STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

Docket No. DG 21-008
Petition for Approval of a Firm Transportation Agreement with Tennessee Gas Pipeline Company, LLC

DIRECT TESTIMONY OF

DAVID G. HILL, PH.D.

ON BEHALF OF CONSERVATION LAW FOUNDATION

ENERGY FUTURES GROUP

JUNE 25, 2021

I. INTRODUCTION AND QUALIFICATIONS

Q: Please state your name, occupation, and business address.

A: My name is David G. Hill, Ph.D. I am a Managing Consultant with Energy Futures Group, Inc. located in Hinesburg, Vermont.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of Conservation Law Foundation ("CLF"), 27 North Main Street Concord, NH 03301. CLF is a non-profit organization dedicated to protecting New England's environment for the benefit of all people.

Q: Dr. Hill, what is your education and professional background?

A: I joined Energy Futures Group ("EFG") in January of 2020. My work since then has included expert testimony on the Dominion Energy South Carolina's 2020 Integrated Resource Plan; a critical analysis for the need of a proposed natural gas pipeline expansion in New York City; support for testimony on the partial transfer of ownership of a coal fired power plant in Montana; analysis of the customer economics for strategic electrification in Illinois; scenario modeling for statewide greenhouse gas ("GHG") reduction strategies in Massachusetts; and analysis of cost recovery for utility efficiency and demand response initiatives in Maryland.

EFG is a clean-energy consulting firm headquartered in Hinesburg, Vermont, with offices in Boston and New York. EFG designs, implements, and evaluates programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. EFG staff have delivered projects on behalf of energy regulators, government agencies, utilities, and advocacy organizations in 40 states, 8 Canadian provinces, and several countries in Europe. EFG brings to its work a unique combination of technical, economic, program, and policy expertise. EFG is currently engaged or has recently provided expert testimony and analysis on proposed gas infrastructure, pilot programs, and future planning in Illinois, New York, Rhode Island, and Massachusetts.

Prior to joining EFG, I worked for the Vermont Energy Investment Corporation ("VEIC") for 22 years, starting in 1998 as an analyst, subsequently holding several positions over the decades, and serving my last five years as Director of Distributed Resources and Policy

Fellow. As the Director of Distributed Resources and a Policy Fellow at VEIC, I was responsible for advancing sustainable energy program design and evaluation. For two decades, I regularly led major consulting assignments at VEIC, being best known for my work in distributed energy resources, particularly solar energy. I provided expert testimony and regulatory support on renewable energy and energy efficiency in six jurisdictions in Canada and the United States. I was regularly engaged as an expert on renewable energy market design and regulatory issues at international, national, and regional conferences and workshops. I served on national, state, and local level boards. I also led policy committees and conferences, and comprehensive studies of the economic, technical, and achievable potentials for sustainable energy programming. My work also supported detailed level program budget planning and implementation.

Over the years, I have led or significantly contributed to the design and development of more than six large programs, with annual budgets of $100+ million, for initiatives in New Jersey, New York, Vermont, Arizona, and Maryland. My clients are in more than a dozen states and provinces, and six countries outside North America. I have conducted work for several international organizations, including the World Bank. I have also created and led the launch of Sun Shares, a subsidiary of VEIC that develops and provides community solar services to employers and their employees.

I have provided testimony in regulatory hearings on more than a dozen occasions and have participated in scores of technical workshops and working groups on behalf of many clients. My recent and current work includes several assignments relating to gas infrastructure, pilot programs, and planning. In early 2020, I led an EFG team, and was the lead author for a critical assessment of National Grid's long-term needs assessment of gas supplies and proposed pipeline infrastructure investments for their downstate New York service territories.[1] I was also the lead author for a whitepaper, prepared for CLF, which assessed critical issues for gas system infrastructure investments in Rhode Island.[2] This year, I have filed expert witness testimony with the Illinois Commerce Commission on three proposed gas pilot programs in Illinois on behalf of Citizen's Utility Board,

[1] Exhibit DGH-2.
[2] Exhibit DGH-3.

Environmental Defense Fund, and the Natural Resources Defense Council.[3] Other recent work related to long term energy planning and the future of gas include leading a team conducting building sector analyses and integrated scenario planning for the Massachusetts Decarbonization Roadmap in 2019 and 2020, and the recent initiation of a subcontract to serve as a lead on the technical consultant team advising the Vermont Climate Council on their Roadmap to meet the requirements of the Global Warming Solutions Act.

In the electric sector, recent work includes submitting and defending expert testimony on the characterization and analysis of energy efficiency and demand response in Dominion Energy South Carolina's 2020 Integrated Resource Plan on behalf of the Southern Environmental Law Center and the Coastal Conservation League. In 2019, I presented at a technical workshop on efficiency portfolio diversification and submitted supporting testimony in Nova Scotia on behalf of EfficiencyOne. In 2018, I provided testimony on behalf of the Ecology Action Centre to the Nova Scotia Utility and Review Board regarding NS Power's Advanced Metering Infrastructure project. For the last decade, I have provided ongoing expert review and testimony on EmPOWER Maryland's energy efficiency portfolio on behalf of that state's Office of People's Counsel.

In addition, I have written, presented, and/or defended written analyses and/or testimony for regulatory workshops, commission staff, and legislative hearings on efficiency, alternative rate design, net metering and interconnection of distributed energy systems, and strategies for sustainable development of solar markets. This has included my work in New York, Pennsylvania, Vermont, Arizona, Michigan, and New Jersey.

I earned my Ph.D. in Energy Management and Policy Planning at the University of Pennsylvania. Further details on my work experience and education are provided in my professional resume, included as Exhibit DGH-1.

Q: Have you previously filed testimony before this Commission?

A: Yes, I testified in Docket No. DE 20-092, 2021-2023 Triennial Energy Efficiency Plan.

II. <u>OVERVIEW</u>

[3] Illinois Commerce Commission, Dockets No. 21-0098 and 20-0722.

Q: What is the purpose of your testimony?

A: My testimony provides a critical analysis of Liberty Utilities' ("Liberty" or the "Company") petition for approval of the proposed Tennessee Gas Pipeline ("TGP") capacity contract in conjunction with the on-system enhancements that Liberty claims are necessary to optimize the contract. I raise concerns that the Company's petition is based on promotional and sales activities that are in the Company's best interests, but that are not demonstrated to be prudent, aligned with ratepayers' best interests, or consistent with existing or potential future greenhouse gas emissions reduction goals. I identify and consider the stranded cost, equity, and environmental impact risks associated with approval of the petition based on the justifications provided by the Company and I recommend analyses of alternative options necessary before the petition for the capacity contract is approved.

Q: What approvals does Liberty seek in this case?

A: In this proceeding, Liberty has requested that the New Hampshire Public Utilities Commission approve:

> A 20-year, 40,000 Dth per day firm transportation agreement that Liberty has entered into with Tennessee Gas Pipeline ("TGP contract").

In its Order Notice dated February 8, 2018, the New Hampshire Public Utilities Commission noted that the proposal raises issues:

> related to whether the proposed firm transportation agreement is prudent, reasonable, and consistent with the public interest; and whether the testimony provided with the petition addressing resource requirements, evaluation of resource alternatives, possible future capital investment to fully utilize the capacity, and TGP contract risks and risk mitigation, supports approval of the agreement. Those issues relate to RSA 374:1 and 374:2 (public utilities to provide reasonably safe and adequate service at "just and reasonable" rates); RSA 374:4 (the Commission's duty to keep informed of the manner in which all public utilities in the state provide for safe and adequate service); RSA 374:7 (Commission authority to investigate and ascertain the methods employed by public utilities to "order all reasonable and just improvements and extensions in

service or methods" to supp1y gas); and RSA 378:7 (rates co1lected by a public utility for services rendered or to be rendered must be just and reasonable).[4]

Liberty claims that it does not seek approval in this docket for the approximately $45 million in on-system enhancements that are also discussed in its testimony. However, because Liberty has stated that these on-system enhancements are necessary to optimize and utilize the additional capacity of the TGP contract, the Commission should consider these investments and whether they are prudent in this docket.

Q: What is the scope of your testimony?

A: I review the Direct Testimony of Francisco C. DaFonte and William R. Killeen, filed January 20, 2021, and the justification they provide in support of the proposed long-term supply contract with TGP and associated on system enhancements. I provide a critical analysis of this justification, and of the Company's implicit assumption that continued promotional efforts to grow sales and service territory are prudent and in ratepayers' best interests. I provide examples of alternative options to the supply contract that are not considered in the Company's testimony, and I discuss the risks of approving the supply contract if such alternatives are not analyzed.

Q: What are your overall conclusions and recommendations in this docket?

A: My conclusions are that the Company's testimony does not provide sufficient evidence to support approval of the long-term supply contract. I do not reach a definite conclusion on whether with more analysis and evidence the proposed long-term contract should be approved or disallowed. Before making such a decision, I recommend the Commission require:

1. Liberty conduct, and present for stakeholder review, a transparent deficiency analysis that:
    a. Removes promotional activities from the load forecast;
    b. Includes analysis of enhanced energy efficiency at a level equal to, or exceeding, the cost-effective initiative proposed by Liberty for the Joint Utility Triennial Plan;

[4] Order of Notice at 2.

c. Includes analysis of a gas demand response initiative including tariff, direct control, and load coordination options;

d. Accounts for market trends and potential for increased promotion of electrification using high efficiency cold climate heat pumps and heat pump water heaters as a substitute for gas; and

e. Uses one in thirty-year historical weather data as the basis for design day calculations.

2. I also recommend the Commission explicitly deny Liberty's proposed plan of action to proceed with on-system distribution enhancements required to optimize the new contracted supply, without pre-approval. The Commission should clearly require any proposals for gas system expansion, or enhancements be considered in relation to their long-term GHG impacts, the potential for stranded costs, and equity impacts. To fully address these issues such proposals would need to:

   a. Consider future scenarios in which state and regional greenhouse gas emissions are reduced by 50 percent by 2030, and by 80 percent or more by 2050;

   b. Examine the best use of existing gas infrastructure and supplies to serve New Hampshire's ratepayers and economy;

   c. Analyze the resource potential and costs of renewable natural gas from biogenic resources;

   d. Analyze the potential and costs for electrification, primarily for space and water heating to displace gas demand;

   e. Analyze the potential and cost effectiveness of expanded energy efficiency and demand response initiatives for meeting gas and electric system needs.

3. Further, prior to Commission approval of the TGP contract, the Commission should require Liberty to update its 2017 Least Cost Integrated Resource Plan ("LCIRP") to include the TGP contract and the required analyses under New Hampshire's LCIRP statutes, which are consistent with my above recommendations regarding the analyses that Liberty must perform.

These recommendations are aligned with the tenets of least cost integrated resource planning, and if adopted will contribute to a more meaningful comparison of alternatives for supply contracts and proposed system upgrades.[5] As proposed, the Company's petition for approval of the long-term supply contract presents a risk of stranded costs (with the Company proposing to depreciate associated system enhancements over a **BEGIN CONFIDENTIAL [** [redacted] **]END** CONFIDENTIAL horizon) and fails to adequately consider cleaner alternatives such as energy efficiency, and electrification. These oversights create tangible economic and environmental risks for New Hampshire's ratepayers and are not consistent with the LCIRP statutes.

III. DEMAND GROWTH BASED ON PROMOTIONAL SALES AND MARKETING ACTIVITIES

Q: What factors does the Company cite as driving the forecast need for the TGP contract and the associated on-system enhancements?

A: The Company's demand forecast is based on a July 2020 update to the econometric model used by the Company in Docket No. DG 17-198 in support of its 2017 LCIRP.[6] Referring to the Company's 2017 LCIRP filing, the estimated total demand forecast from the econometric model, which includes some level of historical fuel conversions to natural gas, was 0.9% per year for the 2017/2018 to 2021/22 time-period.[7] In addition, as described in the LCIRP and in the testimony of Mr. DaFonte and Mr. Killeen, an out of model adjustment was made to account for the promotional activities provided by the Company's Sales and Marketing Group. These activities include new customers in legacy territory, and targets for expansion of customer and sales in new service territories. The out of model adjustment for these promotional activities results in a tripling of the econometric model's forecast demand growth increasing the compound annual growth rate from 0.9% to 2.7%.[8] In describing the out of model adjustments in the LCIRP, the Company states: "The Company recently expanded its sales and marketing efforts and expects to continue to

[5] The Commission may wish to initiate a "Future of Gas" study, in a subsequent docket, with participation from the utilities and stakeholders, to investigate these issues in greater detail.
[6] Direct Testimony of Francisco C. DaFonte and William R. Killeen, footnote 12, Bates p. 16.
[7] Liberty Utilities Least Cost Integrated Resource Plan, Table 20, Bates p. 25.
[8] *Id.*, Table 23, Bates p. 28.

do so throughout the Forecast Period".[9] In testimony on behalf of CLF, witness Paul Chernick of Resource Insight noted that the promotional activities accounted for 68 percent of the forecast load growth.[10]

For a regional comparison, the 2.7% CAGR forecast by the Company is greater than the forecast growth rate for twenty-one of the twenty-three gas distribution companies in New England from a study conducted by ICF for ISO-NE.[11] In New Hampshire, the forecast CAGR for Unitil (Northern Utilities Inc.) was 0.9% over 2015 to 2030, which is significantly lower than Liberty's econometric model forecast and would be consistent with a Liberty econometric model forecast that did not include its promotional activities.

Q: Are the Company's demand forecasts based on the promotional activities an appropriate justification for the proposed TGP supply contract and on-system enhancements?

A: No. The Company's internal department sales and marketing targets are just that. They do not account for ratepayers' interests, and they are not based on a comparison of alternatives. Internal sales and marketing targets are not sufficient justification for proposed supply contracts, or system expansions. They also do not substitute for analysis of supply alternatives such as enhanced energy efficiency, demand response, flexible load management or strategic electrification.

The current petition is based on promotional activities that are in the Company's best interest, but not in ratepayers' best interest. These are not compared or contrasted with alternatives including reduced or eliminated promotional activities, increasing cost effective energy efficiency, demand response (including flexible load management), and strategic electrification.

This is a particular concern since the supply contract is then used as a basis for distribution system capital investments to "optimize" the distribution of the new supply. The

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[9] *Id.*, Bates p. 26.
[10] Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, Docket DG17-198, September 13, 2019, Bates page 8.
[11] *New England LDC Gas Demand Forecast Through 2030: Prepared for ISO-New England*, ICF International, at Slide 9 (October, 2016), *available at* https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf. This study is now five years old, and so does not reflect recent regional trends on greenhouse gas planning and electrification that are likely to decrease estimated growth rates.

Company's rationale bases approval of the contract and associated capital investments on continued promotional and marketing activities and goals. It also compares the supply contract to other unfavorable supply options, rather than comparison to a portfolio of available, cost-effective demand side management alternatives. These are not sufficient bases for the requested approval of the supply contract.

IV. LIBERTY'S LEAST COST INTERGRATED RESOURCE PLAN

Q: How does Liberty's least cost integrated resource plan relate to this proceeding?

A: Liberty's proposal here must be consistent with the LCIRP statutes, RSA 378:37-378:40. RSA 378:37 provides that it is the:

> energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost-effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.

Further, RSA 378:38 requires natural gas utilities to develop a least cost integrated resource plan at least every five years, and that such plan shall include, in relevant part, the following:

> I. A forecast of future demand for the utility's service area.
>
> II. An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.
>
> III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.
>
> . . .
>
> V. An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.
>
> VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.

Next, RSA 378:39 provides that in deciding whether or not to approve a utility's least cost integrated resource plan, the Commission shall consider "potential environmental, economic, and health-related impacts of each proposed option" and that where the Commission finds that different options have "equivalent financial costs, equivalent reliability, and equivalent environmental, economic, and health-related impacts, the following order of energy policy priorities shall guide the commission's evaluation: I. Energy efficiency and other demand-side management resources; II. Renewable energy sources; III. All other energy sources."

Finally, RSA 378:40 provides as follows:

> No rate change shall be approved or ordered with respect to any utility that does not have on file with the commission a plan that has been filed and approved in accordance with the provisions of RSA 378:38 and RSA 378:39. However, nothing contained in this subdivision shall prevent the commission from approving a change, otherwise permitted by statute or agreement, where the utility has made the required plan filing in compliance with RSA 378:38 and the process of review is proceeding in the ordinary course but has not been completed.

Liberty's petition for approval of the TGP contract is improperly based on promotional marketing and sales activities, that should not be considered by the Commission, and does not adequately comply with several elements of New Hampshire's LCIRP statutes. For example, the petition does not consider new cost-effective efficiency, demand response, or strategic electrification as alternatives, and it does not address environmental and economic impacts, as required under New Hampshire's LCIRP states. These are discussed in further detail in the following sections.

V. INCREASED ENERGY EFFICIENCY, DEMAND RESPONSE, AND ELECTRIFICATION

Q: Did Liberty evaluate additional energy efficiency as an alternative to the TGP contract and on-system enhancements?

A: No. Efficiency is accounted for, but it is based on historic and static efficiency as opposed to expanded levels of cost-effective energy efficiency. To account for energy efficiency, the Company makes an out-of-model adjustment to the demand forecast based on historic 2017 to 2020 energy efficiency efforts, and an assumption that future efficiency savings would continue at 2020 levels. The Company's data response to CLF 2-1 indicates the estimated efficiency savings are 0.67% of demand for the residential sector, 0.9% of demand for the C&I sector, and 0.82% of total demand for the two sectors combined. The level of savings forecast as a percent of sales remains constant through 2039. This results in an increase in absolute efficiency savings, but these are directly proportional to the increased demand forecast, and do not reflect or represent enhanced or expanded energy efficiency savings.

Q: Has Liberty conducted a cost effectiveness evaluation of a portfolio with an enhanced level of energy efficiency?

A: Yes. In Docket DE 20-092 Liberty filed a three-year gas efficiency plan with a Granite State Test cost effectiveness benefit to costs ratio of 2.40 and a total program budget of roughly $30.7 million.[12] Liberty's proposed Triennial Gas Efficiency Plan increased annual incremental savings as a percent of demand to 1.25% by 2022, with cumulative 3-year savings equaling more than 565,000 MMBtus, almost 115,000 MMBtus more than the efficiency as evaluated in this proceeding. Figure 1 illustrates this comparison.

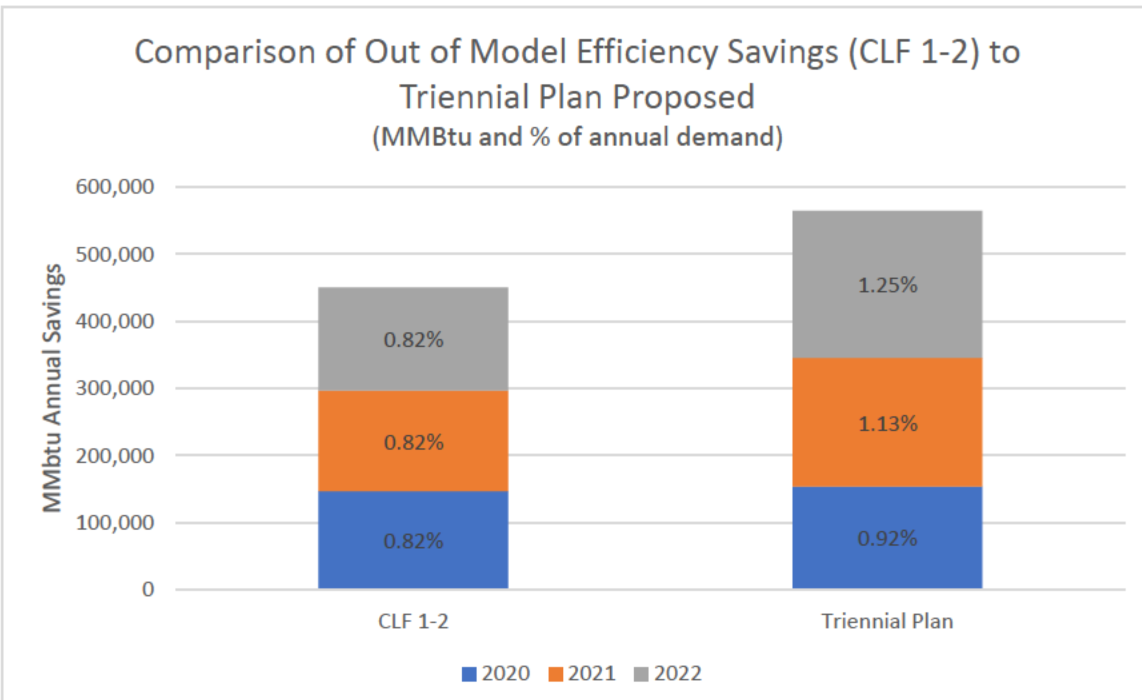

Figure 1: Annual EE Savings Comparison – Response to CLF 1-2 and Triennial Plan

Figure 1 illustrates how the Company has identified significant cost-effective energy efficiency savings beyond those considered in their petition for approval of the TGP supply contract.

[12] NH Saves Joint Utility Triennial Plan Volume 4, Bates page 000840.

Q: Is energy efficiency relevant to Liberty's planning regarding the TGP contract?

A: Yes, New Hampshire's LCIRP statutes create several requirements regarding energy efficiency when conducting gas planning. RSA 378:37 states that amongst other policies, it is the energy policy of the state to "maximize the use of cost-effective energy efficiency and other demand side resources." RSA 378:38 requires natural gas utilities to file least cost integrated resource plans that include "an assessment of demand-side energy management programs, including conservation, efficiency, and load management programs." Further, under RSA 378:39, where proposals have equivalent financial costs and equivalent environmental, economic, and health-related impacts, the Commission is required to prioritize "energy efficiency and other demand-side management resources" over other energy policy priorities.

Q: Has Liberty provided any evaluation in either this docket or the LCIRP docket, DG 17-152, to demonstrate that it has considered increased energy efficiency as an alternative to the TGP contract?

A: No. While Liberty provided general testimony regarding energy efficiency in the LCIRP docket, it provided no new testimony or data in this docket to guide the Commission's analysis of whether increased energy efficiency would obviate the need for the TGP contract.

Q: Would increased levels of cost-effective energy efficiency reduce the need for the TGP contract?

A: Yes, increased cost-effective energy efficiency at or above the levels proposed in the Triennial Plan would reduce the need for the proposed TGP contract. In conjunction with other demand response, strategic electrification, and the reduction or elimination of promotional activities, increased cost-effective efficiency may eliminate the need for the proposed TGP contract and system upgrades.

Q: Does Liberty offer, or did they evaluate demand response tariffs or initiatives as an alternative to the TGP contract and on-system enhancements?

A: In response to CLF data request 1-7, Liberty indicated "the Company does not have any demand reduction programs or tariffs in place".[13] As for evaluation of demand response as an option, the response to CLF 1-7 further states the Company is aware of and monitoring at least three gas demand reduction pilots (SoCal Gas, National Grid NY, and ConEd) all of which have "inconclusive results at this point in terms of ability to produce meaningful reductions in peak gas load."

Q: Are you aware of the demand response pilots referenced by the Company?

A: Yes, for a whitepaper I co-authored in early 2020 we reviewed the early results from the pilots mentioned by Liberty. I disagree with Liberty's position that results were inconclusive in terms of ability to produce meaningful reductions in gas peak load. The initial results from these pilots were promising, tending to exceed design expectations for savings and participation. Based on these early, but promising results, we estimated that a 20% demand reduction within a five-year horizon was a reasonable expectation. I have not had time to update my research on further results from these pilots, but I include the 2020 Whitepaper as an Exhibit.[14] Further exploration of the demand response potential should be required of the Company through this docket.

Q: How would a 20 percent demand reduction impact the Company's projected need for the TGP contract?

A: The updated base case design day resource shortfall presented in Table 2 of Mr. DaFonte and Mr. Killeen's testimony estimates a design day demand of 193,952 Dth in 2025/2026 with current design day resources of 155,033 Dth. A 20 percent reduction equates to 155,161 Dth design day demand, coming very close to eliminating the forecast deficiency. This strongly suggests the Company's cursory dismissal of demand response as another one of the alternative options to the proposed TGP contract is inappropriate, and that demand response needs to be more carefully investigated.

Q: Did Liberty evaluate whether increased electrification would reduce annual or design day natural gas demand?

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[13] Liberty response to CLF Data Request 1-7.
[14] *See* Exhibit DGH-2. Section 3.2, pages 16-21, discusses the demand response pilots and their early results.

A: No, Liberty's proposal does not address the availability, competitiveness, and potential increasing market shares for cleaner and lower cost resources, such as greater use of heat pumps and other electric technologies. [15] The econometric demand forecast as described in the Company's LCIRP filing does not have independent variables to represent the technology or market advances in electric heat pumps, nor the comparative costs for space and water heating with electric heat pump versus gas equipment.[16] The growing market shares for cold-climate efficient air source heat pumps and heat pump water heaters in the Northeast are a factor that should be included in Liberty's demand forecast. A reduction in the demand forecast to account for existing growth trends in electrification would reduce the need for the TGP supply contract. In addition, Liberty should investigate the potential for accelerated promotion and adoption of electrification technologies as non-pipe alternatives to the on system-enhancements proposed as necessary to optimize the TGP supply contract.

Q: Is Liberty required to consider increased electrification as an alternative to the TGP contract proposal?

A: Yes, RSA 378:39 requires the Commission to consider "potential environmental, economic, and health-related impacts of each proposed option." Consequently, to inform the Commission's analysis, Liberty should evaluate strategic electrification as an alternative supply option as an alternative to the proposed TGP contract. For the supply as well as the demand alternatives under consideration the potential environmental, economic and health related impacts should be assessed.

Q: Would increased use of electric technologies reduce the need for the TGP contract over its 20-year period?

A: Yes, increased adoption of electric technologies, either based on current market trends not reflected in the demand forecast, or on increased adoption due to promotion by the electric or gas companies would reduce the need for the TGP contract. Geographically targeted promotion of electrification can reduce peak demands and the need for on-system distribution enhancements.

[15] Liberty Response to CLF Data Request No. 1-8.
[16] Liberty Utilities Least Cost Integrated Resource Plan, Table 2, Bates pages 015-017.

VI. DESIGN DAY TEMPERATURE ESTIMATION

Q: What method does the Company use for estimating the design day requirements?

A: The Company's method for design day and design year temperature estimation is described in the 2017 LCIRP is to use historical weather data from Manchester, NH (KMHT weather station) from 1979 to 2016 as the basis for a Monte Carlo analysis of the statistical distribution of the coldest day of each calendar year. The Company's design standard then subtracts two standard deviations from the mean coldest day estimate to determine the design day conditions.[17]

Q: **Do you have any comments or recommendations on this approach?**

A: Yes. The method used by Liberty is relatively conservative, and assuming a normal distribution for historic mean temperatures results in 97.725% of the expected years to have a design day warmer than the estimate. Given observed and expected trends in warming average and extreme temperatures in the Northeast, I recommend a design day based on historic 30-year observed minimum average temperatures be compared to the current design day standard as a sensitivity analysis, and that it may be prudent to adopt the historical 30-year observed design day conditions as reasonable for consideration of the proposed supply contract and future gas system investments.[18]

VII. COMPARISON OF ALTERNATIVES

Q: You have indicated above that the Company did not consider enhanced energy efficiency, demand response, increasing electrification or reduced promotional activities as alternatives to the proposed TGP supply contract. What alternatives did the Company compare the proposed contract to?

A: The evaluation of resource alternatives presented in the testimony Mr. DaFonte and Mr. Killeen is limited to comparisons with earlier or current supply contracts, and two potential infrastructure projects (NED and Granite Bridge) that were cancelled. Their justification for the proposed TGP supply contract is based on comparing it to supply contracts with less

[17] Liberty 2017 LCIRP, Bates p. 033.
[18] My recommendation on design day methodology agrees with the testimony of Stephen P. Frink in this Docket. However, the adjustment of design day estimation by itself is not sufficient to address the other concerns with the Company's petition, which I discuss in my testimony.

favorable terms, or to large and expensive capital investment projects that did not move forward. As discussed in Section IV of my testimony above, the LCIRP statutes are clear in requiring comparison to efficiency and demand side resources as alternatives to supply side investments. The Company's current petition fails to make such comparisons.

VIII. DISCUSSION OF RISKS

Q: Has the Company adequately identified and discussed the risks associated with the proposed TGP supply contract?

A: No. Following the same pattern as found in their comparison of resource alternatives, the Company's discussion of risks in Section VI "TGP Contract Risks and Mitigation" is very limited in scope, focusing on supply system and contractual risks.

Q: **What additional risks need to be considered in relation to the proposed TGP contract?**

A: Three critically important areas of risk that are not analyzed or even mentioned by the Company are climate, stranded costs, and equity.

IX. CLIMATE RISKS AND IMPACTS

Q: Should the Commission review the climate change risks and impacts of the TGP contract as part of its review?

A**:** Yes, climate change includes a range of impacts to the environment, economy, and public health that are reasonable to incorporate in any evaluation of utility plans or projects, particularly those projects that commit ratepayers to funding a new fossil fuel investment over a long-time horizon, such as the proposed TGP contract.

Q: Is climate change expected to affect New Hampshire?

A**:** Yes. The Fourth National Climate Assessment Report, prepared by the U.S. Global Change Research Program,[19] developed with inputs from over 300 subject matter experts, provides a comprehensive scientific, peer reviewed, overview of impacts, adaptation, and

[19] *Fourth National Climate Assessment*, U.S. Global Change Research Program, at Chapter 18 (2018), *available at* https://nca2018.globalchange.gov/chapter/northeast.

mitigation. Chapter 18 of the Fourth National Climate Assessment presents results for the Northeast United States. Five key messages from Chapter 18:

1. **Changing Seasons Affect Rural Ecosystems, Environments, and Economies** - The seasonality of the Northeast is central to the region's sense of place and is an important driver of rural economies. Less distinct seasons with milder winter and earlier spring conditions are already altering ecosystems and environments in ways that adversely impact tourism, farming, and forestry. The region's rural industries and livelihoods are at risk from further changes to forests, wildlife, snowpack, and streamflow.
2. **Changing Coastal and Ocean Habitats, Ecosystems Services, and Livelihoods** - The Northeast's coast and ocean support commerce, tourism, and recreation that are important to the region's economy and way of life. Warmer ocean temperatures, sea level rise, and ocean acidification threaten these services. The adaptive capacity of marine ecosystems and coastal communities will influence ecological and socioeconomic outcomes as climate risks increase.
3. **Maintaining Urban Areas and Communities and Their Interconnectedness** - The Northeast's urban centers and their interconnections are regional and national hubs for cultural and economic activity. Major negative impacts on critical infrastructure, urban economies, and nationally significant historic sites are already occurring and will become more common with a changing climate.
4. **Threats to Human Health -** Changing climate threatens the health and well-being of people in the Northeast through more extreme weather, warmer temperatures, degradation of air and water quality, and sea level rise. These environmental changes are expected to lead to health-related impacts and costs, including additional deaths, emergency room visits and hospitalizations, and a lower quality of life. Health impacts are expected to vary by location, age, current health, and other characteristics of individuals and communities.
5. **Adaptation to Climate Change Is Underway** - Communities in the Northeast are proactively planning and implementing actions to reduce risks posed by climate change. Using decision support tools to develop and apply adaptation strategies informs both the

value of adopting solutions and the remaining challenges. Experience since the last assessment provides a foundation to advance future adaptation efforts.[20]

These key messages underscore the importance of considering climate related risks and impacts for any proposed expansion of gas supplies, be it through supply contracts or infrastructure investments in New Hampshire.

Q: Did Liberty consider the potential environmental and public health impacts—including impacts from climate change—resulting from the TGP contract?

A: No, in response to CLF Data Request 1-23 asking whether Liberty performed an analysis of the climate change impacts of the TGP contract, Liberty stated that it has not performed such analysis because Liberty's "contract with TGP uses existing TGP capacity. As such, whether the Company contracted for the capacity or not, the environmental impacts would be the same since an entity(ies) other than [Liberty] would be utilizing this capacity that has existed for 20 years."

Q: Do you agree with Liberty's claims regarding the environmental impacts of the TGP contract?

A: No. It is not valid to assume that if Liberty does not enter the TGP contract, other entities will contract for these supplies. As New Hampshire and other states served by the TGP system take steps to mitigate climate impacts and risks, including efforts to reduce gas consumption and emissions, the demand for gas and the use of existing capacity may decline. The Company's response to CLF 1-23 is entirely insufficient as an explanation for not considering climate impacts and risks.

Q: Is an analysis of climate change impacts of the TGP contract required under the LCIRP statutes.

A: Yes. RSA 378:37 provides that it is the energy policy of this state to protect the safety and ***health*** of New Hampshire's citizens and the ***physical environment of the state***. RSA 378:38 requires least cost integrated resource plans to contain an "assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers" and "an

[20] *Id.*

assessment of the plan's long- and short-term ***environmental***, economic, and energy price and supply impact on the state." RSA 378:39 requires the Commission to analyze the potential ***environmental***, economic, and health-related impacts of each proposed option presented in a utility's plan.

X. STRANDED COST AND EQUITY RISKS

Q: What concerns do you have over the risk of stranded costs?

A: While this docket concerns a petition for a long-term supply contract, the Company also indicates that to "optimize" the use of the new supplies, on-system distribution system enhancements estimated to cost $45 million will be undertaken.[21] I am strongly opposed to the Company's proposed approach of using the proposed TGP supply contract as a basis for justifying the need for on-system enhancements. Any capital infrastructure investments need to be subject to rigorous comparisons of supply and demand side alternatives required by the LCIRP statutes and which I have outlined above. In this docket the Commission should make it very clear that under any circumstance the TGP supply contract, if approved, does not translate to an approval for the on-system enhancements. I recommend the Commission make it clear that any on-system enhancements must be submitted for pre-approval, and that proceeding with the on-system enhancements and seeking cost recovery after they are completed is not acceptable.

Nevertheless, in the current case, in the DG 21-008 Technical Session on May 3rd, the Company indicated a proposed depreciation period for the presumed necessary on-system enhancements to optimize the TGP supply contract of **BEGIN** CONFIDENTIAL [[redacted]] **END** CONFIDENTIAL

There would be a clear risk of stranded costs for the proposed on-system enhancements, particularly using the proposed depreciation period of **BEGIN** CONFIDENTIAL [[redacted]] **END** CONFIDENTIAL . Exhibit DGH-3 is a whitepaper I co-authored on behalf of CLF earlier in 2021, in which we recommended a depreciation of no longer than 20 years be used for potential new gas infrastructure investments.

[21] Direct Testimony of Franciso C. DaFonte and William R. Killeen, line 10, Bates p. 26.

The Company has not included enhanced cost-effective energy efficiency, demand response, increased electrification, or reduced promotional activities in their analyses. All of these are likely to reduce future gas demand. If the costs for on-system enhancements are depreciated **BEGIN** CONFIDENTIAL [[redacted],] **END** CONFIDENTIAL reductions in gas demand will mean the base of sales from which the amortized costs are recovered will decline. This in turn makes gas more expensive for customers and can create feedbacks that further reduce demand. Therefore, I would make the same recommendation here as in the CLF whitepaper that a depreciation period of no longer than 20 years be used for any new gas infrastructure investments.

Q: How might the stranded cost risk also create equity impacts?

A: If gas demand declines, which is certainly plausible, due to climate concerns, potential future legislation or regulation to address climate risks, and increased adoption of technologies and alternatives that Liberty has not considered in their analyses, then recovery of costs for the on-system enhancements will be recovered from a smaller sales base.[22] While rate design might be used to try and protect lower income customers in such a situation, it is also possible that rates for income vulnerable households and businesses would need to increase. These customers are at the greatest risk for energy burden related to their incomes. They are also less likely to be able to adopt alternative technologies, such as cold climate heat pumps, and so may have fewer options to reduce their consumption and costs if gas prices rise. The Executive Summary for a 2021 study examining the Challenge of Retail Gas in California includes the following statement:

> "If demand for natural gas in California falls dramatically because of some combination of policy and economically driven electrification, the fixed costs to maintain and operate the gas system will be spread over a smaller number of gas sales and, ultimately, will increase costs for remaining gas customers. This outcome raises the possibility of a feedback effect where rising gas rates caused by electrification spur additional electrification. Such a feedback effect would threaten the financial viability of the gas system, as well as raise substantial equity concerns over the costs that remaining gas system customers would face."[23]

[22] New Hampshire's neighbors across New England and the Northeast have adopted or are considering global warming solutions acts, setting statutory targets for emissions reductions. At the local level, moratoriums on gas system expansion and new connections have been implemented in Massachusetts and New York and are being considered elsewhere. Federal legislation establishing emissions caps or carbon pricing also remain a possibility.
[23] *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*, prepared by E3 Economics for the California Energy

Q: Can you please recap recommendations for the Commission?

A: Yes. Before approving the TGP supply contract I recommend the Commission require:

1. Liberty conduct, and present for stakeholder review, a transparent deficiency analysis that:
   a. Removes promotional activities from the load forecast;
   b. Includes analysis of enhanced energy efficiency at a level equal to, or exceeding, the cost-effective initiative proposed by Liberty for the Joint Utility Triennial Plan;
   c. Includes analysis of a gas demand response initiative including tariff, direct control, and load coordination options;
   d. Accounts for market trends and potential for increased promotion of electrification using high efficiency cold climate heat pumps and heat pump water heaters as a substitute for gas; and
   e. Uses one in thirty-year historical weather data as the basis for design day calculations.

The Commission should require that these analyses be transparent and the inputs, calculations, and results be available for review and comment by intervenors. I anticipate that such an analysis will reduce the demand sufficiently that the proposed contract is not required. If the proposed contract is not required as a supply resource to meet projected demands, it may still have value, as a hedge on future gas costs, or to retire other higher cost supply contracts. I have not analyzed or reached conclusions on whether the contract has merit as a hedge or replacement for other supply contracts.

However, under any circumstances, approval of the proposed supply contract should not indicate a tacit or explicit approval of Liberty's approach to on-system enhancements the Company claims are required to optimize the additional capacity. Therefore,

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Commission, at ES p. 1 (April 2020), *available at* https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf. Note, this study discusses strategic planning for gas system with declining demand, not the elimination of the gas system or services.

2. I also recommend the Commission explicitly deny Liberty's proposed plan of action to proceed with on-system distribution enhancements required to optimize the new contracted supply, without pre-approval. The Commission should clearly require any proposals for gas system expansion, or enhancements, be considered in relation to their long-term GHG impacts, the potential for stranded costs, and equity impacts. This should include:

   a. Considering future scenarios in which state and regional greenhouse gas emissions are reduced by 50 percent by 2030, and by 80 percent or more by 2050;

   b. Examining the best use of existing gas infrastructure and supplies to serve New Hampshire's ratepayers and economy;

   c. Analysis of the resource potential and costs of renewable natural gas from biogenic resources,

   d. Analysis of the potential and costs for electrification, primarily for space and water heating to displace gas demand; and

   e. Analysis of the potential and cost effectiveness of expanded energy efficiency and demand response initiatives for meeting gas and electric system needs.

3. Further, prior to Commission approval of the TGP contract, the Commission should require Liberty to update its 2017 LCIRP to include the TGP contract and the required analyses under New Hampshire's LCIRP statutes, which are consistent with my above recommendations of the analyses that Liberty must perform.

These recommendations are aligned with the tenets of least cost integrated resource planning, and if adopted will contribute to a more complete consideration of the future of gas in New Hampshire's energy economy. This will benefit ratepayers, and the state's economy and environment.

Q: Does this conclude your testimony?

A: Yes.

David Hill
Managing Consultant

ENERGY FUTURES GROUP

Professional Summary

David Hill joined EFG as a Managing Consultant at the start of 2020, after 22 years of employment with VEIC, most recently as Director of Distributed Resources and a VEIC Policy Fellow. He is known nationally for his advancement of sustainable energy program design and evaluation, and renewable energy policy. David has been the principal investigator and led analysis teams for multi-year stakeholder informed studies on solar market and decarbonization pathways and scenarios. David provides expert testimony and regulatory support; participates in international, national, and state boards; leads policy committees and conferences; provides comprehensive studies of the economic, technical, and achievable potentials for sustainable energy programming; and supports program budget planning and implementation. He has led or significantly contributed to the design and development of efficiency and renewable energy programs with annual budgets of $100+ million for initiatives in New Jersey, Washington DC, New York, Vermont, Arizona, and Maryland. Recent work includes expert testimony and whitepaper analyses related to gas infrastructure investments, pilot programs and planning. He has clients in more than a dozen states and six countries; several of them are international organizations.

Experience

January 2020 – present: Managing Consultant, Energy Futures Group, Hinesburg, Vermont (VT)

2014 – 2019: Director, Distributed Energy Resources, Policy Fellow, VEIC, Burlington, VT

2010 – 2014: Managing Consultant, VEIC, Burlington, VT

2008 – 2010: Deputy Director, Planning and Evaluation, VEIC, Burlington, VT

2000 – 2008: Senior Consultant, VEIC, Burlington, VT

1998 – 2000: Consultant, VEIC, Burlington, VT

1993 – 1998: Research Associate, Tellus Institute and the Boston Center of the Stockholm Environment Institute

Testimony as Expert Witness

Expert witness at technical working groups and before commissions on renewable energy and energy efficiency initiatives in Illinois, Vermont, New York, New Jersey, Maryland, Pennsylvania, South Carolina, Nova Scotia and Ontario.

2021 Nicor Smart Neighborhood and Total Green Pilots. Expert witness testimony on behalf of Citizens Utility Board, Environmental Defense Fund and Natural Resources Defense Council, Docket 21-0098 before the Illinois Commerce Commission.

Energy Futures Group, Inc
PO Box 587, Hinesburg, VT 05461 – USA | 802-482-4874 | dhill@energyfuturesgroup.com

2021 Nicor Renewable Natural Gas Pilot. Expert witness testimony on behalf of Citizens Utility Board and Natural Resources Defense Council, Docket 20-0722 before the Illinois Commerce Commission.

2020 *NH Saves 2021-2023 Triennial Plan.* Expert witness testimony reviewing joint gas and electric triennial efficiency plan before the New Hampshire Public Service Commission submitted on behalf of Clean Energy New Hampshire, DE 20-092.

2020 *Dominion Energy South Carolina, 2020 Integrated Resource Plan*. Expert witness testimony before the South Carolina Public Service Commission submitted on behalf of Southern Alliance for Clean Energy and the South Carolina Coastal Conservation League on the characterization and analysis of energy efficiency and demand response in Dominion's 2020 IRP. Docket No. 2019-226-E.

2019 *Efficiency One 2020-2022 DSM Plan: Portfolio Diversification and Lighting Transition*. Expert Witness Testimony submitted on behalf of Efficiency Nova Scotia, to the Nova Scotia Utility and Review Board, Matter 09096.

2018 *In the Matter of an Application by Nova Scotia Power for Approval of its Advanced Meter Infrastructure Project*. Expert Witness Testimony submitted on behalf of Ecology Action Center, to the Nova Scotia Utility and Review Board, Matter 08349.

2018 *Becoming an Advanced Solar Economy.* Testimony before the Vermont House Committee on Energy and Technology, Montpelier.

2017 Maryland Public Service Commission. On behalf of Office of People's Counsel on EmPOWER Maryland Utilities 2018-2020 plans. Presentation and testimony, October 25-26, 2017.

2016 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015 Semi Annual (Q3 and Q4) Review.* Presentation and testimony, May 4, 2016.

2015 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015 Semi Annual Review.* Presentation and testimony, October 14-15, 2015.

2014 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015-2017 Utility Proposed Plans.* Presentation and testimony, October 21-22, 2014.

2014 Maryland Office of People's Counsel, EmPOWER Maryland. Evaluation of Semi-Annual Reports - Case Nos. 9153-9157. Presentation and testimony, April 7, 2014.

2013 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer Advocate, regarding Petitions of the Pennsylvania Power Company for Approval of its Act 129 Phase II Energy Efficiency and Conservation Plan (Docket Nos. M-2012-2334395 and M-2012-2334392); Petition of Metropolitan Edison Company (Docket No, M-2012-2334387); and Petition of West Penn Power Company (Docket No. M-2012-2334398). Written testimony. January 8, 2013.

2013 Maryland Office of People's Counsel, EmPOWER Maryland. *Written comments on 2012 Q3-Q4 Semi-Annual Report.* Presentation and testimony, October 2-3, 2013.

2011 Maryland Office of People's Counsel. *Utility-Specific Comments on the 2012-2014 EmPOWER Maryland Program Plans*. Case Nos. 9153-9157. Written testimony. October 19, 2011.

2011 Maryland Office of People's Counsel. *Written Comments on 2010 Annual Reports, and Q4 2010 reports*. Case Nos. 9153-9157. Presentation and testimony. March 31, 2011.

2011 Maryland Public Service Commission. On behalf of the Maryland Office of People's Counsel. *Comments on the 2012-2014 EmPOWER Maryland Utility Program Plans.* October 2011.

2009 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer Advocate, regarding Petition of Duquesne Light Company for Approval of Its Energy Efficiency and Conservation and Demand Response Plan, Docket No. M-2009-2093217. August 7, 2009.

2005 Ontario Energy Board. On behalf of Green Energy Coalition, regarding Hydro One Networks and Brampton Conservation and Demand Management Plans. February 4, 2005 (written comments) and February 17-18, 2005 (testimony).

2005 Pennsylvania Public Utility Commission. On behalf of Penn Future, regarding net metering standards. Written comments and testimony. June 2005.

2005 Pennsylvania Public Utility Commission. On behalf of Penn Future. Written testimony and comments on interconnection standards. April 2005.

2005 Testimony to the Vermont State Legislature House Committee on Energy and Natural Resources on Vermont's Solar and Small Wind Incentive Program. February 9, 2005.

Selected Projects (from more than 100)

Conservation Law Foundation. Lead author, for "*Rhode Island's Investments in Gas Infrastructure A Review of Critical Issues"*, discussing renewable gas potential, gas planning in relation to greenhouse gas reduction goals and, depreciation periods for gas new infrastructure.

Institute for Energy Economics and Financial Analysis. Lead author, for "*Critical Elements in Short Supply: Assessing the Shortcomings of National Grid's Long-Term Capacity Report"*, study calling into question proposed natural gas pipeline investment for New York City region.

Massachusetts Executive Office of Energy and Environmental Affairs. Senior advisor for team creating Low Emissions Analysis Platform (LEAP) integrated scenario modeling to inform Massachusetts efforts to reach greenhouse gas reduction targets.

Pennsylvania Department of Environmental Protection. Led team creating scenario modeling using the Low Emissions Analysis Platform (LEAP) model in support of two- and half-year study "*Pennsylvania's Solar Future*". Presentations for modeling review and collaborative stakeholder feedback at more than half a dozen stakeholder meetings and webinars.

U.S. Department of Energy. Principal Investigator for a three-year SunShot Initiative Solar Market Pathways study, investigating the technical, regulatory, and business model implications of getting 20 percent of Vermont's total electric supply from solar by 2025.

Sun Shares. Created and launched, and responsible for management and business development of, a community solar business subsidiary to provide "Easy and Affordable Solar for Employers and their Employees," 2015 – present.

New Jersey Clean Energy Program. Program design and policy advisor for the renewable energy program for more than a decade.

Rhode Island Office of Energy Resources. Strategic Advisor on State Energy Plan and System Reliability Procurement and Distributed Generation programs.

Alaska Energy Authority. Principal consultant for two studies on renewable and energy efficiency financing and funding strategies.

New York State Energy Research and Development Authority (NYSERDA). Twice led the renewable energy analysis for 20-year forecast of energy efficiency and renewable energy potential, 2003 and 2012.

World Bank. Expert consultant on a short-term study of efficiency and micro- / mini-grid opportunities in Tanzania, 2014.

Arizona Public Service. Managed a rapid assessment and redesign of PV and solar hot water incentives, 2009.

Selected Presentations

2017 Sun Shares, Easy and Affordable Solar for Employers and their Employees, American Solar Energy Society, Solar 2017, Denver.

2017 Vermont Solar Market Pathways, American Solar Energy Society, Solar 2017, Denver.

2016 *Oxymoron: Harmonizing Distributed Energy Integration Realities with Policy Frameworks*. Solar Power International.

2015 World Bank, International Conference on Energy Efficiency in Cities, Puebla New Mexico. Invited Panel speaker on Efficiency Vermont and Third-Party Administration Model. February, 2015.

2015 *Vermont Solar Market Pathways.* Presentations at Solar 2015 (State College, Pennsylvania), and Renewable Energy Vermont Conference.

2014 New York State Energy Research and Development Authority (NYSERDA), Renewable Energy Potential Study Results, Albany, NY.

2013 *Transformative Energy Planning*. Invited speaker at Innovations in Renewable Energy Symposium, Metcalf Institute for Marine and Environmental Reporting, Narragansett, Rhode Island.

2012 World Renewable Energy Forum, 2012 – Welcome Address and Introduction of Keynote Plenary Speakers. American Solar Energy Society, Denver.

2012 *Efficiency Vermont: A Successful Statewide Clean Energy Utility Model.* Presented at the 2012 Business of Clean Energy in Alaska Conference, Anchorage.

2011 Nova Scotia Feed In Tariff Forum: Invited speaker for two panels addressing Regional Coordination and Export Potential and International Feed-in Tariffs.

2011 *Integrating Renewable Energy and Efficiency Services.* Presentation to the Clean Energy States Alliance Fall 2011 Meeting, Washington, DC.

2010 *The Potential for Energy Efficiency and Renewables as Resources in Wholesale Capacity Markets,* Presentation at EUEC 2010 Conference, Phoenix, AZ.

2008 "Technology and Policy; Getting it Right." Solar Power International, Invited panel speaker. San Diego, California.

2008 *Solar Market Transition in New Jersey: Promise and Progress towards Sustained Growth*. Solar 2008, American Solar Energy Society.

2008 *Review of Efficiency Vermont Administrative Structure and Experience*. Penn Future 2008 Clean Energy Conference, May 2008.

2006 *Scoping Analysis of Potential Photovoltaic Contributions Towards Offsetting Transmission System Upgrades in Southern Vermont.* Solar 2006, American Solar Energy Society.

2006 *Growing New Construction Markets for Photovoltaics: Recent Strategies and Activities from LIPA's Solar Pioneer Program.* Solar 2006, American Solar Energy Society, 2006.

2005 *Market Response to Photovoltaic Incentive Offerings: An Analysis of Trends and Indicators*. Presented at the International Solar Energy Society Solar World Congress, 2005.

2003 *Solar Energy Value and Opportunities in Vermont*, Invited Session Panel Moderator and Speaker, 2nd Annual Power for a New Economy Conference, Burlington, Vermont, October 8, 2003. Renewable Energy Vermont.

2003 *Renewable Energy Case Studies: Redefining the Models, Refining the Messages, and Getting the Word Out*, Invited Session Panel Moderator, Solar 2003 National Solar Energy Conference, Austin, Texas June 22, 2003. American Solar Energy Society.

2002 *Transforming Markets for Customer Sited Clean Renewable Energy: Connecting Field Experience with Lessons from the Efficiency World*, Invited Session Panel Moderator, Solar 2002 National Solar Energy Conference, Reno, Nevada June 18, 2002. American Solar Energy Society.

1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global Climate Change.* Software and paper prepared for the United Nations Industrial Development Organization, presented at the 1997 ACEEE Summer Study on Energy Efficiency in Industry.

1997 *E2/FINANCE: A Software System for Evaluating Industrial Eco-Efficiency Opportunities*, sponsored by the U.S. Department of Energy. ACEEE 1997 Summer Study on Energy Efficiency in Industry.

1995 *Process Evaluation of Three Gas Utility Commercial Industrial Demand Side Programs.* Prepared for the Colonial Gas Company, and presented at ACEEE 1995 Summer Study on Energy Efficiency in Industry.

Selected Publications

2017 Smart Electric Power Alliance, 51st State Initiative, *Role of Utilities in the Transforming Energy Economy of the 51st State*, September 2017.

2016 *Vermont Solar Market Pathways: From a Developed to an Advanced Solar Economy*. A Phase II Roadmap document prepared for the *Smart Electric Power Alliance 51st State Initiative*.

2016 *Vermont Solar Market Pathways,* Vols. 1-4. U.S. Department of Energy, Sun Shot Initiative, Office of Energy Efficiency and Renewable Energy. Award DE-EE-0006911. www.Vermontsolarpathways.org.

2016 *Energy Efficiency Program Evaluation and Financing Needs Assessment*. Report prepared for the Alaska Energy Authority, May 2016.

2015 *Michigan Renewable Resource Assesment*. Final Report, prepared for the Michigan Public Service Commission Staff under agreement with the Clean Energy States Alliance. April 2015.

2012 *Renewable Energy Grant Recommendation Program: Process and Impact Evaluations.* Principal in Charge for comprehensive two-volume study. Alaska Energy Authority.

2011 "Solar in Nepal: Small Systems, Big Benefits." *Solar Today*. July / August 2011.

2011 "National Clean Energy Standard: Congress Needs to Design It Properly." Perspective with Shaun McGrath and Jeff Lyng. *Solar Today.* July / August 2011.

2010 "National RPS Now!" *Solar Today*. July / August 2010.

2009 "Carbon Regulation: What's the Most Effective Path?" *Solar Today*. June 2009.

2009 "Policy Recommendations for the 111th Congress: Tackling Climate Change and Creating a Green Economy." Prepared by the American Solar Energy Society Policy Committee.

2008 "Pennsylvania Solar Assessment." Final Report, November 25, 2008. Incorporated into American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency, Demand Response, and Onsite Solar Energy in Pennsylvania.* ACEEE Report No. E093. Washington, DC: ACEEE, April 2009.

2008 "Solar Market Transition in New Jersey: Promise and Progress towards Sustained Growth." *Proceedings of Solar 2008*, American Solar Energy Society.

2004 "Cost Effective Contributions to New York's Greenhouse Gas Reduction Targets from Energy Efficiency and Renewable Energy Resources." *Proceedings of 2004 ACEEE Summer Study on Energy Efficiency in Buildings.*

2002 "The Ten Percent Challenge: A Participatory Community Scale Climate Campaign." *Proceedings of 2002 ACEEE Summer Study on Energy Efficiency in Buildings.* Volume 9, (with Tom Buckley, Jennifer Green, and Debra Sachs).

2000 "Implementing and Monitoring Community-Based Climate Action Plans." *Proceedings of 2000 ACEEE Summer Study on Energy Efficiency in Buildings.* Volume 9, pp. 149-160 (with Tom Buckley, Mark Eldridge, Debra Sachs, and Abby Young).

1998 *Eco-Efficiency Financing Resource Directory*. Electronic web-site, and printed directory prepared for the Environmental Protection Agency, Region I, New England.

Regulatory and Other Governmental / NGO Documents

2000 – 2012 *New Jersey's Clean Energy Programs – Honeywell Team Program Plans.* Led team on designing and implementing of Renewable Energy Program plans and initiatives. Many program plans and strategies for transition to market-based incentives.

1998 – 2008 *Long Island Power Authority's Clean Energy Initiative.* Lead Technical and Senior Advisor on Renewable Energy Plans, including the Solar Pioneer Initiative and Residential Energy Efficiency Programs.

2000 *The Climate Action Plan: A Plan to Save Energy and Reduce Greenhouse Gas Emissions*, Lead author for the Burlington (Vermont) Climate Protection Task Force.

1998 *Home Weatherization Assistance Program Environmental Impact Analysis*. Prepared for the Ohio Department of Development, Office of Energy Efficiency.

1997	*Achieving Public Policy Objectives Under Retail Competition: The Role of Customer Aggregation*. Prepared for the Colorado Governor's Office of Energy Conservation.
1997	*IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global Climate Change*, software and paper. For the United Nations Industrial Development Organization.
1997	*Review of the Swaziland Energy Information System and Report on LEAP Training Activities*. Prepared for the Ministry of Natural Resources and Energy, Government Kingdom of Swaziland.
1996	*Evaluation of the IDB's Policies and Practices in Support of Renewable Energy and Energy Efficiency: A Report to the Inter-American Development Bank*. Brower and Company and Tellus Institute.
1996	*Action Plan for the Massachusetts' Industrial Services Program (ISP)*, prepared for the Sustainable Industries Initiative of the Corporation for Business Work and Learning.
1995	*Framework for National Energy Planning: Mission Report*, The Republic of Maldives. United Nations Department for Development Support and Management Services.
1994	*The SEI / UNEP Fuel Chain Project: Methods, Issues, and Case Studies in Developing Countries. Venezuela Case Study*.
1994	*Future Energy Requirements for Africa's Agriculture (Sudan Case Study)*. Report to the African Development Bank by the UN Food and Agriculture Organization.
1994	Report to the Idaho Public Utility Commission on Suggested Cost Allowances for the Idaho Power Company's DSM Programs. Prepared for the Idaho Public Utilities Commission, Tellus Report No. 94-177.
1994	Review of Pennsylvania Electric Company's 1995 Demand Side Management Filing. Prepared for: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-071.
1994	Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings. Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300.
1994	*Incorporating Environmental Externalities in Energy Decisions: A Guide for Energy Planners*. A Report to the Swedish International Development Agency. SEI-B Report No. 91-157.

Leadership

2017 – 2019	Energy Coop of Vermont, Board Member and Treasurer.
2013	Solar 2013, "Power Forward, Baltimore Maryland." Chair of Conference Advisory Committee responsible for recruiting and coordinating four main conference plenary sessions.
2012 – 2013	American Solar Energy Society (ASES), Chair of the Board.
2012	Policy Track Chair for the World Renewable Energy Forum, Denver, Colorado, May.
2009 – 2012	ASES Policy Committee, Board Member and Chair.
2007	Vermont Governor's Climate Change Committee, Member of the Plenary Working Group.

2000 – 2010 Renewable Energy Vermont, Founding Board Member, Past Board Chair.

Education

Ph.D., Energy Management and Policy Planning, University of Pennsylvania, Philadelphia, Pennsylvania (PA), 1993.

- Fulbright Scholar: Research on energy decision-making in rural Nepal, 1991 – 1993.

Master's, Appropriate Technology and International Development, University of Pennsylvania, Philadelphia, PA, 1989.

B.A., Geography and Political Science, Middlebury College, Middlebury, VT, 1986.

Other Qualifications

Nepal, Himalayan Light Foundation. Installed solar lighting systems in 3 remote health clinics and 3 homes, 2010.

Advanced PV Installation certificate. Solar Energy International, 2010.

Peace Corps volunteer. Sierra Leone, 1984 – 1986.

Languages

- Nepali: ILR Level 3, speaking; ILR Level 2, reading
- Krio and Mende (Sierra Leone): ILR Level 2, speaking

Software competency

- LEAP (Low Emissions Analysis Platform), Stockholm Environment Institute. Former trainer and current Principal Investigator of team using scenario modeling on three projects.
- NREL System Advisor Model. Financial and technical modeling tool for renewable energy systems.

Critical Elements in Short Supply:

Assessing the Shortcomings of National Grid's Long-Term Capacity Report

Conducted by:

David G. Hill, Ph.D., Energy Futures Group

Chelsea Hotaling, Energy Futures Group

Gabrielle Stebbins, Energy Futures Group

Prepared for:

350.org and 350Brooklyn

Original March 9, 2020

With Addendum:

April 17, 2020

This whitepaper was prepared by David Hill, Chelsea Hotaling and Gabrielle Stebbins of Energy Futures Group with support and review or comment from Suzanne Mattei of Lookout Hill Public Policy Associates, Robert Wood and Sara Gronim of 350Brooklyn, and Richard Brooks of 350.org. Any omissions or errors are the responsibility of the primary authors. Questions for the authors should be directed to dhill@energyfuturesgroup.com

Table of Contents

EXECUTIVE SUMMARY

The Settlement Agreement between the New York State Public Service Commission ("PSC") and National Grid regarding National Grid's recent self-imposed moratorium on new natural gas connections included a requirement for National Grid to conduct a long-term needs assessment. This paper presents an alternative analysis that casts doubt on National Grid's claim to need new gas infrastructure by analyzing National Grid's findings from three perspectives:

Questions on Whether the Predicted Need is Inflated: The U.S. Energy Information Administration's forecasted demand is significantly lower than National Grid's. **An adjustment based on EIA's data would reduce National Grid's projection of future energy needs by nearly 85%.** Furthermore, National Grid's own analysis shows that the historical growth in Design Day Gas Demand has slowed between 2014 and 2020 compared to 2010 to 2014. Transparency is critical when forecasting future demand. A meaningful debate regarding the need for new gas infrastructure requires National Grid to present the underlying assumptions and methodology used to develop the demand forecast.

Better Ways to Meet Demand: Comprehensively incorporating non-pipeline alternatives such as energy efficiency, demand response, flexible load management, strategic electrification through cold climate air source heat pumps as well as geothermal heat pumps, and sealing gas leaks in existing pipelines can greatly reduce future demand. This paper shows that aggressive implementation of **non-pipeline alternatives can reasonably be expected to meet 88% of National Grid's projected need** – and would more than address future demand if National Grid's projection is inflated.

Meeting our Climate Goals: Construction of new gas infrastructure is inconsistent with State climate policy, goals, and initiatives. **Consistency with State climate policy requires that National Grid's high projections be reduced by more than 95%**; the non-pipeline option is the appropriate route for our energy future.

Careful, critical assessment of new gas infrastructure is necessary. Investment in new gas infrastructure with a decades-long lifespan can lead to stranded costs, under-utilized assets, and emissions that are incompatible with climate targets. Ratepayers may end up bearing undue costs, and investment in new pipeline capacity may discourage investments in energy efficiency, peak demand reduction programs, electrification of space heating and decarbonization of the grid, all of which are critical to a sustainable energy future.

National Grid must play a constructive role in meeting New York State and local energy goals by vigorously promoting a comprehensive and integrated strategy that relies on energy efficiency, demand response, flexible load management, strategic electrification, reduction of gas leaks and renewable solutions.

Introduction

Under a settlement agreement with the New York State Public Service Commission ("PSC") in November 2019, which lifted National Grid's self-imposed moratorium on new gas service connections, the company agreed to investigate a range of options to address long term supply needs for its downstate New York territory - the Keyspan Gas East (KEDLI) and Brooklyn Union Gas (KEDNY) service areas. National Grid had asserted in May 2019 that its refusal to process applications for new or expanded gas service in most of its downstate New York territory was due to concerns over sufficient firm gas supplies during periods of peak demand.[1] The settlement agreement requires National Grid to produce a report assessing long-term need and options to address it, and to present its analysis for public input.[2]

National Grid's proposed report, released on February 24, 2020,[3] emphasizes the Williams Northeast Supply Enhancement Project (NESE) pipeline as a key element of the solution set that it intends to submit to the PSC—a costly, questionable and problematic option. The NESE proposed by the Williams corporation and Transcontinental Gas – and supported by National Grid as its sole named customer – would allow the burning of up to 400,000 Dekatherms more per day (400 MDth/day[4]) of gas, which would be a 14% increase to National Grid's existing 2,888 MDth/day of total system firm peak day capacity for the KEDLI and KEDNY systems combined.[5]

Careful, critical assessment of new gas infrastructure is necessary. Investment in new gas infrastructure with a decades-long lifespan can lead to stranded costs,[6] under-utilized assets, and emissions that are incompatible with climate targets. Ratepayers may end up bearing undue costs,[7] and investment in new pipeline capacity may discourage investments in energy

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[1] Implementation and Contingency Plan, Oct 21, 2019, NYS PSC Case 19-G-0678. p. 2.

[2] New York Public Service Commission, "*PSC Approves Settlement to Lift National Grid Gas Moratorium*", 19101/19-G-0678, 11/26/2019. The long-term options to be considered, among others, include a new pipeline, liquified gas (LNG) facilities, compressed gas (CNG) facilities, renewable energy sources, conservation strategies and interoperable systems. *Id.*

[3] National Grid, Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island (Feb. 2020) (hereafter, National Grid Report.)

[4] One MDth = 1,000 Dekatherms (one million Dekatherms, in contrast, is designated as 1 MMDth). National Grid's report uses the MDth unit of measurement, and this report does the same, for ease of comparison.

[5] New York Public Service Commission, Case 19-M-0382, Winter Supply 2019-2020 forms, Table 1a. See National Grid Report, p. 9.

[6] Pipelines such as NESE are typically expected to be in service for ~50 years (or, 2070), while state climate targets net zero emissions by 2050.

[7] https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf

efficiency, peak demand reduction programs, electrification of space heating and decarbonization of the grid, all of which are critical to a sustainable energy future.
This paper provides a framework for critiquing the National Grid report on long-term supply needs and options. Our work is preliminary; we present three elements and parameters, together with guidelines and suggestions, that should inform the public review and assessment of National Grid's pending plan:

- Transparency: What are National Grid's underlying assumptions regarding future demand, and are these reasonable? Is the predicted need inflated?
- Comprehensiveness: Has National Grid truly incorporated the savings achievable through non-pipeline alternatives? We identify better ways to meet demand.
- Consistency: National Grid's report is incompatible with greenhouse gas reduction targets set to meet our climate goals.

Based on these parameters, we provide a qualitative and semi-quantitative overview of factors to be considered when reviewing and assessing the validity of National Grid's report.

Figure 1 compares the results of our preliminary analysis of the key parameters listed above with the proposed capacity of the pipeline option presented in National Grid's report.

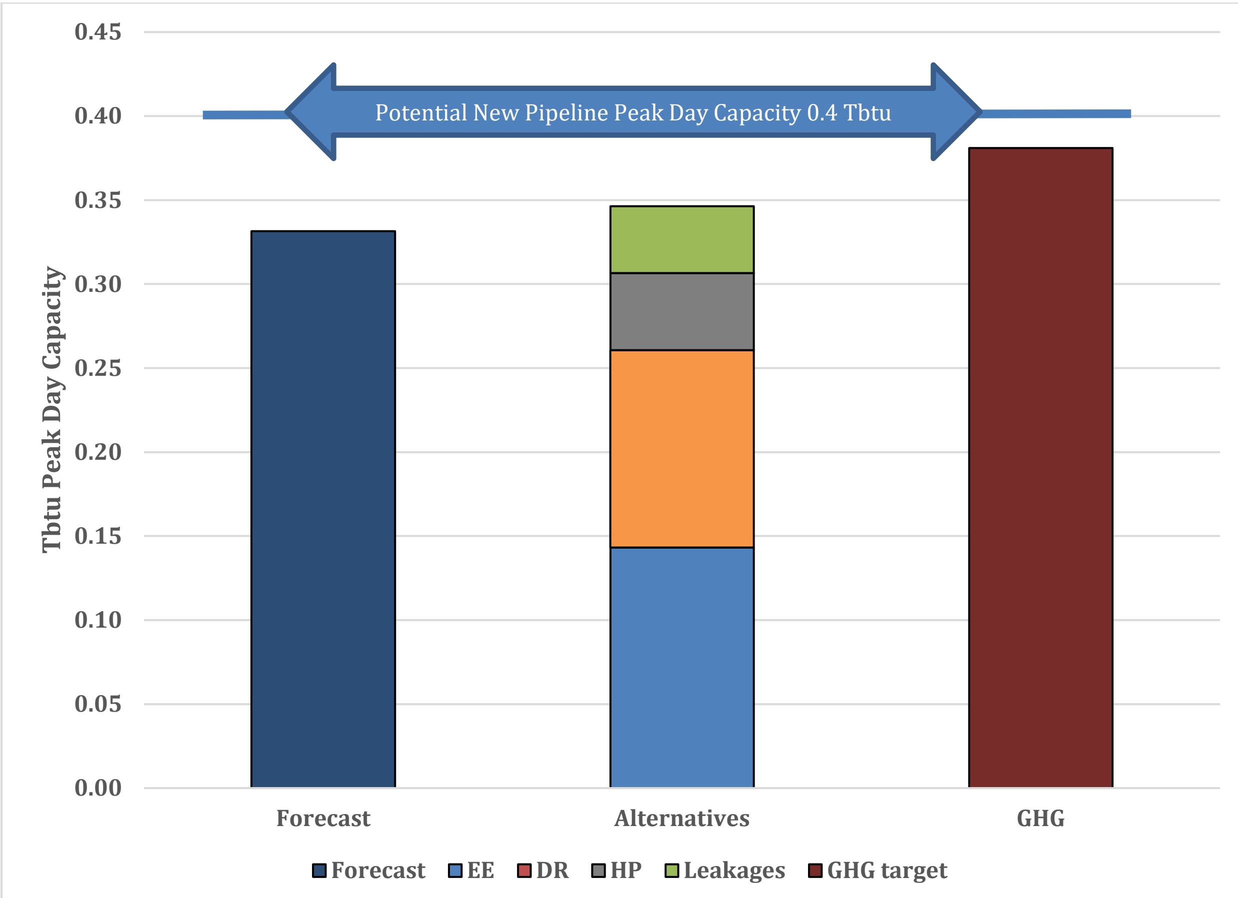

Figure 1: Proposed Pipeline Capacity Compared with Adjusted Needs Forecast, Non-Pipeline Solutions and New York Goal to Reduce Greenhouse Gases

The first stacked bar indicates that adjusting the demand forecast to be consistent with both historic trends and long-term energy outlook forecasts by the Energy Information Administration from 2019 to 2030 off-sets nearly 85% of the new peak day capacity that the proposed NESE pipeline would provide, leaving just slightly more than 15% capacity that would need to be met – and certainly could be met by non-pipeline solutions. This is discussed in Section 2 of this paper.

The second stacked bar in Figure 1 represents how a combination of non-pipeline alternative can be expected to off-set 88% of the peak day capacity that the proposed NESE pipeline would provide, not even taking into consideration any adjustment to National Grid's forecast of peak day demand. This is discussed in Section 3 of this paper.

Note that the first and second bars show a significantly lower demand than National Grid's forecast, each unto themselves. Scrutinizing the proposed forecast (the first bar) *in combination* *with* an aggressive non-pipeline alternatives plan (the second bar) would reduce demand even further, raising even more doubt as to the need for new gas infrastructure.

Finally, the third bar indicates the amount of new gas capacity that must be avoided (more than 95%) if National Grid's pending long-term plans are to be consistent with statewide greenhouse gas reduction targets, presented in Section 4 of this paper.

The following sections of this paper explain the analysis that led to these results.

1 Background: National Grid's Downstate Customer Base

National Grid provides gas services to roughly 1.8 million customers in downstate New York through the Keyspan Gas East (KEDLI) and Brooklyn Union Gas (KEDNY) service territories. Figures 2 and 3 illustrate deliveries of gas by customer class in 2018 as reported by Energy Information Administration Form 176.

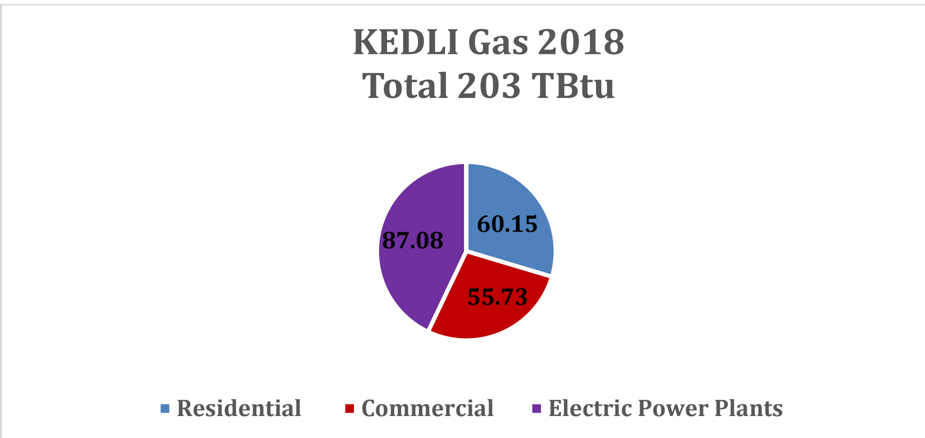

Figure 2: Keyspan Gas East Gas Deliveries by Customer Segment.[8]

The Brooklyn Union Gas KEDNY territory has slightly higher annual volume, with the notable difference of less delivery for electric power generation than KEDLI. Figure 3 provides the 2018 data for KEDNY.

[8] EIA. Form 176 Custom Report (User-defined). Natural Gas Annual Respondent Query System

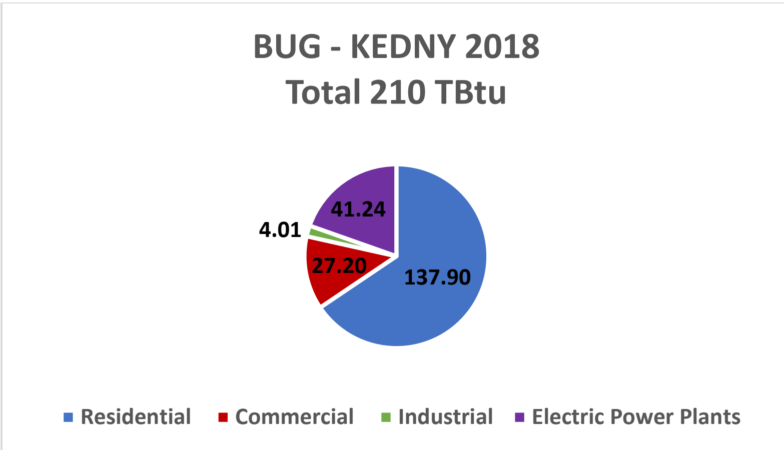

Figure 3: Brooklyn Union Gas KEDNY 2018 Deliveries by Customer Segment.[9]

2 Transparency: Forecasting Baseline Need

While National Grid presents a variety of data in the February 2020 report, the underpinning data sets, assumptions, and modeling methodology remain a "black box." As a result, it is impossible to analyze and verify the validity of National Grid's final forecasted demand. However, it is possible to compare historical demand to the estimates used by National Grid.[10]

National Grid's most recent report from February 24, 2020 asserts that the Downstate New York area will experience a Design Day[11] demand growth at a rate of 1.8% between 2020 and 2035, with a range of 0.8% to 1.1% to represent low and high demand scenarios.[12]

[9] EIA. Form 176 Custom Report (User-defined). Natural Gas Annual Respondent Query System.

[10] Note that the analysis in this paper was based on an August 29, 2018 presentation submitted to the U.S. Army Corps of Engineers, in which National Grid had originally projected gas demand growth of 10% over the next ten years.

[11] A "design day" is a 24-hour period of demand which is used as a basis for planning gas capacity requirements.

[12] National Grid Report, p.8. National Grid's projection for their baseline demand forecast is a CAGR of 1.8% between 2020 and 2035. National Grid then provides a range of 0.8% for a low demand scenario and 1.1% for a high demand scenario that take into consideration ranges of energy efficiency, demand response, and electrification.

While National Grid is projecting growth in its Design Day Gas Demand between 2020 and 2035, the continued growth in demand may not be as strong as it is projecting. This same pattern of slower growth appears in National Grid's report where it provides the historical Design Day Gas Demand compared to its projections for the future. Figure 4 illustrates National Grid's comparison between historical and projected Design Day Gas Demand. The historical growth in Design Day Gas Demand has slowed between 2014 and 2020 compared to 2010 to 2014. This slowing pace of growth calls into question the reasonableness of National Grid's assumption that the higher pace of growth from 2010 to 2014 would continue in the future.[13]

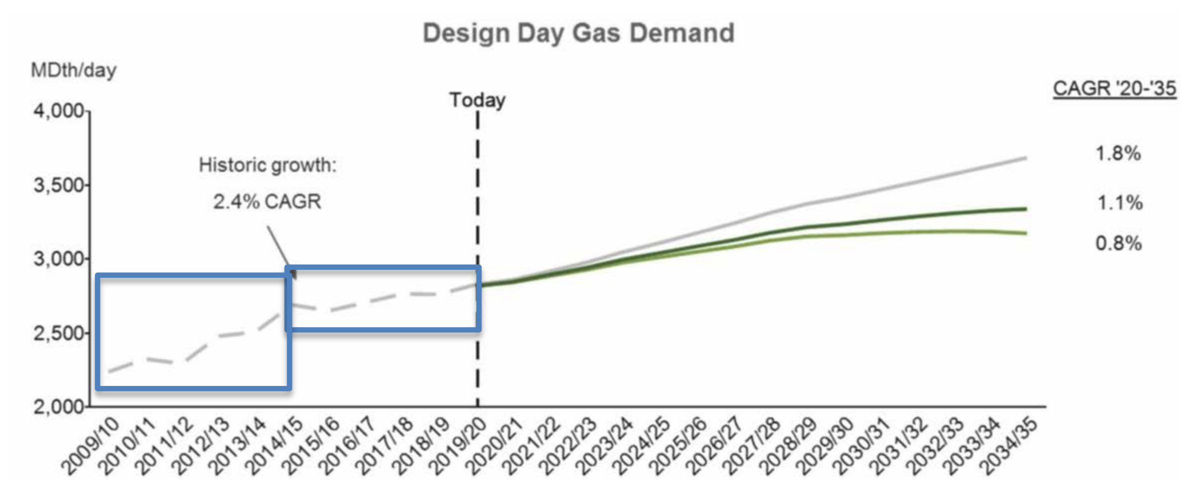

Figure 4: National Grid's Historical and Projected Design Day Gas Demand[14]

In its discussion on the key drivers for Design Day Demand growth, National Grid lists numerous drivers, which include: population growth, business and economic growth, increased gas usage per customer, and continued conversions from oil to gas. For stakeholders to understand what is driving the projected growth in Design Day Demand, National Grid needs to provide the sources for the underlying data. Without these citations, there are questions about the assumptions National Grid is making for these drivers.

Not only does historical demand not align with National Grid's demand forecast - other forecasts do not align either. The Annual Energy Outlook for 2020 produced by the U.S. Energy

[13] In order to fully understand National Grid's forecast, the report must discuss the forecasting methodology used, including whether National Grid used regression analysis focusing on key variables explaining growth in demand, or whether they applied extrapolation methods. If National Grid did use regression analysis, it would be helpful to understand what variables they chose to include in their model. In addition, it would be beneficial for stakeholders to see what the demand breakdown by customer class has been historically and what National Grid is forecasting for 2020 to 2035. Stakeholders will not be able to truly understand the derivation of National Grid's forecast without this key information.

[14] National Grid Report, Figure 1, p.8.

Information Administration (EIA),[15] in contrast to National Grid, projects that gas consumption will increase from 31.03 trillion cubic feet in 2019 to 31.54 trillion cubic feet in 2030.[16] This represents only 1.6% growth over the next ten years—which may itself be a conservative estimate given increased commitments to energy efficiency and renewable energy.

As represented in Figure 1 above, adjusting National Grid's 1.8% annual forecast[17] load growth downward, to be more consistent with the EIA's outlook, would offset almost 85% of the asserted need for a 400 MDth/day pipeline expansion for peak day purposes (not counting any potential adjustment to carbon output from changes in pipeline fuel[18]).

Decarbonization of our power grid is another issue that has not been included in National Grid's analysis or in this paper. However, it should be incorporated into future analyses and deliberations. Figures 2 and 3 above show that electric power plants constitute 31% of the current customer load base. With a State target of 70% renewable electric generation by 2030, and the addition of new offshore wind capacity, National Grid's downstate service territory can reasonably expect to see significant declines in demand for gas for electric generation. Additionally, Figure 5 below shows the results of a Long Island Power Authority's (LIPA) Integrated Resource Plan (IRP) presentation demonstrating that the run time for gas and other fossil generation stations is expected to be reduced due to the addition of off-shore wind.

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[15] The U.S. Energy Information Administration (EIA) is a federal entity that collects, analyzes and disseminates detailed energy-related information. See Department of Energy (DOE) Organization Act of 1977 (P.L. 95-91, 42 USC 7135).

[16] Energy Information Administration, Annual Energy Outlook 2020. Table: Table 13. Natural Gas Supply, Disposition, and Prices. The 1.6% growth is for national gas consumption. The EIA Annual Energy Outlook projects that gas consumption in New England will decrease from 0.885 quadrillion Btu in 2019 to 0.729 quadrillion Btu in 2030.

[17] Taking National Grid's assumed baseline annual growth rate from 2020 to 2025 represents 9.33% growth between 2020 and 2025.

[18] This paper does not evaluate the passages of National Grid's report that describe pilot studies of blending hydrogen with gas.

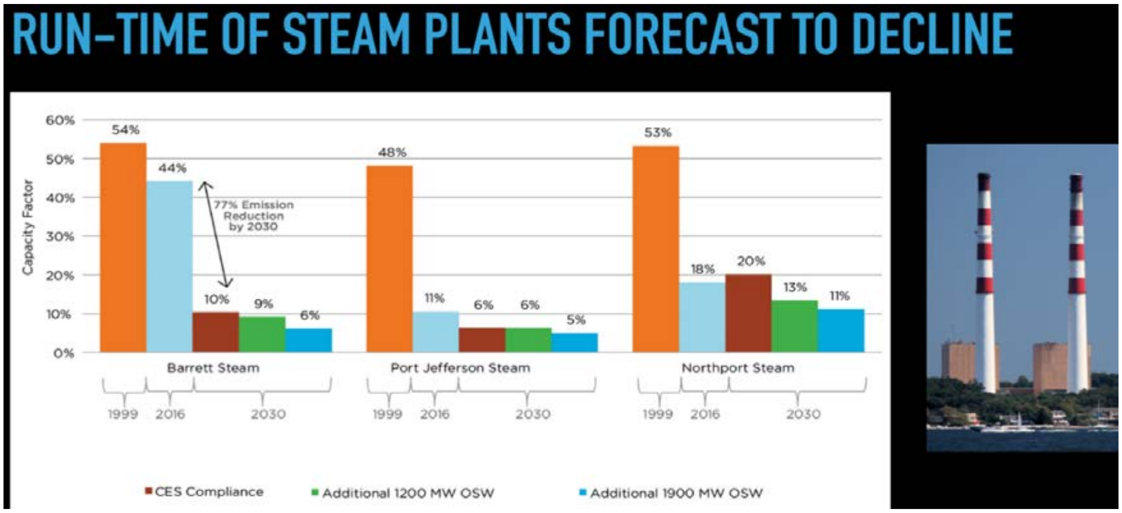

Figure 5: LIPA Anticipated Reductions in Non-Renewable Station Run Times.

Moreover, while strategic electrification and increasing variable renewable generation will require more coordination and planning for peak electric and gas demand loads during winter periods, the decisions to not build new gas fired electric generation must be explicitly recognized and included in National Grid's long-term gas needs assessment. In the KEDLI territory, the Long Island Power Authority's (LIPA) most recent Integrated Resource Plan has led to decisions to not build new gas fired capacity and to not repower existing gas generation stations.[19]

We are unable to assess the role of a decarbonizing grid in National Grid's forecasting. Its report should provide key information to allow such an assessment. It should disclose the highest level of capacity used by interruptible-service power plants in National Grid's Downstate New York territory during a non-peak period. It should also discuss how LIPA's recent and projected reduction in gas consumption by power plants affect the frequency of need for peak capacity or peak demand reduction.

We recognize that power plants running on interruptible service are taken off the pipeline system during periods of peak demand, operating instead temporarily on an alternate fuel. Nevertheless, if such power plants reduce the use of gas on average-to-increasingly colder days, that reduction does improve to some extent the capacity of the transmission pipelines to accommodate the increasingly higher gas usage by other customers that occurs as the temperature drops toward severe cold (*before* reaching peak capacity). Therefore, a significant reduction in gas use by power plants could affect how often the system reaches the point at which peak demand strategies are triggered. This should be quantified.

[19] Long Island Power Authority, DPS Public Statement Hearings. https://www.lipower.org/wp-content/uploads/2016/10/Irp20Presention20BEST1.pdf

3 Comprehensiveness: Non-Pipeline Alternatives

A major policy in New York State that should drive non-pipeline alternatives in National Grid's plan is Governor Cuomo's Reforming the Energy Vision (REV) energy strategy. National Grid has proposed gas initiatives as part of the REV strategy and includes them in its current proposed plan. National Grid's REV strategy discusses its commercial gas demand projects to address gas constraints on the customer side and a green gas tariff program.[20] National Grid reports that it is looking into exploring solutions that include smart thermostats, building management systems, and solutions for thermal storage.[21]

While National Grid discusses an array of non-pipeline approaches in its proposed long-term needs assessment, a more aggressive program is possible. Indeed, when implemented in a comprehensive, integrated, strategic manner, non-pipeline alternatives result in considerable savings.

Table 1 summarizes our findings and estimate of peak day savings (in MDth) from non-pipeline alternatives that a comprehensive analysis should incorporate.

Table 1: Non-Pipeline Alternatives

Alternative	Peak Day MDth	Notes
Gas Energy Efficiency	140	Annual incremental efficiency savings of 1%, consistent with leading initiatives, with 5% cumulative annual savings by 2025.
Demand Response	120	Annual average savings of 20%, which is relatively conservative compared to pilot results. Based on saturation of 20% of residential and commercial customers by 2025.
Heat Pumps	50	Based on 1% of residential customers switching per year, a total of 80,000 customers by 2025.

[20] National Grid. Reforming the Energy Vision for Gas. Retrieved from https://www.nationalgridus.com/new-energy-solutions/Community-Projects/New-York/Gas-Rev

[21] National Grid. Gas Demand Response. Retrieved from https://nyrevconnect.com/gas-demand-response-national-grid/

Reduced Gas System Leakage	40	Based on reducing National Grid's current 2.32% leakage rate by 60%, down to a 0.93% reduction rate.
Total	**350**	**88% of potential 400 MDth/day pipeline expansion**

In its report, National Grid considers energy efficiency, demand response, and heat pumps for strategic electrification as a suite of options for its "No-Infrastructure Solution." Table 2 below highlights the Design Day Demand impact National Grid is projecting for these resources for two points in time in its forecast. Our preliminary analysis indicates a higher potential for savings by 2025 compared to what National Grid is projecting in its report.

Table 2: National Grid's Design Day Impact From No-Infrastructure Solution[22]

	Required Impact 2026/2027 (MDth/Day)	Required Impact 2034/2035 (MDth/Day)
No Infrastructure Solution	148 - 199	230 - 400

Our preliminary analysis includes one alternative that National Grid did not consider in its needs assessment: addressing leaks in the distribution system. Additional, critical information is missing from National Grid's presentation of the assumptions it made regarding its no-infrastructure solution options. For stakeholders to assess whether National Grid is harnessing all possible savings, National Grid must provide the annual impacts assumed for each year of the needs assessment, as well as additional information regarding the impact of specific energy efficiency and demand response programs.

3.1 Incremental Energy Efficiency

On January 16, 2020, the PSC released its Order on a Comprehensive Energy Efficiency Initiative, which establishes targets for increased use of heat pumps and calls for annual levels of efficiency savings of 3% for electricity and 1.3% for gas by 2025.[23]

[22] National Grid Report, Table 38, p. 97.

[23] Case 18-M-0084. January 16, 2020. State of New York Public Service Commission. In the Matter of a Comprehensive Energy Efficiency Initiative. Note that the "3,600 MDth" cited in the Case did not have a unit associated with it, hence none is provided here.

But if National Grid only achieves the minimum level of incremental energy efficiency required by this Order, the cumulative percentage of incremental savings for National Grid's downstate New York territory would be only 1.5% of its 2018 deliveries.[24] For our analysis, we assume that National Grid would achieve cumulative savings of 5% by 2025 and a reduction in demand of 140 MDth/day.

While higher than National Grid's current energy efficiency achievement of 0.4% of gas sales, this level of savings is comparable to what utilities elsewhere have achieved. Figure 6 presents the energy efficiency achievements of several utilities, as a percentage of retail gas sales, in 2015. National Grid's service territory in Massachusetts is one of the leaders in savings as a percent of sales. It is not unreasonable to assume that National Grid would be able to replicate that success in its downstate New York service territories.

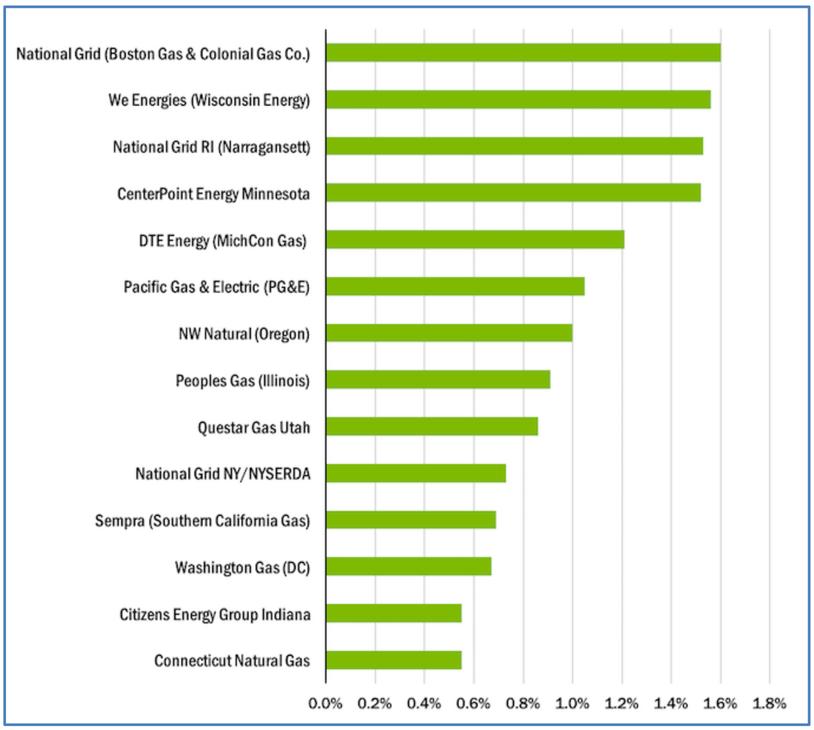

Figure 6: Incremental 2015 Energy Efficiency Savings as a Percent of Retail Gas Sales[25]

[24] Case 18-M-0084. Appendix A, Table A4. Total savings for KEDLI and KEDNY between 2021 and 2025 are 6.10 Tbtu. The cumulative incremental savings between 2021 and 2025 only amount to 1.5% of National Grid's 2018 sales.

[25] ACEEE. March 31, 2017. Leading states and utilities achieve substantial gas energy efficiency savings. Retrieved from https://www.aceee.org/blog/2017/03/leading-states-and-utilities-achieve

3.2 Demand Response

More aggressive demand response programs present another opportunity to reduce future need. Demand response programs for gas would work essentially in the same way as demand response electricity programs. During periods of high demand and/or low supply, utilities provide an incentive to customers to lower their usage during the peak demand period. National Grid has an existing pilot demand response program for commercial and industrial customers. Since National Grid does not have an existing demand response program for residential customers in KEDNY or KEDLI, we used the savings results from a residential demand response program used by Southern California Gas Company ("SoCalGas"). When customers enroll in the program, they agree to allow SoCalGas to adjust[26] their smart thermostat remotely when an event is called.

During the 2017-2018 winter season, SoCalGas enrolled 9,267 customers and 10,798 smart thermostats. On average, each participant reduced their usage between 16-25%, which translated to 0.03-0.05 therms during the morning event period and between 10.7-15.6% or 0.012-0.019 therms during the evening event period.[27]

For the savings estimate in our analysis, we assumed a conservative level of 16% from a residential program similar to that of SoCalGas, and a 25% savings from a commercial and industrial program.[28] The weighted average savings across both programs is 20.5%. We assume that National Grid is able to reach 20% saturation for demand response programs by 2025.

[26] Up to four degrees.
[27] Case U 904 G. Direct testimony of Darren Hanway. Public Utilities Commission of the State of California. November 6, 2018. Retrieved from https://www.socalgas.com/regulatory/documents/a-18-11-005/Demand_Response_Testimony_Chapter%201_Final.pdf
[28] National Grid has not released results on peak impacts from their commercial and industrial demand response pilot.

Table 3 shows the breakdown of customers across National Grid's downstate service territories for 2018.

Table 3: Customers by National Grid Service Territory[29]

Company	Customers	2018
KEYSPAN ENERGY	Residential	505,303
	Commercial	46,695
THE BROOKLYN UNION GAS CO	Residential	1,025,428
	Commercial	32,101
	Industrial	3,652

Based on this saturation level, National Grid could achieve 120 MDth savings from implementing demand response programs. This is a reasonable assumption given the penetration SoCalGas has been able to achieve for its smart thermostat program, in addition to the penetration level from a smart thermostat program launched in Massachusetts.[30]

Our assumptions for National Grid's ability to scale its demand response programs is based on progress with its existing demand response program and results from other pilot studies. National Grid won the Utility Industry Innovation in Gas Award for its demand response program powered by AutoGrid software,[31] and it cited "greater than previously anticipated"

[29] EIA. Form 176 Custom Report (User-defined). Natural Gas Annual Respondent Query System.

[30] In a pilot program launched between December 2014 and January 2015, 20,104 nest thermostats enrolled, which translated to 54% of all eligible thermostats in Massachusetts. Information from Nest Seasonal Savings: MA DOER Heating Season Impact Evaluation. 2015. Retrieved from https://www.mcecleanenergy.org/wp-content/uploads/2016/08/MCE-AL-17-E-Seasonal-Savings-Pilot.pdf

[31] Autogrid. November 20, 2017. National Grid Recognized by NARUC for Natural Gas Flexibility Program Power by Autogrid. Retrieved from https://www.auto-grid.com/awards/national-grid-recognized-by-naruc-for-natural-gas-flexibility-program-powered-by-autogrid/

savings from demand-reduction programs and energy efficiency initiatives as one of the ways that it achieved compliance with the order to end its self-imposed moratorium on gas.[32]

National Grid has seen some demonstrated savings with the commercial customers participating in its pilot program. It was able to engage 16 large customers in its demand response pilot in New York. Based on information included in a presentation at the AEE East Energy Conference, the pilot in New York was able to see reduction in account-level gas consumption.[33] Figure 7 below illustrates how a university was able to achieve its fixed service level[34] targets during a gas demand event.

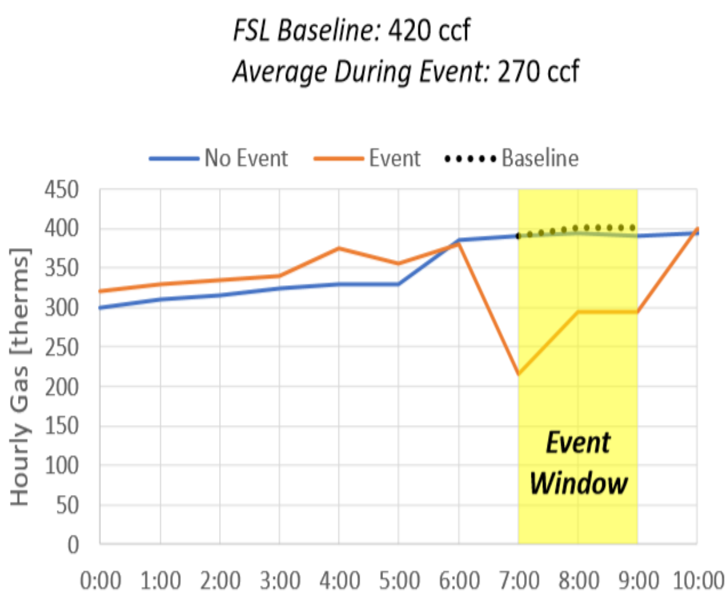

Figure 7: Reproduction from presentation at AEE East Energy Conference

The demand reduction potential and actual load reduction potential in National Grid's downstate commercial demand response pilot program exceeded its initial target. Table 4

[32] Harrington, M. and McDermott, M. November 26, 2019. National Grid Finds Gas to Resolve Short-Term Supply Problem. Retrieved from https://www.newsday.com/long-island/politics/national-grid-moratorium-gas-1.38936730

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

[34] Fixed service level is when the customer manages their gas consumption to achieve a target gas consumption level relative to a pre-determined baseline.

shows the targets National Grid set for the pilot program compared to the results it has seen from the program.

Table 4: National Grid Pilot DR Program[35]

	National Grid Target	Results
Customer Enrollment	30 customers	15 facilities
Demand Reduction Potential	.14 MDth/hr	.19 MDth/hr
Actual Load Reduction Potential	Average of 25% process and 10% heating loads	Average of 63% and median of 50%

Even though National Grid had lower enrollment from customers, it was able to realize greater demand reduction potential than it originally anticipated from 30 customers. Considering the number of customers enrolled in the program to date, National Grid has the potential to scale this program to reach more of its commercial and industrial customers. With 15 customers enrolled across National Grid's downstate service territory, that represents a small percentage of the market, as illustrated in Table 5 below. Calculations were based on the number of customers National Grid reported for 2018 as shown in 3.

Table 5: National Grid Pilot DR Program Market Penetration

Territory	Customers Enrolled	% of C&I Customers
KEDLI / KeySpan	4	0.01%
KEDNY / Brooklyn Union Gas	11	0.03%

In its 2019 REV update on the pilot program, National Grid reported on a new customer that submitted demand response applications for 41 of its facilities. Due to project constraints, the project team worked with this company to select one facility that would provide the maximum level of value to the participant and the Project.[36] Nevertheless, the customer's willingness to include all of its facilities in a demand response pilot is a positive indication of the ability of this concept to be scaled. Based on this update provided by National Grid, significant potential exists to scale the program to reach more customers.

[35] National Grid Gas Demand Response REV Demonstration Project in New York City and Long Island. January 31, 2018. Q4 2017 Report.

[36] National Grid Gas Demand Response REV Demonstration Project in New York City and Long Island. January 31, 2019. Q4 2018 Report, p.2.

SoCalGas's recent proposal for its demand response plan includes additional pilot programs. Table 6 below illustrates the four pilot programs SoCalGas plans to explore for demand response offerings to customers. National Grid should look to some of the programs SoCalGas is implementing to expand upon its pilot program to reach a higher penetration for demand response.

Table 6: SoCalGas Gas Demand Response Pilot Programs[37]

Pilot Programs	Description	Pilot Goals
Space Heating Load Control	Smart Thermostat Load Control program that offers customers incentives to lower gas use during an event	• 50,000 thermostats by the end of 2018-2019 winter season • 7,000 new enrollments every year
Water Heating Load Control	Controlling water heating equipment to lower gas usage during an event	Participants: • 500 for 2019-2020 • 1,000 for 2020-2021 • 1,500 for 2021-2022
Load Reduction	Targeted for commercial and industrial customers to lower gas consumption	With 1% enrollment of customers, the program has the potential to reduce 22,172 therms per day with an average savings of 20%
Behavioral Messaging Pilot	Using messaging strategies to encourage customers to reduce their gas usage during peak demand periods	Sending energy reports to customers that provides information on peak demand events and the impact that customers had during the event

[37] Case U 904 G. Direct testimony of Darren Hanway. Public Utilities Commission of the State of California. November 6, 2018. Retrieved from https://www.socalgas.com/regulatory/documents/a-18-11-005/Demand_Response_Testimony_Chapter%201_Final.pdf

Another demand response program with smart thermostats also saw similar savings from heating use. The Massachusetts Department of Energy Resources partnered with Nest[38] to deploy a pilot program launched between December 2014 and January 2015. The program saw a high penetration of thermostats, as 20,104 nest thermostats enrolled, which translated to 54%[39] of all eligible thermostats in Massachusetts. The program saw a reduction in heating usage by an average of 3.5%.[40]

Achieving New York State's climate goals will require a substantial reduction in the reliance on gas. Demand response programs can address peak demand concerns while also reducing gas consumption. National Grid identified higher than expected savings from its pilot program, and it should replicate those savings by introducing other demand response programs similar to SoCalGas. These savings will be key to addressing its reported capacity need.

3.3 Flexible Load Management

Flexible load management—which includes coordination of loads through smart devices across multiple end users, and the ability to pre-heat and stagger loads such as water and space heating—further expands the potential beyond the conventional approach to demand response. A recent report by the Brattle Group found that a portfolio of load-flexibility programs, especially targeting the residential sector, could triple existing demand response capability by 2030.[41] It noted that, "For reasons entirely unrelated to demand response, customers are increasingly adopting technologies with load flexibility capabilities," and it predicts that while the commercial and industry sector has provided 70% of retail demand response capacity up to now, residential load flexibility additions ultimately will exceed those of the commercial and industry sector.[42]

3.4 Strategic Electrification

New York State's Order on Energy Efficiency identified a heat pump target of 88,000 buildings throughout the entire State.[43] Our analysis assumes that National Grid can target 1% of residential customers each year for installation of heat pumps in the Downstate area. This

[38] Nest is one of the companies that have developed smart thermostats. Smart thermostats are electronic thermostats that optimize heating and cooling.
[39] Nest identified 37,586 thermostats in Massachusetts for the program.
[40] Nest Seasonal Savings: MA DOER Heating Season Impact Evaluation. 2015. Retrieved from https://www.mcecleanenergy.org/wp-content/uploads/2016/08/MCE-AL-17-E-Seasonal-Savings-Pilot.pdf
[41] The Brattle Group, The National Potential for Load Flexibility: Value and Market Potential Through 2030. June 2019., p. 18. Retrieved from https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.
[42] *Id.*, p. 25.
[43] Case 18-M-0084. January 16, 2020. State of New York Public Service Commission. In the Matter of a Comprehensive Energy Efficiency Initiative.

results in 5% of residential customers, or 80,000 households in Downstate New York alone, switching to heat pumps between 2020 and 2025. Our analysis indicates that installing heat pumps in 80,000 homes in the targeted area translates into savings of 50 MDth/day for National Grid by 2025. NYSERDA's report on its heat pump analysis indicates that more technical potential exists for use of heat pumps across the state. Table 7 outlines the technical potential identified by NYSERDA in its analysis of potential savings from heat pumps across existing and new buildings in New York State. This considers households switching from gas and fuel oil to heat pumps. Table 8 demonstrates the potential for National Grid's downstate service territory.

Table 7: Technical Potential Annual Thermal Load Served by Small-Scale Residential Heat Pumps for Existing and New Buildings to 2025 (MDth)[44]

Fuel	Area	ASHP	Minisplit	GSHP	Total
Gas	Long Island	16,300	10,100	16,800	43,200
	NYC	10,505	6,600	8,690	25,795
Fuel Oil	Long Island	18,300	11,700	18,800	48,800
	NYC	1,705	1,100	1,430	4,235

Table 8: Heat Pump Technical Potential for Existing and New Buildings for National Grid's Service Territory (MDth)[45]

Geography	ASHP	GSHP
Long Island	34,600	35,600
New York City	12,210	10,120
Total	**46,810**	**45,720**

National Grid should capture this potential for significant savings from the installation of heat pumps to mitigate the impact of peak demand events on its system.

[44] NYSERDA. New Efficiency: New York Analysis of Residential Heat Pump Potential and Economics. January 2019. Table 4-9, p. 18.

[45] Assume that National Grid's share of residential customers if 55% for New York City. ICF 2012 Assessment of NYC Natural Gas Market and Emissions, p. 26.

3.5 Gas Leakage

Leakage from gas pipeline systems results in emissions of methane, a greenhouse gas that is 86 times more powerful than carbon dioxide in the first 20 years. Our savings calculation for reducing the problem of leakages within National Grid's system is based on the weighted average of the current leakage rate for KEDLI and KEDNY, which is 2.32%.[46] Our assumption of the impact of reducing leakage on gas savings is based on a MIT study[47] finding that a 30% to 90% reduction in leakages would be needed to meet climate targets. From this range, we then targeted a reduction rate of 60% as a midpoint. This means that National Grid would need to lower its leakage rate down to 0.93%, which translates into a savings of 40 MDth/day.

4 Consistency: Greenhouse Gas Reduction Targets

Building a new gas pipeline is not consistent with the recent legislation passed in New York State to address climate change. Table 9 below highlights some of the policy enacted in New York State to address emissions and move toward a carbon free energy system. A new gas pipeline goes against the goals identified by New York State climate policies. Under these initiatives, the gas pipeline would become a stranded asset since New York will not be able to continue to rely on gas if the state wants to meet its emission reduction goals. In addition, it would not be prudent for National Grid to invest in the pipeline before evaluating and considering all other non-pipeline options to address the gas supply.

[46] EIA. Form 176 Custom Report (User-defined). Natural Gas Annual Respondent Query System. We took the weighted average of 2018 reported leakage volume for KEDLI and KEDNY service territories.

[47] Chandler, David. December 16, 2019. MIT News. The uncertain role of natural gas in the transition to clean energy. Retrieved from http://news.mit.edu/2019/role-natural-gas-transition-electricity-1216

Table 9: New York State and Local Policies on Emissions

Policy	Goals
Governor Cuomo's budget initiatives and the Climate Leadership and Community Protection Act of 2019	● Electricity grid must be 100% carbon-free by 2040
Climate Mobilization Act	● Buildings over 25,000 square feet in New York City must lower than emissions footprint by 40% by 2030 ● Explore feasibility study on retiring 21 gas fired power plants and replacing them with renewable energy and storage
One City	● Reduce GHG emissions by 80% by 2050 in New York City ● Reduce GHG emissions from energy used to heat, cool, and power buildings by 30% from 2005 levels

New York State has joined many other states and local and international jurisdictions that are now defining and embarking on a path leading toward a less risky climate future. It has made the commitment to reduce greenhouse gas emissions by 85% by 2050 with offsets for the remaining 15%, to achieve a net zero increase. It has also established a 70% renewable electricity goal by 2030, and a goal to achieve 100% carbon free electricity by 2040.[48]

The State is making progress in reducing emissions; 2016 levels—the latest available—are 13% lower than the 1990 base year, and 2016 emissions are 21% lower than New York's highest year of emissions, which was 2005.[49] ***Reducing emissions by 85% from 1990 requires that total annual statewide emissions be no more than 35 million metric tonnes of CO_2 equivalent (MMTCO2e) by 2050.***

Gas combustion in New York State created more than 70 MMTCO2e of emissions in 2016, representing 43% of the State's combustion related emissions, and more than a third of the total statewide greenhouse gas emissions.[50] Leakage from the gas system accounted for another 2 million metric tonnes. ***Therefore, gas emissions in the latest inventory, taken by***

[48] Climate Leadership and Community Protection Act, 2019.
[49] New York State Greenhouse Gas Inventory: 1990–2016 Final Report, July 2019. Table S-2.
[50] Ibid. Table S-1, and Figure S-4.

themselves, were more than two times greater than the eventual target for statewide total emissions.

These numbers provide context for consideration of National Grid's pending plan for long-term gas supply needs. Major new investments in pipeline infrastructure that would increase the combustion of gas in the downstate service territories is not a strategy consistent with state energy and policy goals.

The combined gas consumption by buildings in the KEDLI and KEDNY territories was 281,000 MDth in 2018.[51] To be consistent with New York's target of 40% greenhouse gas reduction by 2030, this consumption would need to be reduced by 20%, or 56,000 MDth by 2025. As represented in Figure ES 1, this level of reduction off-sets 95% of a potential new pipeline capacity expansion.

National Grid's report also sends confusing messages to stakeholders about how it is accounting for the emissions from the proposed NESE pipeline. MJ Bradley released a report[52] on CO2 emissions from the pipeline that was riddled with concerns, and National Grid is using that study in its long-term needs assessment.[53] National Grid asserts that the NESE pipeline would produce fewer emissions than non-pipeline alternatives in part by relying on this report. But the Bradley report relied on the Department of Energy's outdated statistics on methane leakage rates and focused on methane's 100-year warming potential rather than its far more potent 20-year impact. While it briefly mentions the correct methane data in passing, it consigns its discussion of it to an appendix.

Conclusions and Recommendations

The PSC's enforcement action agreement requiring National Grid to conduct a comprehensive long-term needs assessment presents an important opportunity to scrutinize our future energy options. The analysis and findings above lead us to the following conclusions and recommendations:

- Transparency: National Grid's data assumptions and methodologies must be scrutinized, as National Grid's projection is not consonant with the EIA's Annual Energy Outlook national and regional projection for gas consumption nor with recent historic demand. National Grid must provide full transparency to the assumptions and approach utilized in order for stakeholders to assess the validity of its needs assessment.
- Comprehensiveness: A far more aggressive plan embracing non-pipeline alternatives can reasonably be expected to meet future needs even if National Grid's high projections

[51] Energy Information Administration, form 176.
[52] MJ Bradley. June 11, 2019. Life Cycle Analysis of the Northeast Supply Enhancement Project. Retrieved from https://www.mjbradley.com/sites/default/files/MJBA_NESE_LCA_06112019.pdf
[53] National Grid Report, p. 51.

are correct – and would more than address future growth needs if National Grid's projection is inflated.

- Consistency: Construction of new gas infrastructure is not consistent with State climate policy, goals, and initiatives. National Grid should play a constructive role in meeting New York State and local energy goals by promoting vigorous non-pipeline alternatives such as energy efficiency, demand response initiatives and deployment of renewable technologies.

Critical Elements in Short Supply: April 17th Addendum

On February 24, 2020 National Grid released the "Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")". Energy Futures Group (EFG) issued a critical assessment of National Grid's report on March 9, 2020. EFG's work examined National Grid's approach and findings to projecting long term capacity needs, from several perspectives:

- The basis and component factors driving demand forecast projections;
- The characterization and consideration of non-pipeline alternatives; and
- Consistency of the long-term capacity report with state policy and targets related to reducing greenhouse gas emissions.

National Grid has subsequently released a revised Summary Report (March 11, 2020), a single page spreadsheet with further detail on Demand Scenario assumptions (March 23, 2020), A Customer Cost Impact Supplement (March 23, 2020), and a Technical Appendix (latest revision April 1, 2020). National Grid has also conducted six remote public information sessions and solicited feedback via survey and direct comments.

This Addendum to EFG's original report further highlights several topics with additional research and analysis. The sections presented below on gas demand response programs and natural gas leakage mitigation complement, rather than replace the material presented in our original assessment.

To date, National Grid's Long-Term Capacity Report and the supporting documents and presentations have not identified a preferred solution; they have been intended to inform the public, regulatory and policy decision makers about the range of options under consideration. Based on their analyses and feedback to the report and public sessions, National Grid is expected to bring forward preferred option(s) and investments in the coming months. The final section of this addendum to EFG's original report outlines an important set of questions to assist in the critical review and assessment of National Grid's pending proposal for a preferred solution to meeting the long-term capacity needs for the downstate New York service territory and customers.

Demand Response

Natural gas demand response efforts have traditionally focused on interruptible service rates where customers (typically large users) have flexibility to curtail usage either by operating changes or fuel switching during high peak demand periods. National Grid has a temperature control tariff in place and includes an enhancement to this tariff as an option for the low demand scenario, as discussed further below.

Natural gas demand response initiatives can also include device-based (direct load control) and behavioral strategies. These are relatively newer approaches for natural gas system planning offering additional means to reduce peak day demands and offset the need for supply side infrastructure investments.

Both National Grid[54] and Con Edison[55] have reported favorably on gas demand reduction pilot initiatives, with encouraging results on savings per participating customer, lower than anticipated costs, and high levels of potential customer interest.

As Grid takes next steps in identifying its preferred options for meeting long term needs, taking full advantage, and building upon, the pilot experience is essential. The market is also evolving rapidly and taking advantage of new connected device control and communication strategies. Looking forward capturing the industry's emerging innovation and ability to deliver gas demand response savings will be critical.

In our review of the Grid's Technical Appendix materials and the initial Long-Term Needs Assessment report we have the following additional comments and questions on the demand response elements of the plan.

Enhanced Temperature Control Tariff

National Grid's assumptions around potential savings from an enhanced Temperature Control demand response program call into question why they only applied this assumption to one of the demand scenarios. In the Technical Appendix, it states:

> *In the High demand scenario, we assumed that Commercial & Industrial and Residential (C&I/R) demand response programs will take place, and that the existing Temperature Controlled program would remain in place. In the Low demand scenario, we assumed that on top of the C&I/R programs there will be an additional demand reduction due to an enhanced Temperature Controlled tariff.*[56]

Table 1 outlines the differences that National Grid assumed around the Temperature Control DR program under the Low and High Demand scenarios. Given National Grid's success with their pilot program, savings from a new enhanced Temperature Control Tariff should be considered under both demand scenarios evaluated and not just the Low Demand scenario. In the Long-Term Needs Assessment Report, National Grid stated, "We have proposed new incentives for this program and believe this could reduce TC conversions to firm service by

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[54] Gas Demand Response REV Demonstration Project in New York City and Long Island Q4 2018 Report, Table 3.1.2 Checkpoints, p. 9.

[55] Gas Demand Response Report on Pilot Performance – 2018/19, Consolidated Edison Company of New York, Inc. July 1, 2019 Case 17-G-0606 Case 14-E-0423.

[56] National Grid Natural Gas Long-Term Capacity Report Technical Appendix, p.3. April 1, 2020. Retrieved from https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_Technical%2BAppendix%2B04-01-20.pdfNational Grid Technical Appendix. Hereafter referred to as the National Grid Technical Appendix.

25%."[57] If the program can be redesigned with new incentives, then this should be the assumption used to gauge the savings from the Temperature Control program. It does not make sense for National Grid to assume that the new Enhanced Tariff can be made available in only the Low Demand scenario.

National Grid reports its assumption for Temperature Control customers to be 50 Dth on the design day.[58] Not including potential savings from an enhanced tariff across both demand scenarios distorts the savings and downplays the role demand response can play in helping to address National Grid's identified supply and demand gap.

Table 1. Temperature Control Assumptions Under Demand Scenarios[59]

Temperature Control	Low Demand	High Demand
Conversion Rate	25% slower than historic	Historic rates
New Enhanced Tariff	Yes	No

Commercial/Industrial and Residential Heat Programs

It appears that savings for the Commercial and Industrial (C&I) and residential heat demand response programs are considered for both the Low Demand and High Demand scenarios, but some of the language used in National Grid's Technical Appendix is misleading. For example, in one section it mentions that the savings are in both scenarios,[60] but another section states "The thermostat direct load control (DLC) program participation was assumed to increase linearly over 4 years to reach 40% of residential heating customers by 2024 in the high gap scenario. This program was assumed to not be necessary in the low gap scenario."[61] Similar to the use of different assumptions for the enhanced Temperature Control tariff, it seems like National Grid is presenting misleading information on savings that can be achieved from a C&I and residential heat demand response program. As was discussed in our initial report, other thermostat control programs have achieved success in helping to lower demand during peak events. It is disingenuous for National Grid to not consider this program under both of their demand scenarios.

[57] National Grid Long-Term Needs Assessment, p. 35.
[58] National Grid Technical Appendix, p.11.
[59] National Grid Technical Appendix, p. 36.
[60] Please see Footnote 2.
[61] National Grid Technical Appendix, p. 11.

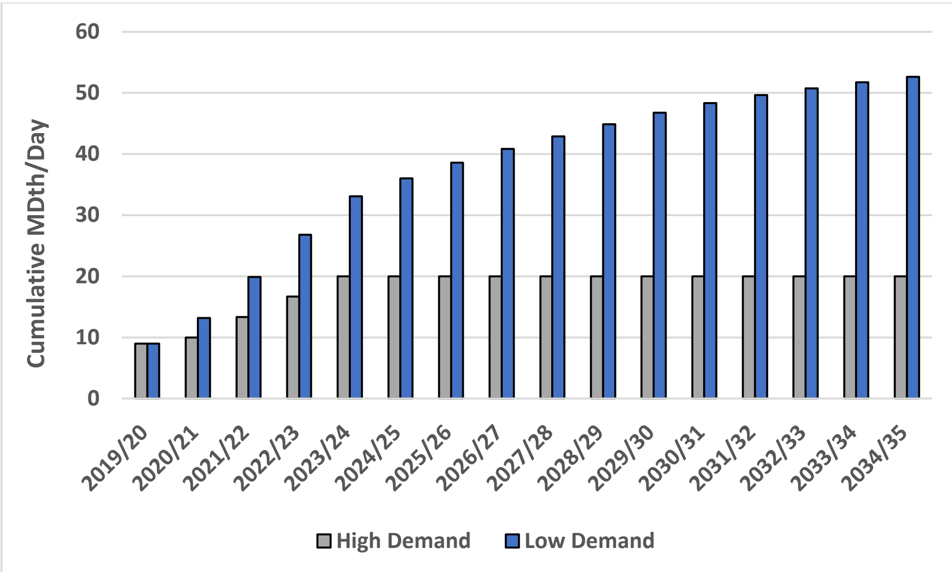

Figure 1. Cumulative Savings from Demand Response (MDth/Day)[62]

Under the high demand scenario, the graph illustrates how the design day savings for demand response programs remains flat at 20 MDth/day by the 2023/2024 winter season with no potential for additional savings thereafter. National Grid assumes a ramp up of savings from 9MDth/day to 20 MDth/day by 2024/2025. Since National Grid's projections cap at 20 MDth/day, this leads to questions around the assumptions made for technical or market adoption limits and why there is no further potential savings beyond the 20MDth/day.

These savings contrast with the analysis we performed for our initial report as Illustrated in Table 2. The demand response savings analysis included in our initial report assumed savings level similar to what Southern California Gas has seen with their demand response pilot programs. We assumed that National Grid is able to reach 20% saturation for demand response by 2025.

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[62] National Grid Detailed Demand Scenario Assumptions for Natural Gas Long-Term Capacity Report. Retrieved from https://ngridlongtermsolutions.com/docs/Long_Term_Capacity_Report_Technical_Appendix_Demand_Assumptions_Year_by_year_03-20-20_vF.pdf.

Table 2. Comparison of Per Customer Demand Response Design Day Reductions:

	National Grid[63]	SoCalGas[64]	EFG Assumption[65]
Savings/Customer	2%	16-25%	20.5%

National Grid specifies the assumption that the demand response program reaches 40% penetration for residential customers, but there is no information included in the Technical Appendix about the assumption for commercial and industrial customer participation. The January 2019 REV Gas Demand Response pilot program indicates average space heating savings of 10% and average process savings of 25%.[66] Given the results from the pilot program, it is unclear why those savings would not be incorporated into the estimated savings rate for an expanded program.

National Grid's Demand Response savings also do not consider the potential to expand their program offerings to include controlled devices, such as hot water heaters, or behavioral messaging programs for the residential sector. Behavioral demand response programs, which may or may not include financial incentives for participation. As discussed in EFG's initial report, Southern California Gas is expanding their Demand Response program offerings to include hot water heaters. They are also exploring pilot Behavioral Messaging Programs to help lower use during peak demand periods.[67] If National Grid considered the potential for expanding their Demand Response program offerings, they could achieve even more savings from Demand Response on the Design Day. Not exploring additional Demand Response program options fails to characterize the full potential of Demand Response programs to help address the supply and demand gap reported by National Grid.

In the Table 1 of the Long-Term Capacity Report, Demand Response is ranked attractive or highly attractive on all criteria, except for reliability. National Grid includes a footnote that "reliability could improve over time as programs mature."[68] The REV Gas DR pilot report

[63] National Grid Technical Appendix, p. 12.
[64] Case U 904 G. Direct testimony of Darren Hanway. Public Utilities Commission of the State of California. November 6, 2018. Retrieved from https://www.socalgas.com/regulatory/documents/a-18-11-005/Demand_Response_Testimony_Chapter%201_Final.pdf.
[65] Weighted average of 16% and 25% savings.
[66] Gas Demand Response REV Demonstration Project in New York City and Long Island Q4 2018 Report, Table 3.1.2 Checkpoints, p. 9.
[67] Case U 904 G. Direct testimony of Darren Hanway. Public Utilities Commission of the State of California. November 6, 2018. Retrieved from https://www.socalgas.com/regulatory/documents/a-18-11-005/Demand_Response_Testimony_Chapter%201_Final.pdf
[68] National Grid Long-Term Needs Assessment, p. 12.

includes the observation that for large commercial firm gas customers the interest in the pilots indicates the "concept could be scaled relatively easily if the need presented itself".[69]

Natural Gas Leakage Reductions

Natural gas system leakage, across the entire system from production, processing, long distance transmission, and local distribution reduces the overall system efficiency. Because methane has a higher global warming potential than carbon dioxide, particularly over shorter time horizons, leakages also have disproportionate environmental impact. Leakages can also create health and safety risks.

While efforts to identify and reduce system leakages have a relatively small impact on total annual consumption, and on peak day demand, they should be considered as foundational, with opportunities identified and addressed as part of any long-term needs assessment.

The estimation of leakage rates and mitigation opportunities is complicated, and complex as the system and equipment operation vary seasonally and with pipeline pressure and across a wide range of older and newer infrastructure. Our initial assessment included an estimate of the design day demand impact of reducing gas leakage by 60% to 0.93% down from 2.32% that has been reported. Figure 2 provides a further indicator that gas leakage reduction may present an important opportunity for National Grid's KEDLI and KEDNY territories. While the number of backlog leaks reported is trending downwards, it remains well above the values reported for other gas utilities in the state.

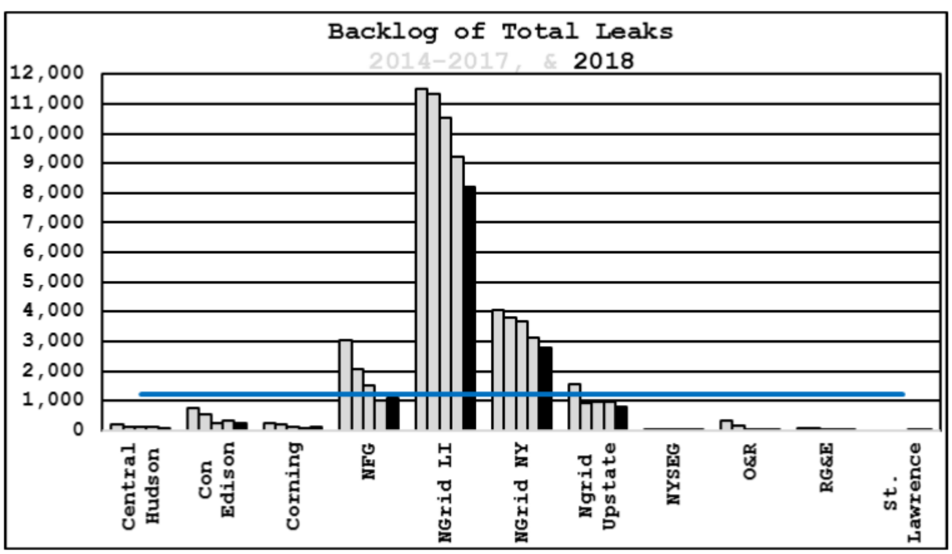

Figure 2. KEDNY and KEDLI Territories Have Relatively High Backlog of Known Leaks[70]

[69] Gas Demand Response REV Demonstration Project in New York City and Long Island Q4 2018 Report, Table 3.1.2 Checkpoints, p. 2.
[70] State of New York Department of Public Service, 2018 Pipeline Safety Performance Measures Report, Pipeline Safety Section Office of Electric, Gas & Water June 13, 2019, p. 30.

Studies of Natural Gas leakage in other eastern cities include Washington D.C.,[71] and New Jersey. The Environmental Defense Fund is partnering with Google Earth and gas utilities to promote new approaches to leak detection, mitigation and prioritization. In January 2019, People's Gas in Pittsburgh committed to using the new approaches to reduce leakages from their distribution system by 50%,[72] which is slightly less, but in the same range that EFG recommended as 2025 reduction for National Grid in our assessment.

We emphasize that investments and initiatives to reduce gas system leakage are complements, not replacements for, the demand side options under consideration by National Grid.

Framework Questions for Evaluating Preferred Option(s)

Based on the initial Long-term Needs Assessment, additional research, and feedback from stakeholder including the public sessions, National Grid is expected to propose preferred options in the coming months.

Below we list critical questions and observations that will deserve careful attention as the preferred options are developed and proposed.

Review of Grid's Options Ranking

National Grid identifies five criteria for assessing the attractiveness of options for meeting long term capacity needs, providing a summary in Table 1 of their report.[73]

Though the table is presented without providing a summary ranking on either a qualitative or quantitative basis, we note the no infrastructure options score at or near the top in three of the five categories (safety, environment and community). The only category where no infrastructure options are consistently low scorers is reliability. However, the score is foot-noted with a caveat indicating that a reliability ranking can improve as programs mature. The presumptive lack of reliability, based on low participation, runs counter to experience, for example from the documented interest and potential over subscription to the demand response pilot.

On the cost criteria, we note that Grid scores the NESE pipeline as attractive, yet as illustrated in the Technical Appendix Figure 5, in the low demand scenario NESE is more expensive than the combined "no infrastructure" package, and that seven of the nine options including demand resources are less expensive than NESE solution. The scoring of the NESE pipeline as "attractive" on the cost criteria in Table 1, is therefore questionable.

We also note that the term *"no infrastructure"* may introduce some bias as it potentially suggests lack of specific assets to address system needs. Energy efficiency, demand response, strategic electrification, and leakage reduction all include investment and deployment of real

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[71] Natural Gas Pipeline Leaks Across Washington DC. *Environ. Sci. Technol.* 2014, 48, 3, 2051-2058.
[72] https://www.edf.org/media/peoples-gas-edf-unveil-new-commitment-help-protect-climate-cutting-methane-emissions
[73] National Grid, Long-Term Capacity Report, Table 1, page 12.

assets and infrastructure that can cost effectively and measurably reduce peak and annual demand. It may be more balanced and accurate to distinguish between the demand and supply side resources and infrastructure deployed to help reduce peak demand and assure long term needs are met.

Continued Scrutiny of Forecast Necessary

Our initial assessment identified the need for greater transparency on Grid's demand forecast and the underlying assumptions and drivers. The Technical Appendix provides additional detail, but questions remain.

For example, we would expect to see further rationale and explanation for the predicted growth rates in multi-family sector number of accounts and per customer usage across all three scenarios. The annual and cumulative growth rates for peak day demand for the multi-family sector are illustrated in Table 3.

Table 3: National Grid's Multifamily Design Day Demand Forecasts[74]

Scenario	Compound Annual Growth Rate	Cumulative Growth (2020-2035)
Baseline	3.68%	72%
Hi-Demand	3%	55%
Lo-Demand	2.15%	38%

New or renovated multi-family units can and should be expected to have more efficient shells and mechanical equipment than existing units, even in the absence of energy efficiency and demand response initiatives. If this market segment is growing rapidly with forecast compound annual growth rates for customer accounts ranging from 1.69% in the low scenario to 2.4% in the baseline, then it represents a key opportunity for targeted efficiency, strategic electrification and demand response. As noted further below, contrary to this, the adoption of heat pumps in the multi-family sector does not start until after 2025, and the forecast of increasing per customer gas demand is inconsistent with targeted efficiency or demand response.

Low Heat Pump Adoptions by 2025

As presented in Table 3 of the Technical Appendix, National Grid's forecast of the adoption of air source heat pumps in the residential market through 2025 represent very modest growth, and it is reasonable to anticipate more rapid expansion.

EFG's Critical Assessment projected 80,000 total residential heat pump installs in Grid's downstate territory by 2025. This would require roughly 1% of the residential customers each year to adopt heat pumps either at the time of a natural replacement or as an early retirement

[74] Grid Technical Appendix, Tables 1, 4, and 5.

retrofit. Grid's projections are much more conservative projecting totals of 8,300 (Hi Gas Demand) and 10,400 (Lo Gas Demand) total installations by 2025.

Table 4 compares the market shares of annual natural replacements and total market share for the residential sector, between EFG's critical assessment and Grid's market projections as presented in the Technical Appendix and the supporting participation spreadsheet.

Table 4: Comparative Residential Heat Pump Market Adoptions by 2025[75]

	Share of Annual Natural Replacement Market	**Total Residential Market Saturation**
EFG Critical Assessment	23.5%	6.8%
Grid Hi Gas Demand	2.4%	0.7%
Grid Lo Gas Demand	3.1%	0.9%

A 2016 HVAC market report prepared for NYSERDA documented 43,418 air source heat pump installations statewide, representing roughly 0.5% saturation of annual installations.[76] National Grid's projected rates for 2025 therefore barely surpass what statewide data from several years ago indicate. For further contrast, and to put the EFG estimate of 80,000 total residential installations for National Grid downstate territory by 2025 in perspective, an assessment of rapid heat pump market expansion conducted by VEIC for NRDC projected that annual statewide installations of 60,000 to more than 500,000 units could be attainable by 2025.[77]

Furthermore, National Grid projects zero incremental adoptions of air source heat pumps in the commercial and multi-family sectors by 2025.[78] This is particularly concerning given Grid's forecast of the increasing number of customer accounts in the multi-family sector. New multi-family accounts and major renovations provide excellent opportunities for the installation of heat pumps, and multiple options and good applications including variable refrigerant flow (VRF) heat pump technologies are available for commercial sector customers. Whether the result of already occurring market transformation, or accelerated utility and statewide efforts to expand these markets, the projections by Grid, of no growth through 2025 in the multifamily and commercial market are not credible.

[75] Grid Technical Appendix, Tables 1, 4, and 5.
[76] D+R International, 2017. 2016 HVAC Market Report, prepared for NYSERDA.
[77] "Ramping Up Heat Pump Adoption in New York State Targets and Programs to Accelerate Savings", prepared by VEIC for NRDC, September 2018.
[78] National Grid Technical Appendix Table 3, Commercial & Multifamily gas to electric conversions, p.4.

Rhode Island's Investments in Gas Infrastructure

A Review of Critical Issues

Conducted by:

David G. Hill, Ph.D., Energy Futures Group

Chris Neme, Energy Futures Group

Prepared for:

Conservation Law Foundation Rhode Island

February 26, 2021

This whitepaper was prepared by David Hill of Energy Futures Group with review and support from Chris Neme of EFG, and James Crowley of CLF Rhode Island. Any omissions or errors are the responsibility of the primary author. Questions for the author should be directed to dhill@energyfuturesgroup.com

Table of Contents

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EXECUTIVE SUMMARY

Rhode Island's planning and investments in future energy infrastructure and resources need to consider how each decision contributes to, or possibly hinders, meeting of the state's greenhouse gas emissions reduction targets. Capital investments with long-lasting impacts deserve scrutiny to make sure they serve the public's best interests and that they are compatible with policy and legislated goals.

To meet their regulatory obligation to serve customers, gas utilities invest in capital assets, such as pipelines, meters, and compression stations, and recover the just and reasonable costs of those investments from gas consumers over time. The utility will typically recover such costs from gas consumers over a time horizon, established by the utilities commission, that is intended to be the time-period over which the asset will be used and useful. If an asset becomes obsolete and no longer provides useful service, before the costs of that asset have been fully recovered, those remaining costs are said to be a "stranded cost". Stranded costs may be borne by gas customers, if they are asked to continue paying for an asset even though it is no longer being used, or they may be borne by utility shareholders if the recovery of the stranded costs is not permitted by the utility commission. Stranded costs reflect an inefficient use of utility and consumer resources and are sought to be avoided by ensuring that the period of cost recovery for an asset is aligned as closely as possible with the lifetime over which an asset will be used and useful. Stranded costs are of particular concern at a time when states are developing and implementing plans to transition away from fossil fuels to mitigate climate damage, as the stranded costs risk slowing the transition and burdening consumers with additional costs.

This whitepaper discusses the importance of the depreciation period and other key issues related to the planning and regulatory review of investments in Rhode Island's gas infrastructure. Factors we review at a high level in the whitepaper include:

- Current and historic gas use by sector.
- Gas infrastructure safety and reliability plans.

- Rhode Island's statewide and corporate greenhouse gas goals.
- Pathways for decarbonized energy economy.
- The resource base and costs for renewable gas (RG) production.
- Other issues with reliance on RG.
- Analysis and comparison of alternatives to gas infrastructure investments, including strategic retirement and "pruning" of system assets, and
- The highest value future uses for gas and RG.

Based on our review of these policy, market, and resource conditions, and particularly in a state and region in which climate change policy and regulation are fast evolving, we urge utility commissions to bring especial rigor to their review of gas infrastructure depreciation schedules and to estimations of the useful life of such assets. We further recommend that, the likelihood of more rigorous climate regulation utility commissions should apply shorter depreciation periods for gas infrastructure investments, and in no case longer than 20 years. A shorter depreciation period reduces the risk of stranded costs to gas consumers and shareholders, better ensures a lower-cost transition to clean heating and it provides a better basis for comparing gas infrastructure investments with other alternatives.

Figure ES-1 illustrates the impact of a 20 versus a 33-year depreciation period, using a declining balance method and based on an investment of $180 million and a 10% salvage value. At the end of twenty years the shorter depreciation schedule (blue bars) will have recovered all costs. To do so, it has higher annual cost recovery for each of the first ten years in comparison to the 33-year deprecation period (orange bars). At the end of 20 years, the case with the longer (33 years) depreciation period has $26.7 million of unrecovered costs equivalent to 15% of the initial investment.

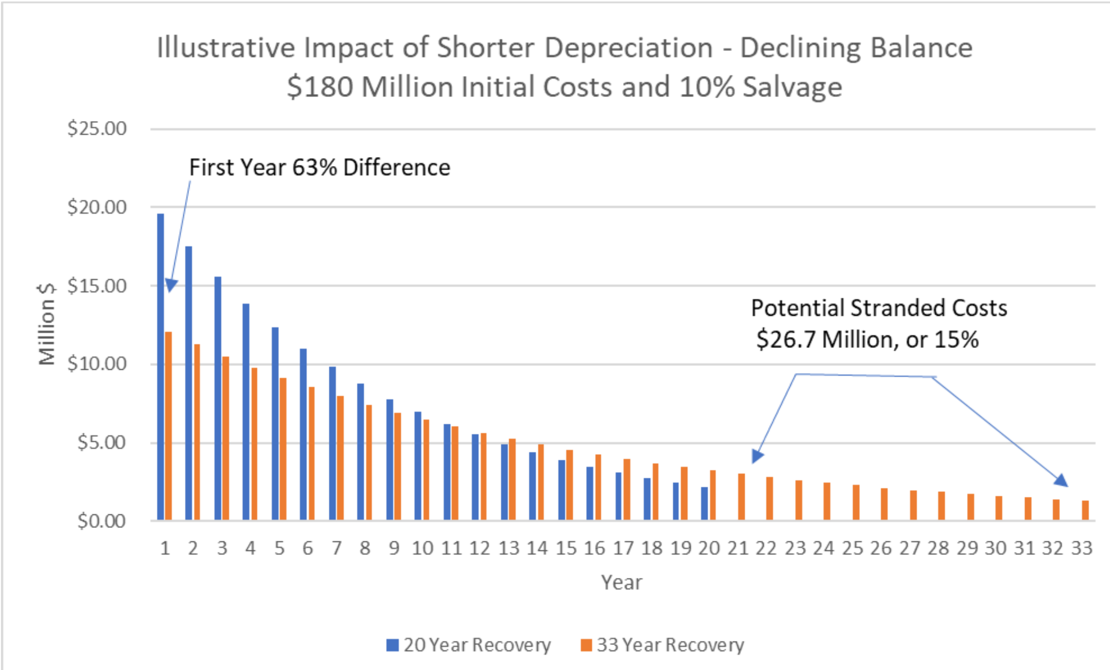

Figure ES-1: Comparison of 20 and 33-Year Depreciation Period

The longer depreciation period spreads costs over a longer time, but it also inherently carries more risk of stranded costs if the asset is retired or becomes obsolete. In this whitepaper we discuss how meeting Rhode Island's greenhouse gas targets, the cost and resource potentials for RG, and the benefit of targeting any future RG use to highest value applications all point towards reduced reliance on gas infrastructure. We therefore recommend a 20-year depreciation period be used to help reduce the risk of stranded costs, and to more accurately reflect the near-term rate impacts of investments that are undertaken.

The future of gas and electric infrastructure planning and investment is complicated. Its scale and associated economic and environmental impacts are significant, and it deserves thoughtful and inclusive planning processes and analyses. We support emerging and ongoing efforts along these lines. The shorter depreciation period we recommend in this whitepaper is just one of the steps that will help improve decision making and planning on gas infrastructure investments to better align them with climate change policy and objectives in Rhode Island.

Introduction

Utilities regularly make capital investments in assets required to provide services for their customers. They recover the costs for such investments from their customers over time. A depreciation period defines the length of time over which the utility recovers capital investment costs from consumers. There are many details, and variations making the accounting and rate design for cost recovery a complex, interesting, and sometimes contentious field for regulators, utilities, consumer advocates, and other stakeholders.

At the risk of simplifying some of this complexity, depreciation periods are fundamentally based on how long an asset is expected to be used and useful. A longer depreciation period spreads the cost recovery over more years. In comparison to a shorter depreciation period, the longer horizon will result in lower initial amounts of cost recovery (since costs are being recovered over a longer time). This can be favorable if the asset remains used and useful for the anticipated depreciation period, and future ratepayers receive services from the asset for which they are paying. However, there are risks if a depreciation period extends cost recovery too far into the future. If the asset becomes technically obsolete, unusable, or uneconomic before the end of the depreciation period, there are likely to be stranded costs to be borne either by ratepayers or by utility shareholders.

This whitepaper examines critical issues related to investment and planning decisions for gas infrastructure in Rhode Island. The first section gives a brief overview of how important gas has been in meeting Rhode Island's energy needs. Looking forward the future of gas and gas infrastructure in Rhode Island needs to be considered in relationship to many factors. These include greenhouse gas reduction targets, potential pathways for decarbonization, the potential costs and resource base for renewable gas, and the alternatives to investments in gas infrastructure. We provide a high-level analysis and discussion of the implications for each with respect to determining an appropriate depreciation period for gas infrastructure investments. Finally, we present our recommendation that shorter depreciation period (at most 20 years) is prudent and give an illustrative comparison to depreciation over 33 years.

Gas Consumption in Rhode Island

Gas is an important energy resource for Rhode Island. Figure 1 illustrates historic consumption in trillion British Thermal Units (Tbtu) per year. In 2018, the last year in this data series Energy Information Administration (EIA) data indicate gas accounted for more than 53% of Rhode Island's total energy consumption across all sectors of 195 TBtu. EIA estimates Rhode Island's 2019 gas consumption to be 97.6 TBtu, a decline of almost 7% from 2018.

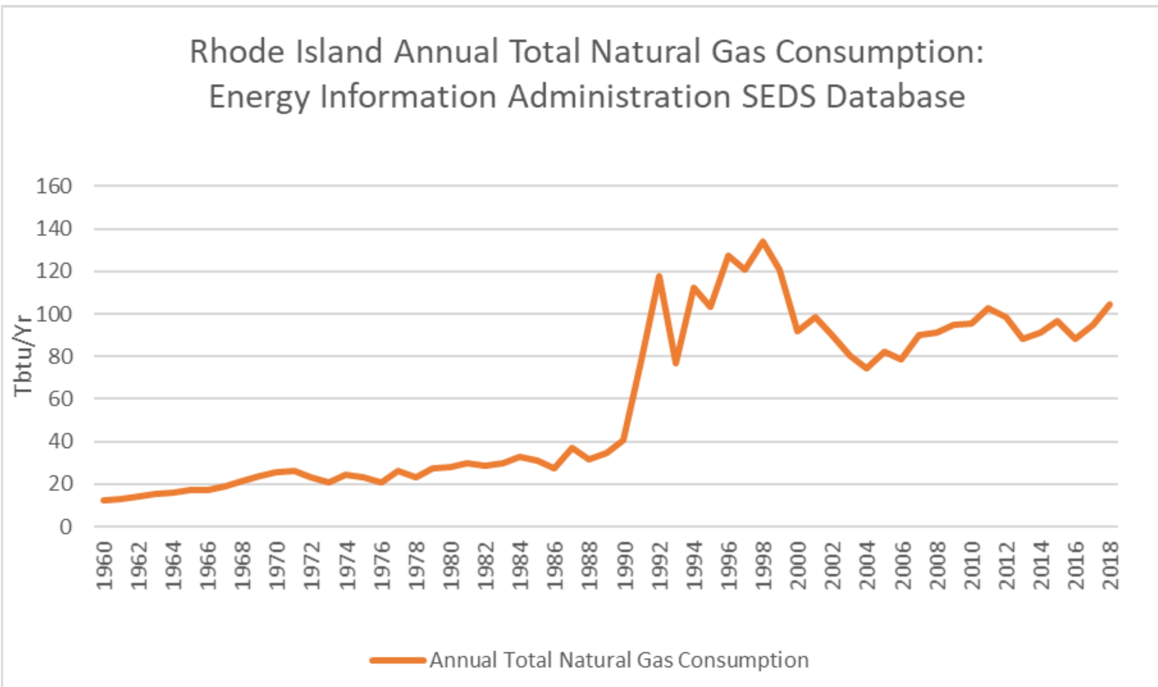

Figure 1: Historic Gas Consumption

The electric power sector is the largest consumer of gas in Rhode Island, accounting for more than half of the gas consumption in the state.[1] More than half of all Rhode Island households use gas as their primary heating fuel and residential heating accounts for roughly 20% of the total gas consumption. Commercial heating is the third largest consumer of gas accounting for about 13% of the total. Together, electricity generation, residential heating, and commercial heating account for 90% of total gas use. Figure 2 presents EIA data illustrating the shares of gas delivered

[1] https://www.eia.gov/state/analysis.php?sid=RI

to the electric power industry (green), residential consumers (blue), commercial consumers (orange), and total deliveries (yellow).

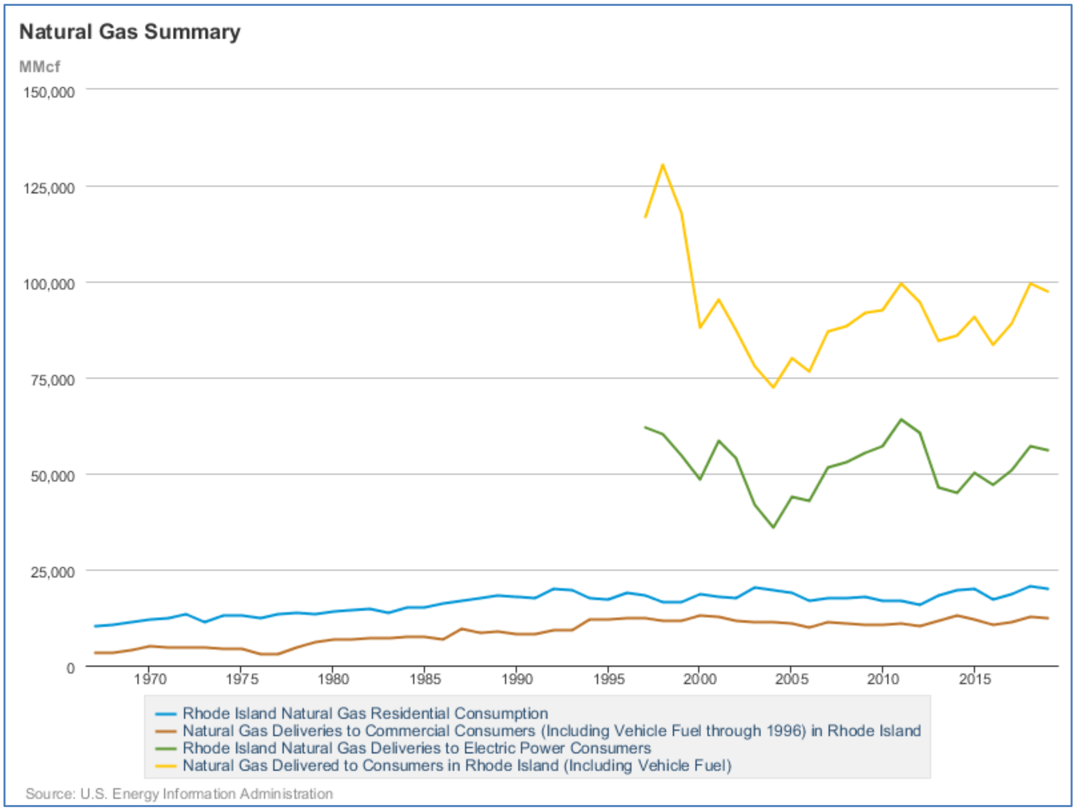

Figure 2: Rhode Island Gas Consumption by Sector

Gas Infrastructure Safety and Reliability Plans

In December 2021 National Grid submitted its proposed FY 2022 Gas Infrastructure, Safety and Reliability Plan (ISR Plan) to the Rhode Island Public Utilities Commission, in Docket No. 5099. The ISR Plan is designed to protect and improve the gas delivery system. It proposes a total of $180.15 million in discretionary and non-discretionary investments in the proactive replacement of leak-prone pipe, upgrading of system components, and addressing emergency leak situations and coordination of infrastructure investment with other construction projects.

Maintaining and improving the safety and reliability of the gas infrastructure system is unquestionably important. The National Association of Regulatory Utility Commissioners (NARUC), and the U.S. Department of Energy have issued recent whitepapers reviewing current activity, plans and cost-recovery issues related to maintenance and upgrading of gas infrastructure.[2] [3] Planning and potential investments in gas infrastructure need to consider the scale and span of future gas system needs, and the appropriate length of time for recovery of costs from ratepayers.

As detailed further below, meeting Rhode Island's greenhouse gas reduction targets will require drastic shifts in the volumes and uses of gas. The review and approval of proposed ISR plan investments should proceed based on careful consideration of the future gas system, and how this may be very different from the legacy infrastructure. Addressing factors such as the depreciation period for new gas infrastructure investments and considering strategic alternatives to infrastructure upgrades including the strategic retirement and pruning of system elements from the gas system will help reduce the risks of potentially redundant investments and stranded costs.

[2] National Association of Regulatory Utility Commissioners, Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs, January 2020.
[3] U.S. Department of Energy, Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations, Office of Energy Policy and Systems Analysis, January 2017.

Rhode Island's Greenhouse Gas Reduction Goals

The Resilient Rhode Island Act of 2014 established the Executive Climate Change Coordinating Council (EC4). It also set specific greenhouse gas emissions reduction targets; established an advisory board and a science and technical advisory board to assist the Council; and incorporated consideration of climate change impacts into the powers and duties of all state agencies. The targets for reductions the EC4 is charged with developing and tracking the implementation of a plan to achieve are represented in Figure 3.

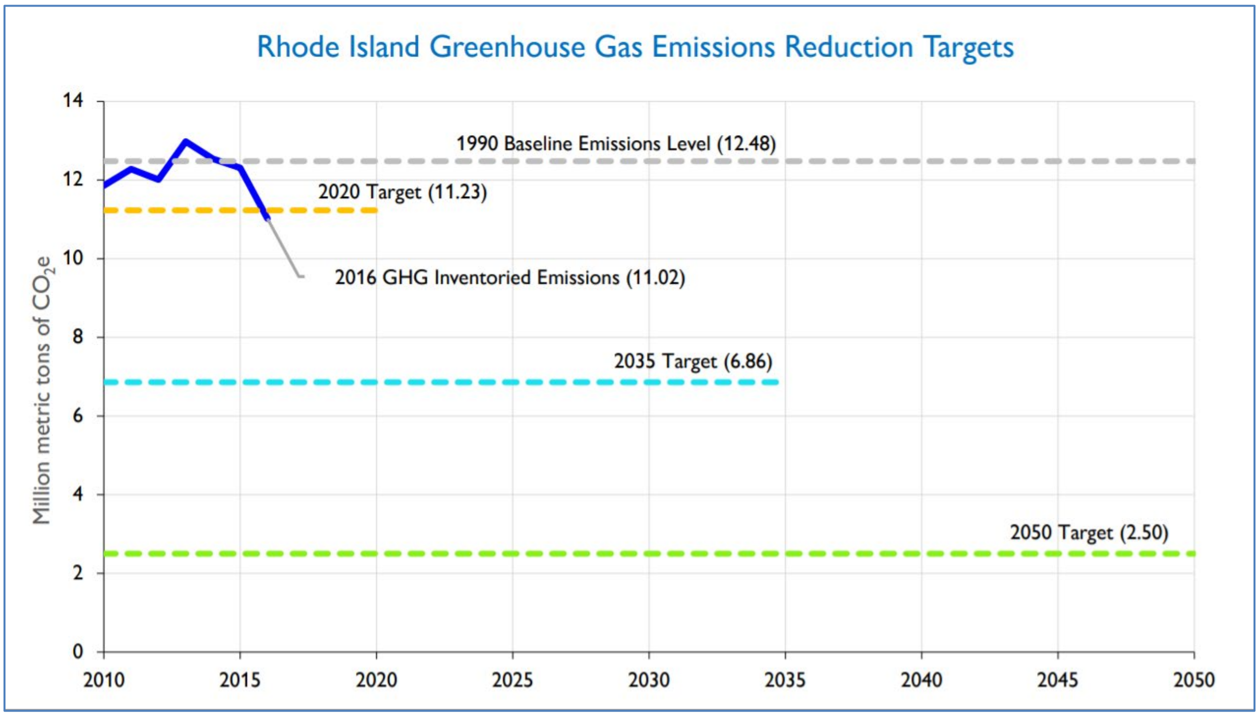

Figure 3: Resilient Rhode Island Greenhouse Gas Emissions Reduction Targets[4]

The 2016 Greenhouse Gas Emissions inventory indicates emissions from the three largest gas consuming sectors to be:

- Electric Generation - 2.84 MMTCO2e
- Residential Heating - 1.84 MMTCO2e
- Commercial Heating - 0.86 MMTCO2e

[4] http://www.dem.ri.gov/programs/air/documents/righginvent16d-pres.pdf

While these sectoral emissions are not exclusively from gas it is the predominant fuel source for each one. The combined 2016 emissions from these three sectors 5.54 MMTCO2e is more than 50% of the Rhode Island's total greenhouse gas emissions of 11.2 MMTCO2e. They are also more than 80% of the 2035 target (which is only 14 years away), and they are more than two times higher than the 2050 target (which is 29 years away). The 2016 inventory does not account for gas leakage, which one study estimates if properly accounted could raise total state emissions by 45%.[5] This brief overview makes it clear that strategies for reducing emissions from gas are essential elements for meeting Rhode Island's current GHG emissions reduction targets.

Furthermore, the best available science indicates we need to achieve zero net emissions by 2050 to avoid worst impacts of climate crisis from exceeding warming of 1.5 degrees Celsius. [6] With that in mind, legislation to increase the emissions reduction target to net zero by 2050 has been introduced in Rhode Island.[7] At the corporate level, National Grid, which owns and operates most of the gas and electric distribution infrastructure in Rhode Island also has its own zero by 2050 goal.[8]

Decarbonization Pathways

Meeting the already established Resilient Rhode Island greenhouse gas reduction targets for 2035 (only 14 years away) or for 2050 (29 years from now) will require significant shifts in the use of gas compared to the historic and current figures presented in Figures 1 and 2 above. Significant increases in electricity produced by renewable electric generation including solar, on- and offshore wind, imported hydropower, and other resources will result in a substantially decreased role and production from gas-fired electric generation, likely limiting their role to, at most, helping to balance intermittent renewable generation.

[5] Stockholm Environment Institute and Brown University Climate & Development Lab, *Deeper Decarbonization in the Ocean State: The 2019 Rhode Island Greenhouse Gas Reduction Study*, September 2019.
[6] https://www.ipcc.ch/sr15/
[7] Rhode Island General Assembly, 2021 Act On Climate
[8] National Grid Net Zero by 2050 Plan

Emissions reductions in the space and water heating realm will likely be most cost-effectively achieved through electrification, using air and ground source heat pumps. Important analysis and planning undertaken in Rhode Island includes the "Heating Sector Transformation in Rhode Island" (HST) study.[9] Figure 4, from the Executive Summary of the HST illustrates estimates of annual space heating costs for a single-family residence, comparing projected costs in 2050 for fossil fuels with the 2050 decarbonized alternatives that will be required to meet GHG emissions reduction targets.

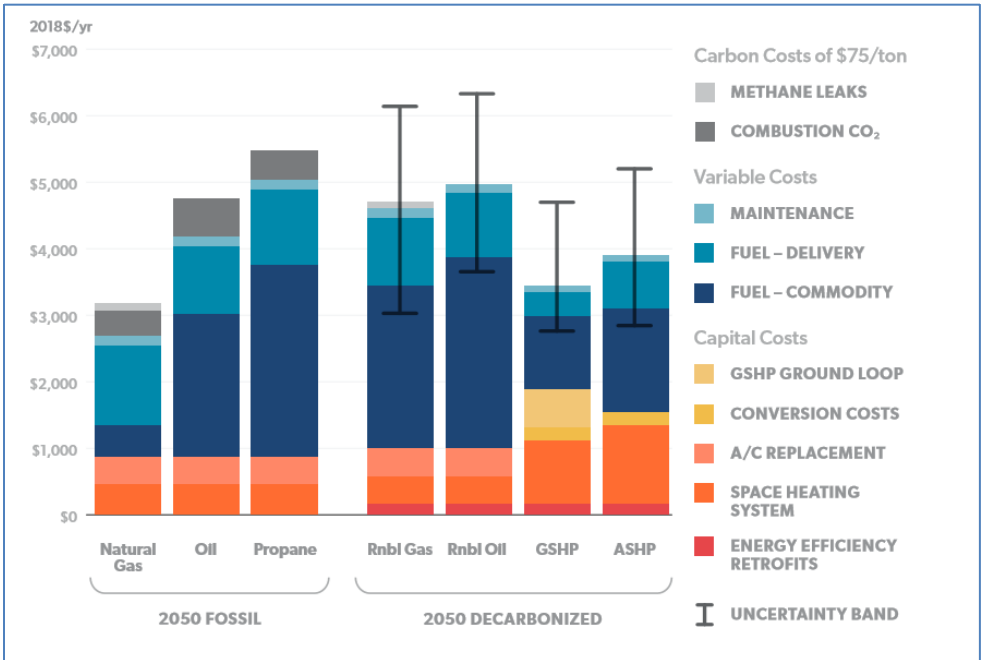

FIGURE ES 1: ANNUALIZED COST OF SPACE HEATING IN 2050, REPRESENTATIVE SINGLE-FAMILY HOME, BOOKEND SCENARIOS, 2018$

Figure 4: Economics of Residential Space Heating Decarbonization Options[10]

While there is some potential overlap in the estimated cost ranges, when considering the uncertainty bands, we observe the central cost estimates for the electrification options (GSHP and ASHP) are significantly lower than the renewable gas and oil options. The electrification options also have somewhat narrower uncertainty bands. The HST analysis and findings are consistent

[9] The Brattle Group, Heating Sector Transformation in Rhode Island, Prepared for the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Office of Energy Resources. Available here.
[10] The Brattle Group, HST Study, Executive Summary, page 2.

with other studies. In this light, planning and investment anticipating that renewable gas will be the sole, or even the dominant, pathway for decarbonization of space heating is not prudent.

Future heating shares by fuel type in 2050 as estimated by the HST study are further illustrated in Figure 5. Note that only the "Fuel Bookend" scenario results in an expansion of the share for renewable gas in comparison to the current share (54%) of fossil gas. In the bookend GSHP and ASHP scenarios the share of heating provided by renewable gas drops to zero, and in the "mixed scenario, the share of heating provided by gas drops to one half of the current share. Gas infrastructure planning and investment decision making should be informed by and account for these potential declines in the share of space heating provided by gas.

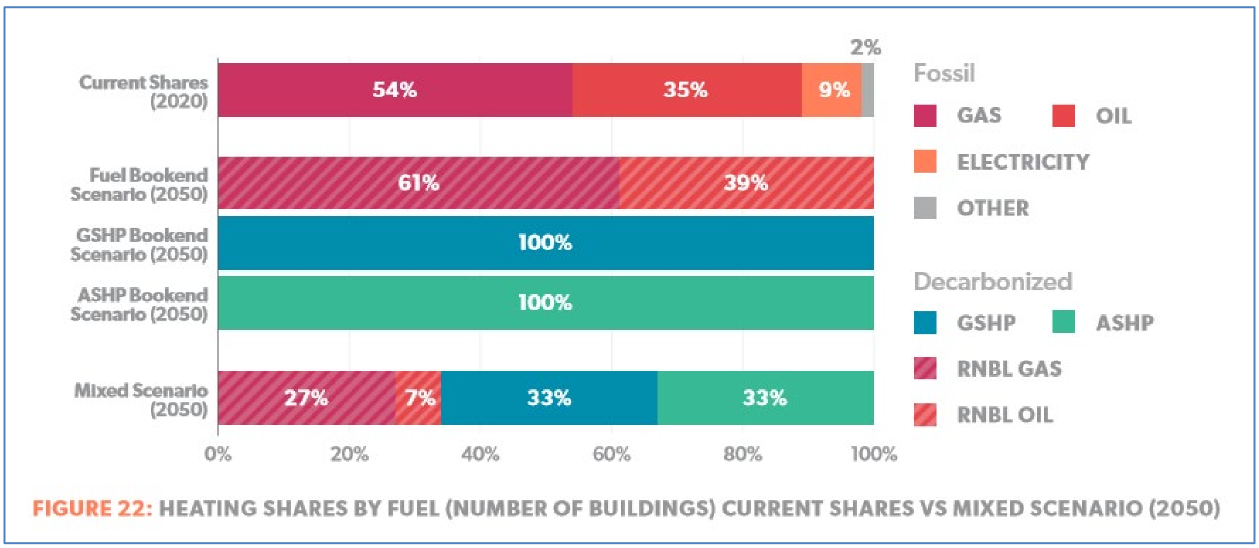

Figure 5: Economics of Residential Space Heating Decarbonization Options[11]

The next section provides additional detail related to the resource base, and estimated costs for renewable gas.

Resource and Costs for Renewable Gas

A 2019 Study conducted by ICF International for the American Gas Foundation includes national and state-level estimates of RG potential by 2040 under low and high development

[11] The Brattle Group, HST Study, Executive Summary, page 2.

scenarios.[12] Table 1 summarizes Rhode Island's estimated 2040 potential as presented in Appendix A of the study.

Table 1: Estimated Rhode Island RNG Achievable Potential 2040

	Anaerobic Digestion				Thermal Gasification				
	LFG	Manure	WRRF	Food Waste	Ag Res	Forest Res	Energy Crops	MSW	Total
2040 Low	1.447	0.008	0.103	0.128	0.001	0.126	0.007	1.037	2.857
2040 High	2.357	0.016	0.15	0.224	0.003	0.251	0.007	2.337	5.345

The values in Table 1 do not represent economic potential. They are technical achievable potential estimates accounting for resource base, adoption rates and conversion technologies. It is notable that Rhode Island's technically achievable potential is heavily concentrated in two resource categories, with more than 85 percent of the identified potential in both the high and low cases coming from the combination of landfill gas and thermal gasification of municipal solid waste.

The high and low scenario results in the AGF study also indicate that thermal gasification is only expected to make meaningful contributions to the RG potential after 2030. Some further concerns with the pursuit of gasification are addressed in the next section of this whitepaper. In any case, Rhode Island's estimated technical achievable potential by 2040 for RG from anaerobic digestion and thermal gasification is only a small fraction (2.9% low, and 5.5% high) of 2019 statewide gas demand as illustrated in Figure 6.

[12] American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, Prepared by ICF, December 2019.

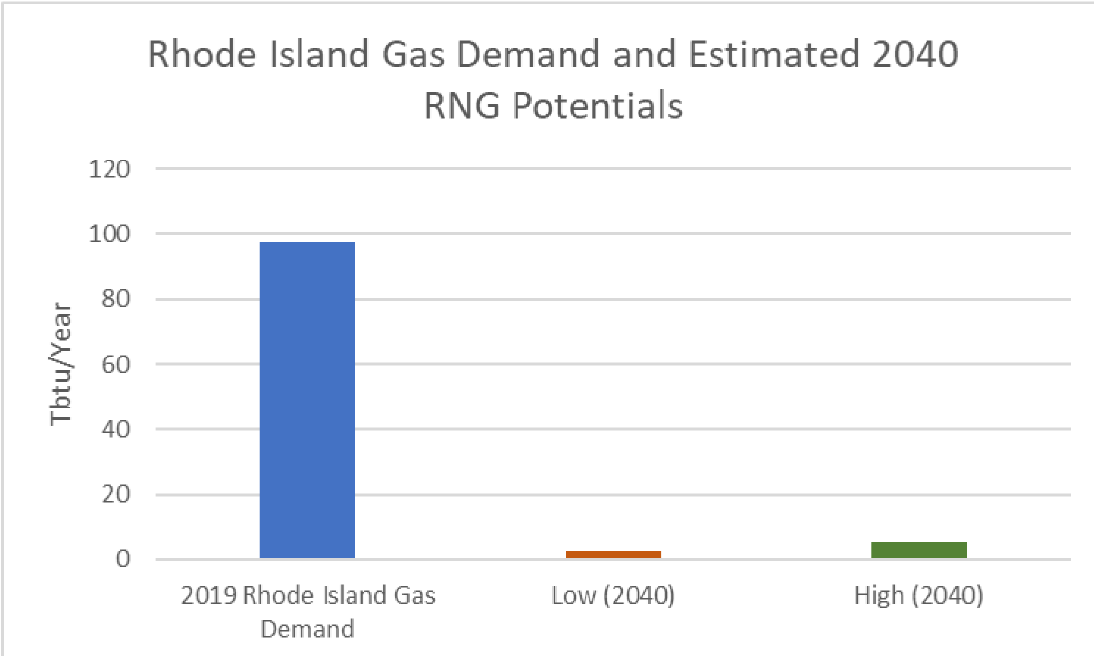

Figure 6: Rhode Island Gas Consumption and Estimated RG Potential by 2040

These scenario results, coming from a study sponsored by the gas industry, indicate that the RG technical resource potential from anaerobic digestion and thermal gasification is very limited, and even by 2040 it only has the potential to replace a small fraction (2.9% to 5.5%) of current gas volumes.

Cost estimates for RG production are summarized in Figure 7 from the HST study.[13] These include estimates from the AGF sponsored study, including costs for anaerobic digestion and thermal gasification processes, as well as for Power to Gas. The latter uses renewable electricity and electrolysis to create hydrogen which can then be used directly as an industrial process fuel or be processed via methanation to produce pipeline decarbonized gas.

[13] The Brattle Group, Rhode Island Heating Sector Transformation Study, Figure 21, page 36.

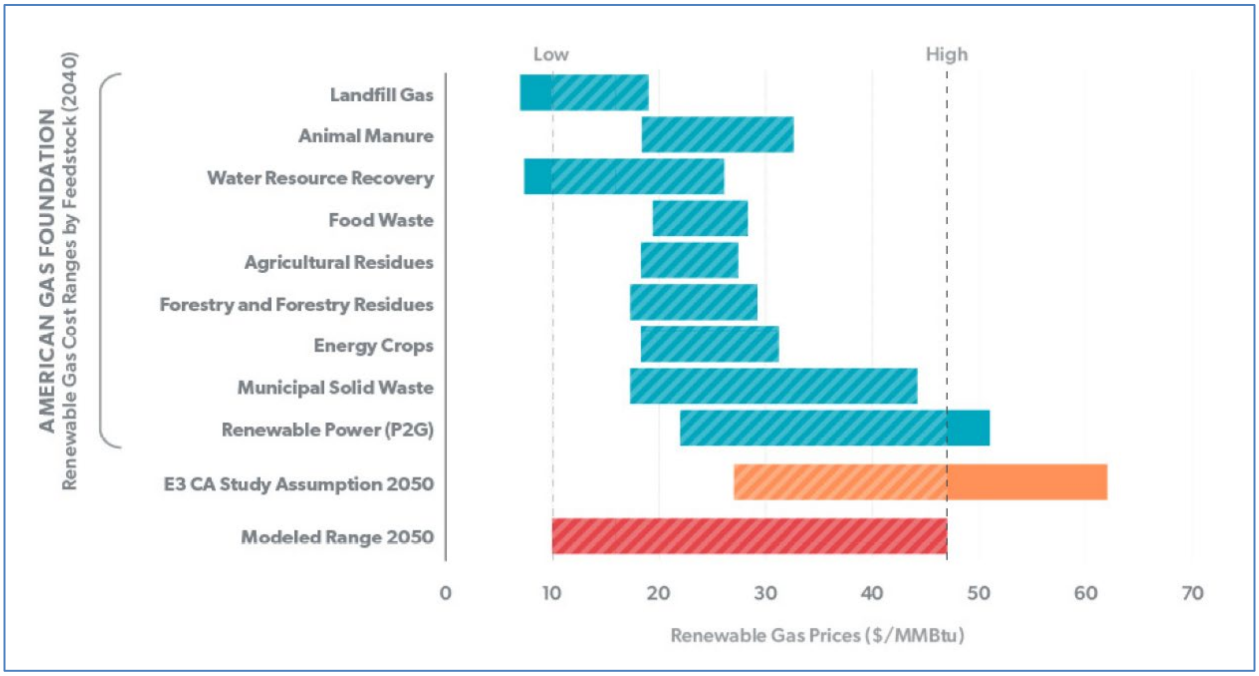

Figure 7: Cost Estimates for Decarbonized Gas Production

Ranging above $20 per MMBtu for most options and with top ends exceeding $50 per MMBtu for Power to Gas, these estimates, again mostly from a study sponsored by the gas industry, make it clear that decarbonized gas options are expensive, both in comparison to conventional gas costs, but also in comparison to alternatives such as electrification and efficiency. This further underscores the importance of careful comparison of alternatives when evaluating proposals for investments in gas infrastructure, and for considering shorter depreciation periods for the cost recovery associated with any such investments.

Additional Concerns on Methanation

National Grid's FY 2022 ISR Plan is only a portion of the longer-term 20-year proactive main replacement program, the latter of which addresses the eventual replacement of leak prone elements of the gas distribution system.[14]

[14] National Grid ISR FY 2022 plan, page 30 lines 10-18.

The integrity and safety of gas infrastructure is important for safety, environmental and economic reasons. Fugitive emissions of methane have a high global warming potential, particularly over near-term horizons, and they contribute to harmful local air pollution including the formation of ground level ozone.[15] The need for a 20-year plan to address the existing "leak prone" distribution infrastructure indicates even new sources of RG are available, they are also prone to leakage, and do not avoid fugitive emissions and the associated problems. As noted above, the accurate accounting of gas leakage may, by itself increase the state's total GHG emissions by 45%.

Increasing research and advocacy suggests that rather than investing in or supporting new resource streams of methane, for example from the gasification of agricultural residues, efforts to reduce or contain existing sources of methane through alternative management practices may be more prudent.[16]

Targeting Applications for Renewable Gas

The heating sector transformation (HST) report cited earlier provides some discussion of decarbonization options for process heat. Rhode Island has limited heavy industry with highly intensive process heat needs, and much of the industrial energy consumption may be used for lower temperature space and water heating. However, where there are industrial processes requiring higher temperatures, these can be good strategic targets for the use of decarbonized gas or liquid fuels. Heat pump technologies, while they are capable of meeting space and water heating loads, are not able to meet higher temperature process heat needs. Recognizing that solutions for industrial processes will be highly specific to a given facility and process, the use of decarbonized liquid or gas fuels for process heating may avoid the need for new capital investments to retool the production process, when they can serve as a "drop-in" fuel replacement for conventional fossil-

[15] Stockholm Environment Institute and Brown University Climate & Development Lab, *Deeper Decarbonization in the Ocean State: The 2019 Rhode Island Greenhouse Gas Reduction Study*, September 2019, discusses the implications of updated methane leakage rates and consideration of 20-year global warming potential for methane emissions at page.

[16] For examples see: Earth Justice and Sierra Club, Rhetoric Vs. Reality: The Myth of "Renewable Natural Gas" for Building Decarbonization, July 2020., and
RMI, A New Approach to America's Rapidly Aging Gas Infrastructure, available here.

based fuels. Industrial process heat conversions to use RG or Power to Gas are likely to be site-specific, may not require pipeline distribution service, and be phased in over a period of decades.

As discussed above the resource potential, and therefore the volumes, of RG are expected to be significantly less than conventional fossil supplies, and to be much more expensive. Matching these limited and more expensive supplies with industrial applications for which there are not viable alternatives will help to maximize the value of any decarbonized fuels, and this may in turn support their higher production costs. Conversely, planning and investing in infrastructure so the more limited and more expensive supplies of RG are used broadly for lower temperature space and water heating requirements is less likely to contribute to meeting GHG reduction goals and less likely to maximize the value of any decarbonized fuels.

Targeted high value industrial uses may also be more geographically concentrated than general space and water heating loads, permitting more targeted ISR type planning for strategic replacement, and pruning, of gas infrastructure. Using RG for electric generation to help balance and support an increasingly renewable grid is another potential high value application. Electric generation use would also be likely to be geographically concentrated and help to limit and prioritize gas infrastructure system upgrades.

Targeting and Coordinating Gas Infrastructure Investments

There is a need to consider ISR plan and other gas infrastructure investments in the context of the issues above and compared to alternatives. The alternatives should include selective targeting and pruning of the gas infrastructure to support high value uses. For example, investments in upgrading a pipeline for a branch with loads dominated by space and water heating loads might be avoided through a strategic electrification program. If branches that can be retired are identified the amount of the pipeline needing safety and reliability upgrades may be reduced.

There is a potential dynamic relationship between investments in the gas and electric systems. A reduction in gas infrastructure investments may require increasing investment in the electric distribution system, say for example, to meet the needs of building and transportation electrification. Specific gas ISR investments may be prudent and necessary, but the they are best considered within this type of more holistic framework.

The potential for coordinating distribution system planning and investment in Rhode Island is enhanced by National Grid being responsible for both gas and electric distribution. The strategies outlined in this whitepaper may help to avoid un-coordinated or redundant investments.

Depreciation Period for Gas Infrastructure Investments

Depreciation periods, for gas infrastructure or other investments, should match the anticipated lifetime over which the assets will be used and useful. This reduces the risk of stranded costs and provides an appropriate estimate of the rate impacts required to recover costs from ratepayers. In general, longer depreciation periods reduce near-term rate impacts by stretching out the cost recovery, so an investment with a longer depreciation period may appear to be more palatable to gas customers.

In this whitepaper we have reviewed factors likely to limit the future use of gas infrastructure. Meeting Rhode Island's greenhouse gas emissions reduction targets, the cost and resource potentials for renewable or decarbonized gas, and the benefit of targeting any future such gas use to highest value applications all point towards reduced reliance on gas infrastructure. We therefore recommend utility commissions should apply shorter depreciation periods for gas infrastructure investments, and in no case longer than 20 years. This reduces the risk of stranded costs, and more accurately reflects the near-term rate impacts of investments under consideration.

As an example, Figure 8 illustrates a twenty-year versus a thirty-three-year depreciation period for an investment of $180 million, the same size as that proposed by the FY 2022 ISR plan, using a declining balance method and a 10% salvage value.

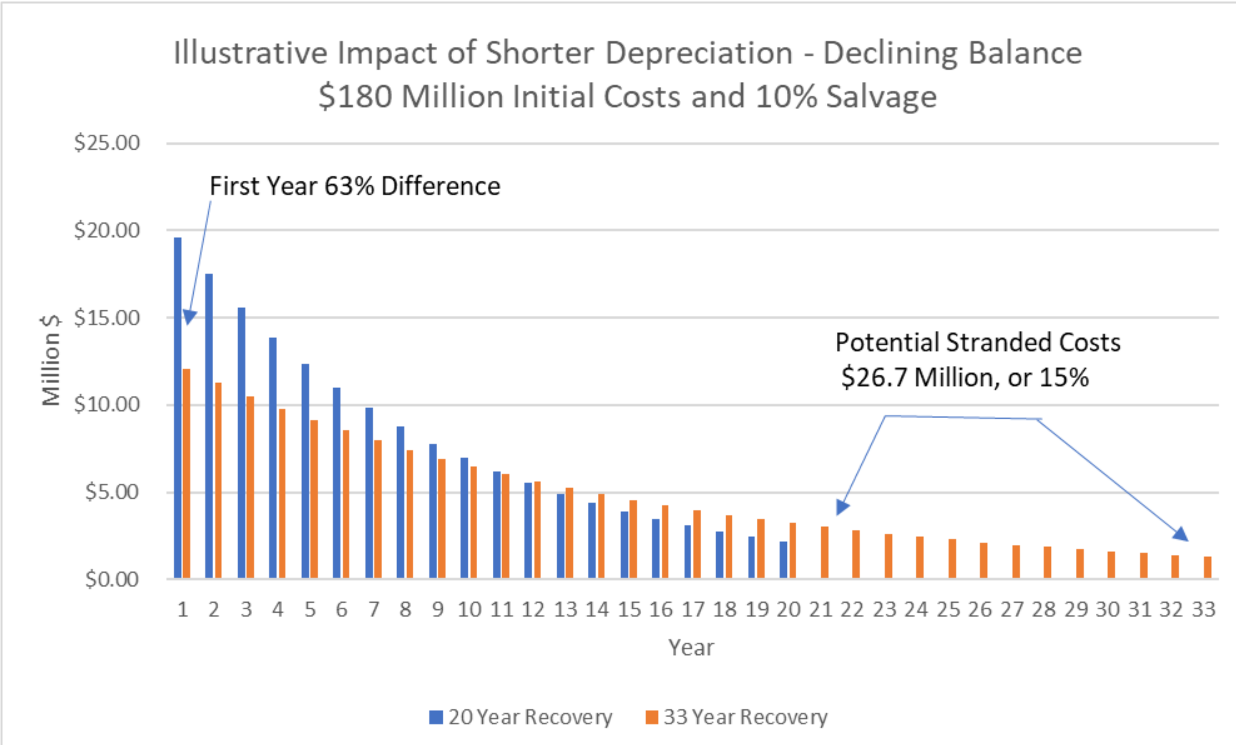

Figure 8: Cost Recovery Comparison for Twenty- and Thirty-Three-Year Depreciation Periods

At the end of twenty years the shorter depreciation schedule (blue bars) will have recovered all costs. To do so, it has higher annual cost recovery for each of the first ten years in comparison to the 33-year deprecation period (orange bars). In the first year, the required cost recovery is 63% higher for the 20-year depreciation period. At the end of 20 years, the case with the longer (33 years) depreciation period has $26.7 million of costs yet to be recovered, equivalent to 15% of the initial investment.

We suggest that the appropriate depreciation period needs to be carefully assessed by commissions in each case as the climate landscape continues to change, and that twenty years should be a cap for new gas infrastructure investments. The shorter deprecation along with more comparative analysis of alternatives and coordinated strategic planning for both gas and electric infrastructure investments are important steps to help Rhode Island meet future GHG emissions reduction targets, to protect ratepayers and shareholders, and provide greatest benefits to the state's economy.

Conclusions and Recommendations

- Continued broad based reliance on gas infrastructure beyond 2050 is incompatible with achievement of the state's GHG emissions reduction goals.
- RG has limited resource potential, and high costs. It doesn't make sense to maintain gas infrastructure on the assumption that we will switch to RG at scale in the future.
- Targeted high value applications of RG may be justified, but they are likely to require a much smaller gas distribution infrastructure.
- We should not be amortizing costs of new gas infrastructure over periods that extend beyond twenty years.
- Options to target and limit the amount of gas infrastructure investment should focus on highest value uses. These may result in concentrated geographic replacement and upgrades.
- Opportunities for greater coordination in planning and investment for gas and electric distribution system should be pursued.