individuals can be exposed without risk of acute noncancer health effects).

Collectively, the results of the HHRA indicate that there would be no significant impact on human health in the Project areas from inhalation of emissions associated with the proposed modifications to the Athens, Brookfield, or Dover compressor stations as a result of the Project.[86] Based on the

[86] It is noted that the proposed modifications for the Milford compressor station will not result in incremental emissions, thus the differentiation between the compressor stations subject to existing operational emissions and future operational emissions evaluations in the HHRA.

conservative findings of the HHRA, it can also be concluded that emissions resulting from the Project will not adversely affect PEJAs or DACs.

Public Outreach

Opportunities for public involvement is an important consideration when assessing environmental justice during the development of a project. Iroquois has provided opportunity for public input and comment throughout the Project planning and permitting process. For example, Iroquois held informal community open houses on January 8, 2020, specific to the proposed Athens Compressor Station Project facilities and on January 9, 2020, specific to the proposed Dover Compressor Station Project facilities. Notice of the open houses were provided to landowners within 0.5-miles of the Project and was published in local newspapers. Informational materials detailing the proposed Project facilities, permitting activities, and construction schedule were made available to all attendees. At all open houses, Iroquois representatives offered an overview of the Project and discussed the Project schedule and how stakeholders can participate in the planning and permitting process. Attendees were invited to discuss questions and concerns with the Iroquois representatives in attendance.

Additionally, Iroquois has involved elected officials and staff (county, state, and federal), community leaders, first responders, and other interested stakeholders throughout the course of the project. Iroquois also established a toll-free number (1-800-253-5152, Option 4) and Project-specific email address excproject@iroquois.com for landowners and any other stakeholders to contact to obtain information about the Project. In addition, a Project web page has been created for the Project (https://www.iroquois.com/operations/projects/exc-project/). Following submission of Iroquois' application to the FERC, to facilitate public review and input, Iroquois made arrangements with local libraries to serve as repositories for a copy of the Project filing. Iroquois published two notices in local newspapers of its FERC application filing and its availability for review and comment on the FERC eLibrary website and local libraries.

During the FERC's Project NEPA review, the public was provided with additional opportunities to provide input and comment on the Project. For example, FERC accepted public comments on the Environmental Assessment prepared for the Project between September 30, 2020 and October 30, 2020.[87] FERC also held a public comment period on the Draft Environmental Impact Statement, which ran from June 11, 2021 to August 9, 2021.[88]

Numerous individuals participated in the public comment process and Iroquois incorporated their comments into the planning process as appropriate. Iroquois continues to provide ongoing communication through website updates, meetings, and other communication measures.

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[87] FERC, Notice of Availability of the Environmental Assessment for the Proposed Enhancement by Compression Project, CP20-48 (filed September 30, 2020).

[88] FERC, Notice of Availability of the Draft Environmental Impact Statement for the Proposed Enhancement by Compression Project, CP20-48 (filed June 11, 2021); FERC, Notice of Revised Comment Period Deadline, CP20-48 (filed July 8, 2021).

Conclusion

Based on all of the foregoing, the Project will not significantly affect PEJAs or disproportionately impacts DACs.

Dated: April 29, 2022

List of Attachments

Attachment A –	Alternative Emission Factors
Attachment B –	Con Edison Comments in Support, March 3, 2020
Attachment C –	Con Edison Letter to FERC, April 20, 2021
Attachment D –	Limited Answer of Con Edison, January 28, 2022
Attachment E –	National Grid Comments in Support, March 4, 2020
Attachment F –	National Grid Letter to FERC, April 9, 2021
Attachment G –	National Grid Letter to FERC, December 17, 2021
Attachment H –	Limited Answer of National Grid, January 27, 2022
Attachment I –	PA Consulting's Assessment of National Grid's LTCSR, September 10, 2021
Attachment J –	National Grid Monitorship Closing Report, September 14, 2021
Attachment K –	National Grid Long-Term Capacity Status Report, December 2021
Attachment L –	Eversource Energy Letter to Iroquois, March 30, 2022
Attachment M –	PEJA and DAC Mapping
Attachment N –	Human Health Risk Assessment Report, April 2020

Attachment A

Attachment A - Alternative Emission Factors

Alternative emission factors were applied for both upstream and downstream segments relative to the emission factors provided by DEC as an attachment to the RFAI. The following sections describe the reasoning behind utilizing these alternative factors for each applicable life cycle segment.

Although NYSDEC provides upstream emission factors that are inclusive of the "extraction, production, and transmission" segments, the Life Cycle Analysis utilizes a more detailed understanding of the Iroquois pipeline supply chain that enables more geographic- and segment-specific emission factors.

Furthermore, individual emission factors were developed for the production, gathering and boosting, processing, transmission, and distribution segments to provide an emission estimate more specific to gas associated with the Iroquois pipeline. Because the Life Cycle Analysis attempts to account for emissions associated with the actual gas entering the Iroquois pipeline rather than emissions associated with imported gas representative of the New York statewide average, these segment-specific factors are more relevant than those provided by DEC. The following assumptions and approach were incorporated into the analysis:

- Production and Gathering & Boosting Segments

    - Natural gas entering the Iroquois pipeline at the Waddington interconnection was assumed to originate from the Appalachian basin and Alberta, Canada (85 percent and 15 percent of gas energy, respectively)
    - Production, gathering and boosting emission factors specific to the Appalachian basin (via NETL, as described in the "Methodology and Assumptions" section below) and Alberta (via GHGenius, as described in the "Methodology and Assumptions" section below) were applied to the delivered gas throughput of the Iroquois pipeline.

- Processing segment

    - Although NETL does not provide basin-specific processing segment emission factors, the approach to apply segment-specific factors necessitated the use of a processing segment emissions factor. NETL provides a national average emissions factor for the processing of gas, which was ultimately applied to the delivered gas throughput of the Iroquois pipeline.

- Transmission segment

    - Because this analysis incorporates the Iroquois pipeline operational and emissions data, transmission segment emissions were treated two ways: transmission emissions upstream of Iroquois (i.e., transmission from production basin to Waddington interconnection) and transmission emissions associated with the Iroquois pipeline related to the ExC Project.

- Transmission emissions upstream of Iroquois were calculated using typical emissions per gas throughput per pipeline mile factors derived from NETL data and applied to the delivered gas throughput and estimated pipeline mileage associated with transmission infrastructure between (i) the Appalachian basin and Waddington and (ii) Alberta and Waddington.
- Transmission emissions associated with the Iroquois pipeline related to the ExC Project were estimated using existing pipeline and compressor emission factors specific to the Iroquois pipeline.

- Distribution segment

  - Because the incremental gas supply from the ExC Project would be delivered to downstate New York and the Project Shippers have provided insight into their expected utilization of this incremental supply, the Life Cycle Analysis applies utility-specific emission factors (via EIA-176, as described in the "Methodology and Assumptions" section below) to the expected delivered throughput associated with each utility .

I. Methodology and Assumptions

Annual upstream GHG emissions are estimated using fuel life cycle segment-specific emission factors and delivered fuel and energy (natural gas, and hydrogen/RNG). These emissions factors account for emissions associated with production, processing, transport to the New York City metropolitan area, and local distribution to end-use customers.

Upstream emission factor assumptions utilize historical EPA Greenhouse Gas Inventory (GHGI) data[1] to project how methane emissions for each upstream segment may change because of upgraded operations, technology and equipment updates, regulation and/or improved reporting.

An upstream emissions calculation methodology utilizing publicly available data and studies was used. This analysis also integrated the proposed methodology developed by ERG for the DEC.[2] Summary emission factors are provided in Table B-2 below (following fuel-specific methodology descriptions).

A. Natural Gas

Upstream GHG emissions associated with natural gas flowing through the Iroquois pipeline were developed using life cycle assessment studies of natural gas published by the Department of

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1 Natural gas systems: https://www.epa.gov/sites/production/files/2021-02/2021_ghgi_natural_gas_systems_annex36_tables.xlsx
Petroleum systems: https://www.epa.gov/sites/production/files/2021-02/2021_ghgi_petroleum_systems_annex35_tables.xlsx

2 See NY DEC website: https://www.dec.ny.gov/energy/99223.html

Energy National Energy Technology Laboratory ("NETL"),[3] GHGenius (for natural gas deriving from Canada),[4] Environmental Defense Fund ("EDF"),[5] and other federal data sources.

i. *Production & Processing*

Eighty-five percent (85%) of natural gas was assumed to derive from the Appalachian basin, while the remaining fifteen percent (15%) was assumed to be produced in western Canada (Alberta). NETL emission factors for Appalachia gas were adjusted with EDF methane study findings, and the GHGenius model was consulted for Alberta gas.

ii. *Transmission*

NETL emission factors (with EDF adjustments) were applied to delivered gas. This analysis assumed a pipeline distance of approximately 350 miles from the relevant production region of the Appalachian basin to the beginning of the Iroquois pipeline in Waddington, New York. For Canadian gas (produced in Alberta), a pipeline distance of approximately 1,400 miles along the TransCanada pipeline was assumed.

iii. *Distribution*

Data reported by CECONY and National Grid utilities (via EIA Form-176) were applied to estimate company-specific, distribution-related emissions.

B. Hydrogen & RNG

Hydrogen was assumed to be produced through electrolysis enabled by renewable electricity; consequently, upstream emissions associated with hydrogen were assumed to be zero. For the "ExC Case" presented in the Life Cycle Analysis, hydrogen composition of delivered gas was assumed to annually and linearly increase from zero percent of gas composition in 2029 until achieving 10 percent of delivered energy in 2043.

Upstream RNG emissions are largely sensitive to the feedstock/origin of RNG and assumed to derive relatively evenly from dairy digestors, landfills, and wastewater treatment facilities. The production and processing emission factors provided by GREET for each RNG type were used.[6] Because RNG and conventional gas are effectively fungible molecules once mixed in the pipeline, RNG transmission and distribution emission factors are assumed to be equal to those of conventional gas. For the "ExC Case" presented in the Life Cycle Analysis, RNG composition was assumed to annually and linearly increase from zero percent of gas composition in 2022 until achieving 15 percent of delivered energy in 2043. See Table B-1 for production and processing emission factors associated with each included RNG feedstock.

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3 NETL. Accessible through https://www.netl.doe.gov/energy-analysis/details?id=3198

4 GHGenius. Accessible through https://www.ghgenius.ca/

5 Alvarez et al., 2018; accessible through https://pubmed.ncbi.nlm.nih.gov/29930092/

6 All emission impacts resulting from RNG are allocated to the production and processing segments

Table B-1: RNG Feedstock Production and Processing Emission Factors (kg/MMBtu)

RNG Feedstock	CO_2	CH_4	N_2O	Total GHG*
Dairy	43.3	-4.39	-0.01	-328.1
Landfill	-60.4	0.38	0	-28.4
Wastewater Treatment	-75.9	-0.74	-0.02	-143.3

*IPCC AR5 20-year GWP values applied.

The table below provides a summary of the upstream emission factors used for all included fuels (hydrogen assumed to have zero life cycle emissions).

Table B-2: Upstream GHG Emissions Factors (kg CO2e/MMBTu)[a]

Upstream Segment	Natural Gas	RNG
Production and Processing	20.13	-163.14[c]
Transmission	Basin-Iroquois: 10.91 Iroquois: 3.03	Same as Gas
Distribution	CECONY: 2.31 KEDNY: 23.26 KEDLI: 16.16	Same as Gas
Upstream Methane Rate Reduction[d]	*CAGR: -5.5%* *'23-'43 Change: -67.5%*	*Same as Gas* *(exc. prod. & processing)*
TOTAL *(low range corresponds w/ upstream CH_4 rate reduction assumption)*	**CECONY: 28.0-36.4** **KEDNY: 38.7-57.3** **KEDLI: 35.1-50.2**	**CECONY: -150 to -147** **KEDNY: -139 to -126** **KEDLI: -143 to-133**

[a] IPCC AR5 20-year GWP values applied
[b] Proposed DEC methodology emission factors developed by ERG (combined production, processing, and transmission)
[c] Production-weighted average of all included RNG feedstocks
[d] U.S. EPA GHG Inventory used to calculate 10-year CAGR of upstream methane emission factors for gas and oil systems; applied through 2043

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iroquois Gas Transmission System	)))	**Docket No. CP20-48-000**

COMMENTS IN SUPPORT OF
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

In accordance with the Notice of Application issued by the Federal Energy Regulatory Commission ("Commission") on February 12, 2020,[1] Consolidated Edison Company of New York, Inc. ("Con Edison" or "the Company") hereby respectfully submits these comments[2] in support of the abbreviated application for a Natural Gas Act ("NGA") Section 7 Certificate of Public Convenience and Necessity[3] filed by Iroquois Gas Transmission System ("Iroquois") in the above captioned proceeding to construct and operate its Enhancement by Compression Project ("ExC Project").

I. INTRODUCTION

A. Identity of Con Edison

Con Edison is a combination gas, electric, and steam utility company whose retail rates and services are regulated by the Public Service Commission of the State of New York. Con Edison delivers gas to 1.1 million customers in Manhattan, the Bronx, parts of Queens, and most of

[1] 85 FR 9469 (Feb. 19, 2020).

[2] Con Edison has already filed a timely, unopposed "doc-less" motion to intervene in the above proceeding on February 4, 2020.

[3] 15 U.S.C. § 717f (2018).

Westchester County. Con Edison receives transportation services on Iroquois' natural gas pipeline system to service our customers in New York.

B. Summary of Comments

Con Edison executed a binding precedent agreement as an Anchor Shipper on the Iroquois ExC Project for 62,500 dekatherms per day ("Dth/d") of capacity on the project. Con Edison respectfully requests that the Commission approve the project by December 31, 2020 and allow a three-year construction period, as requested by Iroquois, so that Iroquois has enough time to obtain all the required permits and approvals.

Con Edison is a public utility obligated by New York law to serve customers seeking natural gas service. While the State of New York and New York City have ambitious climate change laws and policies, these clean energy laws and policies have not altered our responsibility to provide reliable service to natural gas customers. Con Edison supports clean energy agendas and is committed to working alongside policy makers and stakeholders to develop solutions that will support the transition to a low-emissions future. Honoring our obligation to provide service to customers seeking natural gas while also transitioning to renewable energy requires the Company to balance these interests. Con Edison's contract for incremental natural gas capacity in the ExC Project is consistent with this balance because it is a compression-only project. The ExC Project is accordingly narrowly designed to meet our customers' existing and forecasted demand for natural gas without expanding the pipeline's footprint.

II. COMMENTS

A. Demand for Natural Gas Supply in the Con Edison Service Territory

Con Edison has experienced an increase in customer demand for natural gas supply for the past decade. The increase has been largely driven by local laws that New York City adopted in 2011 mandating that buildings using heavier heating oils convert to more clean-burning fuels.[4] Con Edison's growth in firm customer peak day demand and commensurate pipeline capacity needs have increased at an annual rate of 4.6 percent from 2011-2019. By comparison, firm customer peak day demand and commensurate pipeline capacity needs grew at an annual rate of 1.9 percent during the 10 years ending in 2011. Con Edison requires that sufficient pipeline capacity be available to meet our customers' demand on the coldest expected winter day ("design day"). The design day customer demand only reflects gas used by firm gas customers; it does not include interruptible customers (like generating stations) because they are required to use an alternate fuel on the coldest days.

Con Edison has pursued alternatives to reduce demand. The Company has developed natural gas demand side management programs, including our Smart Solutions Program.[5] These changes have led to some reductions in the amount of natural gas used by our customers and benefitted the environment. Con Edison will continue to pursue these alternatives to mitigate the increased demand for natural gas in our service territory. Thus far, these programs have not been adequate to offset customer requests for additional gas supply or curtail the requirement for additional capacity to meet demand.

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[4] In April 2011, New York City adopted a new heating oil regulation requiring owners of nearly 10,000 buildings to phase out the use of #6 and #4 heating oils. By July 2015, existing boilers must have been switched from burning #6 oil to a cleaner fuel before their current certificate to operate will be renewed. By 2030, boilers that have not yet been modified must meet the equivalent emissions of burning cleaner fuels (e.g., #2 oil or natural gas). Newly installed boilers must burn only clean #2 oil, natural gas, or its emissions equivalent. Power plant owners must phase out the use of these fuel oils sooner, i.e., by 2025.

[5] Con Edison's Smart Solutions Program includes four non-pipeline solutions: a doubling of the Company's existing gas energy efficiency program; a gas demand response program to reduce net customer demand during the entirety of a peak gas demand day(s); a gas innovation program for renewable alternatives to natural gas heating; and a market solicitation for additional non-pipeline solutions on either the supply or demand side, which will provide a pathway for the advancement of new technologies and facilitate new abilities to engage with and deliver services to customers; examples could include beneficial electrification of heating or localized natural gas storage alternatives

Faced with this dilemma, Con Edison entered negotiations with Iroquois to supply new capacity while being mindful of the State's clean energy goals. The ExC Project is designed and narrowly framed to meet these specific objectives. The ExC Project will provide Con Edison with 62,500 Dth/d of additional capacity and allow us to address the existing and forecasted natural gas supply needs of NYC customers. The Company has contracted to purchase this capacity because it will assist us in meeting the obligation to serve our customers in the Bronx and Queens. Moreover, the ExC Project is a "compression only" project that does not expand Iroquois' pipeline footprint, and it does not require Iroquois to acquire additional rights-of-way.

B. Con Edison's Efforts to Facilitate the Transition to Clean Energy

In 2019, New York State enacted the Climate Leadership and Community Protection Act ("Climate Law"), which seeks to achieve "net zero" greenhouse gas ("GHG") emissions by 2050. The Climate Law requires the State to cut GHG emissions to 85 percent below 1990 levels by 2050 and offset the remaining 15 percent through other measures.[6] As stated previously, Con Edison supports these goals, but many of the details of how the Climate Law will be implemented remain unknown and unknowable until the regulations are established.[7] Con Edison will not presume what the ultimate regulations and mandates will look like when they are completed years from now, which are not required to be completed until January 1, 2024. What is known, however,

[6] The Climate Law will require utilities to get 70 percent of the state's electricity from renewable sources by 2030. Last year, 26.4 percent came from renewables, according to a report by New York Independent System Operator.

[7] Con Edison notes in particular that "beneficial electrification" is a consideration under the law and not a requirement, i.e., the Climate Law does not require that natural gas no longer be used for heating. Section 75-0103(13)(g) of the New York Environmental Conservation Law provides the "measures and actions considered in [the law's] scoping plan shall at a minimum include: Measures to achieve reductions in energy use in existing residential or commercial buildings, including the beneficial electrification of water and space heating in buildings."

are the things that the law did not alter, it did not alter Con Edison's obligation to serve those customers who want gas service.[8]

Even without the mandates of the Climate Law, Con Edison has been and will continue to promote clean energy and energy efficiency initiatives. Space heating emissions have decreased from 1990 levels because of enhanced energy efficiency and oil-to-gas conversions. Con Edison has converted more than 7,600 large buildings from oil to cleaner natural gas, which helped NYC achieve its cleanest air in 50 years.[9] To the extent that customers use the natural gas supplied by the ExC Project instead of heating oil, this project will provide a more environmentally and economically responsible option for our customers. Moreover, Con Edison has a Smart Solutions Program that has several elements including: expanding gas energy efficiency, starting a gas demand response program, pursuing non-pipeline alternatives, and testing innovative business models to deploy clean heating technologies. The Smart Solutions Program was developed to offset Con Edison's needs for pipeline capacity, reduce use of third-party-controlled pipeline capacity, and make greater progress in reaching environmental goals. The Company's most recent initiative in this regard was to issue a request for information ("RFI") for the capability to deliver innovative Non-Pipeline Solutions that provide natural gas supply or demand relief during peak days and peak periods. This is an additional effort to bridge gaps in market segments and technologies of our combined portfolio of energy efficiency, demand management and gas supplies. As stated previously, these initiatives have reduced natural gas supply demands but there

[8] Indeed, recent State actions regarding gas moratoriums within New York reinforce our obligation to provide customers energy service options, including natural gas.

[9] Con Edison 2016-2017 Sustainability Report (https://www.conedison.com/ehs/2016-sustainability-report/index.html). *See also*, 2015 New York State Energy Plan, p. 96. (https://energyplan.ny.gov/-/media/nysenergyplan/2015-state-energy-plan.pdf)

is still a need for additional capacity in the Bronx and Queens. The ExC Project provides some of that additional capacity.

III. CONCLUSION

WHEREFORE, Con Edison respectfully requests that the Commission:

1.) give favorable consideration to these comments in support of Iroquois' ExC Project; and

2.) issue the requested certificate by December 31, 2020 at the latest so that Iroquois can meet its commitment to provide service to Con Edison by November 2023.

Respectfully submitted:

By: /s/ Sebrina M. Greene

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Counsel for Consolidated Edison Co. of N.Y., Inc.

Dated: March 3, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at New York, N.Y. this 3rd day of March, 2020.

/s/ Sebrina M. Greene

Sebrina M. Greene

Attachment C

conEdison
a conEdison, inc. company

Ivan Kimball
Vice President
Energy Management

April 20, 2021

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Docket No. CP20-48, Iroquois Gas Transmission System, L.P.

Dear Secretary Bose:

On February 3, 2020, Iroquois Gas Transmission System, L.P. ("Iroquois") filed with the Federal Energy Regulatory Commission ("Commission") an application to construct and own its Enhancement by Compression Project ("ExC Project"), requesting an approval date of December 31, 2020. Consolidated Edison Company of New York, Inc ("Con Edison") is an anchor shipper with 62,500 dekatherms per day of capacity on the ExC Project. On March 3, 2020, Con Edison filed supporting comments with the Commission that detailed its attempts to mitigate customer demand for natural gas supply in its service territory and explained that it still requires additional natural gas supply to meet existing and forecasted customer demand.[1]

Con Edison is submitting this letter to reaffirm its previous comments in support of Iroquois' ExC Project. Our reasons for signing up as an anchor shipper and filing comments in support of the project have not changed. As a local distribution company in the State of New York, Con Edison delivers natural gas to support our customers' critical heating needs and other essential uses. The ExC Project will assist Con Edison in meeting customer demand for natural gas supply.

[1] *See* CP20-48-000, *Iroquois Gas Transmission System, L.P.*, Comments in Support of Consolidated Edison Company of New York, Inc (March 3, 2020). Con Edison hereby incorporates its previous comments by reference.

Consolidated Edison Company of New York, Inc.
4 Irving Place New York, NY 10003-0987 212 460-6060 917 534-4025 fax kimballi@coned.com

Therefore, Con Edison again respectfully requests that the Commission take prompt action approving the ExC Project.

Respectfully submitted,

Ivan Kimball
Vice President, Energy Management

cc: Official Service List
Chairman Richard Glick
Commissioner Neil Chatterjee
Commissioner James Danly
Commissioner Allison Clements
Commissioner Mark C. Christie

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at New York, N.Y. this 20th day of April 2021.

/s/ Sebrina M. Greene
Sebrina M. Greene

Attachment D

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iroquois Gas Transmission System, L.P.	)))	**Docket No. CP20-48-000**

MOTION FOR LEAVE TO ANSWER AND LIMITED ANSWER OF
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure,[1] Consolidated Edison Company of New York, Inc. ("Con Edison") hereby submits this motion for leave to answer and limited answer to the comments submitted by U.S. Environmental Protection Agency ("EPA") in response to the Final Environmental Impact Statement ("FEIS") issued by FERC staff in the above-captioned proceeding.[2]

On January 31, 2020, Iroquois Gas Transmission System, L.P. ("Iroquois") filed an application ("Application") with the Commission pursuant to section 7(c) of the Natural Gas Act ("NGA") in Docket No. CP20-48-000 requesting a certificate of public convenience and necessity associated with the Enhancement by Compression Project ("ExC Project" or "Project"). The Project is a compression-only project designed to provide 125,000 Dekatherms per day ("Dth/d") of incremental firm transportation service of which Con Edison has contracted for 62,500 Dth/d of capacity in order to safely and reliably serve its customers.[3]

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[1] 18 C.F.R. §§ 385.212, 385.213 (2021).
[2] *See* Comments of Environmental Protection Agency on the Final Environmental Impact Statement for Iroquois Gas Transmission System, L.P.'s Enhancement by Compression Project, Docket No. CP20-48-000 (filed Dec. 20, 2021).
[3] Iroquois has contracted the remaining 62,500 Dth/d of the Project to KeySpan Gas East Corporation d/b/a National Grid.

In this limited answer, Con Edison addresses EPA's recommendation that the Commission should delay acting upon Iroquois' application and similar pending certificate applications until the Commission has considered all input received and finalized any forthcoming policy updates associated with its ongoing review of the Commission's certificate policy statement (Docket No. PL18-1) and the Technical Conference on Greenhouse Gas Mitigation (Docket No. PL21-3), which was held on November 19, 2021. Additionally, EPA recommends that after any such policy updates are finalized, the Commission also should reevaluate the environmental reviews conducted pursuant to the National Environmental Protection Act ("NEPA") for the ExC Project and other similar projects to apply these new policies. As further explained herein, the Commission should not further delay its decision and should promptly approve the ExC Project. While Con Edison has undertaken efforts to mitigate the increased demand for natural gas in its service territory, consistent with New York State's and the company's clean energy goals, the ExC Project is nevertheless required to support Con Edison's ability to meet its obligation to provide reliable, safe, and cost-effective service to the public that is connected to Con Edison's system and to whom it provides such gas service.[4]

I. IDENTITY OF CON EDISON

Con Edison is a combination gas, electric, and steam utility company whose retail rates and services are regulated by the Public Service Commission of the State of New York ("NYPSC"). Con Edison delivers gas to 1.1 million customers in Manhattan, the Bronx, parts of Queens, and most of Westchester County. Con Edison receives transportation services on Iroquois' natural gas pipeline system to serve its customers in New York.

[4] *See* N.Y. PUBLIC SERVICE LAW § 65 ("Every gas corporation, every electric corporation and every municipality shall furnish and provide such service, instrumentalities and facilities as shall be *safe and adequate and in all respects just and reasonable*.") (emphasis added).

Con Edison takes an active leadership role in the delivery of a clean energy future for our customers. In accordance with the Climate Leadership and Community Protection Act ("Climate Law") enacted by the State of New York in 2019, Con Edison does this by investing in, building, and operating reliable, resilient, and innovative energy infrastructure, advancing electrification of heating and transportation, and aggressively transitioning away from fossil fuels to a net-zero economy by 2050. In fact, Con Edison has committed to providing 100 percent clean electricity by 2040, tripling our energy efficiency by 2030, and providing focused support for the use of electric vehicles. Con Edison's commitments include plans to reimagine its gas system by reducing the utilization of natural gas and exploring new ways to use the existing gas infrastructure system to service its customers' future needs.[5] This commitment builds on our past activities, outlined in our Sustainability Report,[6] as a climate leader and boldly expands on that work, providing actionable metrics and targets for us to meet in the future. Con Edison continues to productively collaborate with customers, regulators, policymakers, and other stakeholders to ensure the clean energy future is informed by principles of reliability, cost-effectiveness, equity, and environmental justice.

II. MOTION FOR LEAVE TO ANSWER

The Commission's regulations generally prohibit answers to protests and answers to answers unless otherwise ordered by decisional authority.[7] However, the Commission may accept an answer to a protest or an answer to an answer for good cause shown. Good cause exists where the answer ensures a complete record, helps the Commission understand the issues, or assists the

[5] *See* Con Edison, Our Clean Energy Commitment, *available at* https://www.coned.com/en/our-energy-future/our-energy-vision/our-energy-future-commitment.
[6] *See* Con Edison, Sustainability Report 2020, *available at* https://lite.conedison.com/ehs/2020-sustainability-report/index.html.
[7] *See* 18 C.F.R. § 385.213(a)(2).

Commission in its decision-making process.[8] To the extent permission may be necessary under the Commission's rules as they apply to comments submitted in certificate proceedings, Con Edison submits that good cause exists for the Commission to accept this limited answer because it will lead to a more complete record, will contribute to an understanding of the issues, and will assist the Commission in its decision-making process. Accordingly, Con Edison moves for leave to respond to EPA's comments and admit this limited answer into the record of this proceeding.

III. LIMITED ANSWER

A. Demand for Natural Gas Supply in Con Edison's Service Territory Is the Driver of the Company's Need for the Project

Customer natural gas demand in Con Edison's service territory is exceeding its available firm natural gas interstate pipeline capacity that is needed to reliably and safely serve Con Edison's existing customers on peak winter days. Specifically, there has been a significant increase in demand for natural gas service, largely driven by revitalization projects, new construction, and #2 oil and propane to natural gas conversions. Con Edison estimates that growth in firm customer peak day gas demand has increased by just under 40 percent in the last decade. Con Edison has met this increase in demand over the last eight years through the increased use of shorter-duration contracts for pipeline capacity held by other entities. Despite the near-term impacts caused by the COVID pandemic and the recent enactment of a ban on new gas service connections within New York City limits, Con Edison forecasts continued firm customer peak day gas demand growth in its service territory for the next several years.[9]

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[8] *See, e.g.*, *Venice Gathering Sys., L.L.C.*, 155 FERC ¶ 61,325, at P 9 n.7 (2016) (accepting an answer to answer because it did not delay the proceeding, assisted the Commission in understanding the issues raised, and ensured a complete record); *El Paso Nat. Gas Co., LLC*, 144 FERC ¶ 61,004, at P 18 (2013) (accepting an answer to an answer because it aided the Commission in its decision-making process); *Tex. E. Transmission, LP*, 130 FERC ¶ 61,111, at P 8 (2010) (accepting an answer to an answer because it led to a more accurate and complete record and provided information that assisted the Commission in its decision-making process).

[9] *See* New York City, N.Y., Code § 28-506.1.

Con Edison has pursued alternatives to reduce demand and to otherwise manage its natural gas supply needs. Con Edison has developed and implemented natural gas demand-side management programs, including our Smart Solutions Program.[10] These changes have led to reductions in our customers' natural gas consumption and benefitted the environment. Con Edison will continue to pursue these alternatives to mitigate natural gas demand in our service territory. Con Edison forecasts that these programs, however, will not be sufficient to offset projected near-term demand growth on Con Edison's system or eliminate the requirement for additional firm capacity to meet that demand.

Recent growth and forecasts of future growth in customer demand for natural gas in Con Edison's service territory on the one hand, and the resistance to traditional, large-scale natural gas infrastructure projects that involve the construction of new pipelines on the other, requires creative thinking to address these competing concerns. The ExC Project is a product of Con Edison's creative thinking because it is designed and narrowly framed to safely and reliably meet customer needs while being mindful of the State's clean energy goals. Using only compression, the Project will provide Con Edison with an additional 62,500 Dth/d of capacity and allow Con Edison to meet its obligation to safely and reliably serve existing and forecasted natural gas supply needs of customers. Con Edison has weighed the ExC Project against other supply solutions and considers it to be a key component of safely, reliably, affordably, and sustainably meeting existing customers' needs.

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[10] Con Edison's Smart Solutions Program includes three non-pipeline solutions: (1) a doubling of existing gas energy efficiency program; (2) a gas demand response program to reduce net customer demand during the entirety of a peak gas demand day(s); and (3) a market solicitation for additional non-pipeline solutions on either the supply or demand side, which will provide a pathway for the advancement of new technologies and facilitate new abilities to engage with and deliver services to customers; examples could include beneficial electrification of heating or localized natural gas storage alternatives. The Company has begun implementation of these programs.

B. Con Edison's Efforts to Facilitate the Transition to Clean Energy

The Climate Law, as discussed above, seeks to achieve "net zero" greenhouse gas ("GHG") emissions by 2050 in the State of New York. Specifically, the Climate Law requires, subject to certain exceptions, the State to cut GHG emissions to 85 percent below 1990 levels by 2050 and offset the remaining 15 percent through other measures. Con Edison is committed to meeting these requirements and has released its own commitment to deliver 100 percent clean energy to its customers by 2040 and reimagine its gas system by reducing the utilization of natural gas and exploring new ways to use the existing as infrastructure system to service its customer's future needs.[11]

Regardless, these commitments do not alter Con Edison's obligation to safely and reliably serve customers that are connected to Con Edison's gas system. The NYPSC, which is charged with implementing major portions of the State's Climate Law,[12] recently emphasized that this act does not alter a gas company's obligation to provide safe and reliable gas service. The NYPSC stated its evaluation of decisions for consistency with the State's Climate Law are "made in the context of the [NYPSC's] core responsibility to ensure that 'every gas corporation . . . furnishes and provides such service, instrumentalities and facilities as *shall be safe and adequate* and in all respects just and reasonable.'"[13] The NYPSC further stated that it "views the long-standing [Public Service Law] statutory mandate to maintain safe and adequate service as being fundamental to protecting the public health and welfare."[14] Similarly, this Commission should recognize Con Edison's need to provide safe and adequate service to the public that are connected and receiving

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[11] *See* Con Edison, Our Clean Energy Commitment, *available at* https://www.coned.com/en/our-energy-future/our-energy-vision/our-energy-future-commitment.
[12] Climate Law, S. 6599, 2019-2020 Sen., Reg. Sess. § 7 (N.Y. 2019).
[13] Case 19-G-0309, *et al.*, Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements, at 73 (Aug. 12, 2021) (quoting N.Y. PUBLIC SERVICE LAW § 65) (emphasis in original).
[14] *Id.* at 73-74.

service from Con Edison today. Delaying approval of the Project will harm Con Edison's ability to safely and reliably serve customer demand, including service to Con Edison's existing customers.

Even without the mandates of the Climate Law, Con Edison has been and will continue to promote clean energy, the integration of low-carbon fuels into their gas streams, and energy efficiency initiatives. Space heating emissions have decreased from 1990 levels because of enhanced energy efficiency and oil-to-gas conversions. To the extent that customers use the natural gas supplied by the Project instead of heating oil, this Project will provide a more reliable, environmentally and economically responsible option for our customers. Moreover, Con Edison has a Smart Solutions Program that has several elements, including expanding gas energy efficiency, starting a gas demand response program, and pursuing non-pipeline alternatives. Con Edison developed the Smart Solutions Program to offset its needs for pipeline capacity, reduce use of third-party controlled pipeline capacity, and make greater progress in reaching environmental goals.

Con Edison's two most recent initiatives in this regard were to issue a request for information ("RFI") for the capability to deliver innovative Non-Pipeline Solutions that provide natural gas supply or demand relief during peak days and peak periods, and to file a statewide heat pump implementation plan[15] (in conjunction with other utilities in New York State and the New York State Energy Research and Development Authority) (the "Heat Pump Implementation Plan"). The RFI is an additional effort to bridge gaps in market segments and technologies of our combined portfolio of energy efficiency, demand management and gas supplies. The NYSPSC

[15] NYS Clean Heat: Statewide Heat Pump Program Implementation Plan, Docket No. 18-M-0084 (filed June 1, 2020).

recently authorized Con Edison to implement some of these solutions.[16] The Heat Pump Implementation Plan supports customers transitioning to energy-efficient electrified space heating and water heating technologies, and specifically commits Con Edison to supporting customers affected by natural gas supply constraints.[17]

As stated previously, while these initiatives have reduced natural gas demand, begun to decouple GHG emissions from utilization of gas infrastructure, and will continue to do so going forward, there is still a need for additional capacity for Con Edison to continue to safely and reliably serve its existing customers in accordance with the Public Service Law of New York. This Project will provide that needed additional capacity.

C. The Commission Should Not Further Delay Acting on Iroquois' Requested Certificate for the Project

Delaying action on Iroquois' requested certificate in this proceeding until the Commission decides whether it will keep, modify, or replace its current policy on new interstate natural gas transportation facilities, as the EPA advocates, will further impair Iroquois' ability to provide the requested transportation service to Con Edison. On the merits, the need for the ExC Project is clear and well-established in the record of this proceeding and Con Edison asserts that the Project

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[16] Case 19-G-0066, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Order Approving with Modifications the Request for Funding Approval to Pursue Additional Solutions for Load Relief (June 23, 2021).

[17] Beginning in 2019, Con Edison began offering the nation's first generally applicable natural gas demand response program to its customers to complement its existing interruptible rate offering. For large firm gas customers, the program is modeled on Con Edison's successful electric demand programs, in which the customer receives a reservation payment in exchange for a pledge to reduce gas use during extreme conditions and a use payment based on performance. Smaller customers receive a monthly bill credit for agreeing to allow their Wi-Fi thermostat provider to reduce the temperature of their home upon receiving a signal from Con Edison. In addition, Con Edison is pursuing reduction of upstream fugitive methane emissions across the natural gas production and delivery value chain, including research and development regarding green hydrogen and integrating renewable natural gas supplies from local producers into its natural gas distribution system. Con Edison adopted a standard interconnection procedure for renewable natural gas in 2020 and has executed an agreement with a project developer that will locate its facility in Con Edison's service territory. Con Edison also has reduced fugitive methane emissions from its natural gas delivery system by 40 percent since 2005 and has set a goal of net-zero emissions by 2040. This has been achieved through the application of leak detection, repair best practices, and continued acceleration of Con Edison's main replacement program.

would pass any revised need determination test that may result from the Commission's pending policy initiatives on new interstate natural gas transportation facilities. In terms of GHG mitigation, the ExC Project is a compression-only project that has already been meticulously designed to minimize GHG emissions. The ExC Project has been designed with state-of-the-art emission control equipment to provide additional GHG-related benefits. Vent recovery systems will be installed to *reduce* methane emissions at all ExC Project compressor stations by approximately 70% compared to historic levels. Moreover, as part of Con Edison's process to determine the best course of meeting customer demand given supply constraints, Con Edison thoroughly reviewed a number of alternative projects and determined that the ExC Project was the best option for safely and reliably meeting customer demand and in accordance with the goals of the Climate Law.

Procedurally, following EPA's recommendation to reevaluate the NEPA assessment of the ExC Project to apply revised policies would diverge from the Commission's traditional approach of evaluating certificate applications based on the policy guidance in effect at the time the application was submitted. Such action also would contradict the assurances provided by the Commission in its 2018 Notice of Inquiry in Docket No. PL18-1 initiating the ongoing review of its certificate policy statement that "[d]uring the pendency of this proceeding, the Commission intends to continue to process natural gas facility matters before it consistent with the Policy Statement."[18]

[18] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,042, at P 4 (2018) ("2018 Notice of Inquiry"). Furthermore, Chairman Glick has made numerous public statements since the issuance of the 2021 Notice of Inquiry seeking new stakeholder perspectives on the certification process to reiterate that the Commission does not plan to hold up the processing of gas infrastructure certificate applications while it undertakes a review of its certificate policy statement. *See, e.g.*, Letter from FERC Chairman Richard Glick to U.S. Senator Joe Manchin III, Docket No. PL18-1-000 (issued May 24, 2021) ("I agree that the Commission should not delay action on these Certificates during the pendency of our ongoing inquiry into potential reforms to the Commission's Natural Gas Certificate Policy Statement") *and* ("I can assure you that the Commission will not wait to act on Certificate applications while we consider options for improving the process").

To avoid delays during periods that FERC may be considering policy revisions, Con Edison endorses the approach that FERC staff took in the FEIS. That is, FERC staff applied current Commission policy related to GHG emissions rather than attempting to address policies that do not yet exist.[19] That approach minimizes potential adverse real-world impacts that policy considerations may have on the industry and customers. This especially makes sense for a limited project that is compression only. In accordance with that approach, the Commission should not further delay a decision on the ExC Project until such time that the Commission may decide to modify or replace its existing policy as suggested by EPA in its comments because such delay is unnecessary, contrary to Commission policy, and would impair Con Edison's ability to safely and reliably serve its customers.

IV. CONCLUSION

For the foregoing reasons, Con Edison respectfully request that the Commission grant Con Edison's motion for leave to answer and admit this limited answer into the record of this

[19] FEIS, Docket No. CP20-48-000, at 30 (Nov. 12, 2021) (stating "we cannot address mitigation measures for the Project's GHG emissions because there are policy decisions pending at the time of this EIS publication and their resolution is beyond the scope of staff's NEPA review in this proceeding.").

proceeding, reject EPA's recommendation to further delay action on this Project, and issue a decision on the ExC Project as soon as possible.

Respectfully submitted:

/s/ Blake R. Urban
Blake R. Urban
Senior Attorney
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Counsel for Consolidated Edison Co. of New York, Inc.

Dated: January 27, 2022

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at New York, N.Y. this 27th day of January, 2022.

/s/ *Blake R. Urban*
Blake R. Urban

Attachment E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In The Matter Of:	)	
	)	
Iroquois Gas Transmission System, L.P.	)	**Docket No. CP20-48-000**

MOTION TO INTERVENE AND COMMENTS IN SUPPORT OF
THE NATIONAL GRID GAS DELIVERY COMPANIES

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.214, The Brooklyn Union Gas Company d/b/a National Grid NY ("National Grid NY"); KeySpan Gas East Corporation d/b/a National Grid ("National Grid LI" or "Company"); Boston Gas Company ("Boston Gas") and Colonial Gas Company, collectively d/b/a National Grid; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid ("Narragansett"), all subsidiaries of National Grid USA, Inc. (collectively the "National Grid Gas Delivery Companies" or "National Grid") hereby jointly and severally move to intervene and comment in support of the January 31, 2020 application ("Application") filed by Iroquois Gas Transmission System, L.P. ("Iroquois") in the above referenced proceeding for a certificate of public convenience and necessity associated with the Enhancement by Compression ("ExC Project" or "Project").

In support hereof, the National Grid Gas Delivery Companies respectfully state:

1. National Grid NY is a corporation duly organized and existing under the laws of the State of New York, with its principal office located at One MetroTech Center, Brooklyn, New York 11201.

2. National Grid LI is a corporation duly organized and existing under the laws of the State of New York, with its principal office located at 175 East Old Country Road, Hicksville, New York 11801.

3. Boston Gas Company and Colonial Gas Company, collectively d/b/a National Grid, are corporations duly organized and existing under the laws of the Commonwealth of Massachusetts, with their principal offices located at 40 Sylvan Road, Waltham, Massachusetts 02451.

4. Niagara Mohawk Power Corporation d/b/a National Grid is a corporation duly organized and existing under the laws of the State of New York, with its principal office located at 300 Erie Boulevard West, Syracuse, New York 13202.

5. The Narragansett Electric Company d/b/a National Grid is a corporation duly organized and existing under the laws of the State of Rhode Island, with its principal office located at 280 Melrose Street, Providence, Rhode Island 02907.

6. The National Grid Gas Delivery Companies are engaged primarily in the purchase and distribution at retail of natural gas, serving approximately 2 million customers in New York State and over 1 million customers in Massachusetts and Rhode Island.

7. The following persons are designated to receive service in this proceeding:

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Director, FERC Gas Markets Policy
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andrew.macbride@nationalgrid.com

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and

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Motion To Intervene

8. On January 31, 2020, Iroquois filed an application pursuant to section 7(c) of the Natural Gas Act[1] ("NGA") for the ExC Project. Iroquois requests authorization to construct, own, operate, and maintain certain new natural gas compression and cooling facilities to be located at the sites of four existing Iroquois compressor stations in Athens, N.Y.; Dover, N.Y.; Brookfield, Conn.; and Milford, Conn.

9. The Project is a compression-only project designed to provide 125,000 Dekatherms per day ("Dth/d") of incremental firm transportation service to two of Iroquois' existing customers, National Grid LI and Consolidated Edison Company of New York, Inc. ("Con Edison"), with National Grid and Con Edison each receiving 62,500 Dth/d of incremental firm natural gas transportation service pursuant to Iroquois' existing Rate Schedule RTS for a term of 20 years.[2]

10. Iroquois states that the Project will cost an estimated $272 million to be borne by the Project shippers and will be limited to the addition of equipment within existing compressor stations in Iroquois' Zone 2.[3] Iroquois states it determined that the most advantageous method of adding the Project capacity from an environmental and efficiency standpoint is through the

[1] 15 U.S.C. § 717f(c).
[2] Application at 2.
[3] Application at 4.

addition of compression and cooling equipment at three existing compressor stations and the installation of cooling facilities at a fourth existing compressor station.[4]

11. Specifically, Iroquois proposes to construct:

- At the existing Athens, N.Y compressor station, one new approximately 12,000 horsepower ("HP") turbine with associated cooling, filter separators, and other typical facilities connecting to the Iroquois 24-inch mainline in the Town of Athens, Greene County, New York;
- At the existing Dover, N.Y. compressor station, one new approximately 12,000 HP turbine with associated cooling, filter separators, and other typical facilities connecting to the Iroquois 24-inch mainline in the Town of Dover, Dutchess County, New York;
- At the existing Brookfield, Conn. compressor station, a control/office building and two new turbines with approximately 12,000 HP each with associated cooling, filter separators and other typical facilities connecting to Iroquois' 24-inch mainline at the Town of Brookfield, Fairfield County, Conn. as well as incremental cooling equipment to be added to existing facilities;
- At the existing compressor station in the City of Milford, New Haven County, Conn., install new gas cooling equipment and associated piping.[5]

12. Iroquois states that it also plans to: include modifications at Brookfield to address noise levels to maintain compliance with FERC standards for the Brookfield compressor station; to install new oxidation catalysts in the new compressors and two existing compressors to reduce

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[4] Application at 12.
[5] Application at 12-13.

carbon monoxide; and to install vent recovery systems at each of the ExC Project compressor stations.[6]

13. Iroquois requests that the Commission issue the certificate order by December 31, 2020 so that there is adequate time for the project to be constructed and commence service by November 1, 2023.

14. The National Grid Gas Delivery Companies include National Grid LI, a shipper that has entered a precedent agreement for capacity on the ExC Project. As such, the National Grid Gas Delivery Companies have a substantial interest that will be directly affected by Commission action in this proceeding. National Grid will not be adequately represented by any other party. Unless permitted to intervene and participate fully, National Grid may be bound and adversely affected by the Commission's orders herein without an opportunity to have its views heard and considered. Accordingly, the public interest will be served by granting this motion to intervene.

Comments

15. National Grid supports the ExC Project for its ability to significantly increase deliverability into capacity-constrained downstate New York with a design that minimizes environmental impacts and complements greenhouse gas reduction and other pollution-control efforts underway within New York, as well as addresses certain operational concerns.

16. National Grid LI expects its demand growth to remain steady in coming years due to population and economic growth as well as continued oil-to-gas conversions. National Grid LI's current supply resources are already challenged to meet existing peak demand during cold weather and, looking ahead, the Company's existing and planned capacity is not sufficient to meet forecasted peak demand. The ExC Project will support the Company's ability to address

[6] Application at 13-14.

this gap between forecast demand and available supplies and to meet projected demand growth within its service territory.

17. Recognizing its statutory obligations to serve increasing demand, National Grid also fully supports the decarbonization policies of New York State such as the Climate Leadership and Community Protection Act,[7] which sets the goal of achieving net-zero carbon emissions in all sectors of the economy by 2050. As such, National Grid LI is striving to reduce the greenhouse gas intensity of its own gas distribution operations by pursuing low carbon gas options such as renewable natural gas and hydrogen blending.

18. Satisfying the dual goals of meeting increased demand for gas and these important environmental goals is a complex challenge. National Grid is already aggressively striving to reduce peak demand in its downstate New York service territories through measures such as energy efficiency and demand response. Even after accounting for its own demand-reduction efforts as well as emerging trends such as electrification, National Grid LI is still projecting consistent peak demand growth. National Grid LI has a statutory obligation to serve customer requests for new gas connections and will require incremental supplies of natural gas to meet forecast demand levels. The ExC Project is designed to help alleviate these concerns.

19. On February 24, 2020, National Grid released its Natural Gas Long-Term Capacity Report ("Long-Term Capacity Report" or "Report"), a comprehensive assessment of its long-term capacity needs in downstate New York. The Report takes into consideration the State's decarbonization policies and the supply options available to meet long-term demand. The Report specifically analyzes the ExC Project among other alternatives and demonstrates that the ExC Project offers significant economic and environmental benefits among the available supply

[7] 2019 N.Y. Laws, c.106

options and will support National Grid LI's ability to reliably and sustainably meet projected demand growth across its distribution system.

20. The Project also would provide important operational benefits for National Grid LI while minimizing physical impacts. The ExC Project would provide valuable pressure reinforcement in northern and eastern Long Island that would otherwise require on-system upgrades to the Company's own distribution system. As a "compression-only" project, the ExC Project is an infrastructure solution that would be constructed entirely in Iroquois' existing right of way and that would not require any new pipeline construction.

21. For all of the reasons stated herein, National Grid supports Iroquois' application for a certificate of public convenience and necessity associated with the ExC Project.

Conclusion

WHEREFORE, the National Grid Gas Delivery Companies respectfully request that the Commission:

a. issue an order permitting the National Grid Gas Delivery Companies to intervene in this proceeding with full rights as parties hereto;

b. approve Iroquois' ExC Project in a manner that will permit Iroquois to commence service by November 1, 2023; and

c. grant the National Grid Gas Delivery Companies such other and further relief as may be required to protect their interests and the interests of the gas consumers they serve.

Respectfully submitted,

The National Grid Gas Delivery Companies

/s/ *Kenneth T. Maloney*

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Dated: March 4, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties to this proceeding in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Washington, D.C. this 4th day of March, 2020.

/s/ *Kenneth T. Maloney*

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Attachment F

nationalgrid

April 9, 2021

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, D.C.

Re: CP20-48: Iroquois Gas Transmission System, L.P. – Enhancement by Compression Project

Dear Secretary Bose:

The National Grid Gas Delivery Companies[1] ("National Grid" or "Company") submit these supplemental comments to urge the Federal Energy Regulatory Commission ("Commission") to act swiftly in issuing a decision on the Iroquois Gas Transmission System, L.P.'s ("Iroquois") Enhancement by Compression Project's ("ExC Project") certificate application. The National Grid Gas Delivery Companies include National Grid LI, a shipper that has entered into a precedent agreement for capacity on the ExC Project. As National Grid expressed in its initial comments,[2] the project will support the Company's ability to address the anticipated gap between forecast gas demand and available supplies and to meet projected demand within its service territory.

In 2020, National Grid conducted a comprehensive review of available supply- and demand-side resource options for meeting forecasted customer demand in its downstate New York service territories.[3] Even with aggressive assumptions regarding demand reduction opportunities, such as energy efficiency, demand response, and electrification, National Grid determined that additional supply solutions will be required to address the projected gap between forecast demand and its supply capacity portfolio. The ExC Project is a key component of National Grid's current portfolio of supply solutions to deliver reliable and affordable service in downstate New York while also complying with and facilitating New York State's clean energy priorities.

[1] The National Grid Gas Delivery Companies consist of The Brooklyn Union Gas Company d/b/a National Grid NY ("National Grid NY"); KeySpan Gas East Corporation d/b/a National Grid ("National Grid LI"); Boston Gas Company ("Boston Gas") d/b/a National Grid; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid ("Narragansett"), all subsidiaries of National Grid USA, Inc.
[2] Motion to Intervene and Comments in Support of the National Grid Gas Delivery Companies, Docket No. CP20-48, March 4, 2020.
[3] National Grid, Natural Gas Long-Term Capacity Supplemental Report, May 2020, https://ngridlongtermsolutions.com/.

Among the available supply solutions, the ExC Project offers unique operational benefits including pressure reinforcements in northern and eastern Long Island that would otherwise require upgrades to National Grid's distribution system. Moreover, the ExC Project is a "compression-only" project that would not require any new pipeline construction and has been designed to minimize environmental impacts. Projects that leverage existing infrastructure are critical to meeting the region's energy needs.

A prompt decision from the Commission in the instant proceeding is appropriate. The Commission has a complete record with which to determine whether the ExC Project is required by the public convenience and necessity. National Grid respectfully requests that the Commission act promptly to issue a decision in this proceeding.

Sincerely,

James Holodak

James G. Holodak
Vice President, Energy Procurement

cc: Service List
Chairman Richard Glick
Commissioner Neil Chatterjee
Commissioner James Danly
Commissioner Allison Clements
Commissioner Mark C. Christie

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties to this proceeding in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Washington, D.C. this 9th day of April, 2021.

/s/ Kenneth T. Maloney

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Attachment G

nationalgrid

December 17, 2021

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, D.C.

Re: CP20-48: Iroquois Gas Transmission System, L.P. – Enhancement by Compression Project

Dear Secretary Bose:

On November 12, 2021, the Federal Energy Regulatory Commission's ("Commission") Office of Energy Projects released a final environmental impact statement for the Enhancement by Compression Project ("ExC Project") and the Commission now has a complete record on which to issue a decision. The National Grid Gas Delivery Companies[1] ("National Grid" or "Company") submit these comments to again stress the continued need for the ExC Project and to urge the Commission to act expeditiously to approve Iroquois Gas Transmission System, L.P.'s certificate application for the ExC Project.

The National Grid Gas Delivery Companies include National Grid LI, a shipper that has entered into a precedent agreement for capacity on the ExC Project. National Grid originally filed comments in support of the ExC Project on March 4, 2020[2] and supplemented these comments on April 9, 2021.[3] As National Grid expressed in its previous comments, the project will support the Company's ability to address the anticipated gap between forecast gas demand and available supplies and to meet projected demand within its service territory.

National Grid is partnering with the State of New York to achieve deep decarbonization of the state's economy pursuant to New York's Climate Leadership and Community Protection Act ("CLCPA"). We are aggressively pursuing demand-side management, non-pipeline alternatives, and the decarbonization of our gas distribution operations, but these efforts at sustainability must be balanced with our obligation to serve customer demand and the equally fundamental tenets of reliability and affordability.

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[1] The National Grid Gas Delivery Companies consist of The Brooklyn Union Gas Company d/b/a National Grid NY ("National Grid NY"); KeySpan Gas East Corporation d/b/a National Grid ("National Grid LI"); Boston Gas Company ("Boston Gas") d/b/a National Grid; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid ("Narragansett"), all subsidiaries of National Grid USA, Inc.
[2] Motion to Intervene and Comments in Support of the National Grid Gas Delivery Companies, Docket No. CP20-48, March 4, 2020.
[3] Supplemental Comments of the National Grid Gas Delivery Companies, Docket No. CP20-48, April 9, 2021.

Over the past two years, National Grid has been working with the New York State Department of Public Service ("NY DPS") and local stakeholders to develop a long-term supply plan for downstate New York that is consistent with these core values of reliability, sustainability, and affordability. National Grid released its original Natural Gas Long-Term Capacity Report in February 2020 ("DNY Capacity Report")[4] and has, after significant public outreach and stakeholder engagement, released supplements to the report in May 2020 and June 2021.[5] In each of these reports, we outline and update our Distributed Infrastructure Solution, which seeks to maximize the contributions of non-infrastructure measures including energy efficiency, demand response, and electrification. Our analysis clearly demonstrates that the need remains for additional infrastructure to address the projected gap between forecast demand and our supply portfolio. The ExC Project is a critical component of our Distributed Infrastructure Solution.

The updated demand forecast in the latest version of the DNY Capacity Report reflects our most recent demand growth projections and shows an increase in such demand growth relative to previous versions of the report. Absent the implementation of the Distributed Infrastructure Solution, we anticipate a supply shortfall beginning in the winter of 2022/23 and expanding in future years.

In September 2021, PA Consulting released an independent assessment of the DNY Capacity Report, conducted for the NY DPS, that focused on the solutions and contingencies proposed by National Grid to address its anticipated supply gap. The PA Consulting report concluded that: (i) National Grid's latest demand forecast is reasonable;[6] (ii) based on the current maturity level of National Grid's demand-side management, incremental infrastructure is necessary to avoid moratorium risk;[7] and (iii) further delays in the permitting and implementation of the ExC Project expose National Grid to significant curtailment and moratorium risk within the next five years.[8]

In addition to addressing the near-term gap between forecast demand and available supplies, the Distributed Infrastructure Solution—including the ExC Project—is a "no regrets"

[4] Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island, and Long Island ("Downstate NY"), February 2020.
[5] *See* Natural Gas Long-Term Capacity Supplemental Report for Downstate NY, May 2020; *and* Natural Gas Long-Term Capacity Second Supplemental Report for Downstate NY, June 2021.
[6] PA Consulting's Assessment of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report, September 10, 2021, p. 8.
[7] PA Consulting Assessment, p. 11.
[8] PA Consulting Assessment, p. 6.

pathway for National Grid to achieve its net zero ambitions and the most reliable, affordable, and flexible manner in which to comply with New York State's CLCPA mandate.[9, 10]

The ExC Project certificate application, which involves only compressor upgrades and no new pipeline construction, has been pending before the Commission since January 2020--a period of almost two years. If approved by the Commission, the ExC Project will still require air permits from New York and Connecticut, and further action on these state air permit applications remains on hold pending a Commission decision. National Grid reaffirms its support for the ExC Project and respectfully requests that the Commission promptly approve this certificate application.

Sincerely,

James Holodak

James G. Holodak
Vice President, Energy Procurement

cc: Service List
Chairman Richard Glick
Commissioner James Danly
Commissioner Allison Clements
Commissioner Mark C. Christie
Commissioner Willie L. Phillips

[9] *See* Comments of the Utility Consultation Group in Anticipation of the Draft Scoping Plan, December 3, 2021, pp. 4-8, *will be available at*: https://jointutilitiesofny.org/regulatory-resources; *and*, Natural Gas Long-Term Capacity Second Supplemental Report for Downstate NY, June 2021, p. 60.

[10] Our long-term supply planning contemplates that public policy and electrification efforts in New York State will eventually lead to some level of demand destruction, but such proposals, including the New York City Council's proposed ban on the use of natural gas in new buildings, do not eliminate the near-term need for the ExC Project.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties to this proceeding in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Washington, D.C. this 17th day of December, 2021.

/s/ Kenneth T. Maloney
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Attachment H

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iroquois Gas Transmission System, L.P.	**)))**	**Docket No. CP20-48-000**

LIMITED ANSWER OF THE NATIONAL GRID GAS DELIVERY COMPANIES TO COMMENTS OF U.S. ENVIRONMENTAL PROTECTION AGENCY ON FINAL ENVIRONMENTAL IMPACT STATEMENT

Iroquois Gas Transmission System, L.P. ("Iroquois") filed an application ("Application") on January 31, 2020 with the Federal Energy Regulatory Commission ("Commission" or "FERC") pursuant to section 7(c) of the Natural Gas Act ("NGA") in the above referenced proceeding for a certificate of public convenience and necessity associated with the Enhancement by Compression ("ExC Project" or "Project"). The Project is a compression-only project designed to provide 125,000 Dekatherms per day ("Dth/d") of incremental firm transportation service to KeySpan Gas East Corporation d/b/a National Grid ("National Grid LI" or the "Company") and Consolidated Edison Company of New York, Inc. to support system reliability and serve growing heating demand in downstate New York. The National Grid Gas Delivery Companies ("National Grid")[1] file this limited answer to address comments the U.S. Environmental Protection Agency ("EPA") submitted in response to the Final Environmental Impact Statement ("FEIS") issued for the ExC Project on November 12, 2021.[2]

[1] The National Grid Gas Delivery Companies consist of The Brooklyn Union Gas Company d/b/a National Grid NY ("National Grid NY"); KeySpan Gas East Corporation d/b/a National Grid ("National Grid LI"); Boston Gas Company ("Boston Gas") d/b/a National Grid; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid ("Narragansett"), all subsidiaries of National Grid USA, Inc.
[2] *See* Comments of Environmental Protection Agency on the Final Environmental Impact Statement for Iroquois Gas Transmission System, L.P.'s Enhancement by Compression Project, Docket No. CP20-48-000 (filed Dec. 20, 2021) ("EPA Final EIS Comments").

In its comments, EPA urges the Commission to postpone any further action on this Application and similar pending certificate applications until it has considered all input received and finalized any forthcoming policy updates associated with its ongoing review of the Commission's certificate policy statement (Docket No. PL18-1) and the Technical Conference on Greenhouse Gas Mitigation (Docket No. PL21-3), which was held on November 19, 2021. Additionally, EPA recommends that after any such policy updates are finalized, the Commission should also reevaluate the environmental reviews conducted pursuant to the National Environmental Protection Act ("NEPA") for the ExC Project and other similar projects to apply these new policies. As further explained herein, the Commission should not further delay its decision and should promptly approve the ExC Project, which will support National Grid's ability to meet it statutory service obligation and serve its customers in a manner that is reliable, cost-effective, and equitable.

I. IDENTITY OF NATIONAL GRID

National Grid is a diversified energy company providing natural gas and electric distribution services in New York, Massachusetts, and Rhode Island. National Grid is engaged primarily in the purchase and distribution at retail of natural gas, serving approximately 2.2 million customers in New York State and 1.2 million customers in Massachusetts and Rhode Island.

National Grid is deeply committed to a clean energy future and helping New York achieve its energy and environmental goals under the Climate Law. These commitments are documented in National Grid's Net Zero by 2050 Plan and its Responsible Business Charter.[3] National Grid believes that a hybrid net zero strategy—one that leverages existing electric and gas systems for

[3] *See* National Grid, Net Zero by 2050 Plan *available at*: https://www.nationalgridus.com/media/pdfs/our-company/netzeroby2050plan.pdf; *and* National Grid, Responsible Business Charter, *available at*: https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf.

heating—is the most feasible, cost-effective, and equitable pathway to deep decarbonization. To deliver this future, National Grid is significantly reducing methane emissions from our networks, increasing investments in energy efficiency and demand response, expanding the use of renewable natural gas ("RNG") and hydrogen, integrating innovative technologies to decarbonize heat, and advancing clean transportation.

II. MOTION FOR LEAVE TO ANSWER

The Commission's regulations generally prohibit answers to protests and answers to answers unless otherwise ordered by decisional authority.[4] However, the Commission may accept an answer to a protest or an answer to an answer for good cause shown. Good cause exists where the answer ensures a complete record, helps the Commission understand the issues, or assists the Commission in its decision-making process.[5] To the extent permission may be necessary under the Commission's Rules as they apply to comments submitted in certificate proceedings, National Grid submits that good cause exists for the Commission to accept this answer because it will lead to a more complete record, will contribute to an understanding of the issues, and will assist the Commission in its decision-making process. Accordingly, National Grid moves for leave to respond to EPA's comments and admit this answer into the record of this proceeding.

[4] *See* 18 C.F.R. § 385.213(a)(2).

[5] *See, e.g.*, *Venice Gathering Sys., L.L.C.*, 155 FERC ¶ 61,325, at P 9 n.7 (2016) (accepting an answer to answer because it did not delay the proceeding, assisted the Commission in understanding the issues raised, and ensured a complete record); *El Paso Nat. Gas Co., LLC*, 144 FERC ¶ 61,004, at P 18 (2013) (accepting an answer to an answer because it aided the Commission in its decision-making process); *Tex. E. Transmission, LP*, 130 FERC ¶ 61,111, at P 8 (2010) (accepting an answer to an answer because it led to a more accurate and complete record and provided information that assisted the Commission in its decision-making process).

III. ANSWER

A. System Reliability and Demand for Natural Gas Supply Drive the Need for the Project

Customer natural gas demand in National Grid LI's service territory is exceeding the Company's available natural gas interstate pipeline capacity to serve its customers. Specifically, there has been a significant increase in demand for natural gas service, largely driven by revitalization projects, new construction, and #2 oil and propane to natural gas conversions. Growth in National Grid's downstate New York firm customer peak day gas demand has increased by 24 percent in the last decade. Despite the near-term impacts caused by COVID and the recent enactment of a phased ban on new gas service connections within New York City limits, National Grid forecasts continued firm customer peak day gas demand growth in its downstate New York service territories for the next several years.[6]

As previously stated in this docket, National Grid has worked closely with the New York Department of Public Service and local stakeholders to develop a resource solution to address this potential supply gap.[7] National Grid's proposed Distributed Infrastructure Solution--which includes the ExC Project--seeks to maximize the application of demand-side management efforts such as energy efficiency and demand response to serve forecast demand. Despite aggressive assumptions around the contribution of demand-side management measures toward reducing the need for incremental supply resources, National Grid's analysis still found a need for additional gas capacity.

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[6] *See* New York City, N.Y. Code § 28-506.1 (2021); N.Y.C. Law No. 2021/154 (Dec. 12, 2021). The new law applies to new buildings under seven stories beginning in 2024 and those seven stories or higher beginning in 2027. The law also makes exceptions for certain types of buildings and renovation activities.

[7] Natural Gas Long-Term Capacity Second Supplemental Report for Downstate NY, June 2021.

The obligation to maintain reliable service and meet growing customer demand in National Grid's service territories on the one hand, and the resistance to traditional, large-scale natural gas infrastructure projects that involve the construction of new pipelines on the other, requires creative thinking to address these competing concerns. The ExC Project balances and addresses these concerns in that it is designed and narrowly framed to meet our customers' needs while also being mindful of the State's clean energy goals. The Project, through compression only, will provide National Grid LI with an additional 62,500 Dth/d of capacity and allow the Company to meet the existing and forecasted natural gas supply needs of its customers. National Grid has weighed the ExC Project against other supply solutions and considers it to be a key component of reliably, affordably, and sustainably meeting the needs of our customers.

B. National Grid's Efforts to Facilitate the Transition to Clean Energy

The Climate Law, as discussed above, seeks to achieve "net zero" greenhouse gas ("GHG") emissions by 2050 in the State of New York. Specifically, the Climate Law requires, subject to certain exceptions, the State to cut GHG emissions to 85 percent below 1990 levels by 2050 and offset the remaining 15 percent through other measures. National Grid is committed to meeting New York's GHG emission reduction requirements and has also announced its own clean energy commitments. National Grid has committed to reducing GHG emissions from its direct operations to net zero by 2050, and to reduce GHG emissions from the gas sold to customers by 20 percent by 2030 with further reductions beyond that consistent with the targets laid out on the Climate Law.[8]

[8] *See* National Grid, Responsible Business Charter, *available at*: https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf.

Regardless, these longer-term commitments do not alter National Grid's obligation to serve customer demand today.[9] The NYPSC, which is charged with implementing major portions of the State's Climate Law,[10] recently emphasized that this act does not alter a gas company's obligation to provide reliable gas service. The NYPSC stated its evaluation of decisions for consistency with the State's Climate Law are "made in the context of the [NYPSC's] core responsibility to ensure that 'every gas corporation . . . furnishes and provides such service, instrumentalities and facilities as *shall be safe and adequate* and in all respects just and reasonable.'"[11] The NYPSC further stated that it "views the long-standing [Public Service Law] statutory mandate to maintain safe and adequate service as being fundamental to protecting the public health and welfare.[12] Similarly, this Commission should recognize National Grid's need to provide safe and adequate service. Given the particular facts of this proceeding--*i.e.*, a limited compression project that is needed to reliably serve customer demand--the Commission should reject any attempt to delay issuance of the certificate.

Even without the mandates of the Climate Law, National Grid has and will continue to promote clean energy, the integration of low-carbon fuels into their gas streams, and energy efficiency initiatives. National Grid is implementing a multi-pronged approach to support the goals of the Climate Law and to achieve its own decarbonization goals. National Grid recognizes

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[9] Indeed, recent State actions regarding gas moratoriums within New York reinforce our obligation to provide customers energy service options, including natural gas. *See, e.g.*, Case 19-G-0678 - *Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid*, Order Adopting and Approving Settlement (Nov. 26, 2019). *See also* N.Y. Pub. Serv. Law § 31 ("Every gas corporation, electric corporation or municipality shall provide residential service upon the oral or written request of an applicant."); *see also* N.Y. Trans. Corp. Law § 12 ("Except in the case of an application for residential utility service pursuant to article two of the public service law, upon written application of the owner or occupant of any building within one hundred feet of any main of a gas corporation . . . appropriate to the service requested, and payment by him of all money due from him to the corporation, it shall supply gas.").

[10] Climate Law, S. 6599, 2019-2020 Sen., Reg. Sess. § 7 (N.Y. 2019).

[11] Case 19-G-0309, *et al.*, Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements, at 73 (Aug. 12, 2021) (quoting Public Service Law § 65) (emphasis in original).

[12] *Id*. at 73-74.

that electric and gas energy efficiency and demand response are foundational elements of the pathway to net zero. In New York, efficiency programs are on track to nearly double the level of gas and electric savings from 2020 to 2025, reaching more than 3.6 million dekatherms (Dth) of natural gas and over 525,000 megawatt-hours (MWh) of electric energy savings. National Grid is also planning to integrate increasing quantities of RNG and hydrogen into its gas streams serving downstate New York over the next decade and beyond. National Grid is in the process of commissioning an RNG project from the largest sewage treatment facility operated by the New York City Department of Environmental Protection and is exploring additional RNG opportunities. In December 2021, National Grid also announced the HyGrid Project, which is a collaboration with the Town of Hempstead, New York, to build one of the largest clean hydrogen facilities in the country to demonstrate the feasibility of blending green hydrogen into National Grid's local gas streams. Simultaneously, National Grid has also issued multiple requests for information and requests for proposals seeking non-pipeline solutions for natural gas supply as well as demand solutions to meet peak period needs.

As stated previously, while these initiatives have reduced natural gas demand, begun to decouple GHG emissions from utilization of gas infrastructure, and will continue to do so going forward, there is still a clear need for additional capacity for National Grid to continue to reliably serve its customers. Importantly, National Grid has also tested the ExC Project specifically against an aggressive net zero demand scenario and found that the Project is still necessary and provides the flexibility to right size National Grid's gas supply portfolio if gas demand declines in the future as New York State pursues its clean energy goals.[13]

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[13] *See* Section 5.1.3 of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report for Downstate NY, June 2021.

C. The Commission Should Not Further Delay Acting on Iroquois' Requested Certificate for the Project

National Grid strongly disagrees with EPA's recommendation that the Commission postpone a decision on the ExC Project until the above-mentioned policy reviews are completed. On the merits, the need for the ExC Project is clear and well-established in the record for this proceeding[14] and National Grid asserts that the Project would pass any revised need determination test. National Grid has been clear that further delays in the permitting of the Project will impede its ability to fulfill its legal obligation to reliably serve customer demand. An independent assessment commissioned by the New York Department of Public Service ("NY DPS") of the supply solutions and contingencies proposed by National Grid to address its anticipated supply gap found that further delays in the permitting of the ExC Project and other projects expose National Grid to significant moratorium risk within the next five years.[15] In terms of GHG mitigation, the ExC Project is a compression-only project that has already been meticulously designed to minimize GHG emissions. The ExC Project has been designed with state-of-the-art emission control equipment to provide additional GHG-related benefits. Vent recovery systems will be installed to *reduce* methane emissions at all ExC Project compressor stations by approximately 70% compared to historic levels. Moreover, as part of the National Grid's process to determine the best course of meeting customer demand given supply constraints, National Grid thoroughly reviewed a number of alternative projects and determined that the ExC Project was the

[14] *See* Comments in Support of Consolidated Edison Company of New York, Inc., Docket No. CP20-48, March 3, 2020; Motion to Intervene and Comments in Support of the National Grid Gas Delivery Companies, Docket No. CP20-48, March 4, 2020; Supplemental Comments of the National Grid Gas Delivery Companies, Docket No. CP20-48, April 9, 2021; Comments of Consolidated Edison Company of New York, Inc. on the Enhancement by Compression Project, Docket No. CP20-48, April 20, 2021; *and* Second Supplemental Comments of the National Grid Gas Delivery Companies, Docket No. CP20-48, December 17, 2021.

[15] PA Consulting's Assessment of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report, New York Department of Public Service Case No. 19-G-0678, September 10, 2021.

best option for reliably meeting customer demand and in accordance with the goals of the Climate Law.

Procedurally, following EPA's recommendation to reevaluate the NEPA assessment of the ExC Project to apply revised policies would diverge from the Commission's traditional approach of evaluating certificate applications based on the policy guidance in effect at the time the application was submitted. Such action also would contradict the assurances provided by the Commission in its 2018 Notice of Inquiry in Docket No. PL18-1 initiating the ongoing review of its certificate policy statement that "[d]uring the pendency of this proceeding, the Commission intends to continue to process natural gas facility matters before it consistent with the Policy Statement."[16] Furthermore, Chairman Glick has made numerous public statements since the issuance of the 2021 Notice of Inquiry seeking new stakeholder perspectives on the certification process to reiterate that the Commission does not plan to hold up the processing of gas infrastructure certificate applications while it undertakes a review of its certificate policy statement.[17] Finally, we note that the Commission is under no obligation to complete the policy review initiated in Docket No. PL18-1 by a date certain, and that the Commission issued the 2018 Notice of Inquiry nearly four years ago. Granting the EPA's request in this proceeding would not only delay a needed project but subject it to an unnecessary and open-ended period of uncertainty.

To avoid delays during periods that FERC may be considering policy revisions, now and in the future, National Grid endorses the approach that FERC staff took in the FEIS. That is, FERC staff applied current Commission policy related to GHG emissions rather than attempting to

[16] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,042, at P 4 (2018) ("2018 Notice of Inquiry").
[17] *See, e.g.*, Letter from FERC Chairman Richard Glick to U.S. Senator Joe Manchin III, Docket No. PL18-1-000 (issued May 24, 2021) ("I agree that the Commission should not delay action on these Certificates during the pendency of our ongoing inquiry into potential reforms to the Commission's Natural Gas Certificate Policy Statement") *and* ("I can assure you that the Commission will not wait to act on Certificate applications while we consider options for improving the process").

address policies that do not yet exist.[18] That approach minimizes potential adverse real-world impacts that policy considerations may have on the industry and customers. This especially makes sense for a limited project that is compression-only. In accordance with that approach, the Commission should not further delay a decision on the ExC Project until such time that the Commission may decide to modify or replace its existing policy as suggested by EPA in its comments because such delay is unnecessary, contrary to Commission policy, and would impair National Grid's ability to reliably serve its customers in its downstate New York service territories.

IV. CONCLUSION

For the reasons stated above, National Grid respectfully requests that the Commission grant this motion for leave to answer and admit this limited answer into the record of this proceeding, reject EPA's recommendation to further delay action on this Project, and issue a decision on the ExC Project as soon as possible.

Respectfully submitted:

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Counsel for the National Grid Gas Delivery Companies

Dated: January 27, 2022

[18] FEIS, Docket No. CP20-48-000, at 30 (Nov. 12, 2021) (stating "we cannot address mitigation measures for the Project's GHG emissions because there are policy decisions pending at the time of this EIS publication and their resolution is beyond the scope of staff's NEPA review in this proceeding.").

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties to this proceeding in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Washington, D.C. this 27th day of January, 2022.

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Attachment I

PA CONSULTING'S ASSESSMENT OF NATIONAL GRID'S NATURAL GAS LONG-TERM CAPACITY SECOND SUPPLEMENTAL REPORT

September 10, 2021

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Table of Figures

1 Executive Summary

PA Consulting ("PA") conducted an independent assessment of The Brooklyn Union Gas Company's d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation's d/b/a National Grid ("KEDLI," and collectively with KEDNY, the "Company" or "National Grid") Natural Gas Long-Term Capacity Second Supplemental Report for Brooklyn, Queens, Staten Island and Long Island (the "Report"). This review, conducted for the New York State Department of Public Service (the "Department"), focused on the solutions and contingencies proposed by National Grid to address the anticipated growth in Design Day[1] demand. The solutions, collectively referred to as the Distributed Infrastructure Solution (the "DIS") are a mix of infrastructure projects and new energy efficiency and demand side management measures.

PA's review of the DIS started with an assessment of the Design Day demand forecast. The Design Day forecast is critical since it is the basis for the gap between the forecast and the existing supply and demand side resources that drives the need for the solutions outlined in the DIS. The evaluation of the range of feasible solutions considered the technical feasibility, system reliability (ability to maintain gas flow on the peak day), economics, implementation issues, and legislated policies. The development of a preferred solution to meet the near-term projected peak-day demand gap is complex as a result of uncertainties, matters that are beyond National Grid's control, and evolving policy. As an overall assessment and given the uncertainties, PA has concluded the solutions proposed in the DIS are reasonable at this juncture but are not without risk.[2] This report summarizes the basis for our findings and provides additional details on our assessment as well as important caveats.

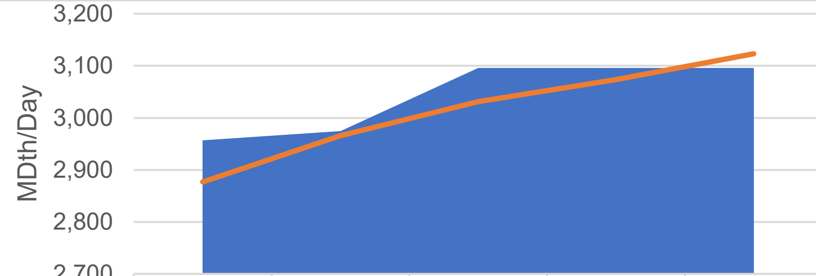
National Grid's assessment of its existing supply and Design Day demand forecast are summarized in Figure 1-1. Figure 1-1 shows that National Grid is anticipating a 9 MDth/day gap in the winter of 2022/23 which grows thereafter absent a combination of incremental supply and demand side measures to close the gap. PA focused on evaluating the gap and potential solutions over the next five heating seasons. While closing the gap over the longer term is also critical and it is appropriate to develop a long-term plan, the key issues we focused on are:

- Is the identified gap over the next five years a reasonable estimate?
- What demand side measures has National Grid identified to fill the gap and is it likely that those measures alone can fill the gap?
- What supply side measures has National Grid identified to fill the gap, are those measures necessary, and what are the implications of not proceeding with those measures?
- What are the risks associated with not implementing the DIS as proposed by National Grid and what are the implications with respect to the need to implement curtailments or a moratorium on new connections?

[1] According to National Grid's Second Supplemental Report, the Design Day is defined as the coldest winter day actually experienced in the downstate service territories, characterized by an average daily temperature of 0° Fahrenheit in Central Park (which is equivalent to 65 Heating Degree Days).

[2] Assessment of the reasonableness of the DIS plan is not intended to be dispositive regarding a determination of need for any Long-Term Capital Capacity Project as outlined in the Joint Proposal approved on August 12, 2021 in Case Nos. 19-G-0309 and 19-G-0310.

Figure 1-1: Design Day Forecasts



	2021/22	2022/23	2023/24	2024/25	2025/26
Total Supply	2,957	2,975	3,096	3,096	3,096
Design Day Demand	2,877	2,966	3,031	3,074	3,123

1.1 Design Day Demand Forecast

PA reviewed two major components of the Design Day load forecast: wind-adjusted Design Day demand conditions and the sales forecast that is translated into the Design Day demand. National Grid commissioned a study by Marquette Energy Analytics which determined that National Grid's Design Day standard is consistent with a one-in-33-year event accounting for wind and temperature[3]. PA's conclusion is that the study presents a reasonable Design Day demand planning criterion. With regard to the load forecast developed by National Grid we note that it is a point forecast rather than a range that had been used in National Grid's Natural Gas Long-Term Capacity Supplemental Report published on May 8, 2020.

PA understands that National Grid develops load forecasts reflecting a range of scenarios and that the forecast presented in the Report reflects a "middle of the road" outlook. However, the Report presents the DIS as a set of solutions in the context of a single demand scenario. Single point forecasts represent an exact prediction of what the future Design Day load will be. This may provide a sense of false precision since it ignores uncertainty and unpredictability due to a host of factors that can potentially influence the outcome. Instead, a range forecast leaves some margin of error and provides a range of plausible estimates and therefore various strategies to meet that demand. There is inevitable uncertainty in any forecast driven by a combination of economic growth and changing use patterns. In PA's review of the forecast, we developed alternative sales scenarios using high-level adjustments. In comparison to PA's scenario, the primary observation of our analysis is that National Grid's load forecast may ultimately be on the high side but it is within reason.[4]

1.2 Demand Side Measures to Fill the Gap

Based upon New York State's environmental goals the ideal solution would be to fill the gap with a combination of energy efficiency and demand side management measures and also have that be the lowest cost solution based upon the existing cost effectiveness tests. However, based upon PA's assessment of National Grid's analysis, our conclusion is that cost-effectively relying on demand side measures alone is unlikely to be sufficient to fill the gap identified over the next five years. Given the current status of National Grid's efforts to date, our assessment is that many of the proposed incremental demand side options ("Incremental"), defined as measures in addition to the demand side management ("DSM") measures

[3] Marquette's analysis assumes a 0-degree Fahrenheit day with a 12 MPH wind speed, the average wind speed on the 1% of historical coldest days from daily Central Park weather data going back to 1950. A 3 degree Fahrenheit day with 16 MPH wind is equivalent to a 0 degree Fahrenheit day with 12 MPH winds.

[4] The Design Day load forecast presented in the Report is based on econometric forecasts of key gas-usage elements using macroeconomic drivers from Moody's Analytics and is characterized as having a 50-50 chance of being higher or lower. National Grid also develops forecasts using alternative economic scenarios provided by Moody's Analytics. As a point of reference, PA's scenarios fall within the range of alternative forecasts developed by National Grid.

reflected in National Grid's Adjusted Baseline ("Baseline")[5] load forecast are in the early stage of testing. As a result, both customer uptake and the savings per participating customer are unproven. Since participation in the programs is voluntary, it is unclear whether customers will enroll at a rapid enough pace to avoid the need for near-term infrastructure enhancements even if budgets were expanded.

1.3 Infrastructure Measures to Fill the Gap

PA's evaluation of the major DIS infrastructure projects currently being proposed concluded that significant risk exists to the timely implementation of both the Iroquois ExC project and the Greenpoint Vaporizers 13 & 14. Further delays in the permitting and implementation of these infrastructure projects exposes National Grid to significant curtailment and moratorium risk within the next five years. The contingency infrastructure projects identified by National Grid remain conceptual and – even assuming ideal permitting and construction timelines – will likely not be in place in sufficient time to cover a Design Day supply/demand gap should any of the major DIS infrastructure projects fail to materialize.

1.4 Risks of a Moratorium on New Connections

National Grid's planning criteria is focused on providing safe, reliable, and cost-effective service to all existing and prospective customers requesting natural gas service. Consequentially, a moratorium on new hookups is not a strategy evaluated by National Grid. Rather, it is a potential outcome if the strategies in the DIS are not successfully implemented. PA's assessment has identified multiple uncertainties related to the design day demand forecast, the efficacy and uptake of the demand side measures, and risks associated with implementing the proposed infrastructure enhancements. In order to minimize the likelihood of a moratorium it is important to pursue both the proposed infrastructure enhancements and demand side measures. However, it is also a policy decision to determine what level of moratorium risk may be acceptable.

In summary, there is real supply risk, and therefore a risk that a supply/demand gap continues to exist, because the only plans National Grid has in place to offset supply risk are (a) demand side management programs that are not fully developed and cannot be expected to fill the gap by such time(s) as would be needed and (b) contingency projects that, even if determined to be feasible and they obtain the necessary approvals, are several years away from implementation – placing even more burden on DSM.

While National Grid's DIS is not unreasonable, it faces significant execution challenges. PA observes that had National Grid presented the range of forecasts that it had developed, as opposed to a single point estimate, it would have afforded its stakeholders alternative perspectives on both the timing and magnitude of need for the DIS components. Regardless of the design day forecast used, given the risks associated with the supply side solutions, it is imperative that the Incremental DSM programs reach scale and maturity as quickly as possible.

[5] Defined in the Report as the baseline demand forecast adjusted for energy efficiency, demand response, and heat electrification. For the purposes of this report, references to "Baseline DSM" reflect the DSM savings which are incorporated in the Adjusted Demand Forecast.

2 Introduction

The purpose of this report is to provide PA's findings following an independent review of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report. This review, conducted for the Department, focused on evaluation of National Grid's load forecast and the mix of supply and demand options that National Grid identified to safely and reliably meet the long-term demand. National Grid has developed a plan, referred to as the DIS that recommends a mix of infrastructure investments and expansions in its energy efficiency and demand side management programs.

2.1 Scope of Work / Engagement and Timing

PA was tasked with the assessment of the content and conclusions contained in the Report. PA was specifically focused on the following workstreams:

- The reasonableness of the Companies' updated gas demand and supply forecasts, including the Companies' consideration of the potential impacts of climate policies on long-term gas demand;
- The status of the distributed infrastructure projects and non-infrastructure solutions;
- The Companies' presentation of additional options for addressing demand in the near/medium term under different scenarios, including the Companies' conclusions on the viability and risks of potential options; and
- Any other issues identified.

Since being engaged in July 2021, PA has observed public meetings hosted by the Department and by National Grid and reviewed feedback from customers and stakeholders related to the Report. PA's effort began in earnest in mid-July with a goal of completing delivery of this Report by September 10, 2021.

3 Key Issues and Observations

The following review and observations are based upon the Report, responses from National Grid to nearly 100 data requests, and over 20 interviews with various National Grid personnel and third-party consultants. Based upon this review, PA has concluded – subject to multiple caveats and concerns – that National Grid's outlook is reasonable. PA observed substantial areas of risk and uncertainty associated with each component of the supply / demand balance which may impact National Grid's ability to meet near term demand. This level of uncertainty coupled with limited capability to mitigate risk causes PA to question whether the DIS could be reprioritized, and whether National Grid could accelerate certain programs to minimize the potential impact associated with contingency supply options which entail long lead times, novel approaches, and their own substantial risk of approval and implementation. In summary, National Grid's DIS (including the proposed infrastructure projects) is a reasonable approach at this point in time given uncertainty regarding load growth and the efficacy of the DSM programs, assuming that avoiding moratorium risk is of critical importance to regulators and other stakeholders.

Support for the reasonableness of National Grid's plan can be summarized across each main component of the forecast:

- The load forecast appears high for certain customer segments but is reasonable compared with alternative scenarios. Since National Grid operates with zero supply contingency relative to Design Day conditions, given the inherent uncertainty in forecasts, assuming a higher load is understandable and appropriately conservative.

- The infrastructure supply options continue to be delayed and face a real risk of outright cancellation. Planning for these resources does presumably entail some opportunity cost, however doing so does not inhibit National Grid's ability to comply with anticipated future climate related laws and environmental goals. PA has not seen evidence that the contingency resources identified in the Report can reasonably be relied upon. PA would also expect that National Grid could conduct "real option" analysis of the current infrastructure options to determine when resources and strategies should be refocused on alternative program components.

- Many of the DSM programs are largely in the early stage of testing and customer uptake is unproven as well as the realized reductions in peak day demand. As such there is little to substantiate that DSM, in the near term, can serve as a backstop if any of the DIS infrastructure solutions do not come to fruition. PA understands that National Grid is multiple years away from validating program feasibility and savings estimates. Further, such programs are heavily dependent upon customer adoption and it is unclear whether National Grid's customers will enroll at a rapid enough pace to de-risk the near-term infrastructure enhancements. While PA is concerned about whether these programs can be relied upon to meet peak demand, more time, peer utility benchmarking data, third party studies, and bottom-up analysis would be required to appropriately validate such expectations. PA expects that these programs will be proven to hold substantial potential and that the targeted savings represent a modest number of customers, however it is the engagement and subsequent ramp up of these programs in the next few years which is the critical unknown.

While National Grid's DIS is not unreasonable, it faces significant execution challenges. PA observes that timing expectations on supply resources and a single point estimate of load deserve reconsideration and that the Incremental DSM programs and contingency supply options need fulsome development. Key issues related to the DIS that PA focused on and associated observations follow.

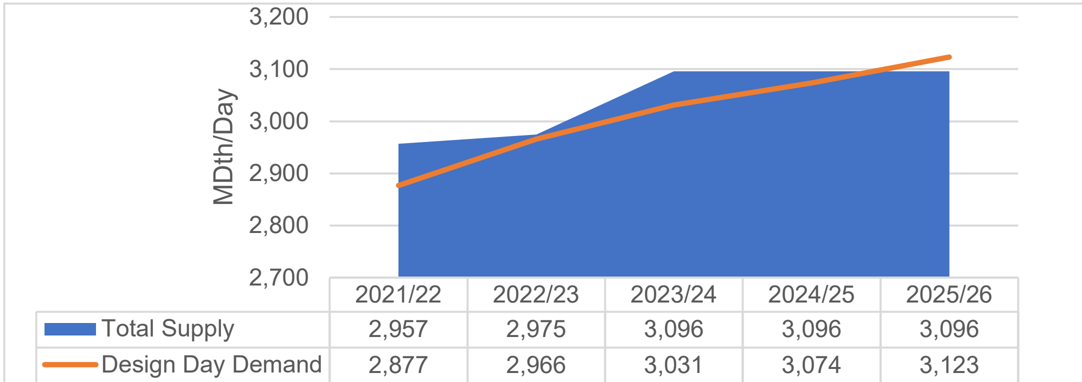
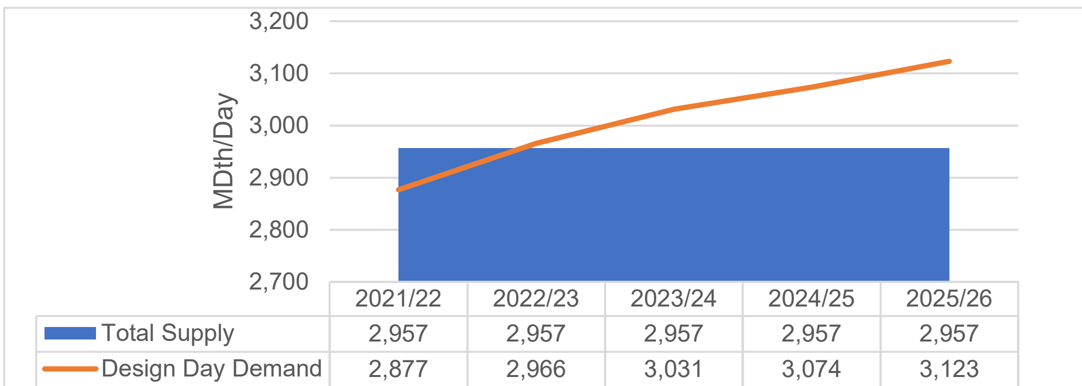
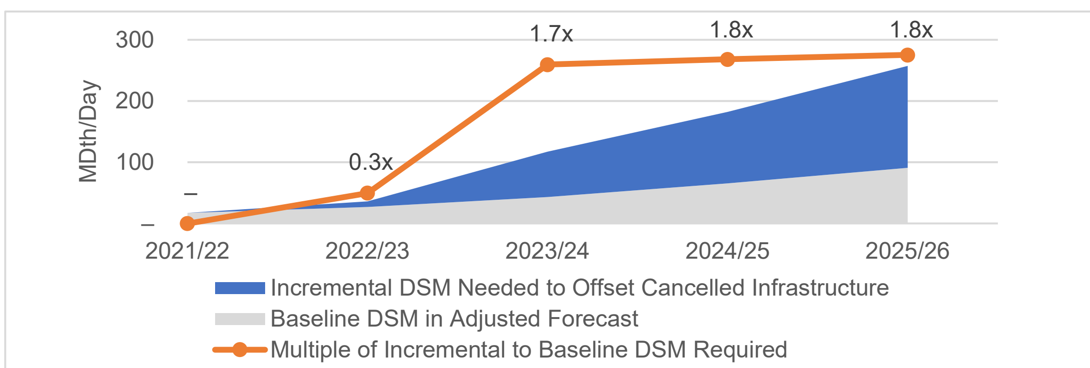
3.1 Key Issues:

- **Supply Resource Sequencing vs. Load Growth:** As part of the above-mentioned optimization process, National Grid has stated that the DIS represents the least cost reliable resource portfolio. This strategy is based on a future which is reliant upon a combination of new gas delivery infrastructure and gas demand reduction. Irrespective of the cost and potential for stranded long-life assets under a net zero regulatory environment[6], National Grid's DIS relies on a combination of infrastructure and demand side management at its core. While the physical asset infrastructure has known capacity, it is by no means guaranteed to be implemented, and in fact carries substantial project development risk and potentially some operational risk. Perhaps the most substantial risk however is the indirect impact that an "infrastructure heavy" approach may have upon National Grid's near-term strategy. From PA's perspective, National Grid's approach to developing the DIS was to continue to pursue near term potentially viable infrastructure for additional supply and DSM programs to fill any shortfall caused by inability to execute the infrastructure plan. In the near term and based upon the programs identified by National Grid, it appears unlikely that Incremental DSM can be relied upon to displace or defer investment in the DIS supply projects, assuming the infrastructure can be completed ahead of when it is needed to meet the load forecast. Still, given the risks associated with developing new infrastructure, parallel planning efforts that include DSM provide the best opportunity to ensure customer demand can be reliably served. As illustrated below, when the additional CNG capacity (the "fifth CNG facility"), Iroquois Enhancement Compression project ("ExC"), the Greenpoint 13 & 14 vaporizers (the "Greenpoint Vaporizers") are completed on schedule, supply meets demand in 2024/25. At the other end of the spectrum when the major infrastructure projects (ExC and Greenpoint Vaporizers) are cancelled, supply may be sufficient to meet demand in 2022/23[7], but not thereafter. In order to achieve a similar supply/demand balance without ExC and the Greenpoint Vaporizers, Incremental DSM would need to reach nearly twice the level of currently planned (or assumed in National Grid's Adjusted Baseline demand forecast) DSM included in the DIS as shown in the third chart in Table 3-1 below. Note that in the charts below, the Design Day demand reflects National Grid's adjusted demand forecast, which does not include in the Incremental DSM components of the DIS (for the purpose of highlighting the magnitude and timing of the Incremental DSM necessary).

[6] Net Zero is illustrative here as it may represent a variety of different definitions. It is anticipated that National Grid will be required to contribute to the goals underlying the Climate Leadership and Community Protection Act.

[7] Note: PA understands that National Grid believes it can manage a supply gap of up to 10 MDth/day. PA believes it is reasonable to assume a gap of that size would be manageable; the 2022/23 gap in this scenario is ~9 MDth/day, or approximately 0.3% of the Adjusted Baseline Demand Forecast. Otherwise, additional supply assets would be required to address that gap. PA notes that the fifth CNG facility fills the gap if it is in service by 2022/23.

Table 3-1: 5-Year Outlook of Supply & Demand Under Various Scenarios[8]

<table>
<tr><td>Supply / Demand with DIS Infrastructure[9]</td><td>
</td></tr>
<tr><td>Supply / Demand without DIS Infrastructure</td><td>
</td></tr>
<tr><td>Comparison of Baseline and Incremental DSM to Offset Supply Gap</td><td>
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1. **Supply Risks are Real:** National Grid has identified three primary near-term infrastructure investments as necessary under the DIS. All in, the likelihood that the three infrastructure investments are not operational without further delay or termination appears high. Under a scenario where only ExC is approved (the fifth CNG facility and the Greenpoint Vaporizers are cancelled), the

[8] Source: National Grid's forecast model provided to PA, filename: *Set - 1 DNY_TechnicalAnalysis_2021-06-30.*
[9] Assumes the earliest feasible in-service dates of 2022/23 for the fifth CNG facility and 2023/24 for both the Greenpoint Vaporizers and ExC.

ExC project on its own does not prevent a supply/demand gap. Further, this project is subject to highly uncertain federal approval. While the Greenpoint Vaporizers project is sufficient on its own to meet Grid's projected capacity needs in 2023/24, thereafter a demand gap persists in the absence of other supply. Finally, the additional CNG capacity is not a given; even if the fifth facility is permitted and constructed, there remain supply and transportation risks to any CNG facility's ability to provide Design Day supply. The contingency projects identified by National Grid in its Report are conceptual, are faced with long term and high-risk development timelines, and their successful implementation is anything but guaranteed. Finally, National Grid has ~250MDth/d of firm pipeline capacity whose contracts are set to expire, without a right of first refusal, in 2023 – not to mention the inherent risk of the availability of peaking supplies discussed below.

2. **DSM Programs have Uncertain Adoption and Savings Potential:** To date**,** components of the energy efficiency and demand response programs in the DIS are still in the development stage and / or not scaled up. National Grid's energy efficiency efforts have proven successful to date in achieving the state's New Efficiency: New York ("NE:NY") goals. And further efficiency savings are likely to be more resilient during severe cold weather conditions than demand response. While National Grid is continuing to evaluate how to increase energy efficiency and weatherization, there is meaningful uncertainty that adoption rates and the respective savings are able to meet targets. Outside of policy and other forces, the level of adoptions and continued participation required to meet near-term scale of proposed program savings is uncertain. Firm residential demand response and electrification efforts are early in deployment with limited Downstate New York specific data to de-risk the outlook. It is clear that DSM is a critical component of meeting demand; however, these programs appear to be at least one to two years from being mature enough to reduce the uncertainty of the targeted savings. The uncertainty of these Incremental DSM programs is reflected in the system-wide gas planning models developed between National Grid and Consolidated Edison Company of New York, Inc. ("Con Edison"). These models assume that no Incremental DSM measures will have been implemented by any given winter season; such a conservative approach is reasonable. That said, gas demand response in the US is relatively nascent compared to electric demand response. Electrification of heating equipment will require National Grid to establish clear strategies and plans in coordination with the regional electric utilities – coordination which is in progress but requires more time to mature. The current maturity level of National Grid's demand side programs suggests that incremental infrastructure will be necessary – at least in the near term and under National Grids' baseline demand forecast – to avoid a moratorium risk. In the longer term, a material shortfall in demand savings could place substantial stress on the rest of the system and implies that even more infrastructure support could be necessary.

3. **Load Growth as a Range:** The Report provides a single point estimate of load. While the forecast is characterized as the Adjusted Baseline, it is more than 1% higher in all years than National Grid's "high" estimate from the Long-Term Capacity Report published in May 2020[10]. Evaluating alternative load scenarios and the resources needed to deliver safe, reliable, low-cost supply would provide for the capacity to quantify trade-offs and risks. PA found that in certain segments of customer usage National Grid's forecast is materially higher than historical trends would indicate and that the overall load forecast is highly sensitive to small changes in assumptions about average customer usage. If future usage per customer for certain segments is more in line with historic trends, the resulting load is reduced so as to provide timing flexibility of the supply options while also de-stressing the allowable margin of error for DSM driven demand reduction without triggering moratorium.

[10] See Figure 2-2 of National Grid's Second Supplemental Report, Page 11.

4. **Climate Goals and the DIS:** PA's review did not evaluate whether the contemplated infrastructure investments are either consistent or inconsistent with New York's Climate Leadership and Community Protection Act ("CLCPA"). Abandoning efforts to complete new infrastructure would require that the DSM programs are rapidly accelerated, and that the traditional regulatory metrics used to determine whether certain costs are prudent for recovery would need to be reworked. In addition, customers would need to accept higher rates as the trade-off for increased DSM. Further, policymakers and customers would need to accept the risk of emergency curtailments which can have significant health and safety consequences, in the event that the Incremental DSM programs are unable to deliver the necessary peak demand reduction. Both paths (the DIS plan and a "DSM only" plan outlined above) hold meaningful risks. As discussed in Item 2 above, National Grid is in the early stages of ramping up the DSM programs. It is reasonable to expect that customers would respond to greater incentives to participate accelerating DSM programs. The challenge is determining to what extent larger incentives will increase participation, how those costs will be recovered and the willingness to accept the additional curtailment risk compared to pursuing the strategy put forward in the DIS.
5. **Near Term Moratorium Risk:** Given the above, under National Grid's current load forecast, the risk of a moratorium in the near term (the next 3-5 years) appears to be high based upon the following summary observations:
   - Timely permitting of the Greenpoint Vaporizers and ExC projects are generally out of National Grid's control and have already faced regulatory and other opposition
   - The fifth CNG facility, even if the facility is permitted, is not without supply delivery risk in peak demand conditions. While supply delivery risk would typically be synonymous with curtailment risk, it may be appropriate to consider such potential supply disruptions in the context of moratorium risk as well.
   - The contingency infrastructure projects are long lead-time solutions that remain conceptual at this time and are high risk, given the level of public opposition to other capital projects proposed by National Grid in recent years and the many associated permitting challenges that would be expected. Moreover, while perhaps technically feasible,[11] PA is not aware of the use of Liquified Natural Gas ("LNG") Barges as a source of peaking capacity at any natural gas utility in the United States. A Micro-LNG facility would also have to overcome challenges to trucking LNG supply through the City of New York.
   - Two of the three components (electrification and demand response) of National Grid's DSM strategy are in early development with high uncertainty of adoption and rate of growth.

If load growth does in fact fall in line closer to historical trends, the potential supply/demand gap narrows and provides for a lessening of both schedule and execution risk in the DIS plan. However, PA recognizes that relying on a lower load scenario to offset supply side challenges is a high-risk strategy. Quantifying moratorium risk in the near term should be considered vis-a-vis the timing of when National Grid develops its DSM relative to demand growth patterns.

3.2 Thematic Observations for National Grid Customers

- **Reliability vs. Cost:** National Grid's gas supply resources are planned and designed to be sufficient under a roughly "one-in-thirty-three year" peak winter event. Meeting this threshold

[11] PA did not assess the technical feasibility of any contingency project.

requires substantial investment in both system resiliency to avoid unplanned service disruptions as well as sufficient capacity to meet peak demand in very cold conditions. Planning for what is anticipated to be an uncommon event creates a natural tension between cost and reliability – optimizing for a balance between these two goals ultimately boils down to what level of reliability is reasonable to expect and how much ratepayers can reasonably be expected to pay for that reliability. Furthermore, an extreme event that results in turning off gas supply has the potential to create a serious public safety situation in instances of severe cold. Asking whether such reliability and safety margins are worth the cost is a reasonable question – making the optimization equation much more difficult to solve. This is perhaps the most important theme when considering whether certain projects are necessary and whether the load forecast reflects reasonable assumptions.

- **Safety vs. Cost:** The nature of natural gas and gas supply networks are such that restoration of service following an outage requires a methodical process that, in many cases, is much slower than what customers may be accustomed to for electricity service. Given that gas is predominantly used for heating and cooking, the ramifications of a prolonged outage on human health and safety can be substantially more dangerous than an equivalent electric outage. Determining the margin of safety that is acceptable is on one hand a matter of engineering and operational risk management, but on the other hand represents a difficult-to-quantify social cost. In the event of an emergency situation, curtailing large commercial customers may be done safely, however avoiding curtailment is an altogether better scenario than depending on curtailment to meet customer demand. At the point of curtailment, the margin of safety is too thin and the potential societal cost too high.

As long as residents of National Grid's KEDLI and KEDNY territories continue to use natural gas for heating, the traditional priorities of reliability and least cost create potential conflict with the broader societal and political goals of decarbonization. Meanwhile, the risk of a second moratorium or emergency curtailment action appears to be considerable at least for the next couple of years as DSM strategies mature, supply infrastructure options become clearer, the implications of environmental mandates are defined, and consumer preferences evolve.

4 Overview of National Grid's Load Forecast

The Report stated that the long-term load forecast reflects a slowing customer growth rate (declining from a 2008-2020 average of 0.6% to 0.4% average over the forecast period) and a declining usage per customer ("UPC") (declining from a 2008-2020 average of 1.8% to 0.8% average over the forecast period). However, due to the anticipated rebound in economic activity post-pandemic, the Design Day load is anticipated to increase by 3.0% in 2021/22 and 2022/23 and the overall adjusted load forecast is 1.3% higher than the forecast in National Grid's previous High Demand Scenario.

PA has four primary observations related to the 2021 load forecast used in the Report:

- National Grid presented its analysis and discussions pertaining to the DIS with reference to a single point estimate of load as opposed to a range of potential scenarios. While potentially simpler to reconcile the build-up to total demand, it also restricts the benefit of conducting sensitivity analysis when considering resource and demand reduction options. Further, PA observes that a single point estimate tends to indicate a false sense of precision and it may be more useful to assess whether there are margins on the positive and/or negative sides of the forecast which needs to be considered.
- While National Grid's overall forecasted load growth represents a decline against historical averages, it is important to evaluate not just the simple historical average, but the trend over time. A situation in which a demand-supply gap emerges one year later than anticipated may have material impact on moratorium risk, a load forecast based on the historical trends of key drivers provides an alternative view of likely outcomes.
- National Grid's load forecasting methodology involves analysis of the core components of demand – customer count and annual usage per customer – by customer segment for both service territories. An assessment of this approach highlights how elastic the load forecast is to changes in each variable. For example, moderate adjustments to Commercial and/or Multi-family customers' UPC rate in KEDNY and KEDLI has a material impact on the total load forecast. PA observes that in Section 4 of the Report, National Grid provides analysis of customer counts and UPC by customer segment, but not by region. A disaggregated analysis of UPCs suggested significant differences between historical trends and National Grid's outlook as presented in the Report.

Based upon our review, PA conducted further analysis of the projections.

4.1 Approach

PA's Load Forecast analysis began by developing projections[12] based on historical trends of Customers and UPCs for the three key customer segments – residential heat ("RH"), commercial ("COM") and multifamily ("MF") – across both KEDNY and KEDLI with the objective of comparing to National Grid's econometric forecast of the same variables in the Report.

- A comparison of PA's analysis of historical trends and National Grid's Baseline forecasts revealed that there were no significant differences as far as the customer counts were concerned across all segments.
- With respect to UPCs, PA's analysis of the trend for the RH segment in KEDNY indicated levels modestly lower than National Grid's Baseline forecast while the corresponding trend in KEDLI had a trajectory with values slightly higher than National Grid's forecast during the latter part of the

[12] The best fit specification was used based on a comparison of linear, logarithmic, and polynomial trends.

planning horizon. For both territories combined, this suggests a trend for RH UPC that is generally in line with the Baseline forecast.

- PA's analysis of the trends based on historical data for COM and MF UPCs in both service territories exhibited trajectories noticeably different from National Grid's respective Baseline forecasts. Therefore, PA's trend-based analysis rests on these two customer segments.

Based upon these observations, PA developed two alternative load forecasts: an extension of historical trends (the "Trend" forecast) and an average of National Grid's Adjusted Baseline and PA's Trend (the "Sensitivity" forecast).

4.2 Review of Design Day Conditions

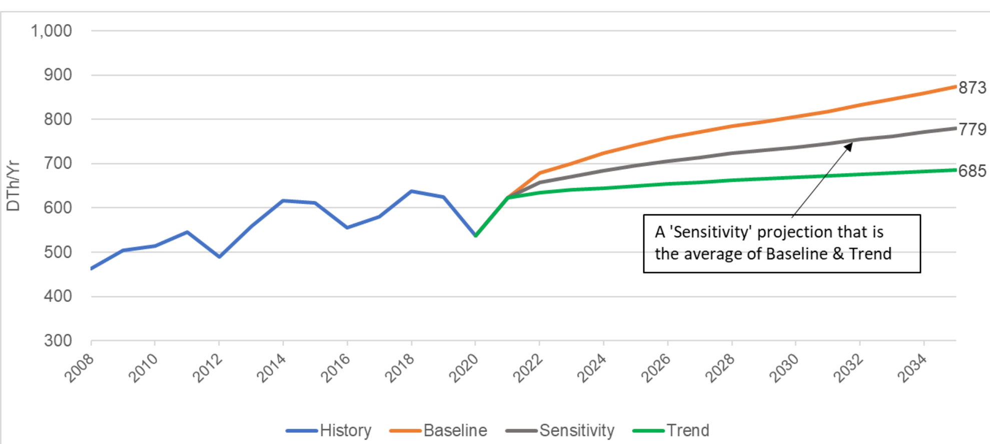
PA evaluated Marquette Energy Analytics' report on National Grid's Design Day conditions against common methods of quantifying and evaluating degree days. This report ultimately concluded that the design day parameters, which assumed an average daily temperature of 0-degrees Fahrenheit and a windspeed of 12 MPH, constituted a 1-in-33 year event, which was not an atypical time frame for a Design Day event when evaluated against other utilities. Upon review of the Marquette Report, PA found that the inclusion of wind speed likely results in a more sophisticated look at the factors that impact heating and that there were no obvious omissions or oversights inherent in the evaluation of the design day parameters.

4.3 Load Forecast Sensitivities

Recognizing that PA's analysis of COM and MF UPC historical trends deviate substantially from National Grid's Baseline forecasts, PA devised a "Sensitivity" projection which is the average of National Grid's Adjusted Baseline and the Trend in order to serve as a point of reference for sensitivity analysis. In conducting this sensitivity analysis, PA was made aware of the fact that National Grid routinely develops a range of econometric forecasts reflecting various economic scenarios. While these scenarios range both higher and lower than PA's sensitivity analysis, National Grid's Report is based upon a baseline scenario which is what PA focused its review upon.

Figure 4-1 below is an example of how PA's alternative projection were developed. Based on the historical data (shown in the blue curve) for KEDNY and KEDLI Commercial UPC over the 2008-21 period, the non-linear fitted Trend forecast (the green curve) appears considerably below National Grid's Baseline econometric forecast.[13]

Figure 4-1: DSNY Commercial Usage Per Customer Forecast Sensitivity

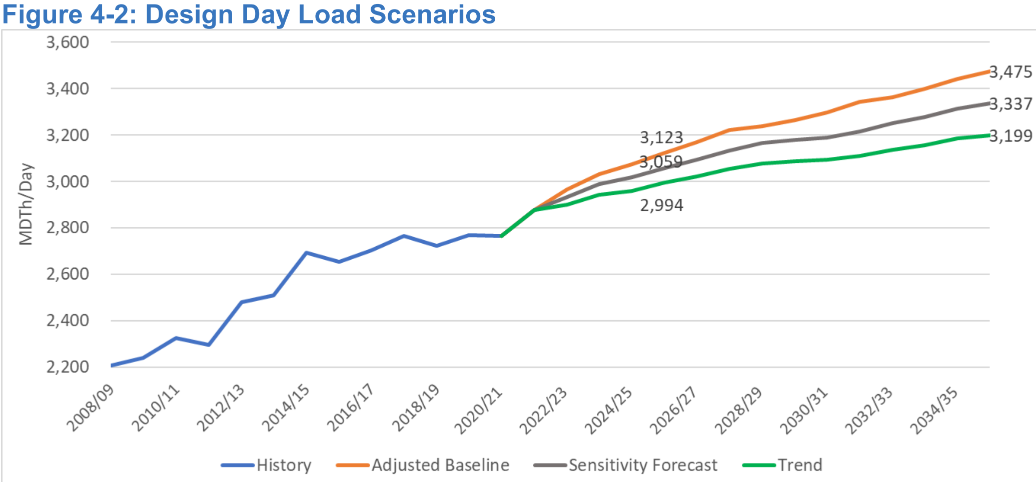


[13] Note: PA modified the Trend forecast such that the first year of the projection is identical to National Grid's Baseline forecast.

The resulting range of Design Day Usage forecasts allows for a scenario analysis reflecting alternative UPC trajectories with the underlying notion that gas-load forecasts are sensitive to relatively minor changes in assumptions regarding customer use patterns.

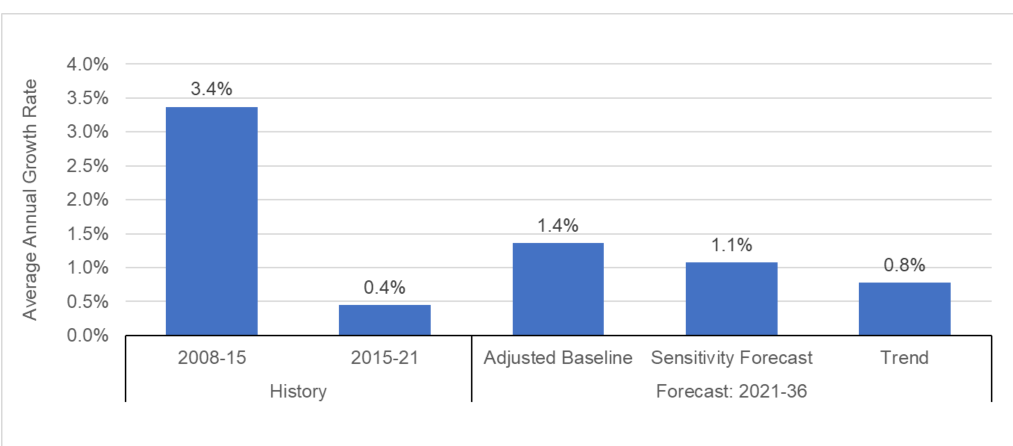
Figure 4-2 below compares National Grid's Adjusted Baseline with the two alternative load forecasts developed by PA. As mentioned above, the factor differentiating the alternative trajectories from the Baseline is the use of Sensitivity and Trend values of the COM and MF UPCs. Acknowledging that varying weather conditions explain the observed volatility, it is evident from historical data that even excluding the 2020/21 year due to Covid-related disruptions, there was a noticeable slowdown in load growth post-2015 – largely due to declining growth in UPC for the non-residential segments. The Sensitivity load forecast reflects non-residential UPC values approximately 10% below the forecasted levels of the Adjusted Baseline by 2035/36.

Figure 4-2: Design Day Load Scenarios



To illustrate the historical trend over time vs. the outlook, Figure 4-3 highlights the post-2015 drop in the annual growth rates in comparison to the implied growth rates in the Baseline and PA's scenario forecasts.[14] PA observes that given the continuing decline in gas load growth, the Sensitivity scenario (and even the Trend scenario) are reasonable alternatives reflecting modest adjustments to the non-residential UPCs. For comparison purposes in this report, PA's Sensitivity case is used as an alternative to National Grid's Adjusted Baseline forecast.

Figure 4-3: Design Day Load Average Growth Benchmarking



[14] National Grid developed alternative analyses of Design Day demand that project both lower and higher growth trajectories. PA's Sensitivity scenario is within the band of the National Grid Scenarios.

5 Supply Overview

Through the course of PA's review of National Grid's Report, PA evaluated National Grid's existing and projected supply stacks, the options available to National Grid in the DIS, and the Contingency projects that have been identified as potential alternatives to the DIS should one or more DIS components be delayed or denied.

5.1 Approach

The purpose of PA's supply analysis was to evaluate whether National Grid's outlook of proposed options as detailed in the Report is reasonable to meet the needs of its customers on a Design Day, and to identify aspects of the outlook which PA believes are at risk of not being approved or completed in a timely manner.

As stated in Section 2.8 of National Grid's Report:

> *In the near term, the distributed infrastructure components of the distributed infrastructure solution are the biggest components of the solution and are critically important to meeting gas demand over these next few winters as incremental DSM programs ramp up…such that no additional infrastructure projects beyond the LNG vaporization project and ExC project would be needed.*

PA has focused its supply side assessment on the benefits and risks associated with the Greenpoint Vaporizers and ExC, as well as National Grid's expectations of increasing CNG peaking capacity. Additionally, PA evaluated over 50 different hydraulic models of the New York Facilities System[15] simulating gas flows and system operating conditions and reflecting different combinations of supply assets in service under peak ("Design Hour[16]") conditions, as forecast for Winters 2021/22 through 2025/26.[17] Finally, PA assessed the infrastructure projects National Grid has identified as potential contingency alternatives to the Greenpoint Vaporizers and ExC. Beyond risks to the notable infrastructure projects, PA also evaluated contracting risk inherent in existing and prospective components of the supply stack.

5.2 Observations

PA developed the following observations about National Grid's Downstate New York supply resources and its ability to meet forecasted Design Day demand:

- **Firm pipeline capacity**: National Grid maintains several contracts which provide long-term, firm pipeline capacity with Transco, Tennessee Gas Pipeline ("TGP"), Iroquois Gas Transmission ("Iroquois"), and Texas Eastern Transmission ("TETCO"). It is safe to assume that the majority of this firm gas supply will be available throughout the forecast period considered in the Report, as National Grid retains a Right of First Refusal ("ROFR") for renewal upon expiration of the related contracts. Any risk to gas supply flowing under these contracts would be limited to unplanned disruptions or outages on the pipelines. National Grid's supply stack does however include some firm capacity for which it does not have a ROFR. These contracts are discussed below in more detail.

- **Short term peaking (and associated risks):** National Grid contracts for a portion of its natural gas capacity for only the winter months in anticipation of peak demand. Some of this capacity,

[15] The New York Facilities System is a network of natural gas transmission mains. See Appendix A for further detail.

[16] The peak hourly demand on a Design Day.

[17] National Grid has communicated to PA that if a certain modeling configuration fails to meet the forecasted Design Hour demand while maintaining minimum operating conditions National Grid has confirmed are required to provide reliable service, those modeling results are not provided. That being the case, PA cannot ascertain the degree to which any such models fail.

referred to as short-term peaking capacity, has been contracted for several years into the future. There is, and will be going forward, continuing risk that this type of capacity may not be available to National Grid, as other parties also have access to this same capacity and the amount that may be available can vary year to year.

- **Compressed natural gas ("CNG") facilities:** National Grid currently has in service four CNG facilities to support Design Day demand. Two sites on Long Island have been identified as viable candidates for a fifth facility, and both are under development in parallel.[18] National Grid's supply stack assumes the fifth facility is in service by winter 2022/23, however permitting risk still exists.
  - When a Design Day is forecast, significant coordination is required to transport fully-loaded CNG trailers to the facilities for injection during the morning peak hours, and then refill and redeliver the supply in time for the supply to be available during the evening peak hours. Future contracting risk may evolve as the market for available CNG is itself limited and as more natural gas utilities compete for CNG supplies.

- **Existing LNG:** Two LNG facilities – Greenpoint and Holtsville – are used to provide natural gas to the system during periods of peak usage, up to and including a Design Day demand. Greenpoint is the facility at which National Grid is proposing to build Vaporizers 13/14 as part of the Distributed Infrastructure Solution. These two facilities are critical components of the supply stack on a Design Day, currently providing more than 13% of National Grid's design day capacity. Proactive maintenance of these facilities will continue to be critically important in order to ensure National Grid has the available capacity to meet Design Day demands.[19]

- **Existing Renewable Natural Gas ("RNG")[20]:** Beginning in 2022, National Grid will source RNG from the Newtown Creek wastewater facility. RNG is natural gas that is sourced from the natural breakdown of organic material. The Newtown Creek facility converts decaying organic material found in wastewater into a natural gas product that can be used in National Grid's gas distribution system. With respect to Design Day demand on the system, the capacity which can be attributed to the Newtown Creek facility is very small (0.03% of total design day capacity).

Other observations regarding long-term planning:

- The hydraulic models of the New York Facilities System provided to PA by National Grid reflect forecasted design hour demand exclusive of Incremental demand side measures that are included as part of the DIS. To the extent those measures successfully reduce demand over time, the system operating conditions observed in the modeling results would be expected to improve; PA cannot quantify those improvements.

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[18] Only one of the two sites (Hicksville or Farmingdale) would proceed to construction. National Grid has assumed in its supply forecast that Farmingdale (which would have twice the capacity of Hicksville) is the ultimate location.

[19] PA notes the agreement in National Grid's recently completed rate cases for National Grid to conduct further studies for the upgrade of its Greenpoint and Holtsville facilities, with particular focus on LNG storage tanks and related systems. With the tanks having been in service for approximately 50 years, developing a plan that allows them to be inspected and modernized is not only appropriate, but necessary. It is possible that the tanks and related facilities will perform as expected until such time as they can be evaluated, however it is reasonable to assume that a risk of failure increases each year that goes by without this work being completed. The loss of a single tank, if that were to occur, may or may not render the entire facility out of service for a winter season but at the very least would adversely impact the available Design Day capacity.

[20] The use of the term "RNG" is used for convenience and is not intended to imply consideration of the environmental attributes or benefits of such gas.

- Based on PA's review of supply and demand forecasts as well as models of Design Hour gas flows on the distribution system provided by National Grid, National Grid is, or would be, positioned to serve Design Day demand in the coming winter seasons with the following supply assets[21]:
  - Only 3 of the 4 CNG facilities currently in service may be needed at the Design Hour for the winter of 2021/22, assuming existing infrastructure and supply assets.
  - All four existing CNG facilities are required for the winter of 2022/23 with existing infrastructure, assuming adequate supply assets have been procured.
- For winter 2023/24, in addition to the existing infrastructure and supply assets, EITHER the Greenpoint Vaporizers OR a fifth CNG facility must be in service. Given the continuing uncertainty around approval of the vaporizers, National Grid must pursue the fifth CNG site in earnest – or face a risk of a moratorium on new service connections.
- For winter 2024/25, in addition to the existing infrastructure and supply assets, the fifth CNG facility and EITHER the Greenpoint Vaporizers OR ExC must be in service. If both Greenpoint AND ExC are in service, Design Day demand can be reliably served with only four CNG facilities operating.[22]
- For winter 2025/26, all infrastructure included in the DIS – the Greenpoint Vaporizers, ExC, the fifth CNG facility – must be in service in order to serve Design Day demand.

Table 5-1 summarizes the minimum infrastructure that must be in service for the coming winter seasons, based on the series of hydraulic models of the New York Facilities System provided by National Grid and reviewed by PA.

Table 5-1: Minimum Infrastructure Required to Serve Design Day Demand[23]

Winter Season	Existing Infrastructure	CNG 5	Vaporizers 13 & 14	ExC
2021/22	✓			
2022/23	✓*			
2023/24	✓	✓		
	✓		✓	
2024/25	✓	✓	✓	
	✓[24]	✓[24]		✓[24]
	✓		✓	✓
2025/26	✓	✓	✓	✓

*As noted previously, adequate supply must be procured. Where there is more than one "minimum" infrastructure option that satisfies Design Hour criteria, each option is included.

[21] Upon review of the provisions of the New York Facilities Agreement (see Appendix A) and based on information included in the gas flow models, it appears that certain Design Hour gas flows from Con Edison to National Grid may exceed the maximum flows established in that Agreement. Additional investigation would be required to confirm, and models would have to be revised and re-evaluated (as applicable) to ensure PA's observations regarding the capabilities of the physical system would be unchanged. A given system configuration may well be viable overall even where certain hourly flows exceed limits established in the Agreement, however doing so may give rise to operational risks and concerns that are not apparent in the models.

[22] In the event that the two DIS facilities that are in service are the fifth CNG facility and ExC, then the TGP expansion to provide additional capacity to Con Edison must also be in service to maintain reliable pipeline system pressures on a design day in winter 2024/25. The TGP expansion is currently pending before FERC.

[23] Source: Hydraulic modeling results provided by National Grid to PA.

[24] In this scenario, the TGP expansion for Con Edison must also be in service.

DIS Infrastructure Timing

Given the risk of permitting delays on completing any of the DIS infrastructure projects, PA attempted to ascertain how the timing of project approvals is expected to impact completion dates. Recognizing the potential for seasonal construction limitations, PA asked National Grid to identify permitting deadlines associated with being able to complete the projects prior to particular winter seasons. Table 5-2 summarizes those deadlines and confirms that, despite delays to date, time remains for the projects to be permitted and completed prior to when they are expected to be required on a Design Day.

Table 5-2: Permitting Deadlines Associated with Winter Season Availability

	In-Service by Winter	Permit Deadline
Greenpoint Vaporizers	2022/23	10/1/2021 [25]
	2023/24	9/1/2022
	2024/25	9/1/2023
ExC	2022/23	n/a
	2023/24	Q1 2022 [26]
	2024/25	Q1 2023
	2025/26	Q1 2024
Fifth CNG Facility	2022/23	9/30/2022 [27]

Observations Regarding Contingency Projects

Few details surrounding the contingency projects identified in the Report were provided to PA. National Grid considers these projects "conceptual" at the time of our review. Based on PA's review of the projected timelines to implement any of the contingency solutions, as well as the lack of any detailed planning and engineering conducted to date, it appears reasonable to assume that the earliest any of these projects could be placed in service would be just prior to winter 2026/27 – and even later if the projects are met with permitting challenges and other public opposition similar to the level National Grid has experienced with other infrastructure projects (e.g., the Greenpoint Vaporizers and MRI). Delayed completion of contingency projects places even more burden on demand side initiatives which, as acknowledged by National Grid, are an ambitious ramp-up of current programs even at the level included in the DIS. The contingency projects have not been developed in parallel with the DIS infrastructure projects. To date, National Grid has instead taken the approach to delay commencement of any detailed planning until more is known about the permitting outcomes of the DIS projects. The absence of any substantive planning for any of the contingency projects at this point in time exacerbates the risk that a Design Day supply/demand gap would occur in the event of a failure of one or more major DIS project.

5.3 Supply Risk Assessment:

PA has identified contracting risks that could materially impact the availability of natural gas capacity within the next several years. This risk is present in several components of the supply stack:

[25] National Grid highlighted in its Third Supplemental Report filed on August 25, 2021 that it had agreed to New York State DEC's request to extend the final permit decision to November 4, 2021; that being the case, an in-service date of winter 2022/23 is unlikely.
[26] National Grid highlighted in its Third Supplemental Report filed on August 25, 2021 FERC's announcement that it will prepare a supplemental Environmental Impact Statement ("EIS") for the project; the EIS must be completed by December 2, 2021. This likely translates to a FERC decision on the project no sooner than Q1 2022. As noted elsewhere in this report, state level permits are also required. This anticipated timing likely places an in-service date of winter 2023/24 at risk.
[27] PA infers from National Grid's response that approvals beyond September 30, 2021 would push the availability of the fifth CNG facility to winter 2023/24.

- **Existing Long-term Firm Transportation Contracts:** While the majority of National Grid's firm gas contracts have a contractual Right of First Refusal ("ROFR"), 346 MDth/d of this contracted capacity is currently contracted at discounted or negotiated rates and lacks a ROFR. Of this volume, three contracts representing 246 MDth/d expire in 2023. National Grid has indicated its intent to extend these agreements beyond their current expiration dates provided the load forecast continues to justify their need as part of the capacity portfolio.
  - National Grid's supply stack assumptions reflected in the Report do include this capacity through winter 2035/36. This may imply the absence of risk in that capacity being available throughout the forecast period. In the absence of a ROFR, that is not necessarily the case. At the very least, it is possible that National Gridmay be unable to extend these contracts at the rates it is currently paying and may have to pay substantially higher rates.
- **Operational Risk and Contingency:** Some degree of risk exists in the normal operation of pipeline infrastructure. Should a compressor or other piece of infrastructure fall offline during a design day event, potentially significant volumes of long-term firm contracted supply may not materialize. In a scenario where supply only narrowly outpaces design day demand, the implications of such unplanned downtime become magnified.
- **Short Term Peaking Capacity:** National Grid has identified approximately 58 MDth/d of short-term peaking capacity currently in the supply stack that is expected to be available for contracting indefinitely, but for which no ROFR exists. As National Gridstated in the Report, their ability to re-contract for these volumes is not guaranteed.
- **Cogeneration Peaking Capacity:** Of National Grid's existing 65 MDth/d of cogeneration natural gas peaking capacity, a contract representing approximately 25 MDth/d of that capacity is up for renewal in 2022, with another approximately 10 MDth/d up for renewal in 2025. In both cases, there is no guarantee that there will be an extension of the existing contracts.
- **CNG Compression Capacity:** As it pursues the development of a fifth CNG site to supplement its Design Day capacity, National Grid has noted that the available market for CNG supply is becoming more constrained as increasing numbers of natural gas utilities are seeking to incorporate CNG supply into their own portfolios. These constraints, in tandem with National Grid's process for contracting for CNG supplies on a year-to-year basis, places security of that supply at some risk each year.

5.4 Infrastructure Assessment

PA evaluated each of the potential incremental infrastructure projects included as part of the DIS on the basis of each project's ability to offset the supply/demand gap at particular points in time.

- PA considered the likelihood and associated timing of project approval, including the risks of permitting delays and/or denial and the related impact on National Grid's ability to reliably serve Design Day demand.
- PA did not consider the relative costs of the projects, inasmuch as the projects fall into one of two categories: either they are positioned to be in service within the next three years and are not presented as alternatives to one another (Greenpoint Vaporizers, ExC and the fifth CNG site), or they are conceptual alternatives to the projects included in the first category and are not expected to be available until winter 2025/26 at the earliest given that no detailed planning has begun.
- Additionally, PA did not validate the technical capabilities of the projects beyond assessing gas flow models that demonstrated the level of supply provided; rather, PA assumed that the projects (if constructed) would provide the level of Design Day capacity identified by National Grid.

The risks associated with securing the necessary approvals for the Greenpoint Vaporizers require that National Grid pursue completion of a fifth CNG facility in earnest. While National Grid has demonstrated its ability to design and deliver these types of projects, PA anticipates that National Grid may face permitting and/or community relations challenges in successfully completing another facility. As noted above, it is imperative that the fifth CNG facility be available by winter 2023/24 in the event the vaporizers are either denied, or further delayed.

Beyond permitting risk, projects such as the Greenpoint Vaporizers also carry a level of execution risk. National Grid has indicated a construction timeline of approximately one year to complete the project once it receives all required approvals. While PA cannot cite specific risks that can be attributed to National Grid, it remains possible that with projects of such size and scale, delays due to equipment and material availability, skilled labor availability, and even inclement construction weather can all impact the construction timeline.

ExC also faces permitting risks; chief among them is securing approval from FERC. Having announced in late May that it will prepare a full Environmental Impact Statement ("EIS") for the project, FERC's procedural schedule calls for the final EIS to be issued on November 12, 2021, with a final decision to be rendered on or before February 9, 2022. Permits are also required at the state level in New York and Connecticut, and those agencies are expected to act only after FERC issues its decision to approve the project. While PA is not aware of any concrete evidence that there is a risk of timely execution of the project (if approved), it is likely that Iroquois will only make certain commitments related to material, equipment, and construction labor after the project is fully approved. Collectively, these approval risks could impact the date by which the project can be placed in-service.

6 Demand Side Management

PA evaluated the reasonableness, uncertainties, and variables related to National Grid's portfolio of demand side management programs. The programs that PA focused on for the purpose of this review included energy efficiency ("EE"), demand response ("DR"), and electrification ("ELEC"). National Grid views measures as either existing programs included within the Adjusted Baseline demand forecast, Baseline, or envisioned savings required to meet a supply/demand gap, Incremental. As discussed in the Report, there are various permutations of each DSM program related to the KEDLI and KEDNY service territories, from Residential to Commercial and Industrial ("C&I") customers, as well as programs which are already deployed and programs which are in varying phases of development.

Whereas the infrastructure supply options have known operating and capacity parameters, the DSM programs are subject to a variety of technical, environmental, behavioral (e.g., customer participation and compliance), and economic drivers. Further, natural gas demand management programs are less common and have received less examination at scale across the US compared to the decades of experience and field validation of measures utilized in the power sector. As such, PA's approach to evaluating the reasonableness of the DSM outlook was to evaluate historic data available from National Grid's programs and compare such data to market potential studies and peer utility benchmarks. PA placed an emphasis on key variables and considered the operational and execution risks associated with each in context of moratorium risk.

6.1 DSM Program Considerations

As stated in Section 2.8 of the Report:

> *The Distributed Infrastructure Solution includes no expansions of gas supply capacity after 2024/2025[28] and relies on incremental DSM components to offset all projected Design Day gas demand growth after 2027/2028.*

National Grid is in early stages of ramping up DSM plans and has conducted this process in a manner typical of a regulated utility – developing a market study, designing and executing a pilot, studying the results, and scaling a program to more customers over time. This approach is defensible under the current environment where cost, reliability, and safety are the optimization parameters. Under a scenario where climate impact becomes at least as important as cost, reliability and safety, such a multi-year scaling approach could theoretically be accelerated, and greater demand savings pursued. However, this carries its own set of risks and increased costs. It also requires changes to the traditional view that expenditures must be cost effective under the current construct of the applicable cost / benefit test. It is similarly likely such a scenario requires considerations of new, and perhaps innovative, rate design. To illustrate a potential acceleration scenario, under PA's sensitivity load forecast and the DIS, energy efficiency may be accelerated to avoid a supply gap through 2025/26 but will require incentive levels that result in programs with a near zero benefit to cost ratio ("BCR").

National Grid's DSM programs, both those currently being executed and those facing multiple years of ramp up before maturity, will incur monetary and non-monetary costs. Absent regulatory directive and a clear social mandate, taking on the additional cost and risk associated with greater reliance on DSM without new infrastructure is unlikely a reasonable strategy to achieve low cost, reliable, and safe service. However, National Grid would be best served to evaluate how long is reasonable to wait on permitting decisions for

[28] PA's note: Except to the extent one or more contingency projects would be required in the absence of the Greenpoint Vaporizers, ExC, or the fifth CNG facility.

the Greenpoint Vaporizers and ExC before initiating DSM acceleration, else it risks both a lack of supply and a lack of time.

6.1.1 Energy Efficiency

Energy efficiency programs employ technologies and products aimed to help consumers use less energy, during peak and off-peak periods, while also reducing emissions. Natural gas energy efficiency programs typically encourage building envelope and insulation improvements, efficient equipment, and efficient appliances via financial incentives to engage participation. Savings are also obtained through marketing-driven efforts, also described as behavioral programs.

PA assessed the achievable energy efficiency savings, also defined as the reasonably achievable portion of technical or economic savings potential from a program and customer level perspective. In other words, total program and customer level savings anticipated to occur in response to proposed programs and incentives. PA evaluated information provided by National Grid, coupled with PA's knowledge of programs in other states and countries, third party studies, and other benchmarking findings of other US gas utilities.

KEDLI and KEDNY residential and multi-family customers provide the greatest potential for peak day savings, due to the number of residential customers and their heating usage, especially multi-family and low-income single-family buildings, according to the Downstate New York Gas Measure and Market Evaluation[29] prepared at the request of National Grid. Similar conclusions are made by another third-party study[30] completed for New York State Energy Research and Development Authority ("NYSERDA") including the following notable natural gas energy efficiency potential conclusions:

1. Due to low natural gas avoided costs, natural gas economic potential is observed at approximately 53% of technical potential.
2. Natural gas energy efficiency economic potential mainly arises within retrofit measures.
    - Key retrofit energy efficiency measures included energy management systems, air sealing, smart thermostatic radiator enclosures, and boiler stack economizers represent approximately 57% of the total economic natural gas efficiency potential, on a combined basis.
    - Notwithstanding the substantial technical potential of replacing multi-family natural gas forced-air furnaces and boilers with more efficient equipment, low natural gas costs render most space heating equipment replacements non-economic. Retrofits of inefficient natural gas boilers, furnaces, and water heaters represent 9% of the total 10-year economic potential.
    - Hot water improvements represent substantial cost-effective savings potential within multi-family buildings, representing approximately 17% of natural gas economic potential evaluated.
3. Building envelope (also referred to as building shell) improvements embody significant technical potential and account for approximately 26% of natural gas technical potential and 11% of the natural gas economic potential.

PA finds that despite substantial natural gas energy efficiency savings technical potential, low-cost natural gas reduces the economic potential. As a result, achievable energy efficiency savings potential is limited without the inclusion of social cost of carbon or other metrics to create additional financial incentives to induce participation. Behavioral savings are less likely to occur on a persistent basis and the differentiation

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[29] Source: National Grid. *Downstate New York Gas Measure and Market Evaluation 2019-2028*. Prepared by DNV-GL, December 2020.

[30] Source: NYSERDA. *Assessment of Energy Efficiency Potential in New York State Multifamily Buildings*. Prepared by CADMUS, June 2021.

of persistent vs. behavioral EE requires consideration, in terms of savings potential and cost effectiveness. PA also finds it is reasonable to assume that specific programs and incentives are needed to support continued and incremental energy efficiency savings within the KEDNY and KENDLI gas service territories. However, given the industry-wide immaturity of natural gas DSM, coupled with the EE program magnitude anticipated by National Grid, uncertainty of achievable savings remains a concern.

6.1.2 Demand Response

National Grid's DR programs aim to reduce peak demand during system emergencies, while also improving system reliability. In other words, DR programs serve as effective tools to alleviate gas pipeline capacity issues often occurring during peak hours/days. DR programs are typically classified as Firm or Non-Firm. Non-Firm entails incentives for customers with Non-Firm service, sometimes targeting customers to maintain dual-fuel equipment when peak load shedding is needed. Firm DR offerings incentivize peak hour/day savings across C&I, multifamily ("MF") and residential customers. Given the limited number of residential natural-gas end uses (space-heating, water-heating, cooking, and appliances) and the critical nature of space-heating, achievable residential gas demand response savings potential is limited.

Typically, DR programs are considered to fall within several forms: Direct Load Control ("DLC") of equipment (typically space heating/water heating for residential customers) via various tools such as DLC smart thermostats and appliance devices, price/incentive-based options including Non-Firm customer load shedding, and behavioral response. As a result, DR program savings are driven by several key variables:

- Customer enrolment,
- Peak hour savings by customer and number of hours per event,
- Reliability factor – capturing the impact of event participants and the extent of their savings, and
- Snapback factor – for some programs

National Grid offers and anticipates expansion of Firm Residential Bring Your Own Thermostat ("BYOT")[31], Firm Residential Behavioral[32], Commercial & Industrial and Multi-Family Firm Daily DR[33], and Peak Period DR programs, as well as Non-Firm/Temperature Controlled service. Firm measures advancing from pilot stage are still early in development, appearing approximately one to two years from the maturity needed to reduce savings uncertainties. Further hampering maturity, 2020/21 pilot results are overshadowed by limited sample sizes, coupled with mild weather test events. Despite the limitations, PA found 2020/21 test event net reductions in alignment with third party conservative DR and moderately cold scenario potential. Additionally, Daily DR (for C&I and MF customers) exceeded the 2020/21 savings enrolment goal, but the BYOT DR program (for residential customers) fell 11% short of the enrollment participant goal.

Unique to Demand Response is the essential measurement of load reductions/load shifting, often requiring customer meter and equipment (e.g. DLC devices, dual fuel equipment) upgrades. Devices such as smart thermostats are increasingly popular, driving potential customer adoption rates but also introduce privacy and security risks. While customers can take additional measures to address these concerns, some may avoid devices altogether. Further, National Grid identifies limitations in meter deployment impacting successful metering of enrolled participants. PA agrees with this assessment and finds customer population limitation uncertainties (e.g. limited service territories, BYOT device data collection and customer privacy restrictions or concerns) contribute to overall DR program uncertainty. PA finds BYOT and Daily Peak program one-time metering/deployment costs diminish one-year BCRs, as reflected within the 2020/21 pilot results. Given the measure deployment risks previously described, it is possible future deployment costs will

[31] Program utilizes Wi-Fi connected thermostats to remotely lower temperature set points and shift peak hour gas loads on event days.
[32] A non-incentivized program which uses e-mail messaging to notify customers of impending cold weather and suggests methods to lower gas consumption during peak hours.
[33] Program incentivizes firm service customers capable of reducing peak day gas loads over a 6 or 8-hour period on event days.

further impact program BCRs. However, hourly measurement/AMI technology enlists a multitude of benefits beyond DSM (allowing the customer to view and manage consumption) such as providing higher reliability and more accurate billing. PA finds winter season natural gas sector Demand Response programs, particularly residential, exist at levels where potential magnitude of savings is not well understood. Metering and measurement risks combined with the magnitude of KEDNY and KEDLI participation growth, at untested Design Day conditions contribute to the overall uncertainty around whether savings may fall short of targets.

6.1.3 Electrification

Electrification programs aim to address supply side constraints and decarbonization goals by encouraging customers to substitute electricity for natural gas for space and water heating and/or other appliances. Substitution can be done via retrofits, but it is typically more cost effective at the end of the equipment's useful life. Electrification of natural gas presents unique challenges, including equipment cost and low natural gas prices which create lower operating costs. Improvements in heat pump technology, with respect to performance in cold climates, increases the potential for electrification savings but, customer adoption barriers remain especially given customer perceptions and awareness. Successful programs provide customers with the education and financial incentives necessary to persuade participation. Peer benchmarking shows bundling of various DSM offerings (such as EE and ELEC) increases potential. While dual-fuel utilities, such as Con Edison, operate conversion programs, electrification programs beyond dual-fuel service territories are just beginning.

PA assessed the reasonableness of the proposed program sizes by assuming an average appliance life of 20 years to approximate potential annual appliance electrification rates. National Grid assumes Baseline Electrification participants are largely driven by the impact of NE:NY heat pump programs, given service territory overlaps. Proposed assumptions reflect approximately 4% residential heating and multifamily appliances switch to electric while C&I switches at a higher rate of approximately 6% in mid 2020s, increasing to approximately 13% in mid 2030s. PA utilised the NYC Pathways Low Carbon Fuels scenario as a benchmark to determine whether National Grid's proposed Baseline Electrification rates are aligned with this scenario. PA also determined Incremental Heat Electrification and NPAs solutions reflect significantly higher customer adoptions of heat electrification than modelled in the NYC Pathways Low Carbon Fuels scenario. Substantial uncertainties influence the success of electrification such as organic and incentivized customer adoption rates, time required to scale program, cost-effectiveness of coordination with electric distribution companies ("EDCs"), and the economics of lower priced natural gas and finally unknown cost/benefit as marginal customers are enrolled. The success of Baseline and Incremental Electrification Programs will hinge on close coordination and aligned strategies between National Grid, EDCs, and regional power providers as well as substantial financial incentives.

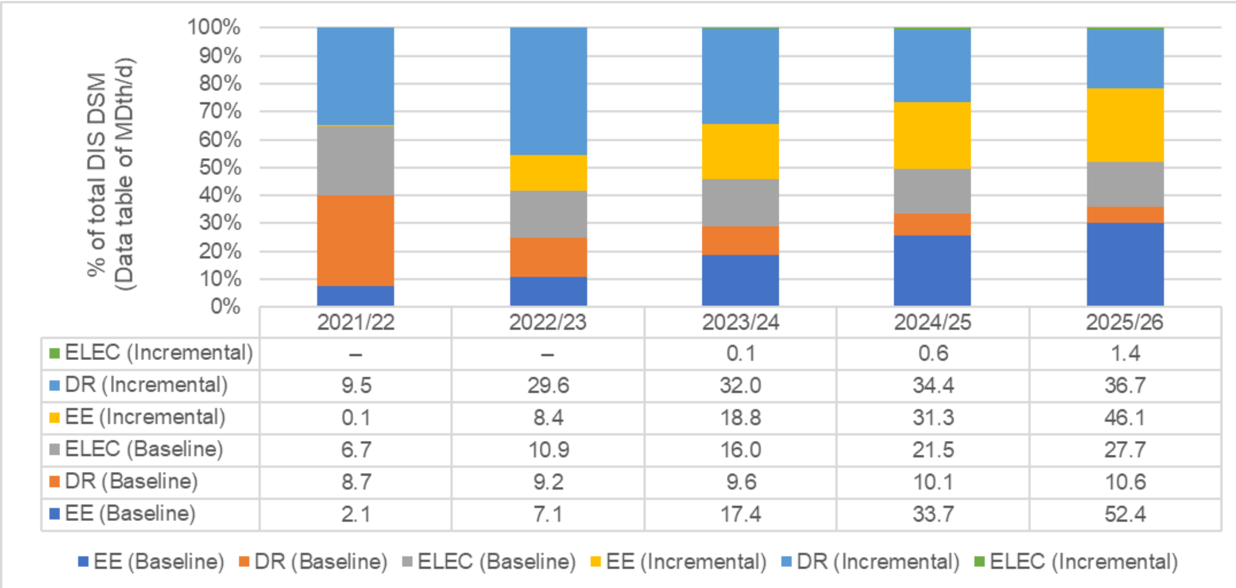
6.2 Approach and Observations

PA evaluated each component of the DSM outlook, with an emphasis on the key variables:

- Customer participation or enrolment rates
- Annual savings per customer

PA assessed information provided by National Grid, coupled with PA's knowledge of programs in other states and countries, third party studies, and benchmarking findings of other US gas utilities. To the extent possible PA evaluated granular variables for each program including but not limited to year-over-year participation and enrolment rates, appliance replacement rates, net savings potential including reliability, snapback, and event hours. Key historical and projected data was used to gauge proposed savings performance against known targets such as NE:NY goals, NY Heat Pump Adoption and stipulations included within the recently approved Joint Proposal.

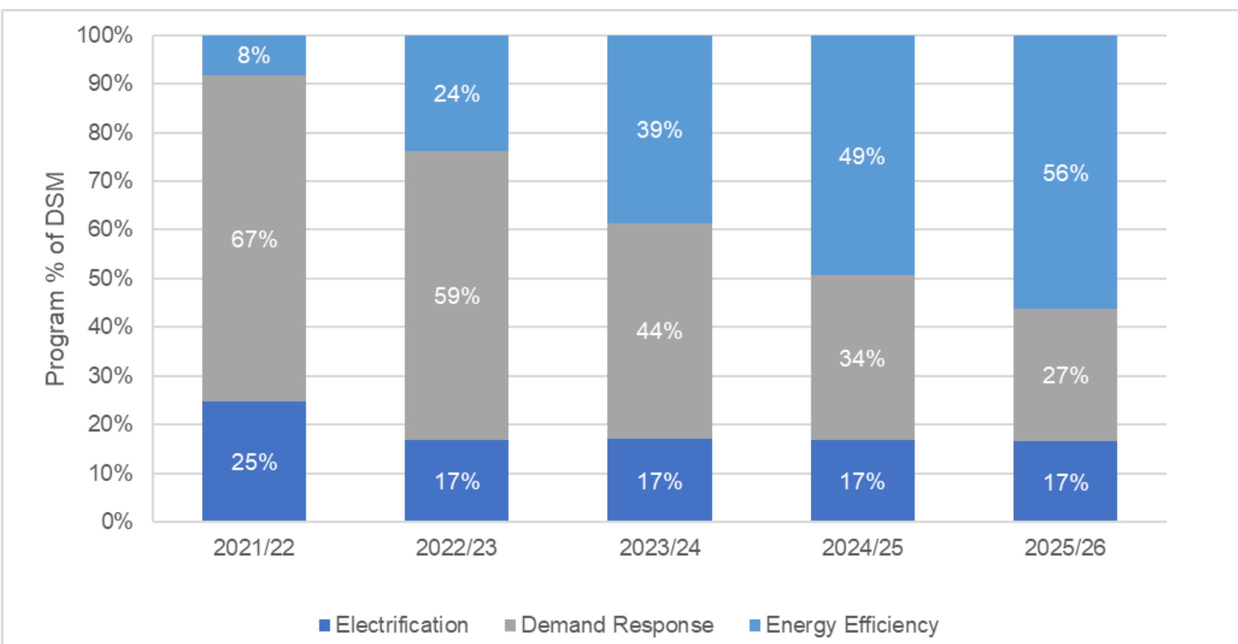
Figure 6-1: Contribution of DSM Components



	2021/22	2022/23	2023/24	2024/25	2025/26
ELEC (Incremental)	–	–	0.1	0.6	1.4
DR (Incremental)	9.5	29.6	32.0	34.4	36.7
EE (Incremental)	0.1	8.4	18.8	31.3	46.1
ELEC (Baseline)	6.7	10.9	16.0	21.5	27.7
DR (Baseline)	8.7	9.2	9.6	10.1	10.6
EE (Baseline)	2.1	7.1	17.4	33.7	52.4

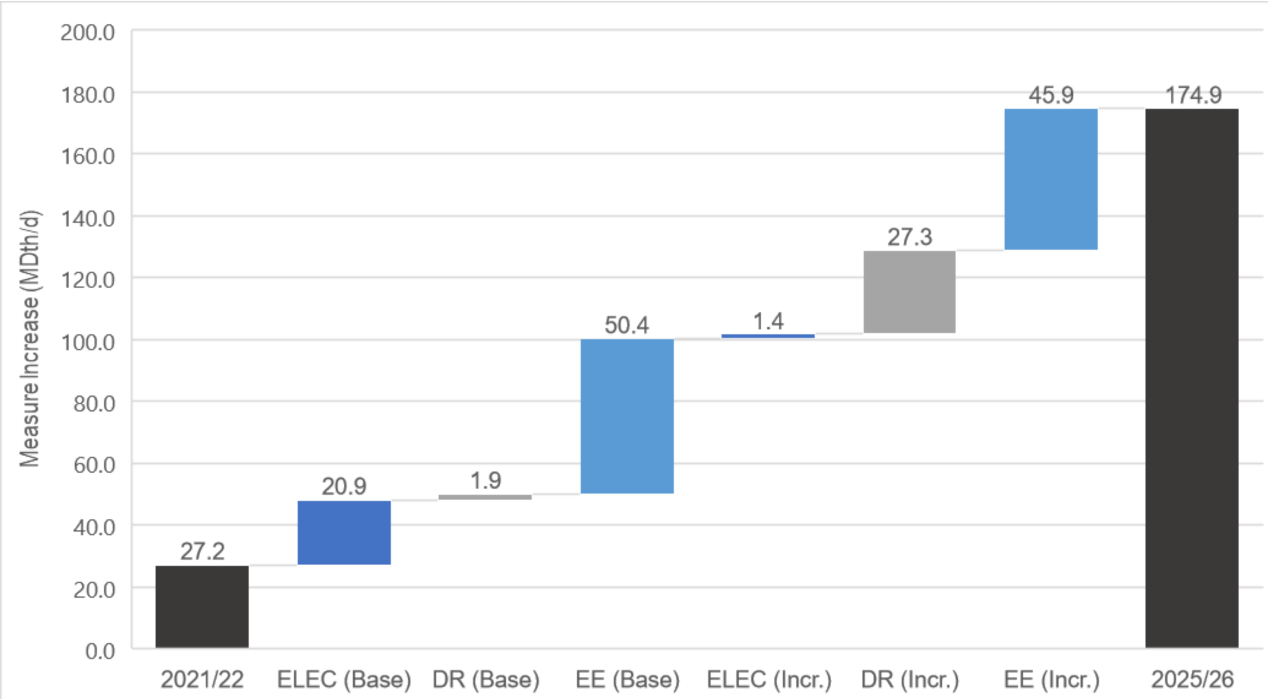
As presented above in Figure 6-1, 2021/22 season savings are primarily driven by Baseline measures (65%). However substantial Incremental DSM growth in subsequent years reduces Baseline measures share of total DSM by the 2025/26 season. This is primarily driven by substantial ramp-up of Incremental DR and EE measures. From a total program measure perspective, DR represents the material share of 2021/22 season savings. Substantial Incremental DSM growth, reduces the DR share of total DSM measures by 2025/26, as presented within Figure 6-2, summarizing combined DSM programs percent contributions below.

Figure 6-2: Percent Contribution of DSM Programs (Baseline and Incremental)



As discussed earlier, National Grid is in early stages of ramping up DSM and Figure 6-3 below presents increases within respective DSM components from the 2021/22 to 2025/26 season. To achieve 2025/26 DSM savings, substantial customer participation and savings increases within Energy Efficiency (both Baseline and Incremental), Incremental Demand Response and Baseline Electrification are required.

Figure 6-3: DSM Component Increases 2021/22 through 2025/26



The following tables provide a summary of PA's evaluation and observations related to each DSM component.

Energy Efficiency	Baseline
2021/22 Goal	2.1 MDth / day
Evaluation	• To date, EE goals under NE:NY have been achieved • Compared to a third-party market potential study for EE in the DNY region, pro-rated 5-year outlook reflects the goal is achievable with "headroom" for further incentives to bolster adoption (subject to the considerations of cost/benefit and other tradeoffs referenced above) • Number of customers to be engaged in EE program represents less than 1% per annum (market saturation is not a risk)
Observations	• Determination and differentiation of persistent vs. behavioral EE needs to be evaluated, in terms of savings potential and cost effectiveness • Achievement of recently approved Joint Proposal NE:NY savings goal stipulation is likely • As a more mature National Grid DSM program, energy efficiency has reasonable, achievable potential to help mitigate Design Day gap
Assessment	• Potential headroom for further incentives to bolster adoption over the near-term. However, such increases are subject to determining how larger incentives will increase participation and how the costs will be recovered.[34]

[34] PA explored the potential for accelerated DSM to avoid near term infrastructure investment while also applying a cost effectiveness view via Total Resource Cost ("TRC") measure by completing a sensitivity on the most mature program, EE. PA utilized DNV GL Market Potential study, provided by National Grid, to assess potential for savings above and beyond proposed Baseline Non-Behavioral and DIS Weatherization EE programs. PA found there is potential from an unconstrained view (assume all customers are adopted, high incentives and TRC below 1 is acceptable). However, this sensitivity also highlights that accelerated

Energy Efficiency	Incremental
2021/22 Goal	0.1 MDth / day
Evaluation	• Incremental EE reflective of additional savings from weatherization and energy efficient connection programs • Use of aerial thermal imagery survey to identify "high value" customers and encourage participation • Compared to a third-party market potential study for EE in the DNY region, pro-rated 5-year outlook reflects "headroom" for further incentives to bolster adoption • Preliminary IDD filing presents reasonable 5-year program cost effectiveness at 2.0 BCR[35], further indicating "headroom" for growth
Observations & Concerns	• On a combined basis, EE aligns with best practices including partnering and bundling of EE offerings, direct install and collaboration with electric utilities • Achievement of substantial increases anticipated over the near-term appears challenging **Concerns:** Time required to scale program; Inability to track detailed savings (due to lack of hourly meters); Unknown cost/benefit as marginal customers are enrolled
Assessment	• While the Incremental EE plans are in early development the forecast appears in line with market potential • Given headroom and funding for weatherization to take place, additional participation should be considered beyond 2025

Demand Response	Baseline
2021/22 Goal	8.7 MDth / day
Evaluation	• Limited 2020/21 winter test event results due to mild winter • Reflective of achieving reduced peak demand at a pilot-levels, with moderate growth assumptions • Number of customers engaged in DR 2020/21 pilot program represents a small percent of customer base: less than 200 Daily DR participants and approximately 2,200 BYOT participants (10% short of BYOT target) • BYOT[Error! Bookmark not defined.] and Daily Peak programs meter deployment risk b eyond the upcoming winter season, coupled with general population limitation risks (e.g., materialization of planned expansion of limited service territories, BYOT devices and customer privacy restrictions or concerns)
Observations	• Daily DR program pilot successes include Design Day enrollment of 17,790 dth/d, or 6% above target; 90% prior season participation and test event

savings are subject to important questions such as how much larger incentives will increase participation, how those costs will be recovered, and the willingness to accept the additional curtailment risk.

35 C&I average BCR of 2.6; Multifamily average BCR of 2.4; combined Residential combined average below 1.0.

	reliability performance of 83%; Test event net reductions align with third party reduction potential results under conservative DR and moderately cold scenario • 2020/21 BYOT DR program pilot successes include 99% prior season participation and test event reliability performance of 68%; However, pilot data is based on a very limited sample size completed under mild weather test event conditions • Limited historic data and high-level forecasting approach limit ability to assess program reasonableness[36] • 2021/22 achievement of C&I DR goals within recently approved Joint Proposal likely, however future years require Incremental DR savings to meet subsequent goals
Assessment	• The DR programs have not been subject to Design Day conditions nor have a meaningful number customers been signed up • PA anticipates that Design Day conditions are likely to cause a substantial drop in participation and reliability compared to pilot performance

Demand Response	Incremental
2021/22 Goal	9.5 MDth / day
Evaluation	• Reflects addition of Peak Period Demand Response program, increased Daily DR and BYOT • BYOT program assumptions consistent with third party benchmarking • Number of customers to be engaged in DR program represents between 1%-2% per annum (market saturation is not a risk) • Assessment of Firm DR customer class options limited by high-level program forecasting approach • National Grid redefined strategy excludes mitigation of historic Non-Firm rate switching resulting in elimination of potential peak day savings, in this version of DIS
Observations & Concerns	• Cost-effectiveness headwinds likely, higher incentives anticipated to further customer adoptions • Ranked second highest of Distributed Infrastructure Solution element by National Grid's customers • Achievement of C&I DR goals within recently approved Joint Proposal requires both Baseline and Incremental programs • Recent approval of Non-Firm rates increases likeliness of savings from mitigation of Non-Firm customer attrition; However, the magnitude is uncertain given customers must also consider back-up equipment costs and maintenance, decisions about fuel technology, fluctuations in back-up fuel price, and the potential environmental liabilities

[36] Forecast based on 2020/21 Winter Pilot data with "moderate CAGRs" representing historic achievements trend.

	Concerns: Lead time to develop and roll out program at scale; Customer adoption rates; Lack of cold weather data to assess reliability contraction under Design Day conditions; Unknown cost/benefit as marginal customers are enrolled
Assessment	• Downward adjustment to Firm Incremental DR forecast to account for latest Baseline forecast data provided by National Grid • PA recommends addition of Non-Firm savings to account for mitigation efforts anticipated to offset a portion of Non-Firm to firm rate switching, considering recently approved incentivized Non-Firm rate structure and previous inclusion within First Supplemental Report (noting that Non-Firm retention savings will be incorporated in future Adjusted Baseline demand forecast updates)

Electrification	Baseline
2021/22 Goal	6.7 MDth/d
Evaluation	• Number of customers to be engaged represents 0.2% total customers per annum, growing to 3% cumulative by 2035 • Year-over-year incremental customer participation increases anticipated at approximately 6% over the near-term • In addition to customer adoption, coordination with Con Edison and partnership with contractors and material suppliers will be fundamental to success
Observations & Concerns	• Assuming an average appliance life of 20 years, Baseline Electrification reflects approximately 4% residential heating and multifamily appliances switch to electric while C&I switches at a higher rate of approximately 6% in mid 2020s, increasing to approximately 13% in mid 2030s. Resulting total customer adoption rates aligned with NYC Pathways Low Carbon Fuels scenario • The program represents a small portion of overall customer base however, coordination with electric utilities, economics and customer perceptions of heat pumps coupled with overall willingness to embrace electrification present uncertainties and challenges **Concerns:** Customer adoption rates; Time required to scale program; Cost-effectiveness of coordination with electric distribution companies; Less favorable economics of low priced natural gas; Unknown cost/benefit as marginal customers are enrolled
Assessment	• PA expects that success of this program will hinge on close coordination and aligned strategies between National Grid, EDCs and regional power providers and substantial financial incentives. Referrals are unlikely to be sufficient.

Electrification	Incremental
2025/26 Goal	1.36 MDth/d
Evaluation	• Reflects significantly higher customer adoptions: residential heating, multifamily and C&I switching rates increase from 15% in 2026 to over 30% • Material savings assumed over mid to late 2020s driven by substantial year-over-year customer participation rates
Observations & Concerns	• Long-term plan assumes aggressive appliance switching rates with substantial increases anticipated beginning in 2027, exceeding the NYC Pathways scenarios • Significant barriers to electrification of heat include coordination with electric utilities, economics and customer perceptions of heat pumps and overall willingness to embrace electrification **Concerns:** Lead time required to scale program, coordination with electric distribution companies given substantial switching rates, Unknown cost/benefit as marginal customers are enrolled
Assessment	• Currently, there is limited information to determine the capacity of Incremental Electrification to help address a supply gap or whether it is a reasonable expectation. In short, until a business plan is developed corresponding with market data, PA does not feel this program savings should be depended upon.

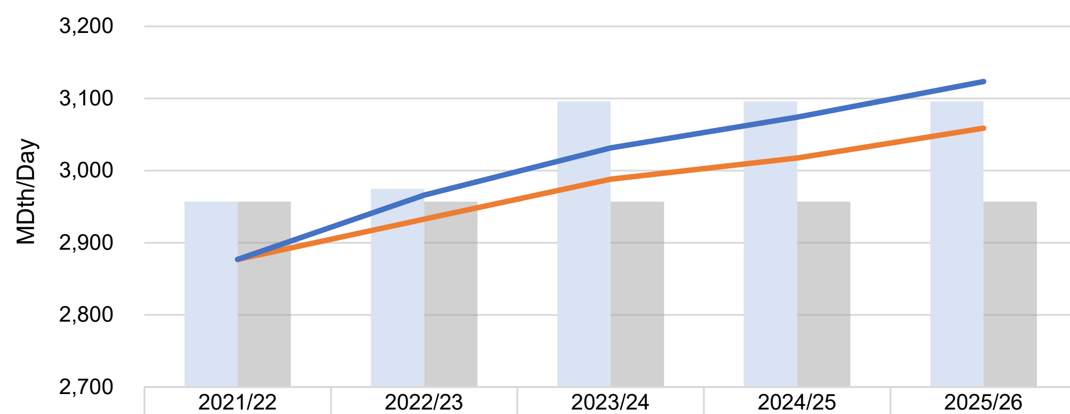
7 Assessing the Risk of a Supply Gap

As discussed throughout this report, there is real supply risk, and therefore a risk that a supply/demand gap emerges and persists. This is because the plans National Grid has in place to offset supply risk are (a) Incremental DSM that is at least one to two years away from achieving scale and (b) contingency infrastructure projects that, even if determined to be feasible and obtain the necessary approvals, are also several years away from implementation – placing even more burden on DSM.

The DSM programs in National Grid's DIS are presented as both the solution to fill the gap and as highly uncertain and unprecedented. As shown below, in a scenario where supply components of the DIS plan do not materialize, National Grid's adjusted demand forecast will soon outpace supply, presenting a moratorium risk as soon as 2022/23 in the absence of adequate incremental supply resources. Under a sensitivity scenario where MF and COM usage levels are more closely aligned with historical trends, National Grid would have roughly two years to develop, implement, and execute on the DSM components of the DIS plan (particularly since incremental supply resources are not forthcoming in the next two years). As stated previously, PA believes it is appropriately conservative to plan for relatively higher forecasts for reliability planning. Over the next two years National Grid should focus on acceleration of DSM execution before a present-day moratorium concern becomes a safety risk in the form of emergency curtailment to the extent load growth outpaces supply capability by the time a mortarium would actually take effect.

Under the most optimistic supply scenario (with DIS) as shown in Figure 7-1 below, full and timely implementation of all infrastructure supply resources similarly provides for two years for the DSM programs to be proven out and implemented to offset the supply gap. As such, perhaps the most critical observation is that National Grid in effect has roughly two years to achieve its goals of current DSM programs, execute on its plans for future programs, and quickly progress through development of feasibility analysis of alternative supply options.

Figure 7-1: Supply vs. Demand Sensitivities[37]



	2021/22	2022/23	2023/24	2024/25	2025/26
Available Supply (with DIS)	2,957	2,975	3,096	3,096	3,096
Available Supply (No DIS)	2,957	2,957	2,957	2,957	2,957
Sensitivity Load Forecast	2,877	2,933	2,988	3,017	3,059
Adjusted Baseline Demand	2,877	2,966	3,031	3,074	3,123

[37] Note: The Available Supply (with DIS) curve assumes the Greenpoint Vaporizers and ExC are in service by 2023/24 and the larger of two potential CNG facilities is in service by 2022/23. The Incremental DSM savings in the DIS are not represented.

APPENDIX A

National Grid and Con Edison jointly own and operate the New York Facilities System, an intra-city transmission pipeline system which is connected to and receives natural gas supply from multiple interstate pipelines.

The New York Facilities Agreement governs how the jointly owned pipeline system will operate and, among other things, specifies each utility's allocated share of interstate pipeline capacity entitlements at each city gate (e.g., each interconnection with an upstream transmission pipeline) as well as maximum hourly volumes of gas that are permitted to flow from one utility to the other. While gas flow is bidirectional at the pipeline interconnections known as Lake Success and Newtown Creek, on a Design Day gas flows from Con Edison to National Grid.

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This report has been prepared by PA Consulting Group on the basis of information supplied by the client, third parties (if appropriate) and that which is available in the public domain. No representation or warranty is given as to the achievability or reasonableness of future projections or the assumptions underlying them, targets, valuations, opinions, prospects or returns, if any, which have not been independently verified. Except where otherwise indicated, the report speaks as at the date indicated within the report.

Attachment J

NATIONAL GRID MONITORSHIP: CLOSING REPORT
(September 14, 2021)[1]

Pursuant to the Settlement Agreement of November 24, 2019 (the "Settlement") between the New York State Department of Public Service ("DPS") and National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid (collectively, "National Grid")

As the provider of natural gas to more than a million residential and commercial customers in New York City and Long Island, National Grid bears important responsibilities for maintaining ongoing service by designing and implementing plans to meet future customer needs. National Grid's failure to fulfill these obligations resulted in its placing a moratorium on new connections and increased gas service in 2018 and 2019. As part of the Settlement with New York State entered in November 2019, the moratorium was lifted, and National Grid agreed to implement a series of remedial steps and enhancements to its operations which, among other things, would reduce the risk of future denials of service through the development of improved contingency planning and options.

As the term of the monitorship of National Grid's compliance with the Settlement comes to an end, the Monitor finds that National Grid has enhanced its operations in several material respects. For example, National Grid has strengthened its internal processes by which its staff across multiple departments collaborate regarding the evaluation of demand forecasts, identifying any gap between demand and supply capacity, and developing scenario analyses and potential solutions to close any such gap. National Grid has improved the accountability of its executives and has undertaken to build out and maintain robust risk management and compliance organizations and tools. Although serious challenges and risks remain in implementing plans that will provide supply capacity in excess of forecasted demand in upcoming years, National Grid has successfully addressed potential shortfalls of supply over the last two winters and has improved the transparency, clarity, and depth of its evaluation of alternative future distribution options, and has shared that analysis broadly with public stakeholders and internally at the highest levels with its Board of Directors.

Despite substantive improvements on multiple fronts by National Grid, the alarming possibility nonetheless remains that National Grid's plans and projects underway toward meeting forecasted demand with sufficient supply capacity will fall short. Whether the potential cause be increases in customer demand for natural gas beyond forecasts, the failure to obtain required permits from federal, state or local government entities for planned distributed infrastructure projects, inadequate customer participation in demand side management efforts, an organizational or management failure by National Grid or other risks faced by National Grid and

[1] A draft of this Closing Report was provided for comment to National Grid and to DPS on September 1, 2021. Insofar as the Monitor independently deemed appropriate, their comments have been incorporated herein. Unless a later time is indicated, the Closing Report contains the Monitor's findings as of September 1, 2021, which date marks the end of the monitorship pursuant to the Settlement, except for the Monitor's subsequent filing of this Closing Report with the PSC. This Closing Report follows nine Reports respectively dated March 13, 2020, April 17, 2020, May 26, 2020, July 15, 2020, September 18, 2020, November 6, 2020, December 18, 2020, March 8, 2021, and May 5, 2021, familiarity with which is assumed.

more generally by the natural gas industry, numerous challenges pose potential stumbling blocks for National Grid's efforts to implement a long-term plan for meeting natural gas demand.

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

Accordingly, the Monitor urges National Grid and the DPS to move forward with continued and persistent vigilance. As described further below, core elements of National Grid's long-term plan for addressing supply capacity remain underway and face ongoing risks as to their successful implementation. Given that the monitorship is now terminating pursuant to the terms of the Settlement between DPS and National Grid, the Monitor recommends that:

1) National Grid produce periodic public reports on the status of its efforts to meet long-term demand, the first of which should be issued before the end of 2021, and should occur at least semi-annually though Winter 2023/2024.

2) National Grid's Chief Compliance Officer for the New York Service Territory hold meetings with the DPS staff, outside the presence of other National Grid executives, to discuss areas of actual or potential concern regarding National Grid's operations in the Service Territory. These meetings should occur at least quarterly through Winter 2023/2024.

3) The U.S. Chief Compliance Officer or his delegate in the compliance organization oversee annual compliance examinations at least through Winter 2023/2024, to assess whether executive annual performance reviews and compensation determinations have been linked to the successful and timely completion of material elements of the Settlement and the Monitor's recommendations, as discussed further below at 22-24, and, if not, to require remedial steps.

4) The U.S. Chief Compliance Officer or his delegate in the compliance organization oversee annual compliance examinations at least through Winter 2023/2024 to assess the progress of both the U.S. and New York Risk Committees and to ensure that they achieve full implementation.

5) Insofar as any CAP or Efficiency Plan funds are unspent after National Grid completes paying all eligible claims, National Grid allocate those funds to incremental EE and DR programs consistent with the spirit of the Settlement. Furthermore, the U.S. Chief Compliance Officer or his delegate in the compliance organization should conduct a compliance examination at the conclusion of Winter 2021/2022: (a) to ensure that the remaining eligible claims under the CAP were paid out; (b) to verify that any leftover funds were allocated to incremental EE and DR programs; and (c) to require, if necessary, remedial steps in order to ensure that any unspent funds are used for EE and DR programs.

6) The U.S. Chief Compliance Officer or his delegate in the compliance organization review at least semi-annually the progress on National Grid's efforts to update customer systems, with a specific focus on improvements made to address the particular deficiencies experienced during the moratorium, as discussed further below at 32. Within 30 days of substantially completing the relevant systems enhancements but in no event later than December 31, 2022, National Grid should certify to the PSC (via the Secretary to the Commission) that it has complied with this recommendation.

I. National Grid's Obligations

Under the November 24, 2019 Settlement between the State of New York and National Grid, National Grid was required to take various steps to address long-term natural gas supply capacity constraints, to meet immediate supply capacity needs through Winter 2020/2021, and to remediate harm caused by the moratorium to customers. The Monitor has written extensively about each of the elements of the Settlement and has issued twelve prior recommendations during the course of the monitorship.

This Closing Report: (1) reviews the key developments discussed in the Monitor's reports relating to National Grid's performance of its Settlement obligations and its implementation of the Monitor's recommendations during the monitorship; and (2) provides a final assessment of National Grid's compliance. The Settlement obligations and the Monitor's prior twelve recommendations are restated below.

A. Settlement Obligations

The Settlement encompasses the following elements:

1. Long-Term Capacity Report (Settlement ¶ IV)

A central component of the Settlement was the requirement that National Grid prepare and publicly release within three months of the Settlement "an analysis of the long-term capacity constraints affecting its downstate operations." The Settlement called for the Long-Term Capacity Report ("LT Report") to "present and analyze comprehensively and clearly all reasonably available options for meeting long-term demand, including but not limited to pipeline construction, LNG facilities, CNG facilities, renewable energy sources, conservation strategies, and inter-operable systems, and [to] include recommendations as well as an identification of actions needed (including but not limited to policy and regulatory changes) to implement each option or options."

National Grid further "agree[d] to work with [DPS] and local officials to conduct no fewer than four (4) public meetings to solicit public input" on the LT Report, the recommendations set forth in the report, and "any available alternatives," with the meetings taking place in Queens, Brooklyn, Nassau and Suffolk counties.

National Grid also "agree[d] that a long-term option or options should be identified and agreed to by the State of New York by June 2020 to allow a safe adequate construction and transition period and have the long-term option or options in place and functioning in approximately two years."

2. Action Plan (Settlement ¶ III)

In addition to presenting a report regarding long-term supply capacity issues, the Settlement further mandated that National Grid address immediate demand by providing to DPS "an action plan that shows how it will provide safe and adequate service to allow it to address the increased load associated with gas being provided" to customers previously denied service. "The action plan shall describe all supply, demand response, energy efficiency, and any other measures the Company will use to address such increased load and show how such measures will otherwise be employed to ensure it will meet the anticipated demands in its Service Territory."

3. Efficiency Plan (Settlement ¶ VI.a)

National Grid "agree[d] to fund" an energy efficiency plan with $8 million to deliver a package of new energy efficiency, demand response, and conservation measures to reduce peak-day gas usage among current customers to enable new customer connections.

4. Customer Assistance Plan (Settlement ¶ VI.b)

National Grid "agree[d] to fund" up to $7 million for a customer assistance plan to address hardships endured by customers affected by the moratorium, including hardships identified in complaints filed with the Office of the Attorney General of the State of New York.

5. Reconnecting Customers (Settlement ¶ VI.a)

National Grid was further required to "lift the [m]oratorium" and make "best efforts" within 30 days of the Settlement to contact and provide service to customers denied service between the imposition of the moratorium and early September 2019, except for customers who informed National Grid that they no longer want service. Within 45 days of the Settlement, National Grid also had to make "best efforts" to contact and provide service to any potential eligible customers who applied for and were denied service prior to the Settlement but after the imposition of the moratorium. For new customers and large commercial and industrial customers, National Grid "shall provide service" as soon as practicable.

6. Clean Energy Projects (Settlement ¶ VII)

National Grid initially agreed to "commit $20 million towards clean energy projects and/or investments in New York-based startup businesses and technologies to reduce reliance on non-renewable sources," to be paid by National Grid shareholders. On April 15, 2021, the PSC issued an order adopting an amendment to the Settlement whereby "National Grid will repurpose the $20 million of shareholder funding . . . to establish a deferral for the benefit of customers that will be used as a credit to offset the costs of National Grid's Commission-approved energy efficiency and demand response programs." (Order Adopting Second Amendment to Settlement Agreement. Att. A ¶ 2 (Apr. 15, 2021), Case 19-G-0678.)

B. The Monitor's Recommendations

In various Quarterly Reports issued throughout the monitorship, in addition to assessing National Grid's compliance with the above Settlement obligations, the Monitor made twelve recommendations relating to National Grid's operations.

First Quarterly Report. The Monitor's First Quarterly Report included four recommendations relating to the LT Report and public meetings and to National Grid's governance structure and forecasting processes.

- Recommendation 1 called for National Grid to provide greater clarity during the public meetings, and in the Long-Term Capacity Supplemental Report ("Supplemental LT Report") that would be issued after the public meetings, regarding "the feasibility, cost, and risk/benefit choices attached to the options (and potential combinations of options), including 'plain English' descriptions of the residual risk" of a moratorium with the options and the extent to which CNG would still be used, and "timeline(s) for pursuing and successfully executing upon various options," including permitting and construction.

- Recommendation 2 stated that: "National Grid should conduct a review of its governance structure and evaluate establishing the standalone role (with suitable staffing and resources) of a Chief Compliance Officer, having the responsibility (among other duties, to be structured in the consultation process recommended in 4 below) of ensuring that National Grid and its relevant departments and leadership take sufficient steps to anticipate and manage risks, test and monitor controls, and prepare contingency plans. The Chief Compliance Officer should be independent of the operational executives and report at least annually to the Board of the National Grid parent company or a committee thereof."

- Recommendation 3 provided for National Grid to "evaluate the benefits of retaining internal or external personnel qualified and capable of conducting periodic independent reviews and testing of the data development, modelling and forecasting processes utilized by National Grid in assessing whether future demand will exceed supply capacity, including providing recommendations for potential improvements to the assumptions, data inputs, models and other tools." Recommendation 3 further stated that "consideration should be given to whether the current Design Day standard . . . remains an appropriate standard for future planning by National Grid. Such independent reviews should be conducted in collaboration with the Chief Compliance Officer and the results incorporated into periodic examinations by the Chief Compliance Officer."

- Recommendation 4 stated that: "[i]n connection with Recommendations 2 and 3 above, National Grid should engage outside management consultants regarding the suitability and manner of structuring the new roles, defining their responsibilities, and similar steps, in consultation with DPS."

National Grid accepted each of these four recommendations.

Second Quarterly Report. The Monitor made four additional recommendations in the Second Quarterly Report, two of which again concerned the LT Report and public meetings. Another recommendation related to National Grid's systems for storing and managing data regarding applications for service, and the remaining recommendation addressed the Customer Assistance Program ("CAP") for remediating customer hardship caused by the moratorium.

- Recommendation 1 urged National Grid, in its Supplemental LT Report, to "specifically address concerns raised by the public regarding the integrity and accuracy of National Grid's demand forecast," including whether climate change or other factors affected the suitability of the current Design Day standard and whether economic changes from Covid-19 provided a basis to reevaluate future demand as set out in the LT Report.

- Recommendation 2 stated that, if social distancing restrictions from Covid-19 were alleviated while considerations continued regarding the options in the LT Report, National Grid should conduct one more in-person public meeting at that juncture in order to create further opportunity for the public to provide input, as the quality of certain public engagement could not be replicated in the virtual public meetings held after Covid-19 restrictions were put in place.

- Recommendation 3 called for National Grid to evaluate its systems for maintaining customer data and, "[i]n particular, in the event of a future moratorium, National Grid should ensure that its systems are capable of tracking applications, contacts and related data without significant manual intervention and reconciliation."

- Recommendation 4 recommended that: "[i]n light of the CAP's low utilization rate to date, National Grid should evaluate potential alternative uses for the funds allocated to the CAP consistent with the Settlement."

National Grid accepted three of these recommendations but rejected Recommendation 2 regarding conducting additional in-person public meetings after issuing the Supplemental LT Report, social-distancing restrictions permitting. As the Monitor observed in the Fourth Quarterly Report (at 4 n.5), National Grid's "unqualified unwillingness to hold another public meeting" represented a reversion "to its past rigidity, shortsightedness and resistance to providing increased transparency to the public." As described below, National Grid did subsequently accept another recommendation in the Monitor's Eighth Quarterly Report to conduct additional public engagement and, in this Closing Report, the Monitor recommends that National Grid issue ongoing public reports.

Eighth Quarterly Report. In response to delays which arose with the long-term options pursued by National Grid and performance issues previously raised by the Monitor, the Monitor issued two new recommendations in the Eighth Quarterly Report.

- Recommendation 1 found that, because of the delays to National Grid's long-term supply projects, "National Grid was at risk of failing to have these solutions in place and functioning within the approximately two-year timeline under the

Settlement." Therefore, the Monitor recommended "that National Grid engage in a further analysis and presentation of options to meet long-term demand, including working with DPS and local officials so that (building on the prior public engagement under the Settlement) National Grid receives public input on its recommendations and any available alternatives as of this time, to be completed no later than three months from National Grid's accepting this recommendation."

- Recommendation 2 recommended that, in connection with addressing concerns the Monitor had raised about "accountability within National Grid for performance failures such as failing to meet key project deadlines, National Grid should incorporate into annual performance reviews and compensation determinations for specific individuals beginning in 2021 the responsibility for the successful and timely completion of material elements of the Settlement and the Monitor's recommendations. These should include but not be limited to responsibility for the recruitment of an external CCO and the implementation of second-line-of-defense testing in the risk organization." The Monitor recommended that "[a]ny lapses or delays should result in articulable reductions in salary increases and bonus allocations to appropriate executives."

National Grid agreed to implement both recommendations.

Ninth Quarterly Report. In the Ninth Quarterly Report, the Monitor made two recommendations relating to: (a) the revision of confidentiality provisions in separation agreements used for departing National Grid executives; and (b) management's presentation of updates to the board of National Grid's parent company when implementing Recommendation 1 of the Eighth Quarterly Report.

- Recommendation 1 recommended that "any confidentiality provision in the separation agreements utilized by National Grid explicitly exempt communications by departing employees with the Monitor, DPS, or any other state or federal regulatory authority." As the Monitor explained in issuing the recommendation, such an exemption would "facilitate the receipt by the Monitor and DPS of candid perspectives from executives departing National Grid and to avoid any actual or apparent risk of their potentially jeopardizing their severance pay and benefits."

- Recommendation 2 provided that the board of National Grid's parent company should meet twice with the responsible National Grid executives in connection with the company's further analysis and presentation of options to meet long-term demand both in advance of National Grid's filing the report and in advance of its publishing feedback on that report. In addition, the Monitor should be invited to attend the two board meetings.

National Grid accepted both recommendations.

* * *

The remainder of this Closing Report reviews National Grid's compliance with its Settlement obligations and its implementation of the Monitor's recommendations. Part II of this Report discusses National Grid's recently updated analysis of the long-term supply options for meeting natural gas demand and the Monitor's recommendations relating to that report. Part III surveys the status of National Grid's ongoing winter supply projects and the challenges that the company faces in achieving its long-term solution. Part IV discusses National Grid's continuing efforts to comply with the Monitor's recommendations concerning significant organizational issues within National Grid identified during the Monitor's investigation. Part V explains the short-term winter supply solutions National Grid implemented under its Action Plan to provide adequate supply capacity through Winter 2020/2021. Part VI reviews National Grid's incremental energy efficiency ("EE") and demand response ("DR") programs funded through the $8 million Efficiency Plan required by the Settlement. Finally, Part VII discusses the remaining Settlement items, such as National Grid's deployment of $7 million as required under the Settlement in order to assist customers harmed by the moratorium, and National Grid's effort to connect customers who were denied service during the moratorium.

II. Second Supplemental Long-Term Report and Public Engagement

A. Background and Recommendation

As required under the Settlement, National Grid issued the LT Report on February 24, 2020, analyzing potential options for meeting long-term demand. After receiving thousands of public comments and holding one in-person and five virtual public meetings, National Grid issued the Supplemental LT Report on May 8, 2020 (together with the LT Report, the "LT Reports"), in which, consistent with the Monitor's recommendations from the First and Second Quarterly Reports discussed above, National Grid sought to provide additional information regarding, among other things, the potential for future moratoria, reliance on CNG trucking in certain scenarios, and permitting and timing demands of the options recommended by National Grid. (See Third Quarterly Report at 6-14; Fourth Quarterly Report at 1-4.)

Of the options National Grid identified, National Grid has been taking steps to pursue LNG Vaporization (i.e., two new LNG vaporizers at National Grid's Greenpoint facility) combined with incremental EE, DR and electrification, and National Grid supports the ExC project being developed by the Iroquois Gas Transmission System. As highlighted in the Fourth Quarterly Report, "[a]s a practical matter, these items depend upon obtaining federal, state and local approvals at certain junctures," and "National Grid obviously cannot ensure its receipt of these various approvals from multiple authorities." (Fourth Quarterly Report at 3.) Indeed, delays have arisen in connection with both LNG Vaporization and the ExC project (discussed further below), which prompted the Monitor to issue Recommendation 1 in the Eighth Quarterly Report (at 2), that "National Grid engage in a further analysis and presentation of options to meet long-term demand including working with DPS and local officials so that (building on the prior public engagement under the Settlement) National Grid receives public input on its recommendations and any available alternatives as of this time."

Accordingly, on June 30, 2021, National Grid publicly released its Long-Term Capacity Second Supplemental Report ("Second Supplemental LT Report"). National Grid also held a public meeting on July 14, 2021, and received both oral and written public feedback, which informed National Grid's Long-Term Capacity Third Supplemental Report ("Third Supplemental LT Report") released on August 25, 2021. In addition, to ensure that these significant matters received attention at the highest levels of National Grid, the Monitor's Recommendation 2 in the Ninth Quarterly Report required that responsible National Grid executives meet twice with the board of National Grid's parent company to review the steps being taken. (Ninth Quarterly Report at 1.)

B. Dissemination of the Second Supplemental LT Report and Public Outreach

On June 30, 2021, National Grid publicly filed the Second Supplemental LT Report with the PSC and posted it on a website dedicated to information about the prior and new LT Reports.[2] The website included notice of the July 2021 public meeting discussed further below, as well as how feedback could be provided to DPS and to National Grid. In addition, National Grid took various steps to disseminate the Second Supplemental LT Report to the public, including: (1) sending e-mails to customers about the report; (2) providing on-bill messaging to customers; (3) posting on social media; (4) placing newspaper ads in Downstate New York papers and issuing a press release; and (5) providing hard copies of the report at seven public libraries in New York City, Nassau County and Suffolk County.

In advance of the report's release, National Grid also engaged state and local government officials to brief them on the then-forthcoming Second Supplemental LT Report. National Grid sent letters with copies of the Second Supplemental LT Report to several environmental advocacy groups before and after the report's release and, according to National Grid, it also sought meetings with those groups to discuss the material.

National Grid's efforts at outreach followed its hiring of a new Vice President, Corporate Affairs for the New York jurisdiction ("VP, Corporate Affairs NY") around the time National Grid eliminated the position of SVP, Corporate Affairs in connection with its corporate reorganization (discussed further below at 21-22). The VP, Corporate Affairs NY was initially hired on an interim basis, and his role has since been made permanent. While the new VP, Corporate Affairs NY does not have a background in the natural gas business, in an interview with the Monitor, the VP, Corporate Affairs NY acknowledged National Grid's missteps in the past and explained that he believed he understood how to navigate and build civic partnerships. The VP, Corporate Affairs NY has reporting to him approximately 160 employees who cover communications, economic development, transmission connection services, and customer community teams. In his interview with the Monitor, the VP, Corporate Affairs NY emphasized community-outreach efforts and initiatives designed to benefit customer communities such as neighborhood beautification projects. In the view of the Monitor, it remains too early to assess what positive impact, if any, such efforts may bring for National Grid's ability to deliver upon the key supply projects it pursues to meet gas demand in the future.

C. The Second Supplemental LT Report

Like last year's LT Reports, the Second Supplemental LT Report analyzes various aspects of the Service Territory's natural gas demand and supply capacity outlook. According to

[2] See https://ngridsolutions.com/.

National Grid, under its latest demand forecast and based upon existing supply capacity, a gap between demand and supply capacity would occur beginning in Winter 2022/2023.

The Second Supplemental LT Report provides an update on the long-term solutions that National Grid has been pursuing to close this forecasted gap -- i.e., Vaporizers 13 and 14, incremental EE, DR and electrification, and the ExC project -- and supplements them "to include incremental portable CNG capacity" to create what National Grid describes as its "Distributed Infrastructure Solution." (Second Supp. LT Report at 57.) As National Grid acknowledges and as the Monitor described in previous reports (see Fifth Quarterly Report at 5; Seventh Quarterly Report a 4; Eighth Quarterly Report at 3-6), significant uncertainty exists around obtaining necessary permits for Vaporizers 13 and 14, and the ExC project still requires FERC approval as well as state and local permits before Iroquois may proceed. As a result, National Grid concedes that its Distributed Infrastructure Solution "faces real risks in the form of permitting delays and denials." (Second Supplemental LT Report at 103.) In addition, National Grid itself highlights that risks involved in its effort to scale up "unprecedented" levels of EE and DR create uncertainty that National Grid will be able to provide adequate supply capacity during a cold weather event even if Vaporizers 13 and 14 and the ExC project are in place. (Second Supplemental LT Report at 67, 80-81.)

Given the uncertainty surrounding National Grid's ability to achieve its Distributed Infrastructure Solution (whether timely or at all), the Second Supplemental LT Report reviews contingency scenarios and additional options to address any delay or failure to deliver components of the Distributed Infrastructure Solution. National Grid evaluated potential additional options "to identify the most affordable, feasible and reliable options to address potential contingency scenario gaps," which would include some combination of the Clove Lakes Transmission Loop (which aims to expand National Grid's ability to receive additional gas in Staten Island at an existing gate), LNG barges, and potentially even more incremental EE and DR. (Second Supplemental LT Report at 95, 99.) While National Grid raises these contingency scenarios and additional options for public consideration, National Grid concludes that they would not be as workable as the Distributed Infrastructure Solution, caveating that "all of these contingency plans are far less favorable for our customers both from an affordability and feasibility perspective than the Distributed Infrastructure Solution." (Second Supplemental LT Report at 100.) In addition, National Grid acknowledges that, if these risks to the Distributed Infrastructure Solution materialize, there is a "substantial risk" that National Grid may not meet demand growth and will choose to impose another moratorium (which National Grid refers to as a "pause" in new customer connections) or to activate customer curtailment plans. (Second Supplemental LT Report at 100-01.)

D. National Grid Board Meetings

In compliance with the second recommendation contained in the Monitor's Ninth Quarterly Report, National Grid executives made presentations to the board of National Grid's parent company on June 21, 2021 and on August 20, 2021, and the Monitor attended both meetings. In advance of the June 21 meeting, the board received a detailed memorandum setting out the context and summarizing several topics to be covered in the Second Supplemental LT Report (subsequently published on June 30, 2021). These topics spanned National Grid's updated demand and supply forecasts, the progress in advancing the Distributed Infrastructure

Solution set out in National Grid's Supplemental LT Report of May 2020, potential alternative options to the Distributed Infrastructure Solution, contingency scenarios, stakeholder engagement, and related topics. The June 21 meeting lasted approximately one hour and included robust discussion by the board following the presentation by the National Grid executives. The board posed detailed questions to the National Grid executives spanning the breadth of topics at hand and displayed a high level of engagement and familiarity with the issues raised. In the opinion of the Monitor, the board exhibited a strong interest in reaching a long-term solution meeting the needs of its customers and engaging with stakeholders to achieve that goal.

Likewise, the board conducted another meeting on August 20, 2021, at which time National Grid executives provided further detail regarding public engagement around the issuance of the Second Supplemental LT Report and National Grid's preparation of the upcoming Third Supplemental LT Report (subsequently published on August 25, 2021). The August 20 meeting also lasted approximately one hour and included a number of questions posed by the board to National Grid executives revealing a high level of familiarity by the board with the relevant issues.

While the challenges faced by National Grid in implementing a long-term solution are complex, the Monitor observed at these two board meetings that National Grid's board is highly knowledgeable about the issues, is fully engaged, and is providing oversight as National Grid pursues a workable long-term solution.

E. Virtual Public Meeting and Public Feedback

On July 14, 2021, National Grid conducted a virtual public meeting regarding the Second Supplemental LT Report. Registration records indicate that more than 50 individuals not associated with National Grid attended the meeting, which lasted from approximately 5:30 pm to 7:00 pm.

During an initial 30-minute portion of the meeting, National Grid executives summarized the contents of the Second Supplemental LT Report, supported in part by a PowerPoint presentation. National Grid then received questions from approximately 15 members of the public, followed by an open forum during which approximately 14 members of the public made comments. All persons interested in asking questions or making comments had the opportunity to do so, and the meeting concluded only at that time.[3] National Grid later published a transcript of the virtual public meeting on its website and appended the transcript to the Third Supplemental LT Report.

In addition, National Grid's website dedicated to information about the prior and new LT Reports included a link for members of the public to provide feedback directly to the PSC. As of September 1, 2021, fewer than 10 public comments had been filed since National Grid publicly released its Second Supplemental LT Report.

[3] A comment submitted to the PSC indicated that some participants had been dropped from the call during the meeting when they pressed the number National Grid instructed them to dial in order to ask a question or to make a comment. When queried by the Monitor, National Grid reported that the telephone company managing the conference call found no indication of participants being dropped from the meeting.

National Grid undertook a survey of its customers following the public meeting, which queried topics related to the Second Report and the Distributed Infrastructure Solution. In contrast to the number of submissions to the PSC, National Grid received approximately 2,000 complete survey responses. While not endorsing the survey methodology or statistical significance, the Monitor observes that the results obtained by National Grid suggest that respondents who read the Second Supplemental LT Report reported a much greater understanding of the gap between natural gas demand and supply capacity than those who did not read the Second Supplemental LT Report, i.e., approximately 60% versus 35%, depending on whether they had read the Second Supplemental LT Report. In addition, while 38% of respondents indicated that the Distributed Infrastructure Solution should be pursued (53% were unsure, and 9% opposed), these figures shift if one focuses only on the subset of respondents who reported an understanding of the demand/supply gap (53% supported the Distributed Infrastructure Solution, 40% were unsure, and 7% opposed).

In comparing the public meeting conducted on July 14, 2021, to the several public meetings held by National Grid in early 2020, the Monitor observes that the circumstances in both contexts included the provision of substantive information from National Grid and robust engagement by the public in response. The number of participants in July 2021 was substantially less than in early 2020, and the strong divergence in views exhibited in the early 2020 meetings seemed somewhat to dissipate by July 2021. In the Monitor's view, this evolution may result in some part from the conduct of the several public meetings in March and April 2020 and National Grid's publication of the several LT Reports. National Grid's shift from strongly advocating the NESE pipeline solution in the past to pursuing at this time the mixed set of options contained in its Distributed Infrastructure Solution may also have factored into the improved civil dialogue.

Also providing greater clarity regarding the potential path forward, the PSC offered comments regarding the Distributed Infrastructure Solution when approving the KEDNY/KEDLI rate case on August 12, 2021.[4] Specifically, the PSC noted (at 76-77) National Grid's analysis that, as compared to relying solely on additional pipeline capacity, "adding Vaporizers 13 and 14, in conjunction with the Companies' proposed incremental energy efficiency, demand response, and electrification programs, would create 'global warming potential savings.'" The PSC also found (at 112) as to the vaporizers that, despite public opposition documented in the record of the rate case, "the record contains no evidence of any viable, short-term solutions that would take the place of the facility."

F. Third Supplemental LT Report

The Third Supplemental LT Report summarizes the feedback National Grid received from the public regarding the Second Supplemental LT Report, including the survey results discussed above. Apart from the survey, National Grid notes that relatively few comments on the Second Supplemental LT Report were submitted either orally during the virtual public meeting or in writing to the PSC, with a total of approximately 25 unique commenters in contrast with the more than 5,000 unique commenters on the LT Report in early 2020. National Grid

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[4] Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements, N.Y. Public Service Commission Case Nos. 19-G-0309 & 19-G-0310 (Aug. 12, 2021).

attributes the relatively few comments to its "increased stakeholder engagement between the original Long-Term Gas Capacity Report and the issuance of the Second Supplement Report," which National Grid believes allowed it "to keep its customers and key stakeholders informed and engaged in [its] business in the regular course." (Third Supp. LT Report at vi.)

More substantively, the Third Supplemental LT Report groups the comments into three topic areas: (1) criticism of the Distributed Infrastructure Solution as inconsistent with the CLCPA or achieving net zero greenhouse gas emissions; (2) opposition to gas infrastructure in favor of demand-side management; and (3) dissatisfaction with the pace of National Grid's efforts to implement EE and DR programs. (Third Supp. LT Report at 16.) The Third Supplemental LT Report also includes a section with National Grid's responses to the feedback received on these issues. (Third Supp. LT Report at 16-24.)

G. PA Consulting Report

As noted in the Third Supplemental LT Report, PA Consulting, working at the direction of DPS Staff, was engaged by National Grid to conduct an assessment of National Grid's demand forecast and the Distributed Infrastructure Solution. (Third Supp. LT Report at vii.) On September 10, 2021, PA Consulting filed its report with the PSC (the "PA Report").

As to National Grid's gas demand forecast, PA Consulting found the forecast to be "on the high side but it is within reason." (PA Report at 5.) The PA Report (at 10) further found that, as the Monitor has emphasized, the likelihood that the components of the Distributed Infrastructure Solution "are not operational without further delay or termination appears high." PA Consulting also stressed the substantial uncertainty around the adoption of National Grid's demand side management ("DSM") programs and the ability to achieve its savings targets. In light of these challenges, PA Consulting identified a "significant curtailment and moratorium risk within the next five years" if National Grid's infrastructure projects are further delayed or not implemented. (PA Report at 6.)

In sum, while the PA Report found National Grid's forecast and its Distributed Infrastructure Solution to be reasonable, the PA Report punctuates the Monitor's significant concerns that National Grid may not timely implement key components of the Distributed Infrastructure Solution and that National Grid may be unable to meet the Service Territory's future supply needs.

III. Status of Ongoing Winter Supply Projects

Significant challenges remain for National Grid in its efforts to implement its Distributed Infrastructure Solution and to meet demand in the Service Territory. This section reviews National Grid's ongoing winter supply projects, including the components of the Distributed Infrastructure Solution. A picture of a precarious work in progress emerges, and significant uncertainty remains as to whether the required permitting will be granted for key infrastructure projects and whether National Grid will succeed in reducing demand through EE and DR efforts to the extent that will be required in order to meet future customer demand.

A. Greenpoint LNG

Vaporizers 11 and 12. Under National Grid's Revised Action Plan to meet short-term demand (discussed below at 24-25), National Grid initially planned to replace two decades-old LNG vaporizers at Greenpoint (Vaporizers 3 and 4) with two brand new LNG vaporizers (Vaporizers 11 and 12) by Winter 2020/2021. (See Seventh Quarterly Report at 2.) In an update filed with the PSC on October 30, 2020, National Grid acknowledged that it would fail to implement Vaporizers 11 and 12 by Winter 2020/2021 because the electrical tie-ins for the vaporizers required greater coordination and planning than National Grid previously had contemplated. National Grid indicated that the Riverhead, Glenwood and Inwood CNG sites would provide adequate supply capacity needed to meet demand for Winter 2020/2021. The electrical tie-in work remains in progress, and National Grid currently plans to place Vaporizers 11 and 12 into service by October 18, 2021, for Winter 2021/2022.

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

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

LNG Trucking Station. National Grid also plans to construct an LNG unloading station to replace an existing LNG unloading station at Greenpoint, which would enable National Grid to truck LNG to Greenpoint as a contingency measure to refill Greenpoint's LNG tanks in the event of an emergency situation. The LNG unloading station was originally included in the Supplemental LT Report as part of the LNG Vaporization option, but National Grid de-emphasized the trucking station in the Second Supplemental LT Report (at 63 n.39), stating that "the LNG unloading station is unrelated to and has no impact on the project to include

Vaporizers 13 & 14." According to National Grid, "[t]he function of the LNG Vaporization Project is to add peaking supply to the system to meet demand on the coldest days of the winter," and "[t]he function of the 'LNG Unloading Station Replacement Project' is to provide a contingency plan for an emergency situation requiring an extraordinary response, such as LNG trucking." Accordingly, National Grid asserts that replacing the LNG unloading station "plays no role in vaporization at the Greenpoint facility."

On July 23, 2021, Sane Energy Project and Cooper Park Resident Council, Inc. filed a lawsuit in New York state court against the City of New York, FDNY, and National Grid arguing that the construction of the LNG trucking station violated the State Environmental Quality Review Act and should be halted until certain environmental review requirements were met. On July 27, 2021, the court entered a temporary restraining order that halted construction of the trucking station pending the resolution of a motion for a preliminary injunction. The court held a hearing on August 16, 2021, and on September 3, 2021, the court issued a decision denying the preliminary injunction. In the meantime, due to the halt in construction of the LNG unloading station, National Grid currently projects that the LNG unloading station will not be in service by December 2021 as planned, but will instead enter into service in February or early March 2022. Even if the LNG trucking station is in service, National Grid still would need to obtain various waivers from New York City authorities prior to trucking LNG to the facility.

B. ExC Project

Another critical component of the Distributed Infrastructure Solution is the ExC project, which is designed to increase capacity on the Iroquois Gas Transmission System.

While National Grid's Supplemental LT Report (at 20) anticipated the ExC project to be in-service by November 2023, that deadline would have required a certification from FERC in early 2021. FERC, however, has not approved the application, and on May 27, 2021, FERC stated that it was going to prepare a supplemental Environmental Impact Statement of the ExC project. A decision by FERC currently is not expected until 2022, and then the ExC project will require state permits from New York and Connecticut before construction may begin. Accordingly, National Grid now expects that the delays in permit approvals will delay the project until Winter 2024/2025. National Grid acknowledges that if there are delays to the ExC project or the vaporizers, the electrification components of the Distributed Infrastructure Solution would need to be accelerated, carrying "significant execution risk given the amount of development work required and the scale at which [it] would need to be implemented." (Second Supp. LT Report at 77.) And if the ExC project were rejected, a gap between supply and demand would occur in Winter 2025/2026, even if Vaporizers 13 and 14 are achieved on time. (Second Supp. LT Report at 81.)

C. Fifth CNG Site

Given the extensive delays to the components of the Distributed Infrastructure Solution, National Grid's Second Supplemental LT Report contemplates the construction of a fifth CNG site for Winter 2022/2023, in order to forestall the projected gap between demand and supply capacity which is one year sooner than National Grid was projecting under its prior forecast.

(Eighth Quarterly Report at 5.) Although the selection process has proceeded, a specific site has not yet been selected.

While National Grid has the benefit of its experience managing the construction and operation of the four prior sites at Riverhead, Glenwood, Inwood and Barrett, National Grid nevertheless must seek local permits on an expedited basis, and prior permitting delays suggest that the timeline still carries risk. (See Fifth Quarterly Report at 2-4.) Indeed, at a recent internal National Grid meeting, National Grid's Gas COO rightly implored his reports to maintain a "sense of urgency" regarding the new CNG site and to "avoid complacency."

D. Long-Term EE/DR

Incremental DSM programs are essential to the Distributed Infrastructure Solution. DSM programs include EE, DR, and electrification of heat ("Electrification"). National Grid estimates the dekatherm ("Dth") savings to be achieved through DSM as basically a 'plug number' generated as the difference between National Grid's gas demand and its supply capacity. Accordingly, the Distributed Infrastructure Solution relies upon gas demand (load) reduction as part of a critical effort to meet the projected gap between gas demand and supply (Demand-Supply Gap). In addition, the Distributed Infrastructure Solution in the Second Supplemental LT Report includes no gas supply capacity expansions after Winter 2024/2025 and therefore wholly depends upon incremental DSM to offset all projected Design Day gas demand growth after Winter 2027/2028. At the same time that such reliance is placed on DSM programs, National Grid recognizes that its proposed DSM programs "face implementation challenges in terms of the need for regulatory approval and funding and the execution risk from the extraordinary magnitude and ramp up of these programs and the unpredictable nature of customer participation." (Second Supp. LT Report at 5.)

In the Second Supplemental LT Report, National Grid refined the EE, DR and Electrification components of the incremental DSM in its Distributed Infrastructure Solution. National Grid designed new intensive weatherization programs and a new "Energy Efficient Connections" program intended to facilitate EE at the time when new demand comes onto the National Grid system. National Grid plans to file for approval of these incremental EE programs at the PSC later in 2021. As to DR, the Second Supplemental LT Report includes three new programs focused on daily reductions in gas consumption and more targeted and pronounced hourly reductions in peak demand. National Grid filed for approval with the PSC on June 14, 2021, in Case 20-G-0086 and Case 20-G-0087.

On Electrification, National Grid is pursuing a collaboration with electric distribution companies ("EDCs") in New York State to study the best pathway to achieve incremental heat electrification targets, and National Grid is providing the EDCs with customer leads for heat pump adoption in an effort to meet their heat electrification targets, which can offset gas demand growth. National Grid is also advancing a new model for gas utility delivery of clean heating solutions, through renewable district heating networks using geothermal energy. A National Grid demonstration project in Riverhead, Long Island, used a shared geothermal loop system to provide lower-carbon heating and cooling service to a residential development; National Grid proposed an expanded demonstration program in its downstate New York gas distribution rate case. (Second Supp. LT Report at 29.) Last, National Grid plans to hold annual non-pipeline alternative ("NPA") solicitations to seek innovations to deliver DSM more cost effectively than traditional utility programs. (Second Supp. LT Report at 17.)

As noted above, National Grid acknowledges in the Second Supplemental LT Report that its DSM proposals are aggressive in scope and timing and face multiple risks. More specifically, each of the proposed incremental EE, DR and Electrification elements faces risks in the possible overestimation of market potential and of the ability to reach accelerated levels of adoption, as well as in the potential for failure to secure legal and regulatory approval of the programs and their costs. Indeed, heat electrification is currently uneconomical for many customers, and costs for heat electrification programs are higher than for all other DSM programs; heat electrification involves multiple incentive programs that would require multiple legal and regulatory approvals. Incremental EE and Electrification also risk the potential lack of market resources needed to execute the proposed projects. (Second Supp. LT Report at 18-19.)

In a bit of reverse-engineering, the amount of demand pursued by National Grid's incremental DSM programs -- i.e., efforts to close the gap between natural gas demand and supply capacity -- is driven largely by the difference between forecasted demand and the supply capacity provided by infrastructure components and city-gate peaking supplies. In August 2020, National Grid reported to the Monitor that it intended to submit in Fall 2020 a regulatory filing -- the Incremental Downstate NY DSM ("IDD") Filing -- to seek regulatory approval for future incremental demand-side program details and funding. In November 2020, National Grid reported to the Monitor that it was targeting submittal of the IDD Filing for January 2021, but that plan changed based on developments in the ongoing rate case (Case 19-G-309/Case 19-G-310). For Winter 2021/2022, National Grid is planning to use anticipated underspend of 2021/2022 NENY funds to cover costs of the weatherization program (a form of EE) and funding sought via the 2019 rate cases (Case 19-G-0309 and Case 19-G-301) to cover DR. (2021-2022 Gas DR Imp. Plan at 3).

Consistent with the process for incremental EE and DR formalized by the PSC in recently approved rated plans, National Grid currently contemplates proposing in the IDD Filing that an annual IDD filing be submitted in July of each year, as well as quarterly DSM program performance filings. The annual IDD filing would report on the past year's program performance, request cost recovery, and provide program details and budget for the following winter season. Thus, National Grid's ability to recover the costs of these programs will likely depend on their ongoing success. National Grid also may seek that DSM program costs for meeting long-term demand be funded through a surcharge, pending the inclusion of the costs in a rate case for recovery.

Whether National Grid will be able to achieve enough DSM to meet the demand reduction needed to cover the gap in future years is unclear. It will depend, in part, on National Grid's success in developing new EE programs for its various customer classes, including weatherization and other measures which reduce gas peak demand on a Design Day, as well as on National Grid's ability to increase participation in its DR programs and possibly to offer additional types of DR. In addition, National Grid is aware that it must keep 100% of its non-firm temperature-controlled customers on non-firm rates if it is to avoid any incremental Design Day gas consumption from these customers. This may be a challenge because, in past years, there has been significant customer interest in moving from non-firm to firm rates. Last, it will depend on National Grid's securing approval of funding at the levels needed to cover the costs of the DSM programs.

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

IV. Organizational Matters

A. Risk

At the beginning of the monitorship, the Monitor identified deficiencies in National Grid's risk and compliance functions, as National Grid relied generally on reactive, ad hoc, crisis management tools -- such as short-lived committees populated by business executives operating without any independent risk/compliance leadership -- in order to address serious issues such as those leading to the moratorium and the Settlement. National Grid lacked a dedicated executive with the title of Chief Compliance Officer or Chief Risk Officer sitting with senior executive teams and having responsibility and resources to identify, examine and manage the key risks, suitable controls and contingency planning needed in order to avoid a future moratorium or other significant risks. Recommendation 2 in the Monitor's First Quarterly Report therefore called for a review of National Grid's governance structure around risk management, the monitoring and testing of controls, and the development of contingency plans, and also including the possible establishment of the role of Chief Compliance Officer. The Monitor further recommended that National Grid obtain support from outside management consultants for this review.

Over approximately the last year and a half, National Grid has taken meaningful steps to improve its risk management. In March 2020, National Grid's U.S. President established a new U.S. Risk Committee, which sought to establish a new enterprise risk management process. The U.S. Risk Committee, for example, has maintained a foundational risk register, has reviewed the reporting of regular testing of controls, has conducted deep dives into top risks, and has taken efforts to implement similar risk management best practices.

After National Grid transitioned to a more jurisdictionally-focused operating model in Spring 2021, National Grid instituted a New York Risk Committee. Thus, instead of a single risk committee addressing all U.S. operations, the U.S. Risk Committee meets quarterly, and a more New York-focused risk committee meets bi-monthly. At both the U.S. and New York levels, the risk committees continue to work toward establishing second-level control testing which had been absent when the Monitor first issued his recommendation and remains a key goal under development at National Grid.

As for the U.S. Chief Risk Officer role, National Grid appointed an interim U.S. Chief Risk Officer in April 2020 and subsequently appointed a permanent U.S. Chief Risk Officer in January 2021. In March 2021, the Monitor interviewed the U.S. Chief Risk Officer, who joined National Grid three years earlier in an internal audit function after working as an external auditor at a major accounting firm for 16 years, where his clients included a number of utilities. Recognizing the challenges still faced by National Grid, the U.S. Chief Risk Officer emphasized ongoing efforts to establish standardized processes for executing the self-assessment and testing of key controls, and to build a dedicated second-line team to carry out controls testing.

While National Grid has made meaningful progress in establishing the new risk committees and appointing a permanent U.S. Chief Risk Officer, the risk committees have not yet achieved full implementation and a steady state. Accordingly, the Monitor recommends that the U.S. Chief Compliance officer or his delegate oversee annual compliance examinations at least through Winter 2023/2024 to assess the progress of both the U.S. and New York Risk Committees and to ensure that they achieve full implementation.

B. Compliance

With respect to compliance, National Grid did not make timely progress in implementing Recommendation 2 from the First Quarterly Report and in addressing concerns about the compliance organization raised by the Monitor. In the First Quarterly Report (at 2), the Monitor recommended evaluating the establishment of a standalone U.S. Chief Compliance Officer "having the responsibility . . . of ensuring that National Grid and its relevant departments and leadership take sufficient steps to anticipate and manage risks, test and monitor controls, and prepare contingency plans. The Chief Compliance Officer should be independent of the operational executives and report at least annually to the Board of the National Grid parent company or a committee thereof."

National Grid worked with the Boston Consulting Group ("BCG") in order to identify ways in which to enhance regulatory compliance in the U.S. Ultimately, National Grid's effort with BCG did generate the outline of a process which should enable the Compliance team to identify high risk areas and then focus their testing and risk management plans. This process, in concept, should result in strengthening the design and effectiveness of controls such as management governance, policies and procedures, testing, training, and reporting of concerns.

Even so, National Grid's progress in implementing this plan has been lackluster. Some of National Grid's earlier efforts to meet Recommendation 2 were wholly inadequate. As detailed in the Sixth and Seventh Quarterly Reports, National Grid's initial plan to establish the U.S. Chief Compliance Officer position failed to address basic concerns such as independence and sufficient access to the board of National Grid's parent company. After the Monitor raised these deficiencies in the Sixth Quarterly Report, National Grid revised its plan in vital ways that more closely aligned with the Monitor's recommendation. First, the U.S. Chief Compliance Officer will not be the U.S. General Counsel as had previously been envisioned, nor will the role sit in National Grid's Legal Department. Second, the U.S. Chief Compliance Officer will report directly to the U.S. President of National Grid and will have direct access to the Board of its parent company, thereby placing the role in a position possessing the ability to raise concerns directly with leadership at the highest levels. Third, National Grid agreed to conduct a search including external candidates for the role of U.S. Chief Compliance Officer.

National Grid proceeded to work with an external recruiting firm in order to identify suitable external candidates for the role of U.S. Chief Compliance Officer. The Monitor attended several discussions between National Grid and the recruiting firm during which the respective qualifications of candidates and their progress through the interview process were reviewed. National Grid ultimately hired an external candidate as U.S. Chief Compliance Officer, who began on August 16, 2021. The Monitor interviewed the new U.S. Chief Compliance Officer and found him to be a knowledgeable and experienced compliance professional who has helped build compliance programs around the world. The U.S. Chief Compliance Officer stressed his goal of achieving a "continuous improvement model" within the compliance organization and throughout National Grid more broadly.

In the opinion of the Monitor, the U.S. Chief Compliance Officer is well qualified for his role and described several worthwhile efforts he seeks to pursue. Having said that, substantial effort will be required by the U.S. Chief Compliance Officer and National Grid as a whole before a mature and comprehensive compliance program might be fully implemented.

C. Gas Forecasting and Planning

Because several internal groups historically have held responsibility at National Grid for the forecasting of gas demand and supply capacity, Recommendations 3 and 4 in the First Quarterly Report called for National Grid to pursue reviews -- with the help of outside management consultants -- of how best to structure related roles and responsibilities. Accordingly, in April 2020, National Grid retained Ernst & Young ("E&Y") and Marquette Energy Analytics ("Marquette").

1. E&Y

E&Y drew conclusions consistent with the Monitor's findings in the First Quarterly Report. For example, National Grid in the past has operated with limited ability and agility to conduct scenario planning in its forecasting efforts, has not fully captured and incorporated demand-side solutions, and has lacked clear accountability and strategic direction in its decision-making process.

As a result of National Grid's engagement with E&Y per the Monitor's recommendation, National Grid has implemented several new capabilities including: a new Transformation Office and a gas scenario planning "process owner"; a significant expansion of scenario analysis; the evaluation of non-supply solutions; the creation of new roles (particularly for more demand-side expertise); and a series of new and enhanced interactions and inputs across departments for developing demand forecasts, identifying any gap with supply capacity, and proposing solutions in order to close any gap. In addition, the project has sought to incorporate this new operating model into National Grid's new risk management efforts, in order to identify and mitigate related risks in gas forecasting and planning.

The new Transformation Office offers significant improvements, and the Second Supplemental LT Report -- which was spearheaded by the "process owner" and incorporated multiple contingency scenarios -- reflects the greater ease and efficacy by which National Grid can assemble and digest inputs from multiple internal resources in order to present a more coherent analysis of demand and supply capacity. At the same time, National Grid operates via a broad mosaic of internal groups and committees having diverse ownership, across which the Transformation Office now provides helpful facilitation. Thus, while the Transformation Office provides valuable support to National Grid's operations, it is premature to conclude that the Transformation Office and the "process owner" -- even when viewed in combination with other controls and enhancements being pursued by National Grid -- will satisfactorily mitigate the gas supply risks faced by National Grid and its customers in the Service Territory.

2. Marquette

The Monitor's First Quarterly Report (at 2) recommended that "consideration be given as to whether the current Design Day standard . . . remains an appropriate standard for future planning by National Grid." This recommendation arose in part from the fact that the last Design Day -- currently defined as a 24-hour period with an average temperature of zero degrees in Central Park -- had not occurred since 1934 and therefore may no longer be the most appropriate gauge for forecasting and gas planning efforts. National Grid accepted the Monitor's recommendation and retained Marquette which performed an independent study of National Grid's data. In addition, on March 19, 2020, the PSC launched a proceeding in Case 20-G-0131 (the "PSC Gas Planning Proceeding") that has been reviewing gas planning processes at the utilities in order to produce proposals to modernize the system.

As discussed in the Fifth Quarterly Report (at 6-7), Marquette's analysis suggested that any adjustments that might be made to National Grid's methodology would result in an overall increase of the demand forecast. Differences between Marquette's methodology and National Grid's methodology included: Marquette incorporated both wind and temperature in its Design Day analysis while National Grid uses only temperature; Marquette utilized multiple weather stations while National Grid relies on Central Park; and Marquette used some different statistical methods than National Grid.

National Grid continues to evaluate the results of Marquette's analysis and has determined to defer implementing changes to its forecast methodology, such as whether to incorporate wind, pending the work with DPS and other utilities in the PSC Gas Planning Proceeding, in which design day criteria have been raised as an issue. Based on the feedback to date from Marquette's analysis, however, it appears that any adjustment that might later be made to the current Design Day standard used by National Grid is unlikely to reduce its demand forecast in a material way or otherwise to narrow the gap between forecasted demand and supply capacity.

D. Language in Former Employees' Non-Disclosure Agreements

In March 2021, National Grid decided to terminate the role of SVP, Corporate Affairs. According to National Grid, because the organization is now more focused on state-specific leadership, National Grid decided to rely upon two Corporate Affairs leads for the New York and New England jurisdictions; the more senior U.S.-level role therefore was eliminated.

Given the importance of the Corporate Affairs department to how National Grid manages obtaining sufficient gas supply capacity to meet demand, the Monitor sought further information regarding National Grid's decision to eliminate the role of SVP, Corporate Affairs. The Monitor had concern that National Grid had delayed the Monitor's receipt of substantive support for National Grid's justification in eliminating the position of SVP, Corporate Affairs, including by insisting upon having its counsel attend the Monitor's interview of the departing SVP, Corporate Affairs.

The Monitor therefore sought to ensure that interviews pursued by external authorities from departing executives in the future are not influenced, for example, by potential concern of those executives that their offering of candid and forthcoming assessments about National Grid might affect the financial or other terms of their separation. For this reason, Recommendation 1 in the Monitor's Ninth Quarterly Report provided that any confidentiality provision in National Grid's separation agreements contain exemptions for communications by departing employees with the Monitor, DPS, or any other state or federal regulatory authority.

National Grid accepted the Monitor's recommendation and has revised its form separation agreement consistent with the recommendation, including by clarifying that the departing executive need not notify or obtain approval from National Grid prior to communicating with regulators or other government agencies in connection with any investigation or proceeding. Accordingly, the form separation agreement now includes language that reads:

> The General Release does not, however, restrict the Executive's right to file a charge, testify, assist or participate in an investigation or proceeding before the Equal Employment Opportunity Commission, the National Labor Relations Board ("NLRB"), the U.S. Department of Labor ("DOL"), any state or federal regulatory body (e.g., the New York Public Service Commission), or any other federal, state or local agency charged with the enforcement of any laws, or their staffs and designated representatives, or from testifying truthfully in the course of any such regulatory, administrative, legal or arbitration proceeding. The Executive does not need to notify, or secure the approval of, the Company prior to communicating directly with regulators or other governmental agencies related to any such investigation or proceeding.

E. Performance Metrics for Settlement Items

In the Eighth Quarterly Report (at 2), the Monitor recommended that individual performance reviews and compensation determinations be linked to the successful and timely completion of material elements of the Settlement and the Monitor's recommendations. This recommendation was necessary because the Monitor had perceived a lack of individual accountability by management of National Grid in connection with implementation of the Settlement and the Monitor's recommendations.

In addressing the recommendation, National Grid initially incorporated goals related to the Settlement in the performance process for only six of its executive roles. In addition, these goals lacked concrete metrics and were only superficially described, e.g., executives were to "support" the long-term supply process. Further, National Grid did not review any of these six executives on these supposed metrics in fiscal year 2020 -- despite 2020 being a critical year for launching the implementation of virtually all aspects of the Settlement -- asserting that a confluence of the pandemic and its annual performance rating cycle caused it to focus on other priorities.

Although National Grid purported to accept the Monitor's recommendation, National Grid initially had failed to enhance its performance management plan in meaningful ways. National Grid subsequently filed a more expansive implementation plan with the PSC on April 15, 2021, which committed, for example, to incorporate "specific deliverables" and "specific, objective metrics" into the performance goals for fiscal year 2022 for those senior executives and management employees having responsibility for material elements of the Settlement. The plan also stated that the individual's "success performing his/her job responsibilities in furtherance of achieving these goals" will constitute a "material factor" in the performance review and any variable compensation award. Further, the performance goals were to be cascaded to reach individuals "with direct responsibility … including, at a minimum and without limitation, in the areas of Asset Management, CNG/LNG Operations, Project Management, Supply Procurement, Transformation, Customer, Future of Gas, and Legal."

In August 2021, National Grid provided the Monitor with revised performance metrics relating to the Settlement for 17 key executives with responsibility over items relating to implementation of the Settlement and the Monitor's recommendations. The metrics include overall objectives for each role, along with several corresponding "targets" the executive must achieve in furtherance of his or her objectives. For example, the New York President's objective is to "[d]evelop a long-term gas supply plan for downstate NY that continues to ensure system reliability and safety for all customers while incorporating non-pipe alternatives." One of the targets includes "[i]mplement[ing] the various components of the Company's long-term solutions on a schedule that avoids future service restrictions, including . . . LNG Vaporizers 13/14 and/or 5th CNG Site," as well as EE and DR programs. In other words, absent the successful and timely implementation of these actions, the target will not be achieved.

For executives reporting up to the New York President, several targets are similarly specific and objective. The VP, New York Compliance's targets include: "Bi-monthly risk and compliance forums are held with risk and control owners to monitor known risks, identify emerging risks, assess effectiveness of risks and controls, and develop action plans to improve controls to mitigate risks." The VP, LNG/CNG Operations must "[p]repare for future winter needs including (i) CNG Site #5 project development and sanctioning and (ii) securing necessary permits and advancing construction for Greenpoint Vaporizer 13/14, in each case on a schedule that supports the need-by date." Again, if these targets are not successfully accomplished, then the performance review should clearly reflect that fact.

Some executives' targets, however, continue to incorporate some inherently subjective elements. For example, one of the targets for the VP, Corporate Affairs NY is to "[s]upport to the satisfaction of the New York President the public engagement efforts on the refreshed long-term report (June/August 2021) as committed in the Company's April 15th Implementation Plan, including: (i) engaging key stakeholders pre/post publication in June-August, (ii) executing the public communications plan (website, social media, advertising, etc.) for the LT Report; and (iii) facilitating a public meeting on the report."

National Grid produced evidence to the Monitor that the performance metrics have been cascaded below the more senior executives to additional employees having direct responsibility in the relevant areas such as Gas Engineering, LNG/CNG Operations, Gas Complex Construction and Compliance.

As noted, the Monitor has expressed concern repeatedly regarding the accountability of National Grid executives for successfully and timely delivering on material components of the Settlement and the Monitor's recommendations. In the Monitor's opinion, establishing specific and objective goals for individual performance constitutes a direct means of ensuring that executives act with appropriate urgency and focus on achieving these goals. Accordingly, a recommendation of this Closing Report is that the U.S. Chief Compliance Officer oversee an annual examination to assess whether these performance reviews are operating in this matter and, if not, to require remedial steps.

V. **Action Plan (Winters 2019/2020 and 2020/2021)**

Pursuant to the Settlement ¶ III, National Grid was required to submit to DPS an action plan describing "how it will provide safe and adequate service to allow it to address the increased load associated with gas being provided" to customers previously denied service for Winters 2019/2020 and 2020/2021 (the "Action Plan"). In contrast to the solutions presented in the LT Reports designed to meet customer demand over the long term, the measures in the Action Plan were intended to provide a stop-gap in order to avoid a moratorium over the past two winters.

National Grid filed its original Action Plan with the PSC in December 2019 and later updated its plans with a Revised Action Plan in June 2020. Both versions of the plan relied heavily upon CNG as a source of supply in the form of trucking CNG from Pennsylvania to National Grid facilities in the Service Territory. This procedure raises risk and reliability questions, for example, because it involves trucking CNG from a distance during the coldest weather and requires National Grid and its vendors to coordinate effectively in inclement conditions. Engineering executives at National Grid in particular voiced concern about the dependability and large-scale reliance upon CNG for meeting Design Day needs over the long term. And while the Action Plan was aimed at only the last two winters, in reality the CNG components of the Action Plan will continue to be part of National Grid's supply portfolio and be employed in a Design Day scenario for the foreseeable future. Indeed, as discussed above (at 15-16), National Grid's Second Supplemental LT Report now incorporates building a fifth new CNG facility as part of the Distributed Infrastructure Solution.

As reviewed in prior monitor reports, National Grid completed the components of the Revised Action Plan for Winters 2019/2020 and 2020/2021, albeit with repeated delays and shifted deadlines. During Winter 2019/2020, National Grid's Action Plan called for the use of CNG at sites in Glenwood and Riverhead, New York, for up to 8 hours per day during a cold weather event, which would require approximately 42 truckloads of CNG per day.

As Winter 2020/2021 approached, National Grid needed to construct one additional CNG site and to expand the existing CNG site at Glenwood. The Action Plan also included the replacement of two vaporizers at Greenpoint (Vaporizers 11 and 12) for Winter 2020/2021. The addition of a third CNG site, however, required state and local permits, which presented risks for National Grid. Accordingly, National Grid pursued multiple CNG sites in parallel, and pursuant to the Revised Action Plan, National Grid ultimately focused its efforts on Inwood for the third site to be commissioned prior to January 2021. National Grid also continued to pursue simultaneously a fourth site at Barrett in the event that Inwood became delayed. The Revised Action Plan continued to plan for Vaporizers 11 and 12 to be in service for Winter 2020/2021.

The Monitor attended regular internal meetings among a large team of professionals responsible for the various elements of the Action Plan. The professionals utilized multiple tools to track, monitor and report on progress of the projects under the Action Plan. But the Monitor on multiple occasions expressed concern with National Grid's tendency to allow its deadlines to be shifted, which raised the prospect that such deadlines may not be viewed as actual deadlines and may not be acted upon with sufficient urgency. The Monitor had related concerns that senior management at National Grid may not have been receiving adequate insight and internal reporting about such shifts in the timeline. These concerns in part led to the Monitor's recommendation (discussed above at 22-24) that National Grid incorporate specific performance metrics relating to the Settlement items.

In October 2020, National Grid filed an update with PSC acknowledging that it would fail to implement Vaporizers 11 and 12 by Winter 2020/2021 (see above at 14) and that the Riverhead, Glenwood and Inwood sites would provide adequate supply capacity needed to meet demand for Winter 2020/2021. National Grid did succeed in commissioning the expanded Glenwood site and new Inwood facility into service for Winter 2020/2021, albeit with virtually no margin for error in the schedule. National Grid also continued its work on the Barrett site and commissioned the fourth CNG site in June 2021.

In sum, despite repeated permitting delays and the failure to complete Vaporizers 11 and 12 by Winter 2020/2021, National Grid added or expanded three CNG sites by Winter 2020/2021, which National Grid determined would supply enough CNG in order to meet Design Day demand, consistent with the Revised Action Plan.

VI. Efficiency Plan

Pursuant to Settlement ¶ VI.a, National Grid developed an Efficiency Plan to deliver a package of EE, DR and other gas conservation measures designed to reduce peak-day gas usage among current customers. As described below, National Grid historically has operated EE and DR programs, and the Settlement accordingly required National Grid to spend $8 million to fund the Efficiency Plan for Winters 2019/2020 and 2020/2021 by enhancing the existing EE and DR programs with supplemental efforts. As of August 19, 2021, National Grid had spent approximately $7,478,000 on the Efficiency Plan, and it is possible a portion of the Efficiency Plan funds will remain unspent. If that is the case, then National Grid should allocate those unspent funds to future incremental EE and DR programs consistent with the spirit of the Settlement.

A. Incremental EE and DR for Winter 2019/2020

1. Enhanced EE

The new EE programs include an enhanced EE incentive for commercial and industrial ("C&I") customers and various incentive programs for residential customers. These EE programs include intense weatherization measures for buildings and homes such as air-sealing and maximized insulation that reduce customer heating needs. For Winter 2019/2020, National Grid invested approximately $682,000 to achieve savings equal to approximately 1,221,700 therms.[5]

C&I Customers. Under the enhanced C&I customer program, National Grid increased the payments offered to C&I customers by $1.00/therm in order to get them to participate in EE efforts, subject to a limit that the incentive be not more than 50% of the total project cost. Eighty-one customers participated in the C&I enhanced EE program.

Residential Customers. For residential customers, the EE programs included a high efficiency heating equipment initiative which offers incentives for replacing natural gas heating equipment with high efficiency equipment such as hot water boilers, furnaces and water heaters as well as a marketplace bundles program which aggregates a variety of products from the National Grid "Marketplace," an online store that facilitates the purchase of energy-saving products (e.g., thermostats, low-flow shower heads) and services while offering instant rebates at the point of sale for certain products.

The residential heating EE initiative was launched on the National Grid and vendor website on November 15, 2019, and consumer marketing started in early December 2019. Customers began taking advantage of the enhanced incentive by December 6, 2019 and the initiative continued to grow through March 2020. Of the EE product bundles offered in the Marketplace, National Grid increased by $25 its incentive for energy saving thermostats that can be operated remotely (i.e., wi-fi thermostats), and National Grid increased by $5 its discount for water saving measures such as energy efficient shower heads or faucet aerators. Manufacturers also offered additional discounts on Marketplace products.

2. Enhanced DR

The enhanced DR program focuses on load (demand) shedding to reduce the amount of gas needed over a 24-hour period. The enhanced DR program includes both C&I and residential programs. National Grid invested approximately $2,931,000 in the Winter 2019/2020 enhanced DR program.

C&I Customers. The C&I program involved 6-hour events during which participating customers would switch to back-up fuel, change their process, or disable gas-fired equipment in order to reduce demand during an event. National Grid enrolled 123 customers in the expanded gas DR program for C&I customers. Under this program, DR events were to be called when the

[5] A therm is a unit of heat equal to the amount of heat required to raise one pound of water one degree Fahrenheit at one atmosphere pressure.

temperature was forecasted to be at or below 10° F. For each event, participating customers receive an incentive based on the reduction in usage they produce during the peak hours of the gas system (4 AM to 10 AM) that results in a reduction in total gas consumption, relative to their expected baseline over the course of a day. National Grid targeted a reduction of 3,000 Dth per event with a $3.6 million budget. Due to the relatively mild winter, the temperature did not reach the level required to call an event. National Grid called a test event on January 22, 2020, and had an overall customer compliance of approximately 94%. The total consumption during the period was 229 Dth as compared to predicted usage of 4,632 Dth by those same customers if an event had not been called. This results in a reduction of 4,403 Dth by participating customers for the test event and was higher than National Grid's target of 3,000 Dth per event.

Residential Customers. National Grid offered a behavioral (no-incentive) residential and small-medium business ("residential/SMB") program whereby National Grid would send email messages to customers prior to days forecasted for cold weather, alert them that the system would be experiencing high levels of use, and provide tips on how they could manage (reduce) their energy use. National Grid called a test event for the non-incentivized residential/SMB program on February 19, 2020. On February 18, 2020, National Grid sent email messages to 443,547 customers asking them to turn back their thermostats on the following morning. Although 134,580 (30%) of those customers opened their emails, National Grid was unable to determine an amount of load reduction from the event.

National Grid also offered a residential bring-your-own-thermostat ("BYOT") program, whereby customers who had wi-fi thermostats connected to a gas heating system could allow National Grid to turn down the temperature set point by 4 degrees for a 4-hour period in the morning or afternoon. National Grid estimated the total number of potential participants at 15,000 on Long Island and set a target of 2,500 participants. The BYOT program was launched in late February 2020 and as of March 23, 2020, 70 participants had enrolled in the program. Due to Covid-19, National Grid decided not to call a test event for the BYOT program.

B. Incremental EE and DR for Winter 2020/2021

In an order issued in January 2020, DPS approved significant increases for EE in the New Efficiency New York ("NENY") budget for National Grid. Based on that increased funding, National Grid determined to use the increased NENY EE budget to fund the incremental EE for Winter 2020/2021 under the Efficiency Plan, and National Grid allocated the unspent portion ($4.16 million) of the $8 million in the Efficiency Plan Settlement funds to incremental DR. In addition, consistent with Section VI.b. of the Settlement, National Grid and DPS Staff agreed to move $1 million from the Customer Assistance Plan to the Efficiency Plan for funding incremental DR. This $1 million reallocation of funds between the Plans did not actually occur; National Grid received requests for significantly more CAP payments near the end of the program, and its total costs for incremental DR in 2020/2021 were within the amount of available Efficiency Plan funding.

National Grid used the same types of DR for Winter 2020/2021 that it had used in Winter 2019/2020: a C&I DR program; a BYOT incentivized program; and a behavioral non-incentivized program. The costs for National Grid to operate the DR programs in Winter 2020/2021 totaled approximately $3,865,000, with the bulk of costs coming from customer incentives. National Grid explained that total costs were less than the projected total costs due to the sub-100% performance of daily DR resources, a low number of DR events and slightly less than expected enrollments in the BYOT program. (2020-2021 DNY DR Annual Rpt. at 18.)

C&I Expanded DR. National Grid revised the C&I program by expanding the options for customers that participate in the program. Customers were allowed to choose between curtailing their gas usage for one six-hour period (4 AM to 10 AM) during a DR event or curtailing their gas usage for two four-hour periods (6 AM to 10 AM and 5 PM to 9 PM) during the day of a DR event. Customers also had the option of allowing National Grid to remotely control certain heating equipment, known as Direct Load Control ("DLC"). National Grid would continue to call DR events for its C&I program when the forecasted low temperature was at or below 10° F (at LaGuardia Airport for KEDNY and at Republic Airport for KEDNY) and would provide customers at least 20 hours' notice of a DR event by sending notices by 8 AM the day prior to an event.

The payment structure for the C&I DR program was changed to include three components. First, a reservation payment would be applied to the Dth reduction that National Grid calculated for the customer when it joined the program. The reservation payments are in $/Dth/Month and increase based on which option the customer selected and whether the customer opted for DLC. Second, National Grid offered a performance payment for the volume of natural gas actually curtailed by a customer during a DR event or test event. The per Dth performance payment is the same for all customers. Last, National Grid included a performance factor that will be based on a three-event rolling average of performance, i.e., the volume of natural gas curtailed by a customer during a DR event or a test event as compared to the volume reduction that National Grid had calculated for that customer.

National Grid targeted 10,000 Dth per DR event from the C&I Expanded DR program and assumed a reliability value of 60% given historical data regarding gas DR. Therefore, National Grid needed to enroll 16,667 Dth/day to ensure it would meet the 10,000 Dth target. The program reached a total of 17,970 Dth/day in Design Day enrollments for the Winter 2020/2021 season, consisting of 156 individual facilities. Over 90% of customer accounts that had participated in the Winter 2019/2020 season returned for the Winter 2020/2021 program.

Similar to Winter 2019/2020, temperatures did not reach the level necessary to call an actual DR event. Therefore, National Grid conducted two separate test events for participating customers, with no overlapping participation. The first test event was held on December 2, 2020 from 6:00 AM-9:00 AM, with 133 customer accounts participating. The second test event was held on December 22, 2020, during the same time window and had 26 participating accounts.[6] Both test events occurred under the same weather conditions. A total of 15 accounts did not have functional or accurate hourly usage data at the time of the events. Those customers were still asked to curtail usage during the test events, but their performance could not be calculated or validated. Of the accounts with functional active hourly metering, National Grid measured a total customer performance of 83% for the test events relative to the weather-adjusted baseline.

[6] Three accounts that participated in the December 22 event discovered that they did not possess working back-up heating equipment and subsequently dropped from the program.

National Grid calculated a weather-adjusted load drop of 2,568 Dth[7] over the course of the 3-hour test events, or an average of 856 Dth/hr.

BYOT Program. Under the BYOT program, residential customers were offered a $25 incentive to enroll their Wi-Fi connected smart thermostats in the program. Customers could sign up through their thermostat vendor or directly with National Grid. Customers are eligible to receive an additional $25 incentive if they participate in the program in subsequent years, provided they participated in at least 70% of the DR event hours.

BYOT events can be called each winter season between November 1 and March 31, when temperatures are forecasted to be far below seasonal averages. National Grid expects to call ten to fifteen BYOT events per season. During an event, National Grid will reduce temperature setpoints on enrolled devices by 4° over a 4-hour period, either from 6 AM to 10 AM or from 5 PM to 9 PM. Customers retain the ability to override the temperature setbacks with no penalty, although future incentives may be withheld from customers that do not meet a certain performance threshold. The BYOT program is intended to achieve peak hour reductions and allows customers to shift their load from peak consumption periods to an earlier or later part of the day. Although National Grid expected to enroll 2,500 devices for Winter 2020/2021, it enrolled 2,251 devices or 90% of its projection.

National Grid designed the Winter 2020/2021 BYOT program as a test case for estimating program potential and capability. To estimate statistically valid results, National Grid developed a "treatment and control" design for the Winter 2020-21 BYOT program. Customer devices were randomly assigned to 3 different treatment groups, of which 1-2 groups could be dispatched during an event (treatment), with the non-dispatched group(s) serving as the control groups. National Grid conducted four events for the Winter 2020-2021 season. The events demonstrate that, despite the increases in consumption for the pre-heating and snapback periods, the BYOT program can achieve reductions in net daily gas consumption in addition to the hourly reductions.

Behavioral Incentivized DR Program. National Grid continued the Behavioral DR Program for residential and small customers. Under the Behavioral DR Program, emails are sent to customers alerting them of pending cold weather and offering tips on ways to reduce gas consumption during peak hours. No incentives are provided to customers that receive the emails, and customers are not obligated to follow the suggestions offered in the emails.

National Grid conducted one large Behavioral DR event on January 29, 2021, and sent email messages to 489,969 residential and small commercial customers with tips on ways to temporarily reduce gas consumption in the early morning hours. The email message also included a call to action for customers. Customers committed to participating in the event by selecting a link in the e-mail. Those commitments were tallied with over 2,894 customers saying they would participate in the Behavioral DR event. If National Grid pursued automatic metering infrastructure, National Grid might more accurately determine the contribution of customers participating in DR programs to reduce peak day load.

[7]This figure is the sum of the load drops across all three hours from each of the two events.

In order to obtain accurate information on customer reductions during Behavioral DR events, National Grid provided 900 customers with devices capable of reading hourly gas consumption from traditional drive-by meters. Due to delays in implementation, these devices were largely inactive during the Behavioral DR event on January 29, 2021. National Grid is continuing to work with customers to complete the connections of these devices, which will be utilized to measure impacts of Behavioral DR events in Winter 2021/2022.

VII. Other Obligations

A. Investment in Clean Energy Projects (Settlement ¶ VII)

Under the Settlement ¶ VII, National Grid and its affiliates agreed to commit $20 million of shareholder funds toward clean energy projects and/or investments in New York-based startup energy businesses and technologies to reduce reliance on non-renewable energy sources. On April 15, 2021, the PSC issued an order adopting an amendment to the Settlement providing that "National Grid will repurpose the $20 million of shareholder funding . . . to establish a deferral for the benefit of customers that will be used as a credit to offset the costs of National Grid's Commission-approved energy efficiency and demand response programs." (Order Adopting Second Amendment to Settlement Agreement. Att. A ¶ 2 (Apr. 15, 2021), Case 19-G-0678.) In other words, the repurposed $20 million of National Grid shareholder dollars will be used for advancing EE and DR programs and minimizing the impacts on customer bills. The Monitor accordingly finds that the PSC's order adopting the amendment effectively satisfies this element of the Settlement.

B. Customer Assistance Program ($7 million)

Under Settlement ¶ VI.b, National Grid "agree[d] to fund" up to $7 million for a customer assistance plan to address hardships endured by customers affected by the moratorium, including hardships identified in complaints filed with the Office of the Attorney General of the State of New York. National Grid developed several programs under its CAP to assist customers in connection with different types of hardships, which National Grid initially intended to make available for one year following the Settlement date (i.e., until November 2020) but later extended to March 31, 2021. Specifically, National Grid established a Customer Inconvenience Credit (a $200 bill credit to customers affected by the moratorium), a Residential Customer Assistance Fund (to address more significant financial hardships caused by the moratorium), and a Small and Medium-Sized Business ("SMB") Assistance Fund (a similar assistance fund for SMB customers).

National Grid initially placed caps on claims of both residential and SMB customers of $2,500 and $50,000, respectively, but raised the residential cap to $20,000 because relatively few claims had been submitted. After the Monitor raised concerns that customers might not be aware that assistance was available, National Grid added information about the CAP to its website that disseminated the LT Report, and to the Summary of the LT Report, and revised its talking points for the public meetings to specifically inform attendees about the CAP during the program. Further, because Settlement ¶ IV.b. provided that if the CAP "funds are not needed in their entirety for the Assistance Plan, such monies will be used to increase funds available for the Efficiency Plan," and due to the relatively few claims early in the program, the Monitor recommended in the Second Quarterly Report (at 11) that National Grid evaluate potential alternative uses for any leftover funds consistent with the intent of the Settlement.

National Grid subsequently removed the limits on the value of the CAP claims it would pay out. However, National Grid continued to scrutinize higher-value claims more closely, including by working with an outside accounting firm to obtain and review documentation relating to more complex claims such as those claiming lost profits by commercial customers. Even after lifting the claim limits, National Grid might still have some portion of the $7 million left unspent. Thus, National Grid planned to allocate any leftover funds to the Efficiency Plan.

On October 2, 2020, the PSC approved an amendment to the Settlement which, among other things, authorized $500 thousand from the CAP to be allocated to continue the Monitor's engagement. In addition, as Winter 2020/2021 approached (along with the November 2020 end of the program), National Grid observed an uptick in claims. More high-dollar claims were filed and approved, and National Grid currently is on track to spend the bulk of the $6.5 million (after the PSC's October 2, 2020 approval of the amendment) under the CAP to address customer hardships. To date, National Grid has paid nearly 220 claims totaling approximately $5.4 million, and additional claims are pending approval. Coupled with the approximately $330 thousand National Grid paid out as Customer Inconvenience Credits, National Grid has spent approximately $5.7 million under the CAP.

Even after the final claims are paid out, it is still possible some portion of the $7 million allocated to the CAP will remain unspent. Insofar as any CAP funds are leftover, National Grid should allocate those funds to incremental EE and DR programs consistent with the spirit of the Settlement. Furthermore, the U.S. Chief Compliance Officer or his delegate in the compliance organization should conduct a compliance exam at the conclusion of Winter 2021/2022: (a) to ensure that the remaining eligible claims under the CAP were paid out; (b) to verify that any leftover funds were allocated to incremental EE and DR programs; and (c) to require, if necessary, remedial steps in order to ensure that the funds are spent on EE and DR programs.

C. Reconnecting Customers

The Monitor previously found that National Grid complied with its obligation under the Settlement to make "best efforts" within 45 days of the Settlement to contact and provide service to applicants who were denied service during the moratorium and to connect new customers and large commercial or industrial customers "as soon as practicable." (Second Quarterly Report at 7-9; Fifth Quarterly Report at 10-11.)

Within 30 days of the Settlement date, National Grid undertook the following efforts to contact denied applicants:

- Outbound calling.
- An e-mail to applicants with an e-mail address on file.
- If no e-mail address was on file or National Grid determined that an e-mail was not opened or bounced back, National Grid sent a certified letter to the physical address on file.

- If National Grid received no response from the call, e-mail or letter, National Grid sent a second certified letter.
- Extended customer call center hours and dedicated call lines for denied applicants. The phone number for the dedicated line was provided on the e-mails and letters to customers.
- Emails to plumbers with whom National Grid partnered in order to assist customers with natural gas conversions. The e-mails notified the plumbers that their mutual customers could be eligible for connections.
- Web banners on the National Grid website.

National Grid tried additional methods of communication to reach customers who had not responded to the above attempted contacts, such as going door-to-door and leaving door hangers on the premises. National Grid continued its efforts to contact and connect customers beyond the 45-day period under the Settlement. As of August 30, 2021, approximately 4,100 of the approximately 5,500 customers who were denied service ultimately had been connected.

D. Data Systems Regarding Applications for Service

Recommendation 3 from the Monitor's Second Quarterly Report recommended that National Grid ensure that, in the event of a future moratorium, "its systems are capable of tracking applications, contacts and related data without significant manual intervention and reconciliation." In its June 1, 2020 letter to the PSC, National Grid accepted the recommendation and acknowledged that "[t]racking applications and customers inquiries received through various channels during the 2019 moratorium presented a challenge that required significant resources to manage day-to-day."

Multiple National Grid personnel involved in the customer-tracking processes developed high-level ideas for enhancing National Grid's systems in order to improve the tracking of applicants in the case of a future moratorium. The Monitor observed the workshop and found it to be a productive session that elicited thoughtful feedback by participants about past challenges and possible solutions going forward. For example, participants discussed their desire for better integration between the systems that track billing, customer contacts, and work management. Participants also proposed various additional process and governance improvements.

National Grid has long had multiple long-term initiatives underway to overhaul data systems and processes within its organization. National Grid has sought to incorporate requirements for its customer-management systems to address the deficiencies that National Grid experienced in connection with the moratorium as it continues with these long-term projects. Because of the longer time horizon associated with these projects, the Monitor recommends that the U.S. Chief Compliance Officer or his delegate in the compliance organization review semi-annually progress on the efforts to update customer systems, with a specific focus on improvements made to address the particular deficiencies experienced during the moratorium. Within 30 days of substantially completing the relevant systems enhancements but in no event later than December 31, 2022, National Grid should certify to the PSC (via the Secretary to the Commission) that it has complied with this recommendation.

Attachment K

National Grid US

Natural Gas Long-Term Capacity Status Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")

December 2021

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

In May 2020, National Grid (the "Company") published the Natural Gas Long-Term Capacity Supplemental Report (the "Supplemental Report"), in which the Company presented the Distributed Infrastructure Solution to close the projected Design Day Demand-Supply Gap.[1] The Distributed Infrastructure Solution is a combination of incremental energy efficiency ("EE") and demand response ("DR") programs and enhancement projects that expand the capacity of existing gas infrastructure. This solution is a portfolio approach that best balances cost, reliability, and feasibility to address the projected Demand-Supply Gap. In June and August 2021, the Company published the Second and Third Supplemental Reports, respectively, that presented the Company's latest gas demand forecast, confirmed the need for the Distributed Infrastructure Solution, described the status of and risks to successful implementation of the Distributed Infrastructure Solution, and responded to stakeholder feedback. In September 2021, PA Consulting published an independent assessment conducted for the New York State Department of Public Service. PA Consulting concluded that: the Distributed Infrastructure Solution is a reasonable solution to address the projected Demand-Supply Gap; the infrastructure enhancements are necessary; and our demand side management ("DSM") programs must reach scale and maturity as quickly as possible.

Specifically, for the Distributed Infrastructure Solution, National Grid is combining: (1) incremental DSM programs, comprising an aggressive set of incremental EE over and above the targets set by the New Efficiency: New York Order, new gas DR programs, and Non-Pipe Alternatives; (2) the LNG Vaporization Option ("LNG Vaporization Project"), which adds two additional LNG vaporizers at National Grid's Greenpoint Facility; (3) the Iroquois Enhancement by Compression option ("ExC Project"), which involves the construction of additional compression facilities to increase capacity on the Iroquois Gas Transmission System; and (4) incremental portable CNG capacity, further expanding the largest CNG operation of its kind in the United States, which takes advantage of the maximum potential for National Grid to expand portable CNG in light of siting, operational and market constraints. Collectively, all of these components now make up the Distributed Infrastructure Solution as set forth in Table 1-1.

Table 1-1: Distributed Infrastructure Solution Components

Component	Gas Capacity / Demand Reduction *(MDth/day)*
Demand Side Management Programs	
Incremental EE	**Grows to 64**
Incremental DR	**Grows to 37**
Heat Electrification and NPA Market Solicitation	**Grows to 284**
Enhanced Infrastructure Projects	
LNG Vaporization Project	**59**
ExC Project	**63**
Incremental CNG Capacity	**18**

The Distributed Infrastructure Solution remains the best available solution to address the projected supply-demand gap and is consistent with NY's Net Zero goals; however, there continue to be significant risks to its successful implementation. Currently the greatest risk to implementation of the Distributed Infrastructure Solution are the permitting uncertainty and regulatory risks to the

[1] The Company's prior long-term capacity reports explain the Demand-Supply Gap and other relevant context and can be found at https://ngridsolutions.com/ as well as being filed in Case 19-G-0678 before the New York Public Service Commission.

infrastructure enhancements. Following that, with regards to the DSM programs, the greatest current challenge is scaling up the ability of the market to deploy the required amount of EE, and the Company anticipates future challenges in achieving shifts in customer behavior and adoption due to the unprecedented levels of these programs, and the unpredictable nature of customer participation. Our LNG vaporization project has already experienced multiple permitting delays and has thus been delayed by one year. Further delays may yield a demand-supply gap in 2023/24. The ExC Project requires its FERC certificate and state permits. There is no date certain by which the FERC must act, and the Company does not expect NY or CT to act until the FERC issues the certificate, further delaying implementation of another infrastructure enhancement that is critical to the success of the Distributed Infrastructure Solution. Our incremental CNG capacity project is proceeding on schedule, but faces siting and construction risks that could also delay anticipated in service dates. Our DSM programs require unprecedented scaling and rely heavily on voluntary customer participation. Global supply chain issues and our recent experience has highlighted resource constraints related to weatherization product availability and contractor capacity.

Our demand forecast contemplates that public policy and electrification efforts in New York State may eventually lead to some level of demand destruction, but such proposals, including the New York City Council's proposed ban on the use of natural gas in new buildings, do not eliminate the near-term need for the infrastructure enhancements included in the Distributed Infrastructure Solution.

Following is an update on each of the components of the Distributed Infrastructure Solution to close the gap between demand and supply, including our progress to date on its implementation and the risks to its successful completion.

2. Distributed Infrastructure Solution Component Status, Updates and Risks

In this section, we detail the following:

- An update, if any, on whether the project or program has changed from the Original Report and/or Supplemental Reports;
- The status of each component; and
- The key risks to the implementation of the component.

2.1. LNG Vaporization Project

LNG Vaporization Project Status and Update

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

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

Permits and approvals have been received from NYC DOB, DEP and FDNY. Other FDNY and DEC State Air Facility permits are still pending.

Assuming approval of all necessary permits in February 2022, the project could be completed for the 2023/2024 heating season. If the permits are delayed further, completion of this project would extend out to the 2024/2025 heating season.

LNG Vaporization Project - Risks to Implementation

Currently, the primary risk to implementation is not obtaining the necessary permitting for the project, or not obtaining them in a timely manner. Failure to receive required permitting by the Spring of 2022 may create a Demand-Supply Gap in 2023/24 without successful implementation of a contingency option.

Table 2-1: Key Risks to LNG Vaporization Project

Risk/Signpost	Likelihood	Impact	Description
Failure to obtain DEC permit	**HIGH***	**HIGH**	Without DEC permit, National Grid cannot construct the LNG Vaporization Project

*Changed from MEDIUM in prior report

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

ExC Project Status and Updates

On May 27, 2021, FERC announced that it will prepare a supplemental Environmental Impact Statement (EIS) for the ExC Project; the final EIS was issued Nov 12, 2021, with FERC concluding that it is unable to determine the significance of the project's climate change impacts and that with that exception, found that ExC would not result in significant environmental impacts. A 7(c) certificate is not expected to be issued by the FERC prior to Q2 2022.The delayed receipt of these federal and state approvals could delay project completion into the 2024/2025 timeframe.

ExC Project – Risks to Implementation

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

Table 2-2: Risks to ExC Project

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

*Changed from MEDIUM in prior report

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

CNG Trucking/Trailers Effort – Status and Updates

The Company is pursuing local and state-level approvals for implementation. These requirements will likely include coordination and/or approvals from first responders, stormwater permits for construction activities, or other local municipal approvals.

The Company is continuing to assess locations that would support this distributed supply resource. Generally, the selected site will require access to a location on the gas transmission system that could disperse the CNG widely throughout the DNY territory. The Company has also commenced procurement of long lead materials required for implementation of this solution. The Company is targeting to have the site constructed and ready for service for the 2022/23 winter, but continues to assess the required in-service date of the site to meet forecasted Design Day demand.

CNG Trucking/Trailers Effort – Risks to Implementation

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

Other risks are those that are consistent with complex projects of similar scope including: construction, procurement, availability of labor, market capacity, and permitting. These risks are mitigated through advanced stakeholder engagement, evaluation of properties owned by National Grid, advanced procurement of long lead materials, and codified complex capital delivery processes.

Table 2-3: Risks to CNG Project

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

2.4. Demand-Side Solutions

The Distributed Infrastructure Solution relies on four major non-gas infrastructure options: energy efficiency ("EE"), demand response ("DR"), heat electrification, and Non-Pipe Alternatives ("NPAs"). Since the Original Report and Supplemental Reports, National Grid's planning for these options has come a long way in terms of innovative program design, and the Company proposed an unprecedented level of new DSM programs this year that are a fundamental part of the Distributed Infrastructure Solution.

The levels of DSM required to close the Demand-Supply Gap in the long term are unprecedented; in our peer benchmarking we have found no other utility who has attempted to roll out DSM programs at this scale so rapidly. Our Second Supplemental Report provided a conceptual example of how DSM strategies might be deployed in the longer term to address the projected Supply-Demand Gap. However, the programs, technologies, and business models that would be required to deliver such aggressive savings do not yet exist. We will continue to invest in the evolution of our DSM programs with the goal of maximizing their potential as non-infrastructure solutions.

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

2.4.1. Incremental Energy Efficiency

Incremental Energy Efficiency Program – Status and Updates

National Grid submitted the first Annual DSM filing on October 4, 2021. A decision from the NY PSC could come as early as March 2022.

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

Incremental Energy Efficiency Program - Risks

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

A description of the likelihood and impact of the key risks to both the NE:NY and Incremental EE programs set forth above is outlined in Table 2-4.

Table 2-4: Risks to DSM Program Success

Risks	Likelihood	Impact	Description
Market Resourcing	**HIGH***	**HIGH***	There are not currently enough market resources (contractors, vendors) to execute programs at required participation levels. National Grid is working hard to increase the contractor pool, support workforce development, and consider program design changes that will enable customers to bring their own contractors to the program.
Market Potential	**MEDIUM**	**HIGH**	Overestimation of market potential in that the DIS may be relying on more DSM than the market can deliver on time.
Costs & Adoption	**MEDIUM**	**HIGH**	Weatherization may continue to be uneconomical for customers, particularly LMI customers. May require increased incentives to spur adoption.
Persistent Increase in Cost of Building Materials	**MEDIUM**	**HIGH***	Costs of building materials are rising faster than the cost of inflation making projects less cost effective
Delays of Approval for Tariff Change	**MEDIUM**	**HIGH**	Increasing the EE mandate requires a tariff change that is subject to stakeholder and regulatory processes
Market Saturation	**MEDIUM**	**HIGH**	The market for EE measures may saturate earlier than forecasted, delivering less total demand day savings than needed.
Regulatory restrictions on incentivizing high efficiency gas equipment	**MEDIUM**	**HIGH***	If utilities are restricted from incentivizing high efficiency gas equipment in the future, including gas heat pumps, there is a risk that we will not be able to achieve long term EE targets
Supply Chain Issues**	**HIGH**	**HIGH**	Supply chain disruptions have delayed the implementation of some Wx projects to 2022

*Changed from MEDIUM in prior report
**New risk identified in this status report

2.4.2. *Demand Response*

Incremental DR Program Update

The Company has taken steps to deploy a portfolio of three firm demand response programs:

1. **CI&MF DR** focused on producing daily reductions in gas consumption;
2. **CI&MF DR** focused on producing peak hour reductions without requiring a reduction in daily gas consumption; and
3. **Residential/SMB BYOT DR**, which produces a more pronounced hourly impact as opposed to a daily reduction.

Program 1 is the largest program deployed to date. For the 2020/21 season, 156 facilities participated to reduce their usage over the gas day and to offer a potential reduction of 17.8 MDth on a Design Day (assuming 100% participation). Program enrollments for the 2021/22 season closed in October 2021, with 201 facilities enrolled as of year-end, and potential reduction of 21.1 MDth on a Design Day. The vast majority of participants in this program switch to an alternative fuel to participate in DR events, typically fuel oil, as their facilities have dual-fuel capabilities on-site; either because they previously were on a non-firm rate that required it, they have an operational mandate to do so (e.g., a resiliency requirement), or because they wished to retain fuel flexibility. The customers participating in this program are likely to be the same customers that would consider non-firm rates.[2] Therefore, it is possible that we could have customers transition from a firm DR program to a non-firm rate, or that we could have a non-firm customer submit a request to transition to a firm rate and then participate in a DR program. For this reason, we must carefully consider the incentive structures of the different programs so that we are not inadvertently motivating customer action that would make it more difficult to meet our system needs.

Program 2 is in its infancy, but closely mirrors the DR pilot that was instituted by the Company beginning in 2017. In Program 2, customers reduce gas usage during peak hours but will not be required to reduce total gas consumption over the entire peak day which offers an attractive, flexible option for customers who can reduce usage during key parts of the day (e.g. waiting to heat up their facilities, completing a production run at a different time), but are unwilling or unable to reduce their usage over a full day. Program 2 may be a valuable tool to manage our intraday demand profile. This program was first launched for the Winter 2021/2022 season. Program enrollments for the 2021/22 season closed in October 2021, with 28 facilities enrolled as of year-end, and potential reduction of 184 Dths for a Design Hour.

Program 3 is a BYOT program. Customers enroll their smart thermostats and provide National Grid with the authorization to adjust their setpoints during event hours. Enrollment into the BYOT program is on a rolling basis, and customers remain in the program unless they request to unenroll or are removed by National Grid for failure to adhere to program rules. As of this report, there are approximately 5,400 devices enrolled in the program, a 100% increase from the corresponding period last year. Eligible[3] customers in our Long Island territory were able to enroll for the first time in 2021. Data collected from this past winter show that customers reduced their usage during event hours, as well as a net daily reduction in usage. The Company plans to utilize learnings from the past winter and upcoming winters, as well as other customer research to increase program participation and refine or introduce new program features in future years.

When the Original Report was written, there was not a clear pathway to fund DR programs. National Grid had submitted a proposal in the then pending rate case that would have provided modest levels of funding ($2-$3M per year), but current plans and needs indicate that we will need significantly more ($8M in 21/22, increasing to $25M in 25/26). The Rate Case Order includes the ability to

[2] Non-firm rates provide the greatest amount of reduction on a Design Day, as customers are assumed to be curtailed throughout the full 24 hours. This is in contrast to Firm DR programs, where customer reductions are currently 4-8 hours of a Design Day. Therefore, a customer who is on a non-firm rate may be offering up to 3x more demand reduction than a DR customer. The incentive structure for firm DR has been established with the cost reduction from being on a non-firm rate as an upper bound.
[3] Due to a technical constraint a small subset of customers who are also enrolled in PSEG-LI electric DR program, are pending enrollment at this time. A resolution is in process.

recover costs for firm DR programs via two different surcharge mechanisms and makes allowances for the increased costs for the programs. This removes the funding risk that was described in the original reports for the DR component of the solution. Additionally, we have hired two full time employees (FTEs) who are focused on managing the Downstate NY DR programs, reducing some of the execution risk. These FTEs are working closely with our metering, regulatory, and gas operations groups to manage the DR portfolio growth, and to manage the non-firm customer class more actively.

Secondly, since the Original Report, the Company has received approval for proposed firm DR programs[4] ("Gas DR Order"). As directed by the Gas DR Order, the Company filed for Tariff Leaves Amendments to add the firm DR programs to the tariffs. These tariffs have currently been adopted on a temporary basis by the Public Services Commission, and are effective beginning November 1, 2021.

As of this report, the DR programs are in the middle of the 2021/22 winter capability period.

Incremental DR Program Risks

The main focus for DR is continuing to increase program participation and delivered savings, determining the right mix of programs (both firm and non-firm), and continuing to improve our understanding of the reliability of DR programs. Since inception, the programs have seen year-over-year growth, and we have seen a strong interest from customers, which is encouraging. Conversely, we have seen some low levels of performance during test events, which reinforces the need to understand the aggregate reliability of the DR portfolio as we increase our dependence on this resource. Similarly, it would be expected that program growth rates would start leveling after a certain level of market saturation.

The biggest implementation risks for demand response involves customer acquisition, retention, and performance. We need to increase the size of the DR portfolio, sell it every year (since we currently don't have multi-year enrollment structures), and ensure that customers perform, both through ensuring they are prepared to perform, and creating incentives/penalties that align our goals with the goals of customers.

For the 2021/22 winter season, National Grid had planned to enroll as much as 27 MDth potential reduction on a Design Day to the Daily DR program. Enrollments into the Daily DR program closed at 21.1 MDth potential reduction on a Design Day. Preliminary analysis from the 21/22 enrollments highlight the need to further investigate market potential, refine program design and features, reconsider the incentive structure and program targets, and further explore third party participation and regulatory policy, as we work towards scaling the DR program to the quantities proposed in the Supplemental Report. We will continue to utilize the learnings from past season enrollment experience, as well as program performance to refine the potential of firm DR programs.

In addition to customer-centric approaches such as targeting and marketing, education and outreach material, the Company has also addressed customer performance by adopting a direct load control (DLC) arrangement for firm DR customers; where we install a device at customer sites that curtails their usage and, if applicable, switches them to a backup fuel similar to arrangement for some non-firm customers. The non-firm customer class has a reliability of ~95% during curtailments so adopting a similar control structure may lead to a similar level of performance reliability. The penalties for non-performance during non-firm curtailments are significant such that it provides a motivation for customers to perform, even if they would otherwise override the DLC setup. We have

[4] Case 19-G-0086 and 19-G-0087, *Order Authorizing Tariff Amendments To Effectuate Gas Demand Response Programs For Firm Gas Customers*, October 07, 2021

established both DLC and non-DLC tiers for our firm DR programs so that we can begin to test whether there is a quantifiable difference between DLC and non-DLC tiers. However, as of now the penalty of non-performance is minimal for firm DR customers[5]. By measuring the reliability of the participants in different tiers, we can begin to improve our forecasts for firm DR performance and market potential.

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

A summary description of the likelihood and impact of certain risks to DR performance is outlined in Table 2-5.

Table 2-5: DR Risks

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

*Changed from MEDIUM in prior report

2.4.3. Incremental Heat Electrification

Incremental Heat Electrification Status and Updates

National Grid requested resources and technical support services through its First Annual DSM Filing to support this ongoing work.

Collaboration will also be an integral part of an incremental heat electrification program’s success, and the Company has started working with the EDCs to discuss what that might look like. The coordinated effort focuses on laying out the regulatory framework to prepare for much greater levels of heat electrification in the future with a joint emphasis on determining the most economical way to meet the demand gap through heat electrification. A potential pilot in collaboration with the EDCs and other industry partners is in discussion. The goals of the studies and pilot to be conducted may include:

- Influencing more full load conversions within the existing EDC programs
- Influencing higher levels of heat electrification adoption in gas constrained areas
- Testing of incentive levels and strategies to accelerate market penetration over Baseline Electrification
- Determining how to drive customers to electrify heat prior to failure of their existing gas systems (early replacement)
- Enhanced marketing, outreach, market potential, customer education on top of existing EDC and statewide initiatives
- Identifying framework required for consultation with EDCs on impacts to their electric networks and suggested approaches to mitigate those impacts (e.g. supporting an electrical “make ready” program to address increased electrical loads)

[5] C&I customers are not eligible to receive Performance Payments in a month where the enrolled account’s Performance Factor is less than 25%. In case of BYOT program, the Companies reserve the right to cancel a customer’s participation in the program if they participate in fewer than 15% of event hours during a season

- Determining barriers to accelerated heat electrification such as workforce development, in collaboration with existing EDC and statewide initiatives
- Pursuing studies to reveal new solutions and strategies
- Determining incentives required for accelerated electrification of heat required for low-and moderate income customers and environmental justice zones

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

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

In the event there are delays to or rejections of the LNG Vaporization Project or ExC Project, some of the aggressive heat electrification may need to be accelerated, which would have significant execution risk given the amount of development work required and the scale at which would need to be implemented.

Incremental Heat Electrification - Risks

The levels of electrification of heat required to close the Demand-Supply Gap are unprecedented; in our peer benchmarking we have found no other utility who has attempted to roll out electrification of heat programs at this scale so rapidly. The Second Supplemental Report provides a conceptual example of how electrification of heat might be deployed in the longer term to address the projected Supply-Demand Gap. However, the regulatory authorities, budgets, programs, technologies, and business models that would be required to deliver such aggressive savings do not currently exist.

A description of the likelihood and impact of certain risks to incremental heat electrification set forth above is outlined in Table 2-6.

Table 2-6: Heat Electrification Risks

Risk/Signpost	Likelihood	Impact	Description
Market Resourcing	**HIGH***	**HIGH**	There may not be enough market resources (contractors, vendors) to execute required number of projects.
Market Potential	**HIGH***	**HIGH**	Overestimation of market potential and ability to reach accelerated levels of adoption. .
Customer Value Proposition & Adoption	**HIGH**	**HIGH**	Heat Electrification may continue to be uneconomical for customers, particularly LMI customers and will likely require higher incentives to spur adoption. Customer's may not choose to electrify their heat unless mandated by state/government due to lack of familiarity with technology, low cost of gas, high cost of electric and concern around perceived reliability with cold-climate heat pumps
Costs	**HIGH**	**HIGH**	Incremental heat electrification costs are significantly higher than all other EE programs and would result in ~10% bill increase LMI programs that align with this acceleration of heat electrification will cost even more than a market rate heat electrification program
Delays in executing MOU, electric system constraints, legal and regulatory processes	**HIGH***	**HIGH**	Incremental heat electrification would require an MOU with EDCs and permission from the PSC. Gas utilities are not currently permitted to incentivize heat pumps in NY
Supply Chain**	**HIGH**	**HIGH**	Supply chain disruptions may limit the speed to scale incremental electrification of heat
Consistency with CLCPA**	**HIGH**	**HIGH**	There is a concern that it may be inconsistent with the CLCPA to spend rate payer money on an electrification of heat program solely to enable continued gas connections

*Changed from MEDIUM in prior report
**New risk identified in this status report

2.4.4. *Non-pipeline alternatives (NPAs)*

NPAs – Status and Update

National Grid has developed an NPA framework this year. In parallel, we are engaging with the market (i.e. third-party solutions providers) to better understand what solutions they may be able to provide in response to future NPA RFPs. We released our first NPA RFP on December 13, 2021.

During the process of developing the RFP, National Grid worked with REV Connect/Guidehouse to conduct a Mini Sprint outreach to potential responders for this RFP. In addition, we discussed the RFP with Con Edison, to gain insights from the previous experience with NPAs.

NPAs - Risks to Implementation

There is still uncertainty for the levels of demand reductions available through NPAs. Though third-parties will be able to offer proposed solutions, these solutions may represent similar types of DSM solutions as those proposed by National Grid. As the market becomes more familiar with NPA solicitations, however, it is likely that our ability to deploy NPAs that are complementary to any planned programs will improve.

3. Contingency Plan Status

In the event certain circumstances prevent or delay the Distributed Infrastructure Solution from being fully implemented, National Grid has evaluated alternative approaches to solve the projected Demand-Supply Gap, including both alternative infrastructure projects and additional non-gas infrastructure options.

In a scenario where one or more of the Distributed Infrastructure Solution enhancements to existing infrastructure are denied, the lead time and feasibility for any alternative approach would entail significant risk that projected customer demand could not be met. The alternative approaches that best balance cost and feasibility would include incremental gas demand response and heat electrification along with substitute infrastructure projects—specifically, the Clove Lakes Transmission Loop project and/or an LNG Barge project—but all alternative approaches have much higher costs and greater risks to successful and timely implementation than the Distributed Infrastructure Solution.

3.1. LNG Barges

This project is currently conceptual and will be further evaluated pending the status of the ExC project.

3.2. Clove Lakes Loop

This project is currently conceptual, but more detailed engineering work will target a Complex Project Gate A approval in January 2022 in the Company's internal stage-gate process, after which National Grid will move forward with more detailed studies as appropriate.

3.3. Accelerated Electrification of Heat

National Grid is in discussions with ConEd regarding a collaborative accelerated electrification of heat proposal. The first hurdle toward program development is ascertaining the levels of accelerated full electrification of heat that could be procured in the short term in a cost-effective manner. Small teams are working on reviewing market evaluation, program design, and the development of an MOU term sheet.

A significant barrier to accelerating electrification of heat, beyond technical feasibility, is obtaining the regulatory authority for a gas utility to incentivize electrification and obtaining a cost recovery mechanism. We estimate that accelerated electrification may cost National Grid and the EDCs approximately $1.2 Billion through 2025, which is several multiples of the entire NE:NY Statewide Clean Heat program through the same period. Program incentives may result in a ~10% increase in gas bills.

There is also a question whether such a large investment in electrification of heat for the sole purpose of creating room on the system for new gas customers, even if feasible, would be consistent with the New York CLCPA.

3.4. Additional Demand Response Options

National Grid is exploring new program design options that will increase the demand reduction capabilities of customers on the design day. National Grid is also exploring participation in demand response of customers with smaller demand reduction capabilities.

To date, National Grid has only called test events and has not called any events under design conditions, due to warmer winter conditions in the past year. Learnings from implementing the program, customer enrollment periods as well as events under design conditions, will inform the market potential and reliability of demand response programs.

Additionally, National Grid is exploring options to retain existing non-firm customers on non-firm rate over and above rate changes that were implemented earlier this year, to make non-firm rates favorable to customers.

4. Potential Risk for Moratorium

In the event that any component of the Distributed Infrastructure Solution faces setbacks to their successful and timely implementation, there is a substantial risk that National Grid will not be able to meet projected customer demand in the coming years as early as Winter 2023/24 given the implementation risks associated with any alternative approach. Faced with an inability to meet projected customer Design Day demand, a targeted pause in new customer connections could be required before the Winter of 2023/24, and if significant supply challenges remain, as a last resort, reliance on customer curtailment under peak demand conditions. The most immediate risk facing the Distributed Infrastructure Solution is the need for approval of the DEC state air permit for the LNG Vaporization Project, where the implications for the risk of restrictions on new customer connections may become evident as early as February 2022.

Attachment L

EVERSOURCE ENERGY

March 30, 2022

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Re: Iroquois-Brookfield BACT Amendment

Response to Questions raised by DEEP's Bureau of Air Management, Engineering & Enforcement Division's correspondence to the Iroquois Pipeline Operating Company concerning the Iroquois-Brookfield BACT Amendment

Dear Mr. Barnes:

The Connecticut Light and Power Company doing business as Eversource Energy ("Eversource") submits this response to the inquiry submitted by Iroquois Pipeline Operating Company ("Iroquois"). That inquiry asked Eversource to study and prepare responses to five (5) questions Iroquois received from the Department of Energy and Environmental Protection's Bureau of Air Management, Engineering & Enforcement Division (hereinafter, "DEEP"). Eversource is pleased to submit this response to the five questions.

1. **Question 1**

Question: Provided "*A full description of the current electricity load and supply to the Brookfield station, including maximum electrical demand (kW) at the site, the average of annual electrical consumption (kW-hrs.) for the five year period ending 12/31/2020, and any supporting documentation available from the local electricity distribution company (EDC) that provides electricity transmission and distribution services to the Brookfield station*."

Response: The current Iroquois electric service in Brookfield peaked within the last five years at 247.7 kilowatts ("kW") in March of 2016. The average annual kW hours ("kW-hrs.") utilized over a five year period, ending on December 31, 2020, was 56,013 kW-hrs. The Iroquois site is currently served pursuant to a 277/480 volt secondary metered electric service.

2. **Question 2**

Question: Provide "*A full description of the increase in electricity consumption (kW-hrs.) and demand (kW) necessary at the site to install and operate EMD compressors with equivalent performance to the proposed Solar turbines*."

Response: Although the Iroquois' electric demand and usage will fluctuate throughout any given year, the peak estimated load that Eversource will size the service to is 22 megawatts ("MW"). The annual kW-hr. usage, based on the same fluctuating pattern of past usage in 2020 at the Brookfield site, totals 104,607,036 kW-hrs.

3. **Question 3**

Question: Provide "*A full description, including supporting documentation available from the local EDC [electric distribution company] that services the site, of any upgrades/replacements to on-site and off-site transmission and distribution equipment necessary to install and operate EMD compressors with equivalent performance to the proposed Solar Turbines*."

Response: In order to satisfy Iroquois' request for a 22MW electric service at the site, Eversource would need to construct and install the following upgraded and/or new infrastructure from the service site and beyond:

- Install two (2) primary metered services versus the one (1) secondary service currently at the site.
- Installed a new duct bank structure along with an overhead circuit coming from the closest substation that will provide sufficient capacity and redundancy for the new service.
- Install additional high voltage infrastructure at the substation requiring the acquisition of additional adjacent land.
  - A transmission study would be performed to determine whether a new high voltage transmission line would be required to serve the new electric load at the substation. The study would evaluate and determine if the proposed new service would overload the current capacity of the available transmission infrastructure in the affected areas. If a new transmission line is required, additional engineering and time would be required for any potential siting and regulatory approvals before construction could commence.
- Based upon Eversource's analysis of the upgrades and replacements to on-site and off-site transmission and distribution equipment necessary to install and operate EMD compressors with equivalent performance to the proposed Solar Turbines, Eversource developed the following ***preliminary*** estimate in the time allotted for this analysis:
  - Estimated upgrades for electric distribution infrastructure: $25 million.
  - Estimated upgrades for electric transmission infrastructure: $20-25 million.
  - These preliminary estimates do not reflect contingencies that could substantially increase the current estimate of the cost of this project, which include but are not limited to: (a) delays caused by weather and other force majeure events; (b) construction delays and increases in the cost of materials, supplies and labor resulting from supply chain constraints, economic conditions and/or other factors;

(c) delays, cost increases and potential refusals from affected landowner(s) in connection with Eversource's attempts to acquire additional adjacent land; and (d) based on past experience, additional infrastructure upgrades and costs are typically identified if Eversource was directed to proceed to the next stage of this process by performing a more detailed engineering and cost analysis of the proposed project.

4. **Question 4**

Question: "*Iroquois's BACT Amendment estimates that the direct capital cost of electrical upgrades needed to install and operate EMD compressors would be $10 million dollars. Please provide all supporting documentation for this cost estimate, including any supporting documentation from the EDC that services the site*."

Response: Please see Eversource's response to Question 3 above, which provides its preliminary estimate of the cost to effectuate the necessary upgrades to electric distribution and transmission infrastructure.

5. **Question 5**

Question: "*Iroquois's BACT amendment estimates that that the annual costs of electricity to operate EMD compressors equivalent to the proposed Solar Turbines would be ~$10.4 million per year. Please provide all supporting documentation for this cost estimate, including any supporting documentation from the EDC that services the site*."

Response: Based upon the fluctuating pattern of demand and usage at the Brookfield location, Eversource provides the following response: (a) the annual distribution billing would total approximately $15.6 million to 16.7 million annually for the "delivery services" portion of the utility bill; *plus* (b) the additional electric supplier charges for the "energy" portion of the utility bill of approximately $9.2 million annually calculated at the current "supplier of last resort" rate of 0.08849 cents per kWh.

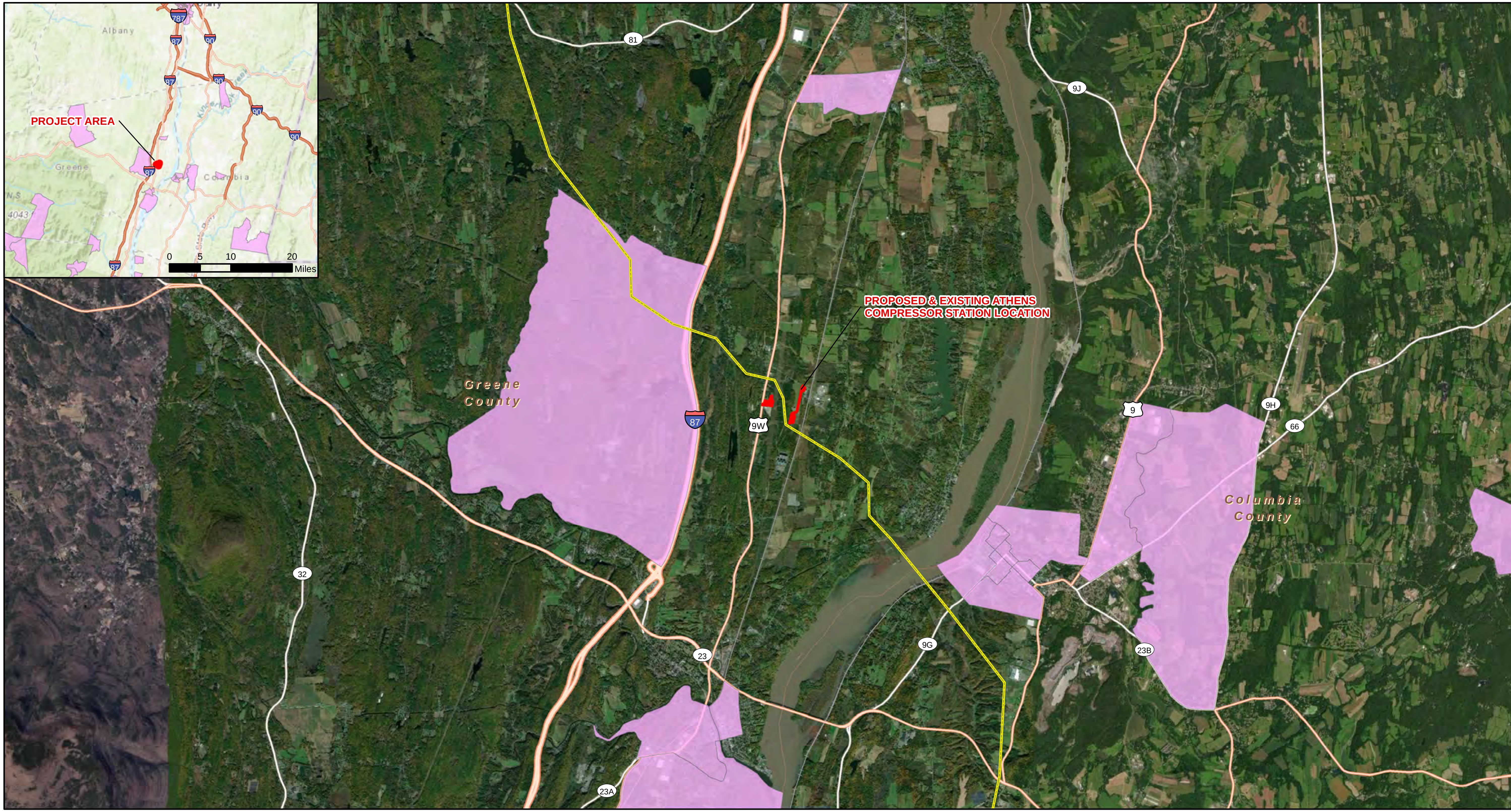
I hope the above-provided information is responsive to DEEP's questions, and is helpful to Iroquois. If you have any questions, or require any additional information, please do not hesitate to contact me. Eversource appreciates this opportunity to review and respond to DEEP's questions.

Sincerely,

Matthew J. Hickey

Matthew J. Hickey
Senior Account Executive
Eversource Energy
203-270-5816 (Landline)
E-mail: matthew.hickey@eversource.com

Attachment M



POTENTIAL ENVIRONMENTAL JUSTICE AREA
PROJECT LIMIT OF DISTURBANCE
IROQUOIS PIPELINE MAINLINE
MAJOR HIGHWAY
HIGHWAY
MAJOR ROAD

IROQUOIS GAS TRANSMISSION SYSTEM, INC.

ENHANCEMENT BY COMPRESSION PROJECT

ATHENS COMPRESSOR STATION
POTENTIAL ENVIRONMENTAL JUSTICE AREAS

GREENE COUNTY, NEW YORK

0 1 2 4 Miles

N E S W

ABSOLUTE SCALE: 1:84,000

REFERENCE SCALE: 1 inch = 7,000 feet

Iroquois

MOTT MACDONALD
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DRAWN BY:	JLM
CHECKED BY:	DRG
APPROVED BY:	DRG
REV. DATE:	11/16/2021
REVISION:	C
DESC:	IFP
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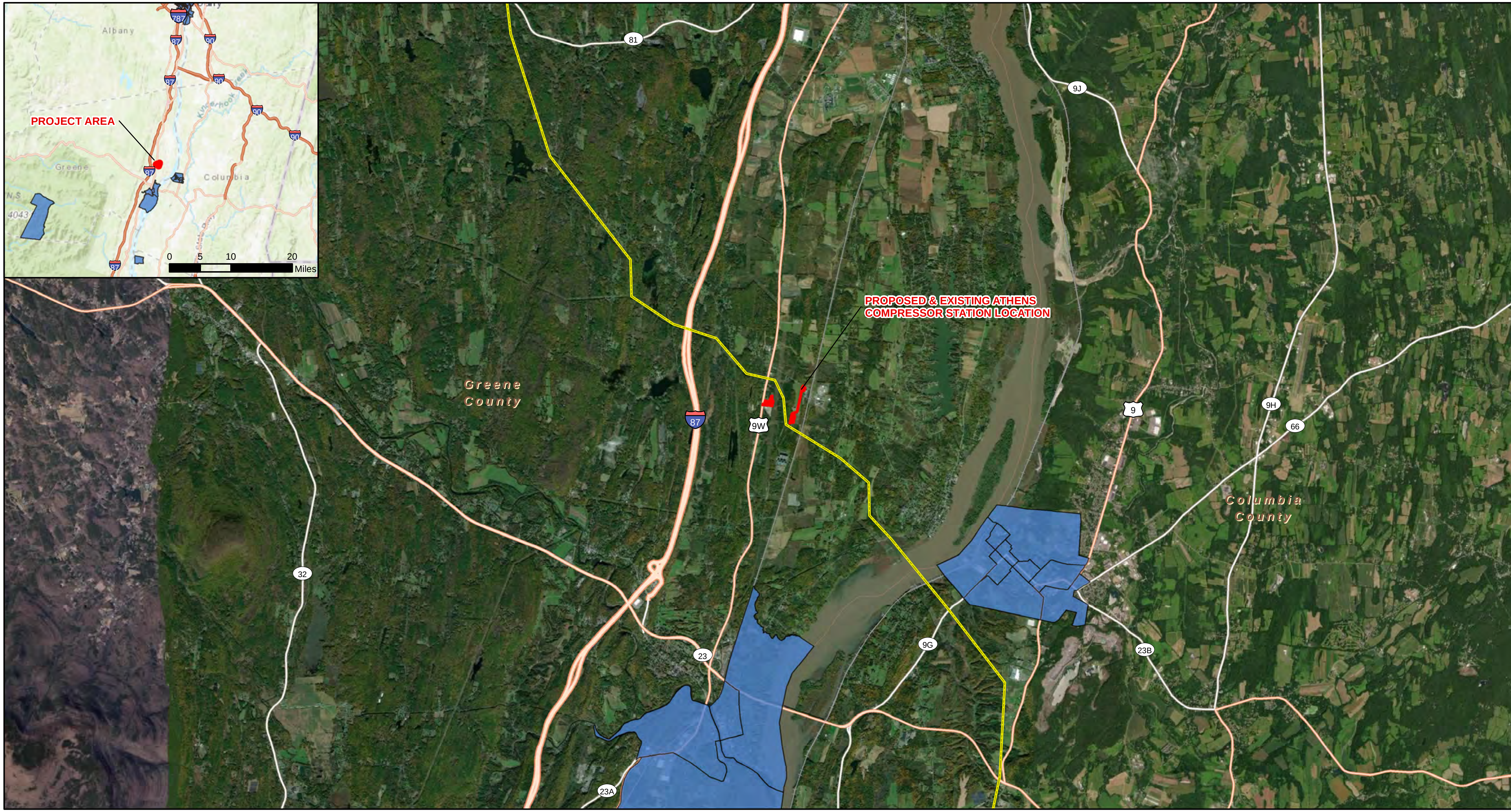

- INTERIM DISADVANTAGED COMMUNITIES
- PROJECT LIMIT OF DISTURBANCE
- IROQUOIS PIPELINE MAINLINE
- MAJOR HIGHWAY
- HIGHWAY
- MAJOR ROAD

IROQUOIS GAS TRANSMISSION SYSTEM, INC.

ENHANCEMENT BY COMPRESSION PROJECT

ATHENS COMPRESSOR STATION
INTERIM DISADVANTAGED COMMUNITIES

GREENE COUNTY, NEW YORK

0 1 2 4 Miles

N W E S

ABSOLUTE SCALE: 1:84,000

REFERENCE SCALE: 1 inch = 7,000 feet

Iroquois

MOTT M MACDONALD

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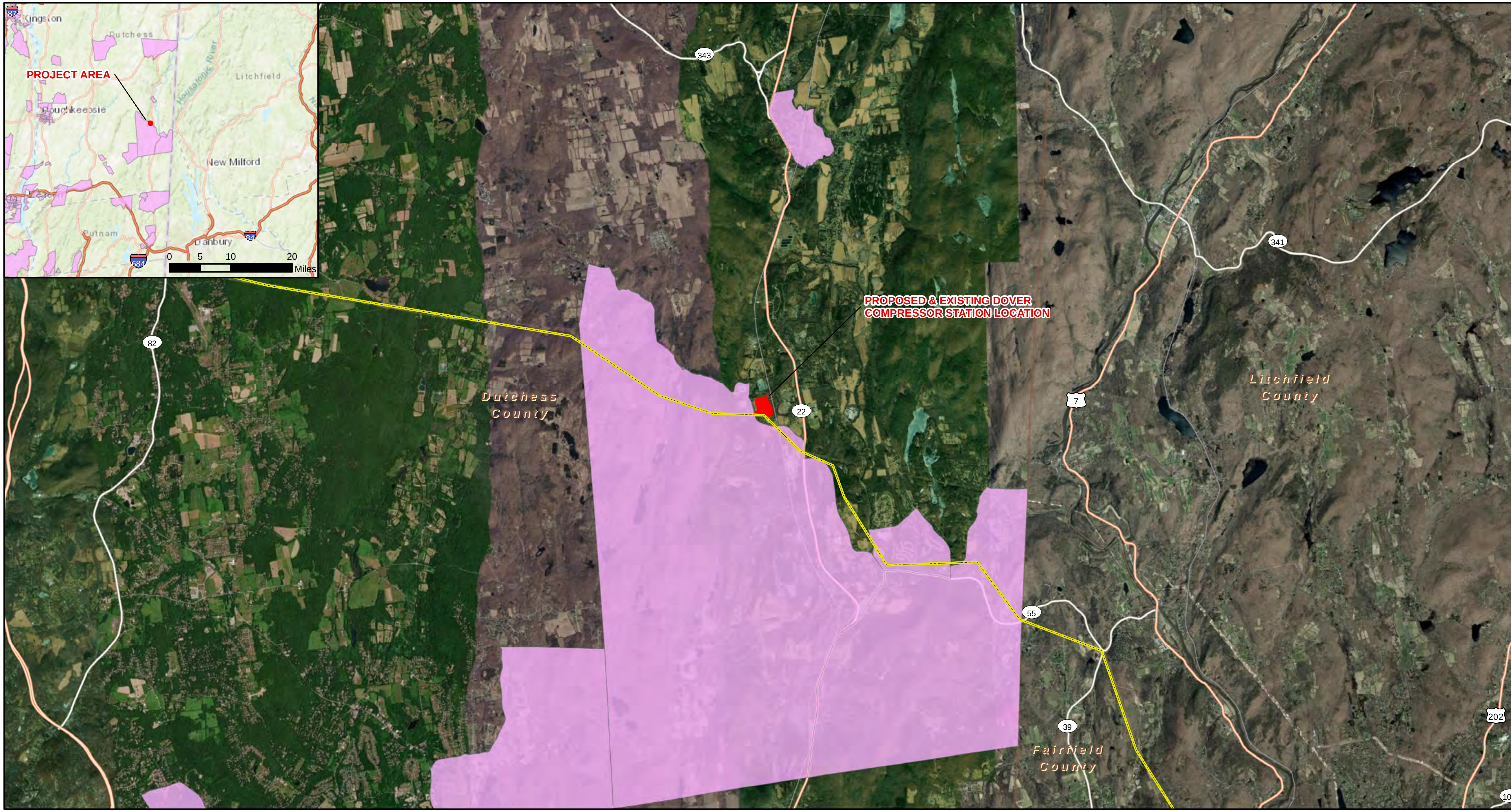
APPROVED BY:	DRG
REV. DATE:	11/16/2021
REVISION:	A
DESC:	IFP
DWG. NO.	1 OF 2



- POTENTIAL ENVIRONMENTAL JUSTICE AREA
- PROJECT LIMIT OF DISTURBANCE
- IROQUOIS PIPELINE MAINLINE
- MAJOR HIGHWAY
- HIGHWAY
- MAJOR ROAD

IROQUOIS GAS TRANSMISSION SYSTEM, INC.

ENHANCEMENT BY COMPRESSION PROJECT

DOVER COMPRESSOR STATION
POTENTIAL ENVIRONMENTAL JUSTICE AREAS

DUTCHESS COUNTY, NEW YORK

0 1 2 4 Miles

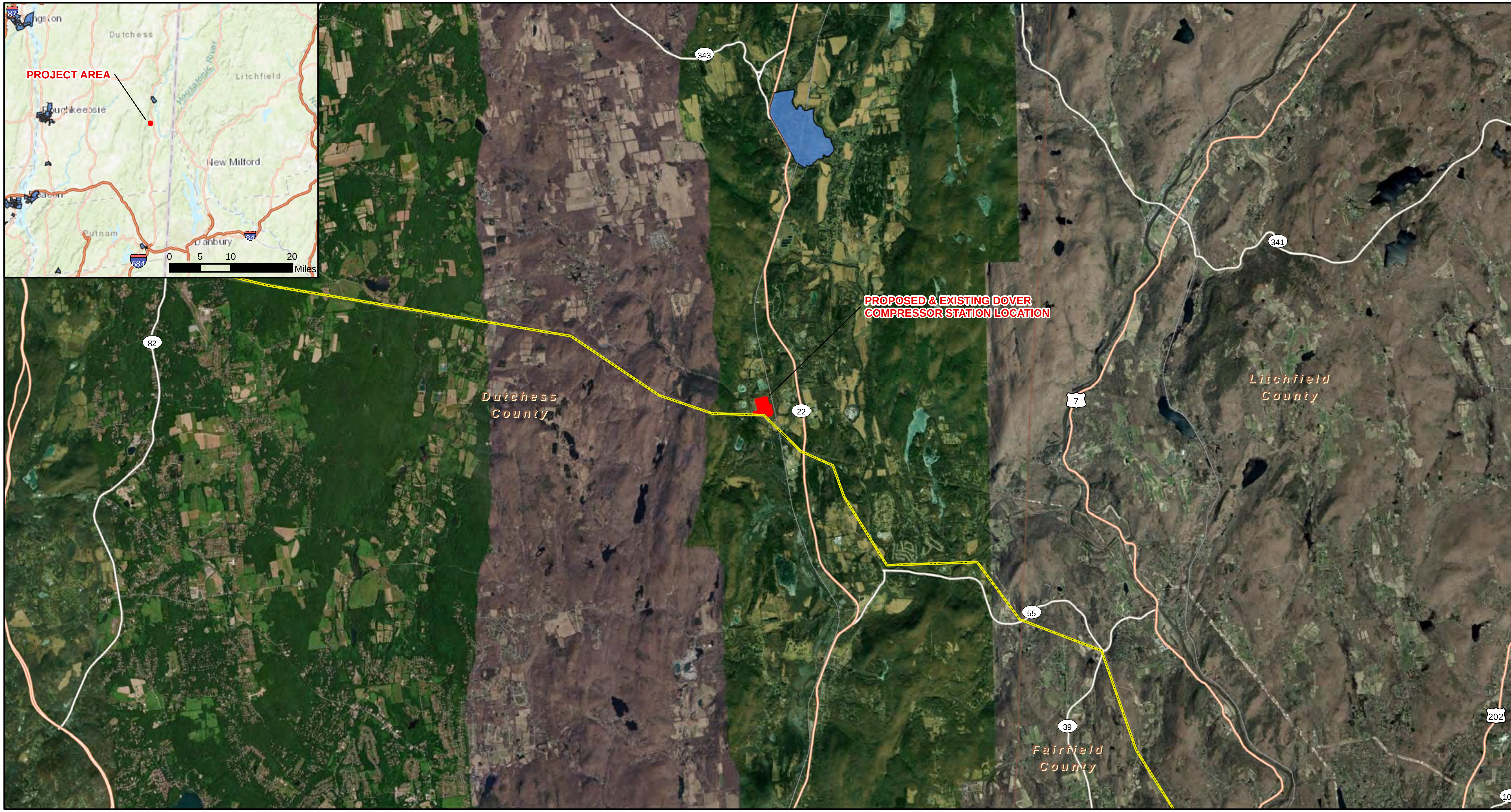
ABSOLUTE SCALE: 1:84,000

REFERENCE SCALE: 1 inch = 7,000 feet

Iroquois

MOTT MACDONALD
5295 S. Commerce Dr., Ste. 500
Salt Lake City, UT 84107

DRAWN BY:	JLM
CHECKED BY:	DRG
APPROVED BY:	DRG
REV. DATE:	11/16/2021
REVISION:	C
DESC:	IFP
DWG. NO.	2 OF 2



INTERIM DISADVANTAGED COMMUNITIES
PROJECT LIMIT OF DISTURBANCE
IROQUOIS PIPELINE MAINLINE
MAJOR HIGHWAY
HIGHWAY
MAJOR ROAD

IROQUOIS GAS TRANSMISSION SYSTEM, INC.

ENHANCEMENT BY COMPRESSION PROJECT

DOVER COMPRESSOR STATION
INTERIM DISADVANTAGED COMMUNITIES

DUTCHESS COUNTY, NEW YORK

0 1 2 4 Miles

N W E S

ABSOLUTE SCALE: 1:84,000

REFERENCE SCALE: 1 inch = 7,000 feet

Iroquois

MOTT MACDONALD
5295 S. Commerce Dr., Ste. 500
Salt Lake City, UT 84107

DRAWN BY:	JLM
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DESC:	IFP
DWG. NO.	2 OF 2

Attachment N

[Report]

Enhancement by Compression (ExC) Project Human Health Risk Assessment

Prepared for Iroquois Gas Transmission System
April 2020

Innovative solutions for a complex world

Catalyst
ENVIRONMENTAL SOLUTIONS

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Acronyms

AEGLs	Acute Exposure Guideline Levels
AIEC	Acute Inhalation Exposure Criteria
ATSDR	Agency for Toxic Substances and Disease Registry
CalEPA	California Environmental Protection Agency
C*e*	Residential Exposure Concentrations
C*ma*	Modeled Air Concentrations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COPC	Chemicals of Potential Concern
ED	Exposure Duration
EF	Exposure Frequency
ERPG	Emergency Response Planning Guidelines
FERC or Commission	Federal Energy Regulatory Commission
HAPs	Hazardous Air Pollutants
HHRA	Human Health Risk Assessment
HHRAP	Human Health Risk Assessment Protocol
HI	Hazard Index
hp	Horsepower
HQ	Hazard Quotient
ILCR	Incremental Lifetime Cancer Risk
IRIS	Integrated Risk Information System
Iroquois	Iroquois Gas Transmission System, L.P.
IUR	Inhalation Unit Risk
mg/m^3	Milligram per cubic meter of air
NA	Not Available/Applicable
NAAQS	National Ambient Air Quality Standard
NO_x	Nitrogen Oxides
OEHHA	Office of Environmental Health Hazard Assessment
PAC	Protective Action Criteria
PAHs	Polycyclic Aromatic Hydrocarbons

PM	Particulate Matter
PPRTV	Provisional Peer Reviewed Toxicity Values
REL	Reference Exposure Level
RfC	Reference Concentration
RME	Reasonable Maximum Exposure
SO_x	Sulfur Oxides
TEELs	Temporary Emergency Exposure Limits
Trinity	Trinity Consultants, Inc.
USDOE	United States Department of Energy
USEPA	United States Environmental Protection Agency
$\mu g/m^3$	Microgram per cubic meter of air

SECTION 1 Introduction

This Human Health Risk Assessment (HHRA) has been prepared as Appendix 9-E to Resource Report 9 for the proposed Enhancement by Compression (ExC) Project (Project) proposed by Iroquois Gas Transmission System, L.P. (Iroquois). Air modeling of facility emissions as used in the HHRA was provided by Trinity Consultants, Inc. (Trinity).

Iroquois is applying to the Federal Energy Regulatory Commission (Commission or FERC) for a Certificate of Public Convenience and Necessity under Section 7(c) of the Natural Gas Act for authorization to upgrade existing compressor stations located in Athens, NY, Dover, NY, Brookfield, CT, and Milford, CT. The Project includes upgrades to four compressor stations:

- Athens, Greene County, NY – integration of one (1) new approximately 12,000 horsepower (hp) turbine (Unit A2) with associated cooling, filter separators and other typical facilities connecting to the Iroquois 24-inch mainline in the Town of Athens, Greene County NY;
- Brookfield, Fairfield County, CT – addition of two (2) new turbines with approximately 12,000 hp each (Unit B1 & Unit B2) with associated cooling, filter separators and other typical facilities connecting to Iroquois' 24-inch mainline at Brookfield and to be installed downstream and independent of Iroquois' existing transfer compressors Unit A1 (Solar T-60) and Unit A2 (Solar T-70). One new approximately 450 kilowatt (kW) natural gas-fired reciprocating four-stroke lean-burn emergency generator would also be installed and operated;
- Dover, Dutchess County, NY – integration of one (1) new approximately 12,000 hp turbine (Unit A2) with associated cooling, filter separators and other typical facilities connecting to the Iroquois 24-inch mainline in the Town of Dover, Dutchess County NY. The existing emergency generator would be replaced with a new, approximately 1000 kW natural gas-fired reciprocating four-stroke lean-burn emergency generator; and
- Milford, New Haven County, CT – addition of gas cooling to existing Plant-A units and associated piping to allow for compressed discharge gas to be cooled. Currently, no gas cooling facilities exist at this station. The compressor station is in the City of Milford, New Haven County, CT.

There are no pipeline facilities proposed as part of the Project; therefore, there is no discussion of pipeline specific project elements within this HHRA.

1.1 Human Health Risk Assessment Approach

The objective of the HHRA is to evaluate potential exposures and human health risks associated with current and future operational emissions at each of the four compressor stations described above. The information provided in Sections 2 and 3 of this HHRA indicate that these emissions may be broadly characterized as hazardous air pollutants (HAPs). Due to the volatile nature of these chemical compounds, the only exposure pathway of significant concern is through inhalation. The human receptors evaluated in this HHRA are hypothetical residents because residential receptors, including children, are considered the most sensitive human receptors. The methods employed to assess health risks in this HHRA explicitly consider exposure and risk to sensitive subpopulations of residents such as children. The HHRA is designed to be highly conservative by assuming chronic exposure to maximum 5-year average concentrations of chemicals of potential concern (COPCs) at each compressor station fence or property line throughout the residential tenure of adults (30 years) and children (6 years) (USEPA 2005). This is a very conservative assumption since exposure and risk will decrease with distance from the fence or property line. The HHRA also evaluates acute exposure and risk associated with short-term (1-hour) maximum COPC emissions at each compressor station fence or property line.

The HHRA provides upper-bound estimates of individual cancer and noncancer risk for the theoretical Reasonable Maximum Exposure (RME) for adult and child receptors based on direct exposures to potential emissions from natural gas combustion. The RME approach is consistent with current USEPA (2005) guidance and is a conservative measure that overestimates potential risks, thus ensuring the protection of public health.

The HHRA was conducted following standardized risk assessment methods consistent with USEPA risk assessment guidance, including, but not limited to, the following guidance documents, as applicable:

- The Risk Assessment Guidelines of 1986 (USEPA 1987);
- Risk Assessment Guidance for Superfund, Volume I, Health Evaluation Manual, Part A (USEPA 1989); and
- Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities (USEPA 2005).

SECTION 2 Sources of Air Emissions

Resource Report 9 discusses the potential effect of the Project on local and regional air quality as it relates to criteria pollutants, greenhouse gases, and HAPs. This HHRA addresses the potential health effects of HAPs emitted from the natural gas-fired equipment. Air emissions from the operation of compressor stations include the following: exhaust emissions from natural gas combustion in reciprocating internal combustion engines, combustion turbines, and ancillary equipment, and emissions from releases of natural gas from fugitive emissions and venting. Iroquois has committed to installing hydrocarbon abatement systems designed to recover approximately 90 percent of vented natural gas emissions due to maintenance activities. In addition, federal regulations will require quarterly fugitive leak detection and 30-day leak repairs after start-up of the compressor horsepower additions. Fugitive emissions and emissions associated with venting are considered insignificant compared to combustion emissions; therefore, the focus of this HHRA is solely on combustion emissions, specifically existing and proposed turbines and emergency generators.

2.1 Natural Gas Combustion Emissions

Natural gas is comprised primarily of methane mixed with other hydrocarbons and contaminants depending on its geographical and geological origin. All gas transported by Iroquois must meet pipeline gas quality standards as defined in Iroquois' tariff.

The combustion of natural gas results in emissions of nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), carbon dioxide (CO_2), particulate matter (PM), volatile organic compounds, and HAPs. HAPs are defined under the Clean Air Act of 1970 and are discussed in more detail below.

NO_x, SO_x, CO, and PM are not considered HAPs by definition but are grouped under the regulatory umbrella of National Ambient Air Quality Standards (NAAQS). The chemicals/compounds included under NAAQS are not typically evaluated quantitatively in health risk assessments but may be evaluated by simple comparison of modeled or measured air concentrations to the current standards. The air quality impacts of criteria pollutants are addressed in Resource Report 9.

The focus of this HHRA is on HAP emissions associated with current and future planned operations at each of the four compressor stations described in Section 1. The specific HAPs to be evaluated including chemical-specific emission factors are based on operating parameters obtained from compressor engine and turbine manufacturers, oxidation catalyst specifications and emission factors provided by vendors, and the 5th Edition of AP-42 Sections 3.1 and 3.2 (EPA 2000). For natural gas-fired turbines, the applicable HAPs are taken from AP-42 Table 3.1-3. For the natural gas-fired reciprocating four-stroke lean-burn emergency generators, the applicable HAPs were taken from AP-42 Table 3.2-2. Potential emissions were estimated for the maximum load case for each compressor engine or turbine.

The full list of HAPs to be evaluated in the HHRA for each compressor station are presented in Table 1. Chemical-specific emission factors utilized in Section 3 to estimate air concentrations for subsequent evaluation in the HHRA are presented in Appendix A.

Table 1: HAPs Modeled for Compressor Station Turbines and Emergency Generators

COPC	Turbines	Emergency Generators
Acenaphthene		X

COPC	Turbines	Emergency Generators
Acenaphthylene		X
Acetaldehyde	X	X
Acrolein	X	X
Benzene	X	X
Benzo(b)fluoranthene		X
Benzo(g,h,i)perylene		X
1,3-Butadiene	X	X
Carbon Tetrachloride		X
Chlorobenzene		X
Chloroform		X
Chrysene		X
1,3-Dichloropropene		X
Ethylbenzene	X	X
Fluoranthene		X
Fluorene		X
Formaldehyde	X	X
n-Hexane		X
Methanol		X
Methylene Chloride		X
2-Methylnaphthalene		X
Naphthalene	X	X
Phenanthrene		X
Phenol		X
Propylene Oxide	X	
Pyrene		X
Styrene		X
1,1,2,2 -Tetrachloroethane		X
Toluene	X	X
1,1,2 -Trichloroethane		X
2,2,4 -Trimethylpentane		X

COPC	Turbines	Emergency Generators
Vinyl Chloride		X
Xylene	X	X

2.2 Athens Compressor Station

Existing emissions sources at the Athens Compressor Station include an existing approximately 11,000 hp natural gas-fired turbine and existing emergency generator; proposed sources include one new approximately 12,000 hp natural gas-fired Unit A2 turbine. All emission sources at the Athens Compressor Station have unobstructed vertical releases and were therefore modeled as point sources. Stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) used in the modeling analyses were based on design values. There were no area or volume sources used in the modeling analysis (Trinity 2020a).

2.3 Brookfield Compressor Station

Existing emissions sources at the Brookfield Compressor Station include two natural gas-fired simple-cycle combustion turbines and an existing emergency generator; proposed sources include two new 12,000-hp natural gas-fired (Unit B1 & B2) turbines, and one new 450 kW natural gas-fired emergency generator. The proposed and existing turbines and emergency generators at the Brookfield Compressor Station have unobstructed vertical releases and were therefore modeled as point sources. Stack parameters used in the analyses were based on design values. There were no area or volume sources used in the modeling analysis (Trinity 2020b).

2.4 Dover Compressor Station

Existing emissions sources at the Dover Compressor Station include an approximately 20,000 hp natural gas-fired simple cycle combustion turbine and an existing emergency generator; proposed sources include one new 12,000 hp natural gas-fired Unit A2 turbine, and one 1,000 kW replacement generator. The proposed and existing turbines and emergency generators at the Dover Compressor Station have unobstructed vertical releases and were therefore modeled as point sources. Stack parameters used in the analyses were based on design values. There were no area or volume sources used in the modeling analysis (Trinity 2020c).

2.5 Milford Compressor Station

Existing emissions sources at the Milford Compressor Station include two existing turbines and one existing emergency generator. There are no new emissions sources proposed at the Milford Compressor Station as part of the proposed Project.

SECTION 3 Characterizing Air Emissions

3.1 Selection of Chemicals of Potential Concern

For the purpose of this HHRA, COPCs are defined as any HAP known or likely to be associated with natural gas combustion for which emission factors are available or could be derived based on the existing and proposed compressor station operations. For each COPC, emission factors were utilized as described in Section 3.2 to estimate chemical-specific air concentrations for use in the HHRA.

3.2 Air Modeling

Air modeling was conducted by Trinity in accordance with applicable rules, guidance, and requirements in the following guidance documents (Trinity 2020a, b, c):

- USEPA's Guideline on Air Quality Models, 40 CFR Part 51 - Appendix W,
- USEPA's AERMOD Implementation Guide,
- USEPA: User's Guide for the AMS/EPA Regulatory Model – AERMOD, and
- New York State Department of Environmental Conservation Guidelines on Dispersion Modeling Procedures for Air Quality Impact Analysis (DAR-10) (for the Athens and Dover Compressor Stations) or the Connecticut Department of Energy and Environmental Protection's Ambient Impact Analysis Guideline (for the Brookfield and Milford Compressor Stations).

The latest version of USEPA's AMS/EPA Regulatory Model (AERMOD version 19191) was used to evaluate the criteria pollutants (CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2) and ultimately estimate maximum ground-level concentrations of each COPC.

Modeling was performed assuming that the turbines operate concurrently at worst case maximum (i.e., 100%) load.

The "normal temperature" operating condition represents an ambient air temperature of 47°F for Athens, Dover, and Milford and 49°F for Brookfield which is based on the annual average temperature at each compression station; "low temperature" operating conditions include an ambient air temperature of 0°F; and "high temperature" operating conditions include an ambient air temperature of 100°F.

Per EPA guidelines, ground-level concentrations were calculated along the facility boundaries and within a Cartesian receptor grid outside the fence or property lines. In general, the receptors covered a region extending from all edges of the fence lines or property lines to the point where impacts from the Project are no longer expected to be measurable.

The unit impact modeling was based on setting the pollutant ID to "NO_2." Specifying "NO_2" as the pollutant and outputting the first high 1-hour concentration allows AERMOD to internally calculate the maximum 5-year average of the maximum hourly impacts on a receptor-by-receptor basis. The annual unit impacts are based on the maximum 5-year average of the maximum annual impacts on a receptor-by-receptor basis. The maximum predicted concentration for each air pollutant was used in the exposure assessment.

Modeling results are presented in Appendix A.

SECTION 4 Toxicity Assessment

Toxicity Assessment is the process of assessing the relationship between human intake of a chemical (e.g., dose) and the corresponding toxic response. This process is also known as dose-response assessment. The results of the dose-response assessment are generally referred to as toxicity values. Over the past 30 years, dose-response assessments have been routinely performed by State and Federal regulatory agencies, which publish toxicity values for various types of health effects and exposure pathways.

For this inhalation pathway risk assessment of residential exposures, the following toxicity values are used to assess potential health risks in Section 6 of this HHRA:

- Inhalation Unit Risk (IUR) in units of $(\mu g/m^3)^{-1}$. The IUR is defined as the concentration of chemical in air that corresponds to a one-in-one million (1×10^{-6}) cancer risk. The IUR is used in risk assessment to estimate potential Incremental Lifetime Cancer Risk (ILCR) associated with exposure to carcinogens.
- Reference Concentration (RfC) in units of mg/m^3. The RfC is defined as the concentration of a chemical in air that corresponds to the threshold air concentration below which chronic noncancer health effects are unlikely.
- Acute Inhalation Exposure Criteria (AIEC) in units of $\mu g/m^3$. The AIEC is defined as the concentration of a chemical in air that corresponds to the threshold air concentration below which acute noncancer health effects are unlikely.

There are multiple State and Federal regulatory agency sources for each of these toxicity values. This HHRA has established a hierarchy of preferred toxicity value sources with consideration given to (1) the use of most current toxicity data in their derivation; (2) whether a peer-review process was used by the agency; and (3) a commonly accepted hierarchy of preferred toxicity values.

4.1 Chronic Toxicity Values

For IURs and RfCs, the preferred source is the USEPA's Integrated Risk Information System (IRIS; USEPA 2019a). For chemicals without IURs or RfCs in the IRIS database, the USEPA's Provisional Peer-Reviewed Toxicity Values (PPRTVs; USEPA 2019b) is the secondary source. Tertiary sources of IURs and RfCs are the California Environmental Protection Agency (CalEPA) Office of Environmental Health Hazard Assessment (OEHHA) Toxicity Criteria Database (CalEPA 2019a) and OEHHA's Acute, 8-hour and Chronic Reference Exposure Level (REL) Summary (CalEPA 2019b).

4.2 Acute Toxicity Values

For AIECs, the preferred source is OEHHA's Acute RELs (see above). For COPCs without Acute RELs, the USEPA's Acute Exposure Guideline Levels (AEGLs; USEPA 2019c) are the next preferred source, and in the absence of either Acute RELs or AEGLs, then the U.S. Department of Energy (USDOE) Protective Action Criteria (PAC; USDOE 2018) are selected as the AIEC. The PACs are a compilation of acute exposure thresholds based on AEGLs, Emergency Response Planning Guidelines (ERPGs), and Temporary Emergency Exposure Limits (TEELs). AEGLs are developed by the USEPA, ERPGs are developed by the American Industrial Hygiene Association, and TEELs are developed by the USDOE. The PAC data set implements the following hierarchy for selecting the PAC values from these three acute exposure thresholds: preference is given to AEGLs, followed by ERPGs, and lastly TEELs. For this HHRA, PAC-1 toxicity benchmarks were selected as these values reflect the exposure threshold for health effects associated with acute exposures corresponding to a 1-hour inhalation exposure.

Chronic and acute toxicity values are summarized in Table 2.

Table 2: Chronic and Acute Human Health Risk Assessment Toxicity Values

COPC	IUR (µg/m^3)$^{-1}$	Source	RfC (mg/m^3)	Source	AIEC (µg/m^3)	Source
Acenaphthene	NA	NA	NA	NA	3.6E+03	PAC-1
Acenaphthylene	NA	NA	NA	NA	1.0E+04	PAC-1
Acetaldehyde	2.2E-06	IRIS	9.0E-03	IRIS	4.7E+02	CalEPA-2
Acrolein	NA	NA	2.0E-05	IRIS	2.5E+00	CalEPA-2
Benzene	7.8E-06	IRIS	3.0E-02	IRIS	2.7E+01	CalEPA-2
Benzo(b)fluoranthene	1.1E-04	CalEPA-1	NA	NA	1.2E+02	PAC-1
Benzo(g,h,i)perylene	NA	NA	NA	NA	3.0E+04	PAC-1
1,3-Butadiene	3.0E-05	IRIS	2.0E-03	IRIS	6.6E+02	CalEPA-2
Carbon Tetrachloride	6.0E-06	IRIS	1.0E-01	IRIS	1.9E+03	CalEPA-2
Chlorobenzene	NA	NA	5.0E-02	PPRTV	4.6E+04	AEGL-1
Chloroform	2.3E-05	IRIS	9.8E-02	ATSDR	1.5E+02	CalEPA-2
Chrysene	1.1E-05	CalEPA-1	NA	NA	6.0E+02	PAC-1
1,3-Dichloropropene	4.0E-06	IRIS	2.0E-02	IRIS	1.4E+04	PAC-1
Ethylbenzene	2.5E-06	CalEPA-2	1.0E+00	IRIS	1.4E+05	AEGL-1
Fluoranthene	NA	NA	NA	NA	8.2E+03	PAC-1
Fluorene	NA	NA	NA	NA	6.6E+03	PAC-1
Formaldehyde	1.3E-05	IRIS	9.0E-03	CalEPA-2	5.5E+01	CalEPA-2
n-Hexane	NA	NA	7.0E-01	IRIS	9.1E+05	PAC-1
Methanol	NA	NA	2.0E+01	IRIS	2.8E+04	CalEPA-2
Methylene Chloride	1.0E-08	IRIS	6.0E-01	IRIS	1.4E+04	CalEPA-2
2-Methylnaphthalene	NA	NA	NA	NA	9.0E+03	PAC-1
Naphthalene	3.4E-05	CalEPA-2	3.0E-03	IRIS	7.9E+04	PAC-1
Phenanthrene	NA	NA	NA	NA	5.4E+03	PAC-1
Phenol	NA	NA	2.0E-01	CalEPA-1	5.8E+03	CalEPA-2
Propylene Oxide	3.7E-06	IRIS	3.0E-02	IRIS	3.1E+03	CalEPA-2
Pyrene	NA	NA	NA	NA	1.5E+02	PAC-1
Styrene	NA	NA	1.0E+00	IRIS	2.1E+04	CalEPA-2
1,1,2,2 -Tetrachloroethane	5.8E-05	CalEPA-2	NA	NA	2.1E+04	PAC-1

Toluene	NA	NA	5.0E+00	IRIS	3.7E+04	CalEPA-2
1,1,2-Trichloroethane	1.6E-05	IRIS	2.0E-04	PPRTV	1.6E+05	PAC-1
2,2,4-Trimethylpentane	NA	NA	NA	NA	1.1E+06	PAC-1
Vinyl Chloride	4.4E-06	IRIS	1.0E-01	IRIS	1.8E+05	CalEPA-2
Xylene	NA	NA	1.0E-01	IRIS	2.2E+04	CalEPA-2

Notes:

NA: Not available

IUR: Inhalation Unit Risk

RfC: Reference Concentration

AIEC: Acute Inhalation Exposure Criteria

IRIS: USEPA Integrated Risk Information System (USEPA 2019a)

CalEPA-1: OEHHA Toxicity Criteria Database (CalEPA 2019a)

CalEPA-2: OEHHA Acute, 8-hour and Chronic Reference Exposure Level (REL) Summary (CalEPA 2019b)

PPRTV: Provisional Peer-Reviewed Toxicity Value (USEPA 2019b)

ATSDR: Agency for Toxicity and Disease Registry; chronic inhalation Minimal Risk Level (MRL)

PAC-1: Protective Action Criteria (USDOE 2018)

AEGL-1: Acute Exposure Guideline Levels (USEPA 2019c)

SECTION 5 Exposure Assessment Methodology

Exposure Assessment is the process of quantitatively characterizing exposure concentrations and potential human intake (e.g., dose). Exposure assessment results are subsequently integrated with toxicity information in the Risk Characterization (Section 6) to assess potential health risks. Modeled air concentrations of COPCs for each compressor station are presented in Appendix A. Toxicity information (e.g., toxicity values) is summarized above in Section 4.

While the 1-hour acute toxicity values (e.g., AEICs) presented in Section 4 correspond directly with the modeled 1-hour maximum air concentrations, relative to a chronic residential exposure scenario, the chronic toxicity values (IURs and RfCs) do not correspond directly with the modeled air concentrations relative to a chronic residential exposure scenario as described in the USEPA (2005) HHRAP guidance.

For chronic residential exposures associated with normal operations, exposure frequency (EF) is assumed to be 350 days per year, for adult and child, and exposure duration (ED) is assumed to be 30 years for an adult resident and 6 years for a child resident (USEPA 2005). In contrast, the laboratory animal-based inhalation toxicity studies upon which the chronic toxicity values are based assume continuous exposure for 365 days/year over the entire lifetime of the laboratory animals. For residential receptors a lifetime is assumed to be 70 years (USEPA 2005). For chronic residential exposures associated with emergency generators, exposure frequency is limited by Connecticut and New York regulations that limit the use of emergency generators to 300 hours per year (12.5 days per year) and 500 hours per year (20.8 days per year), respectively.

In order to account for residential exposure frequency and exposure duration, per USEPA (2005) guidance, the modeled air concentrations (C_{ma}) were converted to residential exposure concentrations (C_e) for application in the Risk Characterization, as follows:

For chronic residential adult exposures:

$$C_e = C_{ma} \times (EF/365) \times (ED_a/70)$$

Where,

C_e = residential air exposure concentration (µg/m^3)

C_{ma} = modeled air concentration (µg/m^3)

EF = exposure frequency (350 days/year for all turbines, 12.5 days/year for emergency generators in Connecticut and 20.8 days/year for emergency generators in New York)

ED_a = adult resident exposure duration (30 years)

For chronic residential child exposures:

$$C_e = C_{ma} \times (EF/365) \times (ED_c/70)$$

Where,

C_e = residential air exposure concentration (µg/m^3)

C_{ma} = modeled air concentration (µg/m^3)

EF = exposure frequency (350 days/year for all turbines, 12.5 days/year for emergency generators in Connecticut, and 20.8 days/year for emergency generators in New York)

ED*c* = child resident exposure duration (6 years)

These equations were incorporated into the risk characterization equations used in Section 6 to estimate potential chronic health risks. These equations do not apply to the estimation of acute health risks because for acute exposures C*e* = C*ma*.

SECTION 6 Risk Characterization

Risk Characterization is the process of integrating exposure and toxicity information to characterize potential health risks. Under this process, chronic cancer risks are estimated for individual carcinogens, and the total risk from all carcinogens combined, referred to as the cumulative cancer risk, is then calculated by summing the cancer risks for all carcinogenic COPCs. A similar process is employed for chronic and acute noncancer risks whereby chronic and acute noncancer risks are estimated for individual COPCs, referred to as Hazard Quotients (HQs), and cumulative noncancer risk, referred to as the Hazard Index (HI), is then calculated by summing the individual chronic and acute noncancer HQs. The equations used to calculate cancer risk, chronic HQs, and acute HQs are as follows:

$$\text{ILCR} = \text{C}e \times \text{IUR}$$

Where,

ILCR = Incremental Lifetime Cancer Risk (unitless)

C*e* = estimated chronic residential air concentration (µg/m^3) associated with normal operation of turbines and emergency generators combined

IUR = Inhalation Unit Risk $(\mu g/m^3)^{-1}$

Note: individual COPC adult and child ILCRs and cumulative adult and child ILCRs are calculated separately based on receptor-specific EDs of 30 years and 6 years for residential adults and children, respectively.

$$\text{Chronic HQ} = \text{C}e \,/\, \text{RfC} \times \text{CF}$$

Where,

HQ = Hazard Quotient (unitless)

C*e* = estimated chronic residential air concentration (µg/m^3) associated with normal operation of turbines and emergency generators combined

RfC = Reference Concentration (mg/m^3)

CF = conversion factor of 0.001 mg/µg

$$\text{Acute HQ} = \text{C}e \,/\, \text{AIEC}$$

Where,

HQ = Hazard Quotient (unitless)

C*e* = estimated acute residential air concentration (µg/m^3) associated with normal operation of turbines and emergency generators combined

AIEC = Acute Inhalation Exposure Criteria (µg/m^3)

Cumulative ILCR = Σ ILCR for individual carcinogenic COPCs

Chronic HI = Σ chronic HQs for individual COPCs

Acute HI = Σ acute HQs for individual COPCs

Risk characterization results are summarized and discussed below for each of the compressor stations.

6.1 Cancer Risk and Chronic Noncancer Risk

Potential cancer and chronic noncancer human health risks associated with modeled air concentrations at each of the four compressor stations are presented below. Note that the COPC air concentrations presented in the following tables are the modeled air concentrations, C*ma*. The residential exposure concentrations, C*e*, are integrated within the adult and child risk and HQ calculations.

6.1.1 Athens Compressor Station

The risk characterization results for chronic exposure to potential natural gas combustion emissions from the existing and modified Athens Compressor Station are summarized in Tables 3 and 4, respectively. Under existing conditions, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1×10^{-6} for any individual COPC, and adult and child HQs do not exceed the target noncancer HQ of 1 for any individual COPC (Table 3). Under the proposed Project, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1×10^{-6} for any individual COPC, and adult and child HQs do not exceed the target noncancer HQ of 1 (e.g., the level at which sensitive individuals can be exposed without risk of chronic noncancer health effects) for any individual COPC (Table 4).

Cumulative cancer risks associated with existing conditions and the proposed Project are both well below the target cancer risk benchmark of 1×10^{-6}. Under existing conditions, adult and child cumulative cancer risks are 4×10^{-7} and 9×10^{-8}, respectively. For the proposed Project, cumulative cancer risk for adults and children are 1×10^{-7} and 2×10^{-8}, respectively. The cumulative noncancer HI for existing conditions and the proposed Project do not exceed the target noncancer HI benchmark of 1 (HI=0.4 for existing conditions and HI=0.08 for the proposed Project; Table 3 and Table 4).

These risk characterization results demonstrate that current emissions and those projected under the proposed Project at the Athens Compressor Station do not pose an unacceptable chronic risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility.

Table 3: Cancer and Chronic Noncancer Risk Assessment Results from the Existing Athens Compressor Station

COPC	C*ma* Turbine[a] (µg/m³)	C*ma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	5.1E-05	1.9E-01	2.2E-06	1.0E-08	2.1E-09	9.0E-03	1.2E-03
Acrolein	8.1E-06	1.2E-01	NA	NA	NA	2.0E-05	3.4E-01
Benzene	1.5E-05	1.0E-02	7.8E-06	2.0E-09	4.0E-10	3.0E-02	2.0E-05
Benzo(b)fluoranthene	--	3.8E-06	1.1E-04	1.0E-11	2.1E-12	NA	NA
1,3-Butadiene	5.4E-07	6.2E-03	3.0E-05	4.5E-09	9.1E-10	2.0E-03	1.8E-04
Carbon Tetrachloride	--	8.5E-04	6.0E-06	1.2E-10	2.5E-11	1.0E-01	4.8E-07
Chlorobenzene	--	7.0E-04	NA	NA	NA	5.0E-02	8.0E-07
Chloroform	--	6.6E-04	2.3E-05	3.7E-10	7.4E-11	9.8E-02	3.8E-07

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Chrysene	--	1.6E-05	1.1E-05	4.3E-12	8.6E-13	NA	NA
1,3-Dichloropropene	--	6.1E-04	4.0E-06	6.0E-11	1.2E-11	2.0E-02	1.7E-06
Ethylbenzene	4.1E-05	9.2E-04	2.5E-06	9.8E-11	2.0E-11	1.0E+00	9.1E-08
Ethylene Dibromide	--	1.0E-03	6.0E-04	1.5E-08	3.0E-09	9.0E-03	6.5E-06
Formaldehyde	9.0E-04	1.2E+00	1.3E-05	3.9E-07	7.8E-08	9.0E-03	7.8E-03
n-Hexane	--	2.6E-02	NA	NA	NA	7.0E-01	2.1E-06
Methanol	--	5.8E-02	NA	NA	NA	2.0E+01	1.6E-07
Methylene Chloride	--	4.6E-04	1.0E-08	1.1E-13	2.3E-14	6.0E-01	4.4E-08
2-Methylnaphthalene	--	7.7E-04	NA	NA	NA	NA	NA
Naphthalene	1.6E-06	1.7E-03	3.4E-05	1.5E-09	2.9E-10	3.0E-03	3.3E-05
Phenol	--	5.5E-04	NA	NA	NA	2.0E-01	1.6E-07
Propylene Oxide	3.7E-05	--	3.7E-06	5.6E-11	1.1E-11	3.0E-02	1.2E-06
Styrene	--	5.5E-04	NA	NA	NA	1.0E+00	3.1E-08
Toluene	1.7E-04	9.4E-03	NA	NA	NA	5.0E+00	1.4E-07
1,1,2,2-Tetrachloroethane	--	9.2E-04	5.8E-05	1.3E-09	2.6E-10	NA	NA
1,1,2-Trichloroethane	--	7.3E-04	1.6E-05	2.9E-10	5.7E-11	2.0E-04	2.1E-04
2,2,4-Trimethylpentane	--	5.8E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	3.4E-04	4.4E-06	3.7E-11	7.4E-12	1.0E-01	2.0E-07
Xylene	8.1E-05	4.3E-03	NA	NA	NA	1.0E-01	3.2E-06
Cumulative Cancer Risk and Hazard Index				**4E-07**	**9E-08**		**0.4**
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the fence line

Cma = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

Table 4: Cancer and Chronic Noncancer Risk Assessment Results from the Proposed Modified Athens Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR $(\mu g/m^3)^{-1}$	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	1.1E-04	4.4E-02	2.2E-06	2.5E-09	4.9E-10	9.0E-03	2.9E-04
Acrolein	1.7E-05	2.7E-02	NA	NA	NA	2.0E-05	7.8E-02
Benzene	3.3E-05	2.3E-03	7.8E-06	5.5E-10	1.1E-10	3.0E-02	5.4E-06
Benzo(b)fluoranthene	--	8.8E-07	1.1E-04	2.4E-12	4.7E-13	NA	NA
1,3-Butadiene	1.2E-06	1.4E-03	3.0E-05	1.0E-09	2.1E-10	2.0E-03	4.1E-05
Carbon Tetrachloride	--	1.9E-04	6.0E-06	2.8E-11	5.7E-12	1.0E-01	1.1E-07
Chlorobenzene	--	1.6E-04	NA	NA	NA	5.0E-02	1.8E-07
Chloroform	--	1.5E-04	2.3E-05	8.4E-11	1.7E-11	9.8E-02	8.7E-08
Chrysene	--	3.7E-06	1.1E-05	9.8E-13	2.0E-13	NA	NA
1,3-Dichloropropene	--	1.4E-04	4.0E-06	1.4E-11	2.7E-12	2.0E-02	4.0E-07
Ethyl Benzene	8.7E-05	2.1E-04	2.5E-06	1.0E-10	2.0E-11	1.0E+00	9.5E-08
Ethylene Dibromide	--	2.3E-04	6.0E-04	3.4E-09	6.8E-10	9.0E-03	1.5E-06
Formaldehyde	1.9E-03	2.8E-01	1.3E-05	9.9E-08	2.0E-08	9.0E-03	2.0E-03
n-Hexane	--	5.9E-03	NA	NA	NA	7.0E-01	4.8E-07
Methanol	--	1.3E-02	NA	NA	NA	2.0E+01	3.8E-08
Methylene Chloride	--	3.5E-04	1.0E-08	8.6E-14	1.7E-14	6.0E-01	3.3E-08
2 -Methylnaphthalene	--	1.8E-04	NA	NA	NA	NA	NA
Naphthalene	3.5E-06	3.9E-04	3.4E-05	3.8E-10	7.5E-11	3.0E-03	8.6E-06
Phenol	--	1.3E-04	NA	NA	NA	2.0E-01	3.6E-08
Propylene Oxide	7.9E-05	--	3.7E-06	1.2E-10	2.4E-11	3.0E-02	2.5E-06
Styrene	--	1.2E-04	NA	NA	NA	1.0E+00	7.1E-09
Toluene	3.5E-04	2.2E-03	NA	NA	NA	5.0E+00	9.2E-08
1,1,2,2 -Tetrachloroethane	--	2.1E-04	5.8E-05	3.0E-10	6.0E-11	NA	NA
1,1,2-Trichloroethane	--	1.7E-04	1.6E-05	6.6E-11	1.3E-11	2.0E-04	4.8E-05
2,2,4-Trimethylpentane	--	1.3E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	7.9E-05	4.4E-06	8.4E-12	1.7E-12	1.0E-01	4.5E-08
Xylene	1.7E-04	9.7E-04	NA	NA	NA	1.0E-01	2.2E-06
Cumulative Cancer Risk and Hazard Index				**1E-07**	**2E-08**		**0.08**

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the fence line

Cma = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

6.1.2 Brookfield Compressor Station

The risk characterization results for chronic exposure to potential natural gas combustion emissions from the existing and modified Brookfield Compressor Station are summarized in Tables 5 and 6, respectively. Under existing conditions, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1 x 10^{-6} for any individual COPC, and adult and child HQs do not exceed the target noncancer HQ of 1 for any individual COPC (Table 5). Under the proposed Project, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1 x 10^{-6} for any individual COPC and adult and child HQs do not exceed the target noncancer HQ of 1 for any individual COPC (Table 6).

Cumulative cancer risks associated with existing conditions and the proposed Project are both well below the target cancer risk benchmark of 1 x 10^{-6}. Under existing conditions, adult and child cumulative cancer risks are 5 x 10^{-7} and 9 x 10^{-8}, respectively. For the proposed Project, cumulative cancer risks for adults and children are 5 x 10^{-7} and 1 x 10^{-7}, respectively. The cumulative noncancer HI under existing conditions does not exceed the target noncancer HI benchmark of 1 (HI=0.2), and the cumulative noncancer HI under the proposed Project also does not exceed the target noncancer benchmark of 1 (HI=0.2) (Tables 5 and 6).

These risk characterization results demonstrate that current emissions and those projected under the proposed Project at the Brookfield Compressor Station do not pose an unacceptable chronic risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility.

Table 5: Cancer and Chronic Noncancer Risk Assessment Results from the Existing Brookfield Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	2.2E-03	1.9E-01	2.2E-06	8.2E-09	1.6E-09	9.0E-03	9.7E-04
Acrolein	3.5E-04	1.2E-01	NA	NA	NA	2.0E-05	2.2E-01
Benzene	6.5E-04	1.0E-02	7.8E-06	3.2E-09	6.5E-10	3.0E-02	3.2E-05
Benzo(b)fluoranthene	--	3.8E-06	1.1E-04	6.2E-12	1.2E-12	NA	NA
1,3-Butadiene	2.3E-05	6.2E-03	3.0E-05	3.0E-09	6.0E-10	2.0E-03	1.2E-04
Carbon Tetrachloride	0.0E+00	8.5E-04	6.0E-06	7.5E-11	1.5E-11	1.0E-01	2.9E-07
Chlorobenzene	--	7.0E-04	NA	NA	NA	5.0E-02	4.8E-07

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR $(\mu g/m^3)^{-1}$	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Chloroform	--	6.6E-04	2.3E-05	2.2E-10	4.4E-11	9.8E-02	2.3E-07
Chrysene	--	1.6E-05	1.1E-05	2.6E-12	5.2E-13	NA	NA
1,3-Dichloropropene	--	6.1E-04	4.0E-06	3.6E-11	7.2E-12	2.0E-02	1.0E-06
Ethyl Benzene	1.7E-03	9.2E-04	2.5E-06	1.8E-09	3.6E-10	1.0E+00	1.7E-06
Ethylene Dibromide	--	1.0E-03	6.0E-04	9.0E-09	1.8E-09	9.0E-03	3.9E-06
Formaldehyde	3.8E-02	1.2E+00	1.3E-05	4.4E-07	8.8E-08	9.0E-03	8.7E-03
n-Hexane	--	2.6E-02	NA	NA	NA	7.0E-01	1.3E-06
Methanol	--	5.8E-02	NA	NA	NA	2.0E+01	9.9E-08
Methylene Chloride	--	4.6E-04	1.0E-08	6.8E-14	1.4E-14	6.0E-01	2.6E-08
2-Methylnaphthalene	--	7.7E-04	NA	NA	NA	NA	NA
Naphthalene	7.1E-05	1.7E-03	3.4E-05	1.8E-09	3.7E-10	3.0E-03	4.2E-05
Phenol	--	5.5E-04	NA	NA	NA	2.0E-01	9.5E-08
Propylene Oxide	1.6E-03	--	3.7E-06	2.4E-09	4.8E-10	3.0E-02	5.0E-05
Styrene	--	5.5E-04	NA	NA	NA	1.0E+00	1.9E-08
Toluene	7.1E-03	9.4E-03	NA	NA	NA	5.0E+00	1.4E-06
1,1,2,2 -Tetrachloroethane	--	9.2E-04	5.8E-05	7.9E-10	1.6E-10	NA	NA
1,1,2-Trichloroethane	--	7.3E-04	1.6E-05	1.7E-10	3.5E-11	2.0E-04	1.3E-04
2,2,4-Trimethylpentane	--	5.8E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	3.4E-04	4.4E-06	2.2E-11	4.4E-12	1.0E-01	1.2E-07
Xylene	3.5E-03	4.3E-03	NA	NA	NA	1.0E-01	3.5E-05
Cumulative Cancer Risk and Hazard Index				**5E-07**	**9E-08**		**0.2**
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the fence line

Cma = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

Table 6: Cancer and Chronic Noncancer Risk Assessment Results from the Proposed Modified Brookfield Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	2.6E-03	2.0E-01	2.2E-06	8.8E-09	1.8E-09	9.0E-03	1.0E-03
Acrolein	4.1E-04	1.2E-01	NA	NA	NA	2.0E-05	2.3E-01
Benzene	7.7E-04	1.1E-02	7.8E-06	3.7E-09	7.3E-10	3.0E-02	3.7E-05
Benzo(b)fluoranthene	--	4.0E-06	1.1E-04	6.4E-12	1.3E-12	NA	NA
1,3-Butadiene	2.7E-05	6.4E-03	3.0E-05	3.2E-09	6.3E-10	2.0E-03	1.2E-04
Carbon Tetrachloride	--	8.8E-04	6.0E-06	7.8E-11	1.6E-11	1.0E-01	3.0E-07
Chlorobenzene	--	7.3E-04	NA	NA	NA	5.0E-02	5.0E-07
Chloroform	--	6.8E-04	2.3E-05	2.3E-10	4.6E-11	9.8E-02	2.4E-07
Chrysene	--	1.7E-05	1.1E-05	2.7E-12	5.4E-13	NA	NA
1,3-Dichloropropene	--	6.3E-04	4.0E-06	3.7E-11	7.4E-12	2.0E-02	1.1E-06
Ethyl Benzene	2.0E-03	9.5E-04	2.5E-06	2.1E-09	4.3E-10	1.0E+00	2.0E-06
Ethylene Dibromide	--	1.1E-03	6.0E-04	9.4E-09	1.9E-09	9.0E-03	4.1E-06
Formaldehyde	4.5E-02	1.3E+00	1.3E-05	4.8E-07	9.7E-08	9.0E-03	9.7E-03
n-Hexane	--	2.7E-02	NA	NA	NA	7.0E-01	1.3E-06
Methanol	--	6.0E-02	NA	NA	NA	2.0E+01	1.0E-07
Methylene Chloride	--	1.6E-03	1.0E-08	2.3E-13	4.7E-14	6.0E-01	9.1E-08
2-Methylnaphthalene	--	8.0E-04	NA	NA	NA	NA	NA
Naphthalene	8.3E-05	1.8E-03	3.4E-05	2.1E-09	4.1E-10	3.0E-03	4.7E-05
Phenol	--	5.8E-04	NA	NA	NA	2.0E-01	9.9E-08
Propylene Oxide	1.9E-03	--	3.7E-06	2.8E-09	5.6E-10	3.0E-02	5.9E-05
Styrene	--	5.7E-04	NA	NA	NA	1.0E+00	1.9E-08
Toluene	8.3E-03	9.8E-03	NA	NA	NA	5.0E+00	1.7E-06
1,1,2,2 -Tetrachloroethane	--	9.6E-04	5.8E-05	8.2E-10	1.6E-10	NA	NA
1,1,2-Trichloroethane	--	7.6E-04	1.6E-05	1.8E-10	3.6E-11	2.0E-04	1.3E-04
2,2,4-Trimethylpentane	--	6.0E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	3.6E-04	4.4E-06	2.3E-11	4.6E-12	1.0E-01	1.2E-07
Xylene	4.1E-03	4.4E-03	NA	NA	NA	1.0E-01	4.1E-05
Cumulative Cancer Risk and Hazard Index				**5E-07**	**1E-07**		**0.2**

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR $(\mu g/m^3)^{-1}$	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the property line

Cma = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

6.1.3 Dover Compressor Station

The risk characterization results for chronic exposure to potential natural gas combustion emissions from the existing and modified Dover Compressor Station are summarized in Tables 7 and 8, respectively. Under existing conditions, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1×10^{-6} for any individual COPC and adult and child HQs do not exceed the target noncancer HQ of 1 for any individual COPC (Table 7). Under the proposed Project, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1×10^{-6} for any individual COPC and adult and child HQs do not exceed the target noncancer HQ of 1 for any individual COPC (Table 8).

Cumulative cancer risks associated with existing conditions and the proposed Project are both well below the target cancer risk benchmark of 1×10^{-6}. Under existing conditions, adult and child cumulative cancer risks are 2×10^{-7} and 4×10^{-8}, respectively. For the proposed Project, cumulative cancer risks for adults and children are 1×10^{-7} and 2×10^{-8}, respectively. The cumulative noncancer HIs under existing conditions and for the proposed Project do not exceed the target noncancer HI benchmark of 1 (HI=0.2 and HI =0.07, respectively; Tables 7 and 8).

These risk characterization results demonstrate that current emissions and those projected under the proposed Project at the Dover Compressor Station do not pose an unacceptable chronic risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility.

Table 7: Cancer and Chronic Noncancer Risk Assessment Results from the Existing Dover Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR $(\mu g/m^3)^{-1}$	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	1.2E-04	8.6E-02	2.2E-06	4.7E-09	9.5E-10	9.0E-03	5.6E-04
Acrolein	1.9E-05	5.3E-02	NA	NA	NA	2.0E-05	1.5E-01
Benzene	3.5E-05	4.5E-03	7.8E-06	9.7E-10	1.9E-10	3.0E-02	9.7E-06
Benzo(b)fluoranthene	--	1.7E-06	1.1E-04	4.6E-12	9.2E-13	NA	NA
1,3-Butadiene	1.3E-06	2.7E-03	3.0E-05	2.0E-09	4.1E-10	2.0E-03	7.9E-05
Carbon Tetrachloride	--	3.8E-04	6.0E-06	5.5E-11	1.1E-11	1.0E-01	2.2E-07
Chlorobenzene	--	3.1E-04	NA	NA	NA	5.0E-02	3.6E-07

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Chloroform	--	2.9E-04	2.3E-05	1.6E-10	3.3E-11	9.8E-02	1.7E-07
Chrysene	--	7.1E-06	1.1E-05	1.9E-12	3.8E-13	NA	NA
1,3-Dichloropropene	--	2.7E-04	4.0E-06	2.7E-11	5.3E-12	2.0E-02	7.7E-07
Ethyl Benzene	9.3E-05	4.1E-04	2.5E-06	1.2E-10	2.4E-11	1.0E+00	1.1E-07
Ethylene Dibromide	--	4.6E-04	6.0E-04	6.7E-09	1.3E-09	9.0E-03	2.9E-06
Formaldehyde	2.1E-03	5.4E-01	1.3E-05	1.8E-07	3.7E-08	9.0E-03	3.7E-03
n-Hexane	--	1.1E-02	NA	NA	NA	7.0E-01	9.3E-07
Methanol	--	2.6E-02	NA	NA	NA	2.0E+01	7.3E-08
Methylene Chloride	--	4.1E-04	1.0E-08	1.0E-13	2.0E-14	6.0E-01	3.9E-08
2-Methylnaphthalene	--	3.4E-04	NA	NA	NA	NA	NA
Naphthalene	3.8E-06	7.7E-04	3.4E-05	6.9E-10	1.4E-10	3.0E-03	1.6E-05
Phenol	--	2.5E-04	NA	NA	NA	2.0E-01	7.0E-08
Propylene Oxide	8.4E-05	--	3.7E-06	1.3E-10	2.6E-11	3.0E-02	2.7E-06
Styrene	--	2.4E-04	NA	NA	NA	1.0E+00	1.4E-08
Toluene	3.8E-04	4.2E-03	NA	NA	NA	5.0E+00	1.2E-07
1,1,2,2 -Tetrachloroethane	--	4.1E-04	5.8E-05	5.8E-10	1.2E-10	NA	NA
1,1,2-Trichloroethane	--	3.3E-04	1.6E-05	1.3E-10	2.6E-11	2.0E-04	9.3E-05
2,2,4-Trimethylpentane	--	2.6E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	1.5E-04	4.4E-06	1.6E-11	3.3E-12	1.0E-01	8.7E-08
Xylene	1.9E-04	1.9E-03	NA	NA	NA	1.0E-01	2.9E-06
Cumulative Cancer Risk and Hazard Index				**2E-07**	**4E-08**		**0.2**
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the fence line

C*ma* = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

Table 8: Cancer and Chronic Noncancer Risk Assessment Results from the Proposed Modified Dover Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	3.4E-04	3.4E-02	2.2E-06	2.1E-09	4.3E-10	9.0E-03	2.5E-04
Acrolein	5.4E-05	2.1E-02	NA	NA	NA	2.0E-05	6.2E-02
Benzene	1.0E-04	1.8E-03	7.8E-06	6.7E-10	1.3E-10	3.0E-02	6.7E-06
Benzo(b)fluoranthene	--	6.8E-07	1.1E-04	1.8E-12	3.6E-13	NA	NA
1,3-Butadiene	3.7E-06	1.1E-03	3.0E-05	8.4E-10	1.7E-10	2.0E-03	3.3E-05
Carbon Tetrachloride	--	3.0E-04	6.0E-06	4.4E-11	8.8E-12	1.0E-01	1.7E-07
Chlorobenzene	--	1.2E-04	NA	NA	NA	5.0E-02	1.4E-07
Chloroform	--	1.2E-04	2.3E-05	6.6E-11	1.3E-11	9.8E-02	6.8E-08
Chrysene	--	2.8E-06	1.1E-05	7.6E-13	1.5E-13	NA	NA
1,3-Dichloropropene	--	1.1E-04	4.0E-06	1.1E-11	2.1E-12	2.0E-02	3.1E-07
Ethyl Benzene	2.7E-04	1.6E-04	2.5E-06	2.9E-10	5.8E-11	1.0E+00	2.7E-07
Ethylene Dibromide	--	1.8E-04	6.0E-04	2.7E-09	5.3E-10	9.0E-03	1.1E-06
Formaldehyde	6.0E-03	2.2E-01	1.3E-05	1.0E-07	2.0E-08	9.0E-03	2.0E-03
n-Hexane	--	4.5E-03	NA	NA	NA	7.0E-01	3.7E-07
Methanol	--	1.0E-02	NA	NA	NA	2.0E+01	2.9E-08
Methylene Chloride	--	8.2E-05	1.0E-08	2.0E-14	4.0E-15	6.0E-01	7.8E-09
2-Methylnaphthalene	--	1.4E-04	NA	NA	NA	NA	NA
Naphthalene	1.1E-05	3.0E-04	3.4E-05	4.1E-10	8.1E-11	3.0E-03	9.3E-06
Phenol	--	9.8E-05	NA	NA	NA	2.0E-01	2.8E-08
Propylene Oxide	2.5E-04	--	3.7E-06	3.8E-10	7.5E-11	3.0E-02	7.9E-06
Styrene	--	9.7E-05	NA	NA	NA	1.0E+00	5.5E-09
Toluene	1.1E-03	1.7E-03	NA	NA	NA	5.0E+00	2.3E-07
1,1,2,2 -Tetrachloroethane	--	1.6E-04	5.8E-05	2.3E-10	4.6E-11	NA	NA
1,1,2-Trichloroethane	--	1.3E-04	1.6E-05	5.1E-11	1.0E-11	2.0E-04	3.7E-05
2,2,4-Trimethylpentane	--	1.0E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	6.1E-05	4.4E-06	6.6E-12	1.3E-12	1.0E-01	3.5E-08
Xylene	5.4E-04	7.5E-04	NA	NA	NA	1.0E-01	5.6E-06
Cumulative Cancer Risk and Hazard Index				**1E-07**	**2E-08**		**0.07**

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the fence line

Cma = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

6.1.4 Milford Compressor Station

The risk characterization results for chronic exposure to potential natural gas combustion emissions from the existing Milford Compressor Station are summarized in Table 9. Under existing conditions, the estimated adult cancer risks and child cancer risks do not exceed the target cancer risk benchmark of 1 x 10^{-6} for any individual COPC, and adult and child HQs do not exceed the target noncancer HQ of 1 for any individual COPC. Cumulative cancer risks and cumulative noncancer HIs for existing conditions also do not exceed the target cancer risk benchmark of 1 x 10^{-6} (1 x 10^{-7} for adults and 2 x 10^{-8} for children) or the target noncancer HI of 1 (HI=0.3) (Table 9). As discussed in Section 1, there are no planned modifications to the Milford Compressor Station under the proposed Project that would result in new natural gas combustion emissions.

These risk characterization results demonstrate that current natural gas combustion emissions at the Milford Compressor Station do not currently pose an unacceptable chronic risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility.

Table 9: Cancer and Chronic Noncancer Risk Assessment Results from the Existing Milford Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Acetaldehyde	6.5E-04	3.0E-01	2.2E-06	1.0E-08	2.0E-09	9.0E-03	1.2E-03
Acrolein	1.0E-04	1.8E-01	NA	NA	NA	2.0E-05	3.1E-01
Benzene	2.0E-04	1.5E-02	7.8E-06	2.4E-09	4.8E-10	3.0E-02	2.4E-05
Benzo(b)fluoranthene	--	5.8E-06	1.1E-04	9.4E-12	1.9E-12	NA	NA
1,3-Butadiene	7.0E-06	9.4E-03	3.0E-05	4.2E-09	8.4E-10	2.0E-03	1.6E-04
Carbon Tetrachloride	--	1.3E-03	6.0E-06	1.1E-10	2.3E-11	1.0E-01	4.5E-07
Chlorobenzene	--	1.1E-03	NA	NA	NA	5.0E-02	7.2E-07
Chloroform	--	1.0E-03	2.3E-05	3.4E-10	6.7E-11	9.8E-02	3.5E-07
Chrysene	--	2.4E-05	1.1E-05	3.8E-12	7.7E-13	NA	NA
1,3-Dichloropropene	--	9.3E-04	4.0E-06	5.4E-11	1.1E-11	2.0E-02	1.6E-06

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator (µg/m³)	IUR (µg/m³)⁻¹	Adult Cancer Risk	Child Cancer Risk	RfC (mg/m³)	Adult and Child HQ
Ethyl Benzene	5.2E-04	1.4E-03	2.5E-06	5.9E-10	1.2E-10	1.0E+00	5.5E-07
Ethylene Dibromide	--	1.5E-03	6.0E-04	1.4E-08	2.7E-09	9.0E-03	5.9E-06
Formaldehyde	1.2E-02	1.9E-04	1.3E-05	6.2E-08	1.2E-08	9.0E-03	1.2E-03
n-Hexane	--	3.9E-02	NA	NA	NA	7.0E-01	1.9E-06
Methanol	--	8.8E-02	NA	NA	NA	2.0E+01	1.5E-07
Methylene Chloride	--	7.0E-04	1.0E-08	1.0E-13	2.1E-14	6.0E-01	4.0E-08
2-Methylnaphthalene	--	1.2E-03	NA	NA	NA	NA	NA
Naphthalene	2.1E-05	2.6E-03	3.4E-05	1.6E-09	3.2E-10	3.0E-03	3.7E-05
Phenol	3.6E-05	2.6E-03	NA	NA	NA	2.0E-01	6.2E-07
Propylene Oxide	4.7E-04	--	3.7E-06	7.2E-10	1.4E-10	3.0E-02	1.5E-05
Styrene	--	8.2E-04	NA	NA	NA	1.0E+00	2.8E-08
Toluene	2.1E-03	1.4E-02	NA	NA	NA	5.0E+00	5.1E-07
1,1,2,2 -Tetrachloroethane	--	1.4E-03	5.8E-05	1.2E-09	2.4E-10	NA	NA
1,1,2-Trichloroethane	--	1.1E-03	1.6E-05	2.6E-10	5.2E-11	2.0E-04	1.9E-04
2,2,4-Trimethylpentane	--	8.8E-03	NA	NA	NA	NA	NA
Vinyl Chloride	--	5.2E-04	4.4E-06	3.4E-11	6.7E-12	1.0E-01	1.8E-07
Xylene	1.0E-03	6.4E-03	NA	NA	NA	1.0E-01	1.2E-05
Cumulative Cancer Risk and Hazard Index				**1E-07**	**2E-08**		**0.3**
Target Cancer Risk and Hazard Index				**1E-06**	**1E-06**		**1**

Notes:

a - Maximum predicted 5-year average concentration at the fence line

Cma = modeled air concentration

IUR: Inhalation Unit Risk

RfC: Reference Concentration

"—" = COPC not modeled

NA – not applicable; toxicity values not available

6.2 Acute Noncancer Risk

Acute noncancer risks to human health from acute exposure to emissions from each of the compressor stations are presented below.

6.2.1 Athens Compressor Station

The risk characterization results for acute (maximum 1-hour) exposure to potential natural gas combustion emissions from the existing and modified Athens Compressor Station are summarized in Tables 10 and 11, respectively. Under existing conditions, the estimated adult and child acute HQs do not exceed the target noncancer HQ of 1 for any individual COPC. Under the proposed Project, adult and child acute noncancer HQs also do not exceed the target noncancer HQ of 1 for any individual COPC. The cumulative adult and child acute noncancer HI for existing conditions is 1 (Table 10), and the cumulative acute HI for the proposed Project is 0.4 (Table 11).

These risk characterization results demonstrate that current emissions at the Athens Compressor Station are unlikely to pose an acute risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility. These results show that the proposed Project would further reduce emissions at the Athens Compressor station to levels that clearly do not pose an unacceptable risk to human health.

Table 10: Acute Risk Assessment Results from the Existing Athens Compressor Station

COPC	C*ma* Turbine[a] (µg/m³)	C*ma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	5.7E-04	3.6E+03	1.6E-07
Acenaphthylene	--	2.5E-03	1.0E+04	2.5E-07
Acetaldehyde	1.9E-02	3.8E+00	4.7E+02	8.2E-03
Acrolein	3.0E-03	2.4E+00	2.5E+00	9.5E-01
Benzene	5.7E-03	2.0E-01	2.7E+01	7.7E-03
Benzo(b)fluoranthene	--	7.6E-05	1.2E+02	6.4E-07
Benzo(g,h,i)perylene	--	1.9E-04	3.0E+04	6.3E-09
1,3-Butadiene	2.0E-04	1.2E-01	6.6E+02	1.9E-04
Carbon Tetrachloride	--	1.7E-02	1.9E+03	8.9E-06
Chlorobenzene	--	1.4E-02	4.6E+04	3.0E-07
Chloroform	--	1.3E-02	1.5E+02	8.7E-05
Chrysene	--	3.2E-04	6.0E+02	5.3E-07
1,3-Dichloropropene	--	1.2E-02	1.4E+04	8.6E-07
Ethyl Benzene	1.5E-02	1.8E-02	1.4E+05	2.3E-07
Ethylene Dibromide	--	2.0E-02	1.3E+05	1.6E-07
Fluoranthene	--	5.1E-04	8.2E+03	6.2E-08
Fluorene	--	2.6E-03	6.6E+03	3.9E-07
Formaldehyde	3.4E-01	2.4E+01	5.5E+01	4.5E-01

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
n-Hexane	--	5.1E-01	9.1E+05	5.6E-07
Methanol	--	1.2E+00	2.8E+04	4.1E-05
Methylene Chloride	--	9.2E-03	1.4E+04	6.6E-07
2-Methylnaphthalene	--	1.5E-02	9.0E+03	1.7E-06
Naphthalene	6.2E-04	3.4E-02	7.9E+04	4.4E-07
Phenanthrene	--	4.8E-03	5.4E+03	8.9E-07
Phenol	--	1.1E-02	5.8E+03	1.9E-06
Propylene Oxide	1.4E-02	--	3.1E+03	4.5E-06
Pyrene	--	6.3E-04	1.5E+02	4.2E-06
Styrene	--	1.1E-02	2.1E+04	5.1E-07
1,1,2,2 -Tetrachloroethane	--	1.8E-02	2.1E+04	8.8E-07
Toluene	6.2E-02	1.9E-01	3.7E+04	6.7E-06
1,1,2-Trichloroethane	--	1.5E-02	1.6E+05	9.1E-08
2,2,4-Trimethylpentane	--	1.2E-01	1.1E+0 6	1.0E-07
Vinyl Chloride	--	6.8E-03	1.8E+05	3.8E-08
Xylene	3.0E-02	8.5E-02	2.2E+04	5.2E-06
Cumulative Acute Hazard Index				**1**
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the fence line

Cma = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

Table 11: Acute Risk Assessment Results from the Proposed Modified Athens Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	1.4E-04	3.6E+03	3.8E-08
Acenaphthylene	--	6.1E-04	1.0E+04	6.1E-08

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acetaldehyde	2.2E-02	9.3E-01	4.7E+02	2.0E-03
Acrolein	3.5E-03	5.7E-01	2.5E+00	2.3E-01
Benzene	6.6E-03	4.9E-02	2.7E+01	2.0E-03
Benzo(b)fluoranthene	--	1.8E-05	1.2E+02	1.5E-07
Benzo(g,h,i)perylene	--	4.6E-05	3.0E+04	1.5E-09
1,3-Butadiene	2.4E-04	3.0E-02	6.6E+02	4.5E-05
Carbon Tetrachloride	--	4.1E-03	1.9E+03	2.1E-06
Chlorobenzene	--	3.4E-03	4.6E+04	7.3E-08
Chloroform	--	3.2E-03	1.5E+02	2.1E-05
Chrysene	--	7.7E-05	6.0E+02	1.3E-07
1,3-Dichloropropene	--	2.9E-03	1.4E+04	2.1E-07
Ethyl Benzene	1.8E-02	4.4E-03	1.4E+05	1.5E-07
Ethylene Dibromide	--	4.9E-03	1.3E+05	3.8E-08
Fluoranthene	--	1.2E-04	8.2E+03	1.5E-08
Fluorene	--	6.3E-04	6.6E+03	9.5E-08
Formaldehyde	3.9E-01	5.8E+00	5.5E+01	1.1E-01
n-Hexane	--	1.2E-01	9.1E+05	1.4E-07
Methanol	--	2.8E-01	2.8E+04	9.9E-06
Methylene Chloride	--	7.4E-03	1.4E+04	5.3E-07
2-Methylnaphthalene	--	3.7E-03	9.0E+03	4.1E-07
Naphthalene	7.1E-04	8.2E-03	7.9E+04	1.1E-07
Phenanthrene	--	1.2E-03	5.4E+03	2.1E-07
Phenol	--	2.7E-03	5.8E+03	4.6E-07
Propylene Oxide	1.6E-02	--	3.1E+03	5.1E-06
Pyrene	--	1.5E-04	1.5E+02	1.0E-06
Styrene	--	2.6E-03	2.1E+04	1.2E-07
1,1,2,2 -Tetrachloroethane	--	4.4E-03	2.1E+04	2.1E-07
Toluene	7.1E-02	4.5E-02	3.7E+04	3.1E-06
1,1,2-Trichloroethane	--	3.5E-03	1.6E+05	2.2E-08

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
2,2,4-Trimethylpentane	--	2.8E-02	1.1E+06	2.5E-08
Vinyl Chloride	--	1.7E-03	1.8E+05	9.2E-09
Xylene	3.5E-02	2.0E-02	2.2E+04	2.5E-06
Cumulative Acute Hazard Index				**0.4**
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the fence line

Cma = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

6.2.2 Brookfield Compressor Station

The risk characterization results for acute (maximum 1-hour) exposure to potential natural gas combustion emissions from the existing and modified Brookfield Compressor Station are summarized in Tables 12 and 13, respectively. Under existing conditions, the estimated adult and child acute noncancer HQs do not exceed the target noncancer HQ of 1 for any individual COPC. Under the proposed Project, adult and child acute noncancer HQs also do not exceed the target noncancer HQ of 1 for any individual COPC. The cumulative adult and child acute noncancer HI for existing conditions is 1 (Table 12), and the cumulative adult and child acute noncancer HI for the proposed Project is 0.8 (Table 13).

These risk characterization results demonstrate that current emissions at the Brookfield Compressor Station are unlikely to pose an acute risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility. These results also show that the proposed Project would reduce emissions at the Brookfield Compressor station to levels that clearly do not pose an unacceptable risk to human health.

Table 12: Acute Risk Assessment Results from the Existing Brookfield Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	4.5E-04	3.6E+03	1.2E-07
Acenaphthylene	--	2.0E-03	1.0E+04	2.0E-07
Acetaldehyde	4.0E-02	3.0E+00	4.7E+02	6.5E-03
Acrolein	6.4E-03	1.8E+00	2.5E+00	7.4E-01
Benzene	1.2E-02	1.6E-01	2.7E+01	6.3E-03
Benzo(b)fluoranthene	--	6.0E-05	1.2E+02	5.0E-07

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Benzo(g,h,i)perylene	--	1.5E-04	3.0E+04	5.0E-09
1,3-Butadiene	4.3E-04	9.6E-02	6.6E+02	1.5E-04
Carbon Tetrachloride	--	1.3E-02	1.9E+03	6.9E-06
Chlorobenzene	--	1.1E-02	4.6E+04	2.4E-07
Chloroform	--	1.0E-02	1.5E+02	6.8E-05
Chrysene	--	2.5E-04	6.0E+02	4.1E-07
1,3-Dichloropropene	--	9.5E-03	1.4E+04	6.8E-07
Ethyl Benzene	3.2E-02	1.4E-02	1.4E+05	3.2E-07
Ethylene Dibromide	--	1.6E-02	1.3E+05	1.2E-07
Fluoranthene	--	4.0E-04	8.2E+03	4.9E-08
Fluorene	--	2.0E-03	6.6E+03	3.1E-07
Formaldehyde	7.1E-01	1.9E+01	5.5E+01	3.6E-01
n-Hexane	--	4.0E-01	9.1E+05	4.4E-07
Methanol	--	9.0E-01	2.8E+04	3.2E-05
Methylene Chloride	--	7.2E-03	1.4E+04	5.1E-07
2-Methylnaphthalene	--	1.2E-02	9.0E+03	1.3E-06
Naphthalene	1.3E-03	2.7E-02	7.9E+04	3.5E-07
Phenanthrene	--	3.7E-03	5.4E+03	6.9E-07
Phenol	--	8.6E-03	5.8E+03	1.5E-06
Propylene Oxide	2.9E-02	--	3.1E+03	9.3E-06
Pyrene	--	4.9E-04	1.5E+02	3.3E-06
Styrene	--	8.5E-03	2.1E+04	4.0E-07
1,1,2,2 -Tetrachloroethane	--	1.4E-02	2.1E+04	6.8E-07
Toluene	1.3E-01	1.5E-01	3.7E+04	7.5E-06
1,1,2-Trichloroethane	--	1.1E-02	1.6E+05	7.1E-08
2,2,4-Trimethylpentane	--	9.0E-02	1.1E+06	8.2E-08
Vinyl Chloride	--	5.3E-03	1.8E+05	3.0E-08
Xylene	6.4E-02	6.6E-02	2.2E+04	5.9E-06
Cumulative Acute Hazard Index				**1**

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the property line

Cma = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

Table 13: Acute Risk Assessment Results from the Proposed Modified Brookfield Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	3.4E-04	3.6E+03	9.3E-08
Acenaphthylene	--	1.5E-03	1.0E+04	1.5E-07
Acetaldehyde	4.6E-02	2.2E+00	4.7E+02	4.9E-03
Acrolein	7.4E-03	1.4E+00	2.5E+00	5.5E-01
Benzene	1.4E-02	1.2E-01	2.7E+01	4.9E-03
Benzo(b)fluoranthene	--	4.4E-05	1.2E+02	3.7E-07
Benzo(g,h,i)perylene	--	1.1E-04	3.0E+04	3.7E-09
1,3-Butadiene	5.0E-04	7.2E-02	6.6E+02	1.1E-04
Carbon Tetrachloride	--	9.8E-03	1.9E+03	5.2E-06
Chlorobenzene	--	8.1E-03	4.6E+04	1.8E-07
Chloroform	--	7.6E-03	1.5E+02	5.1E-05
Chrysene	--	1.9E-04	6.0E+02	3.1E-07
1,3-Dichloropropene	--	7.1E-03	1.4E+04	5.1E-07
Ethyl Benzene	3.7E-02	1.1E-02	1.4E+05	3.3E-07
Ethylene Dibromide	--	1.2E-02	1.3E+05	9.1E-08
Fluoranthene	--	3.0E-04	8.2E+03	3.6E-08
Fluorene	--	1.5E-03	6.6E+03	2.3E-07
Formaldehyde	8.2E-01	1.4E+01	5.5E+01	2.7E-01
n-Hexane	--	3.0E-01	9.1E+05	3.3E-07
Methanol	--	6.7E-01	2.8E+04	2.4E-05

Methylene Chloride	--	1.8E-02	1.4E+04	1.3E-06
2-Methylnaphthalene	--	8.9E-03	9.0E+03	9.9E-07
Naphthalene	1.5E-03	2.0E-02	7.9E+04	2.7E-07
Phenanthrene	--	2.8E-03	5.4E+03	5.2E-07
Phenol	--	6.4E-03	5.8E+03	1.1E-06
Propylene Oxide	3.3E-02	--	3.1E+03	1.1E-05
Pyrene	--	3.6E-04	1.5E+02	2.4E-06
Styrene	--	6.3E-03	2.1E+04	3.0E-07
1,1,2,2 -Tetrachloroethane	--	1.1E-02	2.1E+04	5.1E-07
Toluene	1.5E-01	1.1E-01	3.7E+04	7.0E-06
1,1,2-Trichloroethane	--	8.5E-03	1.6E+05	5.3E-08
2,2,4-Trimethylpentane	--	6.7E-02	1.1E+06	6.1E-08
Vinyl Chloride	--	4.0E-03	1.8E+05	2.2E-08
Xylene	7.4E-02	4.9E-02	2.2E+04	5.6E-06
Cumulative Acute Hazard Index				**0.8**
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the property line

C*ma* = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

6.2.3 Dover Compressor Station

The risk characterization results for acute (maximum 1-hour) exposure to potential natural gas combustion emissions from the existing and modified Dover Compressor Station are summarized in Tables 14 and 15, respectively. Under existing conditions, the estimated adult and child acute noncancer HQs do not exceed the target noncancer HQ of 1 for any individual COPC. For the planned future modifications, adult and child acute noncancer HQs also do not exceed the target noncancer HQ of 1 for any individual COPC. Cumulative acute noncancer HIs for both existing conditions (Table 14) and for the planned modifications (Table 15) also do not exceed the target acute noncancer HI of 1 (HI = 0.7 under existing conditions and HI = 0.5 under the proposed Project).

These risk characterization results demonstrate that current emissions and those projected under the proposed Project at the Dover Compressor Station do not pose an unacceptable acute exposure risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility.

Table 14: Acute Risk Assessment Results from the Existing Dover Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	2.9E-04	3.6E+03	8.1E-08
Acenaphthylene	--	1.3E-03	1.0E+04	1.3E-07
Acetaldehyde	6.1E-03	1.9E+00	4.7E+02	4.2E-03
Acrolein	9.7E-04	1.2E+00	2.5E+00	4.8E-01
Benzene	1.8E-03	1.0E-01	2.7E+01	3.9E-03
Benzo(b)fluoranthene	--	3.9E-05	1.2E+02	3.2E-07
Benzo(g,h,i)perylene	--	9.7E-05	3.0E+04	3.2E-09
1,3-Butadiene	6.5E-05	6.2E-02	6.6E+02	9.4E-05
Carbon Tetrachloride	--	8.6E-03	1.9E+03	4.5E-06
Chlorobenzene	--	7.1E-03	4.6E+04	1.5E-07
Chloroform	--	6.6E-03	1.5E+02	4.4E-05
Chrysene	--	1.6E-04	6.0E+02	2.7E-07
1,3-Dichloropropene	--	6.2E-03	1.4E+04	4.4E-07
Ethyl Benzene	4.9E-03	9.3E-03	1.4E+05	9.9E-08
Ethylene Dibromide	--	1.0E-02	1.3E+05	7.9E-08
Fluoranthene	--	2.6E-04	8.2E+03	3.2E-08
Fluorene	--	1.3E-03	6.6E+03	2.0E-07
Formaldehyde	1.1E-01	12.31	5.5E+01	0.23
n-Hexane	--	2.6E-01	9.1E+05	2.8E-07
Methanol	--	5.8E-01	2.8E+04	2.1E-05
Methylene Chloride	--	9.3E-03	1.4E+04	6.7E-07
2-Methylnaphthalene	--	7.7E-03	9.0E+03	8.6E-07
Naphthalene	2.0E-04	1.7E-02	7.9E+04	2.2E-07
Phenanthrene	--	2.4E-03	5.4E+03	4.5E-07
Phenol	--	5.6E-03	5.8E+03	9.6E-07
Propylene Oxide	4.4E-03	--	3.1E+03	1.4E-06
Pyrene	--	3.2E-04	1.5E+02	2.1E-06
Styrene	--	5.5E-03	2.1E+04	2.6E-07

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
1,1,2,2 -Tetrachloroethane	--	9.3E-03	2.1E+04	4.4E-07
Toluene	2.0E-02	9.5E-02	3.7E+04	3.1E-06
1,1,2-Trichloroethane	--	7.4E-03	1.6E+05	4.6E-08
2,2,4-Trimethylpentane	--	5.8E-02	1.1E+06	5.3E-08
Vinyl Chloride	--	3.5E-03	1.8E+05	1.9E-08
Xylene	9.7E-03	4.3E-02	2.2E+04	2.4E-06
Cumulative Acute Hazard Index				**0.7**
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the fence line

Cma = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

Table 15: Acute Risk Assessment Results from the Proposed Modified Dover Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	2.2E-04	3.6E+03	6.1E-08
Acenaphthylene	--	9.7E-04	1.0E+04	9.7E-08
Acetaldehyde	1.9E-02	1.5E+00	4.7E+02	3.2E-03
Acrolein	3.1E-03	9.0E-01	2.5E+00	3.6E-01
Benzene	5.8E-03	7.7E-02	2.7E+01	3.1E-03
Benzo(b)fluoranthene	--	2.9E-05	1.2E+02	2.4E-07
Benzo(g,h,i)perylene	--	7.3E-05	3.0E+04	2.4E-09
1,3 -Butadiene	2.1E-04	4.7E-02	6.6E+02	7.1E-05
Carbon Tetrachloride	--	1.3E-02	1.9E+03	6.8E-06
Chlorobenzene	--	5.3E-03	4.6E+04	1.2E-07
Chloroform	--	5.0E-03	1.5E+02	3.3E-05
Chrysene	--	1.2E-04	6.0E+02	2.0E-07
1,3 -Dichloropropene	--	4.6E-03	1.4E+04	3.3E-07

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator[a] (µg/m³)	AEIC (µg/m³)	Acute HQ
Ethyl Benzene	1.5E-02	7.0E-03	1.4E+05	1.6E-07
Ethylene Dibromide	--	7.8E-03	1.3E+05	6.0E-08
Fluoranthene	--	2.0E-04	8.2E+03	2.4E-08
Fluorene	--	1.0E-03	6.6E+03	1.5E-07
Formaldehyde	3.4E-01	9.26	5.5E+01	0.17
n-Hexane	--	2.0E-01	9.1E+05	2.1E-07
Methanol	--	4.4E-01	2.8E+04	1.6E-05
Methylene Chloride	--	3.5E-03	1.4E+04	2.5E-07
2 -Methylnaphthalene	--	5.8E-03	9.0E+03	6.5E-07
Naphthalene	6.3E-04	1.3E-02	7.9E+04	1.7E-07
Phenanthrene	--	1.8E-03	5.4E+03	3.4E-07
Phenol	--	4.2E-03	5.8E+03	7.3E-07
Propylene Oxide	1.4E-02	--	3.1E+03	4.5E-06
Pyrene	--	2.4E-04	1.5E+02	1.6E-06
Styrene	--	4.1E-03	2.1E+04	2.0E-07
1,1,2,2-Tetrachloroethane	--	7.0E-03	2.1E+04	3.3E-07
Toluene	6.3E-02	7.2E-02	3.7E+04	3.6E-06
1,1,2-Trichloroethane	--	5.6E-03	1.6E+05	3.5E-08
2,2,4 - Trimethylpentane	--	4.4E-02	1.1E+06	4.0E-08
Vinyl Chloride	--	2.6E-03	1.8E+05	1.5E-08
Xylene	3.1E-02	3.2E-02	2.2E+04	2.9E-06
Cumulative Acute Hazard Index				**0.5**
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the fence line

Cma = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

6.2.4 Milford Compressor Station

The risk characterization results for acute (maximum 1-hour) exposure to potential natural gas combustion emissions from the existing Milford Compressor Station are summarized in Table 16. Under existing conditions, the estimated adult and child acute HQs do not exceed the target noncancer HQ of 1 for any individual COPC. The cumulative acute noncancer HI for existing conditions (Table 16) does not exceed the target acute noncancer HI of 1 (HI=0.6). As discussed in Section 1, there are no planned modifications to the Milford Compressor Station that would result in new natural gas combustion emissions.

These risk characterization results demonstrate that current emissions at the Milford Compressor Station do not pose an unacceptable acute exposure risk to human health, specifically hypothetical adult and child residents located immediately adjacent to the facility.

Table 16: Acute Risk Assessment Results from the Existing Milford Compressor Station

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator (µg/m³)	AEIC (µg/m³)	Acute HQ
Acenaphthene	--	3.5E-04	3.6E+03	9.8E-08
Acenaphthylene	--	1.5E-03	1.0E+04	1.5E-07
Acetaldehyde	4.5E-02	2.4E+00	4.7E+02	5.2E-03
Acrolein	7.2E-03	1.4E+00	2.5E+00	5.7E-01
Benzene	1.3E-02	1.2E-01	2.7E+01	5.1E-03
Benzo(b)fluoranthene	--	4.7E-05	1.2E+02	3.9E-07
Benzo(g,h,i)perylene	--	1.1E-04	3.0E+04	3.8E-09
1,3 -Butadiene	4.8E-04	7.5E-02	6.6E+02	1.1E-04
Carbon Tetrachloride	--	1.0E-02	1.9E+03	5.5E-06
Chlorobenzene	--	8.5E-03	4.6E+04	1.8E-07
Chloroform	--	8.0E-03	1.5E+02	5.3E-05
Chrysene	--	1.9E-04	6.0E+02	3.2E-07
1,3 -Dichloropropene	--	7.4E-03	1.4E+04	5.3E-07
Ethyl Benzene	3.6E-02	1.1E-02	1.4E+05	3.3E-07
Ethylene Dibromide	--	1.2E-02	1.3E+05	9.5E-08
Fluoranthene	--	3.1E-04	8.2E+03	3.8E-08
Fluorene	--	1.6E-03	6.6E+03	2.4E-07
Formaldehyde	8.0E-01	1.5E-03	5.5E+01	1.4E-02
n-Hexane	--	3.1E-01	9.1E+05	3.4E-07
Methanol	--	7.0E-01	2.8E+04	2.5E-05

COPC	*Cma* Turbine[a] (µg/m³)	*Cma* Emergency Generator (µg/m³)	AEIC (µg/m³)	Acute HQ
Methylene Chloride	--	5.6E-03	1.4E+04	4.0E-07
2-Methylnaphthalene	--	9.3E-03	9.0E+03	1.0E-06
Naphthalene	1.5E-03	2.1E-02	7.9E+04	2.8E-07
Phenanthrene	--	2.9E-03	5.4E+03	5.5E-07
Phenol	2.5E-03	2.1E-02	5.8E+03	4.0E-06
Propylene Oxide	3.3E-02	--	3.1E+03	1.0E-05
Pyrene	--	3.8E-04	1.5E+02	2.5E-06
Styrene	--	6.6E-03	2.1E+04	3.1E-07
1,1,2,2 -Tetrachloroethane	--	1.1E-02	2.1E+04	5.4E-07
Toluene	1.5E-01	1.1E-01	3.7E+04	7.0E-06
1,1,2 -Trichloroethane	--	8.9E-03	1.6E+05	5.6E-08
2,2,4 - Trimethylpentane	--	7.0E-02	1.1E+06	6.4E-08
Vinyl Chloride	--	4.2E-03	1.8E+05	2.3E-08
Xylene	7.2E-02	5.1E-02	2.2E+04	5.6E-06
Cumulative Acute Hazard Index				**0.6**
Target Hazard Index				**1**

Notes:

a – highest predicted 1-hour concentration at the fence line

Cma = modeled air concentration

AIEC: Acute Inhalation Exposure Criteria

HQ: Hazard Quotient

"—" = COPC not modeled

SECTION 7 Conclusions and Discussion of Uncertainties

7.1 Uncertainties

Although uncertainty is inherent to the risk assessment process, the decisions made in the risk assessment process are biased towards the protection of human health. The key areas of uncertainty generally include (1) exposure assumptions and (2) toxicity data extrapolations. For chronic exposures, it is assumed that an individual resident may be exposed to maximum five-year average air concentrations at a compressor station fence or property line over the course of their entire residential tenure (30 years for an adult and 6 years for a child). This assumption is highly conservative since residential receptors (and other human receptors) are more realistically exposed to average concentrations over their entire exposure duration, not continuous exposure to maximum concentrations (USEPA 1989). The chronic toxicity data used to characterize cancer and chronic noncancer risks are derived almost entirely from studies of laboratory animals whereby conservative dose-response models are applied to calculate upper-bound estimates of cancer potency and noncancer thresholds. It is generally recognized that these uncertainties result in the over-estimation of health risk, thus ensuring the protection of human health. Many of the AIEC values used to assess potential acute noncancer risks are based on either very mild health effects (e.g., discomfort) or non-health related effects (e.g., odors) rather than overt toxic effects. For these COPCs, the acute noncancer HQs are considered highly conservative, and their contribution to the cumulative acute noncancer HIs in turn renders the cumulative acute noncancer HIs to be very conservative.

7.2 Other Concerns

In addition to potential health risks associated with HAP emissions from compressor stations, other concerns may be raised that are beyond the scope of this HHRA. Several of these are discussed below.

7.2.1 Unconventional vs. Conventional Natural Gas

Unconventional and conventional natural gas are both subjected to the same types of processing, transport, and end-uses and have indistinguishable atmospheric impacts post-production (Moore et al. 2014). Therefore, it is irrelevant whether the natural gas is so-called “fracked gas” (unconventional) or conventional natural gas for the purposes of this HHRA.

7.2.2 Radon

Radon and/or radiation may be present in natural gas, depending on geologic origin. Based on radon’s decay properties, the concentration of radon in processed natural gas can be expected to decrease substantially from the well head (source) and through processing and transport to compressor stations. Radon’s half-life, defined as the time it takes for the element to decay to half its initial concentration, is relatively short (3.8 days). The time needed to gather, process, store, and deliver natural gas allows a portion of the entrained radon to decay, which decreases the amount of radon in the gas before it is used in the turbines at compressor stations. Radon concentrations would also be reduced when a natural gas stream undergoes upstream processing to remove liquefied petroleum gas. Processing can remove an estimated 30 to 75 percent of the radon from natural gas (Johnson et al. 1973). Any radon present in natural gas that is combusted at the compressor stations will be widely dispersed, further reducing concentrations to insignificant levels as compared to natural background concentrations in ambient air.

7.2.3 Food Supplies

Of the COPCs considered in this HHRA, the only COPCs subject to ground-level deposition and considered to be bioaccumulative are polycyclic aromatic hydrocarbons (PAHs) including acenaphthene, acenaphthylene, benzo(b)fluoranthene, benzo(g,h,i)perylene, chrysene, fluorene, fluoranthene, naphthalene, 2-methylnaphthalene, phenanthrene and pyrene. PAHs are persistent and following deposition onto soil or surface water can be taken up by plants, fish, and animals, though many organisms are able to metabolize and eliminate these compounds (ATSDR 1995). The emitted air concentrations of these compounds over an extended period are very low and are considered an insignificant source of PAHs in the environment when compared to other sources such as vehicle exhaust and residential burning of wood. Moreover, based on a comparison of USEPA (2000) natural gas combustion emission factors for PAHs relative to the more toxic and volatile HAPs, the relative rate of emissions of PAHs is expected to be much lower by at least two to three orders of magnitude. Therefore, the potential impact of PAHs on the food supply from natural gas combustion is considered to be insignificant as compared to other sources.

7.3 Conclusions

The HHRA shows that modeled HAP emissions from normal operations of the compressor stations with upgrades under the proposed Project are well below a level of health concern. The analysis of these emissions utilized highly conservative assumptions for receptor exposure (e.g., an individual would be exposed to the maximum concentrations from full-capacity facility operation for 24 hours per day for 350 days per year). Specifically, potential total excess lifetime cancer risk and noncancer hazard indices were calculated based on a theoretical RME adult and child from long-term exposures to the highest predicted maximum five-year average HAP concentrations emitted during normal operations at the facility fence line or property line. This is a very conservative assumption given that concentrations will decrease substantially with distance from the fence line or property line, further reducing exposure and risk. Cumulative cancer risks were below 1 in one million and noncancer hazard indices were at or below the target HI of 1 (e.g., the level at which sensitive individuals can be exposed without risk of chronic noncancer health effects).

Acute exposure evaluations were based on short-term maximum concentrations using conservative meteorological conditions. The potential for short-term health effects due to exposures to the highest predicted 1-hour HAP concentrations emitted during normal operations was assessed to account for periods of high exposures. Air concentrations were evaluated against the AIEC, which are protective of the general public, including sensitive subpopulations, for a variety of toxic endpoints. The AIEC that were used also protect against discomfort, mild health effects, and objectionable odors. The results of the analysis indicate that acute exposures to the highest predicted 1-hour emissions during normal operations of the proposed Project would be at or below the benchmark criteria (e.g., the level at which sensitive individuals can be exposed without risk of acute noncancer health effects).

Therefore, it can be concluded that under existing conditions there is no significant impact on human health in the Project areas from inhalation of emissions associated with the Athens, Brookfield, Dover, or Milford compressor stations. It can also be concluded that there would be no significant impact on human health in the Project areas from inhalation of emissions associated with the proposed modifications to the Athens, Brookfield, or Dover compressor stations.

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Appendix A

Modeled Air Concentrations and Emissions Factors

Catalyst
ENVIRONMENTAL SOLUTIONS

Table A1: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Existing Athens Compressor Station

COPC	1-hour Modeled Impacts ($\mu g/m^3$)		Annual Modeled Impacts ($\mu g/m^3$)	
	A1 Turbine	***Emergency Generator***	***A1 Turbine***	***Emergency Generator***
1,1,2 - Trichloroethane	-	1.46E-02	-	7.34E-04
1,1,2,2 -Tetrachloroethane	-	1.84E-02	-	9.24E-04
1,3 - Butadiene	2.04E-04	1.23E-01	5.44E-07	6.17E-03
1,3 - Dichloropropene	-	1.21E-02	-	6.10E-04
2 - Methylnaphthalene	-	1.52E-02	-	7.67E-04
2,2,4 - Trimethylpentane	-	1.15E-01	-	5.77E-03
Acenaphthene	-	5.74E-04	-	2.89E-05
Acenaphthylene	-	2.54E-03	-	1.28E-04
Acetaldehyde	1.90E-02	3.84E+00	5.06E-05	1.93E-01
Acrolein	3.04E-03	2.36E+00	8.10E-06	1.19E-01
Benzene	5.70E-03	2.02E-01	1.52E-05	1.02E-02
Benzo(b)fluoranthene	-	7.62E-05	-	3.83E-06
Benzo(e)pyrene	-	1.91E-04	-	9.59E-06
Benzo(g,h,i)perylene	-	1.90E-04	-	9.56E-06
Biphenyl	-	9.74E-02	-	4.90E-03
Carbon Tetrachloride	-	1.69E-02	-	8.48E-04
Chlorobenzene	-	1.40E-02	-	7.02E-04
Chloroform	-	1.31E-02	-	6.58E-04
Chrysene	-	3.18E-04	-	1.60E-05
Ethyl Benzene	1.52E-02	1.82E-02	4.05E-05	9.17E-04
Ethylene Dibromide	-	2.03E-02	-	1.02E-03
Fluorene	-	2.60E-03	-	1.31E-04
Fluoranthene	-	5.10E-04	-	2.56E-05
Formaldehyde	3.37E-01	2.42E+01	8.99E-04	1.22E+00
Methanol	-	1.15E+00	-	5.77E-02
Methylene Chloride	-	9.18E-03	-	4.62E-04
Naphthalene	6.18E-04	3.42E-02	1.65E-06	1.72E-03
n-Hexane	-	5.10E-01	-	2.56E-02
PAH	1.05E-03	1.24E-02	2.78E-06	6.21E-04
Phenanthrene	-	4.78E-03	-	2.40E-04
Phenol	-	1.10E-02	-	5.54E-04
Propylene Oxide	1.38E-02	-	3.67E-05	-
Pyrene	-	6.25E-04	-	3.14E-05
Styrene	-	1.08E-02	-	5.45E-04
Tetrachloroethane	-	1.14E-03	-	5.73E-05
Toluene	6.18E-02	1.87E-01	1.65E-04	9.42E-03
Vinyl Chloride	-	6.84E-03	-	3.44E-04
Xylene	3.04E-02	8.45E-02	8.10E-05	4.25E-03

Notes: "-" = COPC not modeled

Table A2: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Proposed Athens Compressor Station

COPC	1-hour Modeled Impacts ($\mu g/m^3$)			Annual Modeled Impacts ($\mu g/m^3$)		
	A1 Turbine	*A2 Turbine*	*Emergency Generator*	*A1 Turbine*	*A2 Turbine*	*Emergency Generator*
1,1,2 - Trichloroethane	-	-	3.52E-03	-	-	1.68E-04
1,1,2,2 -Tetrachloroethane	-	-	4.43E-03	-	-	2.11E-04
1,3 - Butadiene	2.04E-04	3.13E-05	2.96E-02	5.44E-07	6.21E-07	1.41E-03
1,3 - Dichloropropene	-	-	2.92E-03	-	-	1.39E-04
2 - Methylnaphthalene	-	-	3.68E-03	-	-	1.75E-04
2,2,4 - Trimethylpentane	-	-	2.77E-02	-	-	1.32E-03
Acenaphthene	-	-	1.38E-04	-	-	6.59E-06
Acenaphthylene	-	-	6.13E-04	-	-	2.92E-05
Acetaldehyde	1.90E-02	2.91E-03	9.26E-01	5.06E-05	5.78E-05	4.41E-02
Acrolein	3.04E-03	4.66E-04	5.69E-01	8.10E-06	9.25E-06	2.71E-02
Benzene	5.70E-03	8.74E-04	4.87E-02	1.52E-05	1.73E-05	2.32E-03
Benzo(b)fluoranthene	-	-	1.84E-05	-	-	8.75E-07
Benzo(e)pyrene	-	-	4.60E-05	-	-	2.19E-06
Benzo(g,h,i)perylene	-	-	4.59E-05	-	-	2.18E-06
Biphenyl	-	-	2.35E-02	-	-	1.12E-03
Carbon Tetrachloride	-	-	4.07E-03	-	-	1.94E-04
Chlorobenzene	-	-	3.37E-03	-	-	1.60E-04
Chloroform	-	-	3.16E-03	-	-	1.50E-04
Chrysene	-	-	7.68E-05	-	-	3.65E-06
Ethyl Benzene	1.52E-02	2.33E-03	4.40E-03	4.05E-05	4.62E-05	2.09E-04
Ethylene Dibromide	-	-	4.91E-03	-	-	2.34E-04
Fluorene	-	-	6.28E-04	-	-	2.99E-05
Fluoranthene	-	-	1.23E-04	-	-	5.85E-06
Formaldehyde	3.37E-01	5.17E-02	5.85E+00	8.99E-04	1.03E-03	2.78E-01
Methanol	-	-	2.77E-01	-	-	1.32E-02
Methylene Chloride	-	-	7.38E-03	-	-	3.52E-04
Naphthalene	6.18E-04	9.47E-05	8.24E-03	1.65E-06	1.88E-06	3.92E-04
n-Hexane	-	-	1.23E-01	-	-	5.85E-03
PAH	1.05E-03	1.60E-04	2.98E-03	2.78E-06	3.18E-06	1.42E-04
Phenanthrene	-	-	1.15E-03	-	-	5.48E-05
Phenol	-	-	2.66E-03	-	-	1.27E-04
Propylene Oxide	1.38E-02	2.11E-03	-	3.67E-05	4.19E-05	-
Pyrene	-	-	1.51E-04	-	-	7.17E-06
Styrene	-	-	2.61E-03	-	-	1.24E-04
Tetrachloroethane	-	-	2.75E-04	-	-	1.31E-05
Toluene	6.18E-02	9.47E-03	4.52E-02	1.65E-04	1.88E-04	2.15E-03
Vinyl Chloride	-	-	1.65E-03	-	-	7.86E-05
Xylene	3.04E-02	4.66E-03	2.04E-02	8.10E-05	9.25E-05	9.70E-04

Notes: "-" = COPC not modeled

Table A3: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Existing Brookfield Compressor Station

COPC	1-hour Modeled Impacts (µg/m^3)			Annual Modeled Impacts (µg/m^3)		
	A1 Turbine	***A2 Turbine***	***Emergency Generator***	***A1 Turbine***	***A2 Turbine***	***Emergency Generator***
1,1,2 - Trichloroethane	-	-	1.14E-02	-	-	7.35E-04
1,1,2,2 -Tetrachloroethane	-	-	1.44E-02	-	-	9.24E-04
1,3 - Butadiene	1.95E-04	2.32E-04	9.59E-02	1.03E-05	1.30E-05	6.17E-03
1,3 - Dichloropropene	-	-	9.48E-03	-	-	6.10E-04
2 - Methylnaphthalene	-	-	1.19E-02	-	-	7.67E-04
2,2,4 - Trimethylpentane	-	-	8.98E-02	-	-	5.78E-03
Acenaphthene	-	-	4.49E-04	-	-	2.89E-05
Acenaphthylene	-	-	1.99E-03	-	-	1.28E-04
Acetaldehyde	1.82E-02	2.16E-02	3.00E+00	9.54E-04	1.21E-03	1.93E-01
Acrolein	2.91E-03	3.46E-03	1.85E+00	1.53E-04	1.93E-04	1.19E-01
Benzene	5.45E-03	6.49E-03	1.58E-01	2.86E-04	3.62E-04	1.02E-02
Benzo(b)fluoranthene	-	-	5.96E-05	-	-	3.84E-06
Benzo(e)pyrene	-	-	1.49E-04	-	-	9.59E-06
Benzo(g,h,i)perylene	-	-	1.49E-04	-	-	9.57E-06
Biphenyl	-	-	7.61E-02	-	-	4.90E-03
Carbon Tetrachloride	-	-	1.32E-02	-	-	8.48E-04
Chlorobenzene	-	-	1.09E-02	-	-	7.03E-04
Chloroform	-	-	1.02E-02	-	-	6.59E-04
Chrysene	-	-	2.49E-04	-	-	1.60E-05
Ethyl Benzene	1.45E-02	1.73E-02	1.43E-02	7.63E-04	9.65E-04	9.18E-04
Ethylene Dibromide	-	-	1.59E-02	-	-	1.02E-03
Fluorene	-	-	2.04E-03	-	-	1.31E-04
Fluoranthene	-	-	3.99E-04	-	-	2.57E-05
Formaldehyde	3.23E-01	3.84E-01	1.90E+01	1.69E-02	2.14E-02	1.22E+00
Methanol	-	-	8.98E-01	-	-	5.78E-02
Methylene Chloride	-	-	7.18E-03	-	-	4.62E-04
Naphthalene	5.91E-04	7.03E-04	2.67E-02	3.10E-05	3.92E-05	1.72E-03
n-Hexane	-	-	3.99E-01	-	-	2.57E-02
PAH	1.00E-03	1.19E-03	9.66E-03	5.25E-05	6.63E-05	6.22E-04
Phenanthrene	-	-	3.73E-03	-	-	2.40E-04
Phenol	-	-	8.62E-03	-	-	5.55E-04
Propylene Oxide	1.32E-02	1.57E-02	-	6.92E-04	8.74E-04	-
Pyrene	-	-	4.88E-04	-	-	3.14E-05
Styrene	-	-	8.47E-03	-	-	5.45E-04
Tetrachloroethane	-	-	8.90E-04	-	-	5.73E-05
Toluene	5.91E-02	7.03E-02	1.46E-01	3.10E-03	3.92E-03	9.43E-03
Vinyl Chloride	-	-	5.35E-03	-	-	3.44E-04
Xylene	2.91E-02	3.46E-02	6.61E-02	1.53E-03	1.93E-03	4.25E-03

Notes: "-" = COPC not modeled

Table A4: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Proposed Brookfield Compressor Station

COPC	1-hour Modeled Impacts ($\mu g/m^3$)						Annual Modeled Impacts ($\mu g/m^3$)					
	A1 Turbine	***A2 Turbine***	***B1 Turbine***	***B2 Turbine***	***Emergency Generator 1***	***Emergency Generator 2***	***A1 Turbine***	***A2 Turbine***	***B1 Turbine***	***B2 Turbine***	***Emergency Generator 1***	***Emergency Generator 2***
1,1,2 - Trichloroethane	-	-	-	-	3.50E-03	5.02E-03	-	-	-	-	2.85E-04	4.79E-04
1,1,2,2 -Tetrachloroethane	-	-	-	-	4.41E-03	6.32E-03	-	-	-	-	3.59E-04	6.03E-04
1,3 - Butadiene	1.13E-04	1.26E-04	1.27E-04	1.29E-04	2.94E-02	4.22E-02	6.16E-06	7.02E-06	7.03E-06	7.26E-06	2.39E-03	4.02E-03
1,3 - Dichloropropene	-	-	-	-	2.91E-03	4.17E-03	-	-	-	-	2.37E-04	3.98E-04
2 - Methylnaphthalene	-	-	-	-	3.66E-03	5.24E-03	-	-	-	-	2.98E-04	5.00E-04
2,2,4 - Trimethylpentane	-	-	-	-	2.75E-02	3.95E-02	-	-	-	-	2.24E-03	3.77E-03
Acenaphthene	-	-	-	-	1.38E-04	1.97E-04	-	-	-	-	1.12E-05	1.88E-05
Acenaphthylene	-	-	-	-	6.09E-04	8.73E-04	-	-	-	-	4.96E-05	8.33E-05
Acetaldehyde	1.05E-02	1.17E-02	1.18E-02	1.20E-02	9.21E-01	1.32E+00	5.73E-04	6.53E-04	6.54E-04	6.75E-04	7.49E-02	1.26E-01
Acrolein	1.69E-03	1.88E-03	1.89E-03	1.92E-03	5.66E-01	8.12E-01	9.17E-05	1.04E-04	1.05E-04	1.08E-04	4.61E-02	7.74E-02
Benzene	3.16E-03	3.52E-03	3.54E-03	3.60E-03	4.85E-02	6.95E-02	1.72E-04	1.96E-04	1.96E-04	2.03E-04	3.94E-03	6.63E-03
Benzo(b)fluoranthene	-	-	-	-	1.83E-05	2.62E-05	-	-	-	-	1.49E-06	2.50E-06
Benzo(e)pyrene	-	-	-	-	4.57E-05	6.55E-05	-	-	-	-	3.72E-06	6.25E-06
Benzo(g,h,i)perylene	-	-	-	-	4.56E-05	6.54E-05	-	-	-	-	3.71E-06	6.24E-06
Biphenyl	-	-	-	-	2.33E-02	3.35E-02	-	-	-	-	1.90E-03	3.19E-03
Carbon Tetrachloride	-	-	-	-	4.04E-03	5.79E-03	-	-	-	-	3.29E-04	5.53E-04
Chlorobenzene	-	-	-	-	3.35E-03	4.80E-03	-	-	-	-	2.73E-04	4.58E-04
Chloroform	-	-	-	-	3.14E-03	4.50E-03	-	-	-	-	2.56E-04	4.29E-04
Chrysene	-	-	-	-	7.63E-05	1.09E-04	-	-	-	-	6.21E-06	1.04E-05
Ethyl Benzene	8.43E-03	9.38E-03	9.45E-03	9.60E-03	4.37E-03	6.27E-03	4.58E-04	5.22E-04	5.23E-04	5.40E-04	3.56E-04	5.98E-04
Ethylene Dibromide	-	-	-	-	4.88E-03	6.99E-03	-	-	-	-	3.97E-04	6.67E-04
Fluorene	-	-	-	-	6.24E-04	8.95E-04	-	-	-	-	5.08E-05	8.54E-05
Fluoranthene	-	-	-	-	1.22E-04	1.75E-04	-	-	-	-	9.95E-06	1.67E-05
Formaldehyde	1.87E-01	2.08E-01	2.10E-01	2.13E-01	5.82E+00	8.34E+00	1.02E-02	1.16E-02	1.16E-02	1.20E-02	4.73E-01	7.96E-01
Methanol	-	-	-	-	2.75E-01	3.95E-01	-	-	-	-	2.24E-02	3.77E-02
Methylene Chloride	-	-	-	-	7.34E-03	1.05E-02	-	-	-	-	5.97E-04	1.00E-03
Naphthalene	3.43E-04	3.81E-04	3.84E-04	3.90E-04	8.19E-03	1.17E-02	1.86E-05	2.12E-05	2.13E-05	2.19E-05	6.67E-04	1.12E-03
n-Hexane	-	-	-	-	1.22E-01	1.75E-01	-	-	-	-	9.96E-03	1.67E-02
PAH	5.80E-04	6.45E-04	6.50E-04	6.60E-04	2.96E-03	4.25E-03	3.15E-05	3.59E-05	3.60E-05	3.71E-05	2.41E-04	4.05E-04
Phenanthrene	-	-	-	-	1.15E-03	1.64E-03	-	-	-	-	9.32E-05	1.57E-04
Phenol	-	-	-	-	2.64E-03	3.79E-03	-	-	-	-	2.15E-04	3.62E-04
Propylene Oxide	7.64E-03	8.50E-03	8.56E-03	8.70E-03	-	-	4.15E-04	4.73E-04	4.74E-04	4.89E-04	-	-
Pyrene	-	-	-	-	1.50E-04	2.15E-04	-	-	-	-	1.22E-05	2.05E-05
Styrene	-	-	-	-	2.60E-03	3.73E-03	-	-	-	-	2.12E-04	3.56E-04
Tetrachloroethane	-	-	-	-	2.73E-04	3.92E-04	-	-	-	-	2.22E-05	3.74E-05
Toluene	3.43E-02	3.81E-02	3.84E-02	3.90E-02	4.49E-02	6.44E-02	1.86E-03	2.12E-03	2.13E-03	2.19E-03	3.66E-03	6.15E-03
Vinyl Chloride	-	-	-	-	1.64E-03	2.35E-03	-	-	-	-	1.34E-04	2.25E-04
Xylene	1.69E-02	1.88E-02	1.89E-02	1.92E-02	2.03E-02	2.91E-02	9.17E-04	1.04E-03	1.05E-03	1.08E-03	1.65E-03	2.77E-03

Notes: "-" = COPC not modeled

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Table A5: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Existing Dover Compressor Station

COPC	1-hour Modeled Impacts ($\mu g/m^3$)		Annual Modeled Impacts ($\mu g/m^3$)	
	A1 Turbine	***Emergency Generator***	***A1 Turbine***	***Emergency Generator***
1,1,2 - Trichloroethane	-	7.41E-03	-	3.27E-04
1,1,2,2 -Tetrachloroethane	-	9.33E-03	-	4.12E-04
1,3 - Butadiene	6.54E-05	6.23E-02	1.25E-06	2.75E-03
1,3 - Dichloropropene	-	6.16E-03	-	2.72E-04
2 - Methylnaphthalene	-	7.74E-03	-	3.42E-04
2,2,4 - Trimethylpentane	-	5.83E-02	-	2.57E-03
Acenaphthene	-	2.91E-04	-	1.29E-05
Acenaphthylene	-	1.29E-03	-	5.69E-05
Acetaldehyde	6.09E-03	1.95E+00	1.16E-04	8.60E-02
Acrolein	9.74E-04	1.20E+00	1.85E-05	5.29E-02
Benzene	1.83E-03	1.03E-01	3.48E-05	4.53E-03
Benzo(b)fluoranthene	-	3.87E-05	-	1.71E-06
Benzo(e)pyrene	-	9.68E-05	-	4.27E-06
Benzo(g,h,i)perylene	-	9.65E-05	-	4.26E-06
Biphenyl	-	4.94E-02	-	2.18E-03
Carbon Tetrachloride	-	8.56E-03	-	3.78E-04
Chlorobenzene	-	7.09E-03	-	3.13E-04
Chloroform	-	6.65E-03	-	2.93E-04
Chrysene	-	1.62E-04	-	7.13E-06
Ethyl Benzene	4.87E-03	9.26E-03	9.27E-05	4.09E-04
Ethylene Dibromide	-	1.03E-02	-	4.56E-04
Fluorene	-	1.32E-03	-	5.84E-05
Fluoranthene	-	2.59E-04	-	1.14E-05
Formaldehyde	1.08E-01	1.23E+01	2.06E-03	5.43E-01
Methanol	-	5.83E-01	-	2.57E-02
Methylene Chloride	-	9.33E-03	-	4.12E-04
Naphthalene	1.98E-04	1.73E-02	3.77E-06	7.66E-04
n-Hexane	-	2.59E-01	-	1.14E-02
PAH	3.35E-04	6.27E-03	6.37E-06	2.77E-04
Phenanthrene	-	2.43E-03	-	1.07E-04
Phenol	-	5.60E-03	-	2.47E-04
Propylene Oxide	4.41E-03	-	8.40E-05	-
Pyrene	-	3.17E-04	-	1.40E-05
Styrene	-	5.50E-03	-	2.43E-04
Tetrachloroethane	-	5.78E-04	-	2.55E-05
Toluene	1.98E-02	9.51E-02	3.77E-04	4.20E-03
Vinyl Chloride	-	3.47E-03	-	1.53E-04
Xylene	9.74E-03	4.29E-02	1.85E-04	1.89E-03

Notes: "-" = COPC not modeled

Table A6: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Proposed Dover Compressor Station

COPC	1-hour Modeled Impacts ($\mu g/m^3$)			Annual Modeled Impacts ($\mu g/m^3$)		
	A1 Turbine	***A2 Turbine***	***Emergency Generator***	***A1 Turbine***	***A2 Turbine***	***Emergency Generator***
1,1,2 - Trichloroethane	-	-	5.58E-03	-	-	1.30E-04
1,1,2,2 -Tetrachloroethane	-	-	7.02E-03	-	-	1.64E-04
1,3 - Butadiene	6.54E-05	1.42E-04	4.68E-02	1.25E-06	2.41E-06	1.09E-03
1,3 - Dichloropropene	-	-	4.63E-03	-	-	1.08E-04
2 - Methylnaphthalene	-	-	5.82E-03	-	-	1.36E-04
2,2,4 - Trimethylpentane	-	-	4.39E-02	-	-	1.02E-03
Acenaphthene	-	-	2.19E-04	-	-	5.11E-06
Acenaphthylene	-	-	9.70E-04	-	-	2.26E-05
Acetaldehyde	6.09E-03	1.32E-02	1.47E+00	1.16E-04	2.24E-04	3.42E-02
Acrolein	9.74E-04	2.11E-03	9.02E-01	1.85E-05	3.59E-05	2.10E-02
Benzene	1.83E-03	3.96E-03	7.72E-02	3.48E-05	6.73E-05	1.80E-03
Benzo(b)fluoranthene	-	-	2.91E-05	-	-	6.79E-07
Benzo(e)pyrene	-	-	7.28E-05	-	-	1.70E-06
Benzo(g,h,i)perylene	-	-	7.26E-05	-	-	1.69E-06
Biphenyl	-	-	3.72E-02	-	-	8.67E-04
Carbon Tetrachloride	-	-	1.29E-02	-	-	3.00E-04
Chlorobenzene	-	-	5.33E-03	-	-	1.24E-04
Chloroform	-	-	5.00E-03	-	-	1.17E-04
Chrysene	-	-	1.22E-04	-	-	2.84E-06
Ethyl Benzene	4.87E-03	1.06E-02	6.96E-03	9.27E-05	1.79E-04	1.62E-04
Ethylene Dibromide	-	-	7.77E-03	-	-	1.81E-04
Fluorene	-	-	9.95E-04	-	-	2.32E-05
Fluoranthene	-	-	1.95E-04	-	-	4.54E-06
Formaldehyde	1.08E-01	2.34E-01	9.26E+00	2.06E-03	3.98E-03	2.16E-01
Methanol	-	-	4.39E-01	-	-	1.02E-02
Methylene Chloride	-	-	3.51E-03	-	-	8.18E-05
Naphthalene	1.98E-04	4.29E-04	1.31E-02	3.77E-06	7.29E-06	3.04E-04
n-Hexane	-	-	1.95E-01	-	-	4.54E-03
PAH	3.35E-04	7.26E-04	9.44E-03	6.37E-06	1.23E-05	2.20E-04
Phenanthrene	-	-	1.82E-03	-	-	4.26E-05
Phenol	-	-	4.21E-03	-	-	9.82E-05
Propylene Oxide	4.41E-03	9.57E-03	-	8.40E-05	1.63E-04	-
Pyrene	-	-	2.39E-04	-	-	5.56E-06
Styrene	-	-	4.14E-03	-	-	9.66E-05
Tetrachloroethane	-	-	4.35E-04	-	-	1.01E-05
Toluene	1.98E-02	4.29E-02	7.16E-02	3.77E-04	7.29E-04	1.67E-03
Vinyl Chloride	-	-	2.61E-03	-	-	6.10E-05
Xylene	9.74E-03	2.11E-02	3.23E-02	1.85E-04	3.59E-04	7.53E-04

Notes: "-" = COPC not modeled

Table A7: Modeled 1-hour and Maximum Annual Ambient Emissions Concentrations from the Existing Milford Compressor Station

COPC	1-hour Modeled Impacts ($\mu g/m^3$)			Annual Modeled Impacts ($\mu g/m^3$)		
	A1 Turbine	***A2 Turbine***	***Emergency Generator***	***A1 Turbine***	***A2 Turbine***	***Emergency Generator***
1,1,2,2-Tetrachloroethane	-	-	1.14E-02	-	-	1.42E-03
1,1,2-Trichloroethane	-	-	8.94E-03	-	-	1.12E-03
1,3-Butadiene	2.41E-04	2.41E-04	7.51E-02	3.73E-06	3.30E-06	9.38E-03
1,3-Dichloropropene	-	-	7.42E-03	-	-	9.26E-04
2 - Methylnaphthalene	-	-	9.32E-03	-	-	1.16E-03
2,2,4-Trimethylpentane	-	-	7.04E-02	-	-	8.78E-03
Acenaphthene	-	-	3.52E-04	-	-	4.39E-05
Acenaphthylene	-	-	1.52E-03	-	-	1.90E-04
Acetaldehyde	2.24E-02	2.24E-02	2.38E+00	3.47E-04	3.07E-04	2.97E-01
Acrolein	3.58E-03	3.59E-03	1.43E+00	5.56E-05	4.91E-05	1.78E-01
Benzene	6.72E-03	6.73E-03	1.24E-01	1.04E-04	9.21E-05	1.54E-02
Benzo(b)fluoranthene	-	-	4.66E-05	-	-	5.82E-06
Benzo(e)pyrene	-	-	1.14E-04	-	-	1.42E-05
Benzo(g,h,i)perylene	-	-	1.14E-04	-	-	1.42E-05
Biphenyl	-	-	5.90E-02	-	-	7.36E-03
Carbon tetrachloride	-	-	1.05E-02	-	-	1.31E-03
Chlorobenzene	-	-	8.46E-03	-	-	1.06E-03
Chloroform	-	-	7.99E-03	-	-	9.97E-04
Chrysene	-	-	1.90E-04	-	-	2.37E-05
Ethyl benzene	1.79E-02	1.80E-02	1.14E-02	2.78E-04	2.46E-04	1.42E-03
Ethylene dibromide	-	-	1.24E-02	-	-	1.54E-03
Fluoranthene	-	-	3.14E-04	-	-	3.92E-05
Fluorene	-	-	1.62E-03	-	-	2.02E-04
Formaldehyde	3.97E-01	3.98E-01	1.52E-03	6.16E-03	5.45E-03	1.90E-04
Hexane	-	-	3.14E-01	-	-	3.92E-02
Methanol	-	-	7.04E-01	-	-	8.78E-02
Methylene chloride	-	-	5.61E-03	-	-	7.00E-04
Naphthalene	7.28E-04	7.30E-04	2.09E-02	1.13E-05	9.98E-06	2.61E-03
Phenanthrene	-	-	2.95E-03	-	-	3.68E-04
Phenol	1.23E-03	1.23E-03	2.10E-02	1.91E-05	1.69E-05	2.62E-03
Propylene oxide	1.62E-02	1.63E-02	-	2.52E-04	2.23E-04	-
Pyrene	-	-	3.80E-04	-	-	4.75E-05
Styrene	-	-	6.56E-03	-	-	8.19E-04
Tetrachloroethane	-	-	6.94E-04	-	-	8.67E-05
Toluene	7.28E-02	7.30E-02	1.14E-01	1.13E-03	9.98E-04	1.42E-02
Vinyl chloride	-	-	4.18E-03	-	-	5.22E-04
Xylenes	3.58E-02	3.59E-02	5.14E-02	5.56E-04	4.91E-04	6.41E-03

Notes: "-" = COPC not modeled

Table A8: Emissions Factors

COPC	Turbines	Emergency Generators
1,1,2 - Trichloroethane	-	3.18E-05
1,1,2,2 -Tetrachloroethane	-	4.00E-05
1,3 - Butadiene	4.30E-07	2.67E-04
1,3 - Dichloropropene	-	2.64E-05
2 - Methylnaphthalene	-	3.32E-05
2,2,4 - Trimethylpentane	-	2.50E-04
Acenaphthene	-	1.25E-06
Acenaphthylene	-	5.53E-06
Acetaldehyde	4.00E-05	8.36E-03
Acrolein	6.40E-06	5.14E-03
Benzene	1.20E-05	4.40E-04
Benzo(b)fluoranthene	-	1.66E-07
Benzo(e)pyrene	-	4.15E-07
Benzo(g,h,i)perylene	-	4.14E-07
Biphenyl	-	2.12E-04
Carbon Tetrachloride	-	3.67E-05
Chlorobenzene	-	3.04E-05
Chloroform	-	2.85E-05
Chrysene	-	6.93E-07
Ethyl Benzene	3.20E-05	3.97E-05
Ethylene Dibromide	-	4.43E-05
Fluorene	-	5.67E-06
Fluoranthene	-	1.11E-06
Formaldehyde	7.10E-04	5.28E-02
Methanol	-	2.50E-03
Methylene Chloride	-	2.00E-05
Naphthalene	-	7.44E-05
n-Hexane	-	1.11E-03
PAH	2.20E-06	2.69E-05
Phenanthrene	-	1.04E-05
Phenol	-	2.40E-05
Propylene Oxide	2.90E-05	-
Pyrene	-	1.36E-06
Styrene	-	2.36E-05
Tetrachloroethane	-	2.48E-06
Toluene	1.30E-04	4.08E-04
Vinyl Chloride	-	1.49E-05
Xylene	6.40E-05	1.84E-04

Notes: "-" = COPC not modeled

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