**STATE OF NEW JERSEY**
**BOARD OF PUBLIC UTILITIES**

| | |
|---|---|
| In the Matter of Natural Gas Commodity and Delivery Capacities in the State of New Jersey – Investigation of the Current and Mid-Term Future Supply and Demand | BPU Docket No. GO20010033 |
| In the Matter of the Exploration of Gas Capacity and Related Issues | BPU Docket No. GO19070846 |

**COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND AND NEW JERSEY CONSERVATION FOUNDATION**

Pursuant to the New Jersey Board of Public Utilities' ("Board" or "BPU") April 20, 2021 Public Notice establishing a comment deadline of May 13, 2021, Environmental Defense Fund ("EDF") and New Jersey Conservation Foundation ("NJCF") submit the following timely-filed comments. EDF and NJCF set forth below a framework that should guide the Board's threshold inquiry in this proceeding pertaining to whether "the current and future natural gas supply and infrastructure will continue to meet New Jersey's demands, as well as how evolving environmental concerns may drive changes in the way natural gas is transported and used in New Jersey."[1] Because the 2019 Energy Master Plan will dramatically change the way gas is used and transported within the state, the Board should adopt an updated gas planning review process that aligns with the state's clean energy and climate objectives, consistent with the Board's broad, existing authority to review "overall gas purchasing strategies."[2] Finally, our comments provide a list of critical components for a successful planning framework, including a robust long-term plan tied to ultimate cost recovery, all-in cost metrics, a framework to compare non-

---

[1] *In the Matter of the Exploration of Gas Capacity and Related Issues,* Docket No. GO19070846, Order Soliciting Independent Consultant at page 4 (May 5, 2020) ("May 2020 Order").

[2] *In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities*, Docket No. GA05121062 (Feb. 25, 2009).

pipeline alternatives with traditional solutions, a standard method for assessing greenhouse gas emissions, and coordinated gas and electric utility planning.

## I. Background

In a February 27, 2019 Order in Docket No. GO17121241, the Board directed Staff to initiate a stakeholder process to determine whether sufficient natural gas capacity "has been secured to serve all of New Jersey's firm natural gas customers as well as whether and to what extent [Third-Party Suppliers ("TPSs")] are saving customers money on their natural gas supply."[3]

In the course of the stakeholder process, New Jersey Natural Gas ("NJNG") submitted comments on October 16, 2019, which included a report by Levitan & Associates, Inc. ("LAI") commissioned by NJNG.[4] In response, EDF and NJCF (collectively "EDF/NJCF") submitted comments on October 22, 2019 disputing some portions of the LAI report, and included an affidavit of Greg Lander, President of Skipping Stone, who conducted an analysis, on behalf of EDF/NJCF, of natural gas pipeline capacity and supply that has historically served and has been available to serve demand in New Jersey.[5] The LAI Report and Lander Affidavit reached different conclusions about the medium and long-term capacity needs; and while the respective reports reached different conclusions regarding <u>*future needs, neither report identified a near-term capacity shortfall.*</u>[6]

---

3 *In the Matter of the Verified Petition of the Retail Energy Supply Association To Reopen the Provision of Basic Gas Supply Service Pursuant To the Electric Discount and Energy Competition Act, N.J.S.A. 48:3- 49 et seq., and Establish Gas Capacity Procurement Programs*, Docket No. G017121241, Order at page 5 (February 27, 2019).

4 NJNG LAI Report dated July 12, 2019.

5 EDF/NJCF Affidavit of Greg Lander, President, Skipping Stone, dated October 21, 2019.

6 Absent an unforeseen, catastrophic disruption of the interstate pipeline network.

During its December 20, 2019 agenda meeting, the Board directed Staff to take the necessary steps to hire a consultant to independently examine the current and future natural gas capacity outlook for New Jersey. On May 20, 2020, the Board issued an Order, stating that it "recognizes the importance of determining if the current and future natural gas supply and infrastructure will continue to meet New Jersey's demands, as well as how evolving environmental concerns may drive changes in the way natural gas is transported and used in New Jersey." The Board directed Staff to issue an RFQ for selection of a consultant experienced in the following capacity analysis tasks:

- Perform the infrastructure, demand, contracts, market and other analysis and research set forth in the Scope of Work ("SOW");
- Review the LAI Report and Lander Affidavit submitted and/or referenced in the Board's recent statewide Gas Capacity Proceeding;
- Assist Staff in assessing the risk of a shortfall in natural gas capacity in the medium term, considering the normal factors but also considering the effects of Energy Efficiency and conservation expected as the New Jersey 2019 Energy Master Plan is implemented; and
- Assist Staff in developing a robust set of non-pipe mitigation measures, as described (but not limited to those) in the SOW.

On April 20, 2021, the Board issued a Notice soliciting stakeholder feedback on design day issues and non-pipe alternatives. The Board held a stakeholder meeting on April 29, 2021 to discuss the list of issues identified in its April 20, 2021 Notice, among others.

## II. Comments

### A. The Board Must Identify Demand for Gas Capacity, Evaluate All Capacity to Meet Demand, and Direct Gas Distribution Companies ("GDCs") to Obtain Sufficient Capacity to Meet All Firm Customer Needs

The central inquiry in this proceeding is determining "if the current and future natural gas supply and infrastructure will continue to meet New Jersey's demands, as well as how evolving environmental concerns may drive changes in the way natural gas is transported and used in New

Jersey."[7] While the specific questions listed in the most recent Public Notice focus on a narrow subset of issues, answering the Board's initial question posed in the May 20, 2020 Order will require an assessment of the following:

> (1) identify the demand for gas capacity that GDCs should plan for and which ensures sufficient reliability;
>
> (2) evaluate both secured capacity[8] and available capacity[9] to meet demand and reliability targets; and
>
> (3) (a) if a capacity constraint is identified, assess the most cost effective and environmentally beneficial solution using a transparent and competitive RFP process; and (b) direct GDCs to obtain sufficient capacity to meet all firm customer needs "in a manner that tends to conserve and preserve the quality of the environment."[10]

As the Board observed in its initial order, analysis of these issues cannot be divorced from the Energy Master Plan, which will dramatically change the way gas is used and transported within the state. Going forward, these questions should be addressed within an updated gas planning framework that aligns with the state's clean energy and climate objectives.

**1. Identify Demand for Gas Capacity that Ensures Sufficient Reliability**

The first step in the process is to identify demand for gas capacity that ensures sufficient reliability. As explained below, the 1-in-30 design day criteria is the appropriate standard to ensure reliability based on an evaluation of extreme temperature data. The Board must first provide guidance regarding who is responsible for providing capacity reliability for the demands of firm customers sold gas by a TPS; and if that responsibility does not belong to the GDCs, how

---

7 May 2020 Order at page 4.

8 Here, secured capacity is that capacity contracted directly from pipelines to serve New Jersey GDC delivery locations plus delivered service capacity contracted with third party holders of pipeline capacity contracts which, based on pipeline scheduling rules, is able to serve New Jersey GDC locations.

9 Here, available capacity refers to capacity which, based on pipeline scheduling rules is capable of serving New Jersey GDC delivery locations and which is in addition to secured capacity.

10 N.J.S.A. § 48:2-23.

any such capacity reliability requirement is verified and enforced over time.[11] The Board must then establish reliability criteria and mechanisms for determining all GDCs and TPSs' firm customers' needs.

The differences, if any, between reliability and resiliency should be articulated, especially in the context of interstate pipeline rules. Several interstate pipeline tariffs' General Terms and Conditions provide for the proration of impaired deliveries. For example, Algonquin's tariff provides that in the event of an emergency situation, service would be interrupted or curtailed in the order provided in Section 24.4, starting with scheduled service for park and loan service (the lowest priority of interruptible service) and ending with prorated scheduled service under all firm service agreements.[12] In other words, no firm incremental service, or addition of a firm lateral or delivery point service, overcomes the fact that all firm services suffer equally when an emergency arises. Therefore, if a project is offered to meet a "reliability" or "resilience" need, there should be a heightened burden to show that project somehow overcomes the operation of the pipeline's pro-rata curtailment and scheduling provisions of its tariff. The GDC should have to demonstrate, with sufficient detail, the resilience problem asserted to be addressed, the likelihood the event would occur, how the project would solve that problem, and other alternatives considered to address the asserted problem. The Board should view, with particular scrutiny, any "reliability" or "resilience" project where the shipper is the owner/beneficiary of revenues from the project.

---

[11] While New Jersey regulations require TPSs, as part of being licensed in New Jersey, to "meet all of the … applicable reliability standards and requirements of the Federal Energy Regulatory Commission," there are no such 'reliability standards' as related to either retail or wholesale gas suppliers articulated in Federal regulations. *See* N.J.A.C. 14:4-5.2(f)(4) (Basic requirements for an electric power supplier, gas supplier or clean power marketer license).

[12] *See, e.g.*, Algonquin Gas Transmission, LLC FERC Gas Tariff, General Terms and Conditions at Section 16.3, *available at* https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG.

In the planning process, firm customers' design day and design hour should be established by the GDCs, including the articulation of the methodology employed by the GDCs for determining firm customers' design hour and design day demands, respectively.

In addition, the planning process should identify the design day and design hour of non-firm customers so that the GDCs, the BPU and interested stakeholders can come to know and assess the differences between these loads (firm and non-firm) and whether current non-firm customers' obligations for alternate fuel or shutdown[13] are realistic, appropriate, and enforceable.

Once reliability criteria have been established, each GDC should then project future gas demand and: 1) incorporate impacts of electrification on demand profiles in determining peak gas demand, as policies regarding electrification are formalized; and 2) incorporate energy efficiency and demand response programs as components of meeting the demand profile. In particular, the demand forecast should project peak gas demand (hour and day) for electric generation that results from electrification and consider the net impact on peak gas demand. If there is a net reduction in gas consumption for electricity during peak periods, the analysis should assess whether reductions would occur at gas plants in New Jersey or elsewhere in PJM.

### 2. Evaluate Available Capacity to Meet Demand and Reliability Targets

Once the correct level of demand has been identified, the Board will next need to assess current contracts for capacity held by GDCs, including an assessment of available capacity that could be solicited and be reliably obtained (i.e., secured) to address demands in excess of current contracts for capacity held by GDCs. The following issues will need to be addressed as part of this step:

---

13 Alternate fuels' emission differences, as well as whether human needs loads like schools,' hospitals' and others' heating and/or cogeneration loads could/should continue to be subject to interruption are currently under review in other jurisdictions.

- As discussed above, identify the entity responsible for planning and assuring sufficient capacity (with or without contracting for supply through that capacity). In this vein, mandatory release of capacity obtained to meet firm demands for gas on the GDCs' systems, but not receiving BGSS service, should be revisited.

- Address the difference between secured capacity and available capacity.[14]

- Include capacity held by third parties.

The BPU should periodically assess the capacity service available to New Jersey as well as the measurement of capacity service "secured" for New Jersey—whether that capacity service is "secured" directly from pipelines or is existing capacity service held by others but contracted as delivered service to New Jersey location(s). These three assessments (i.e., secured by GDCs directly from pipelines, secured by GDCs indirectly from holders of capacity on pipelines that are committing to delivered service to GDC location(s) and available unsecured capacity) should be performed by the BPU Staff or by consultant(s) to the BPU Staff following an agreed upon definition of "secured" and "available unsecured."[15]

### 3. Direct GDCs to Obtain Sufficient Capacity to Meet All Needs in a Manner that is Consistent with the Obligation to Preserve and Conserve the Quality of the Environment

The Board should then direct GDCs to obtain sufficient capacity to meet all firm needs, including firm customers served by TPSs, and institute mandatory release programs to TPS so

[14] For example, assurance can take the form of securing capacity directly from pipelines as well as securing contracts for multi-year peak period delivered service contracts, which contracts could be structured so as to have staggered maturities such that the GDCs have the assurance of capacity service to meet identified demand well into the future. On the other hand, available capacity is that which can be (and may have previously been) employed to meet New Jersey demand but is not currently contractually committed to serving a peak period New Jersey demand.

[15] EDF/NJCF have proposed definitions in these comments as a starting place, which can be refined going forward to establish a shared understanding going into the planning process.

that there is neither risk to reliability nor risk associated with verification of TPS capacity.[16] Where the periodic and recurring gas planning process identifies a GDC capacity need, the Board should encourage the GDC to solicit multi-year peak period delivered service contracts to use existing capacity. This would eliminate the concern of GDCs that delivered service contracts may not be available "next year."

There must be a robust and transparent means to compare gas capacity expansion with non-pipeline alternatives, and EDF/NJCF propose below a framework for comparison. Given that unnecessary gas capacity expansion is incompatible with state climate targets[17] and could lead to increased costs due to stranded assets, heightened scrutiny must be applied to these proposals, particularly if supported by affiliated entities. All non-pipeline alternatives (i.e., LNG, CNG, RNG, hydrogen, Demand Response, EE, and/or electrification) should be evaluated against existing and future traditional pipeline infrastructure solutions in a manner that enables a transparent assessment of costs and benefits.

### B. The Board's Existing Practices are Insufficient to Ensure Gas Supply Decisions Comply with the State's Climate Goals

To date, there remains a significant disconnect between the Board's implemented regulation of GDCs and the State's ambitious climate goals. The existing processes by which GDCs submit planning information are deficient and do not allow for a thorough weighing of alternatives. GDCs also continue to rely on business as usual scenarios, assumptions, and programs that will hinder the State's ability to reduce GHG emissions. The Board's ability to perform its regulatory duty of ensuring adequate service "in a manner that tends to conserve and

---

[16] Additionally, issues related to TPSs which now hold (i.e., have secured) firm capacity for multi-year periods, to serve firm New Jersey customers, can be addressed so that a mandatory release program assures reliability without unintentionally leading to near-term doubling up of capacity.

[17] It is also incompatible with GDCs' duty to serve in a manner that preserves the quality of the environment.

preserve the quality of the environment"[18] is premised upon receiving sufficient information and analyses from the GDC initiating the request. To date, however, GDCs have not provided the tools or means to assess and weigh climate impacts.

Although the Board has broad authority to review GDCs' "overall gas purchasing strategies,"[19] it does not currently have a rule requiring GDCs to address gas planning in base rate cases or anywhere else. The rule addressing general rate cases, N.J.A.C. 14:1-5.12, titled "Tariff Filings or Petitions That Propose Increases in Charges to Customers" requires basic financial information and, unlike many state rules on rate cases, does not require any pre-filed testimony.[20] To date, these filings have continued to reflect a business-as-usual mindset. For example, in the New Jersey Natural Gas base rate case filed on March 30, 2021 in BPU Docket No. GR21030679, the Company states that capital investments have resulted in an approximate $540 million increase in utility plant in service. The impact of this rate request on the average residential heating customer using 100 therms per month is a $28.07 increase in the customer's monthly bill, from $113.10 to $141.17—nearly a 25% increase.[21]

The Company proposes to recover the costs of distribution gas mains over 75 years, and gas services over 67 years, as detailed in the chart below:

[18] N.J.S.A. § 48:2-23.

[19] In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities, Docket No. GA05121062 (Feb. 25, 2009).

[20] GDCs provide pre-filed testimony in New Jersey due to the common practice and the expectation of BPU Staff.

[21] https://www.njng.com/regulatory/pdf/NJNG-2021-Base-Rate-Case-Filing-GR21030679.pdf.

**NEW JERSEY NATURAL GAS**
Current and Proposed Parameters
Vintage Group Procedure

Statement F

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **STORAGE AND PROCESSING PLANT** | | | | | | | | | | | | |
| 361.00 Structures and Improvements | 2068 | 200-SC | 64.53 | 46.27 | -9.5 | -10.0 | 2068 | 200-SC | 61.85 | 44.53 | -9.6 | -10.0 |
| 362.00 Gas Holders | 2068 | 200-SC | 77.90 | 46.13 | -40.3 | -40.0 | 2068 | 200-SC | 77.79 | 44.39 | -40.3 | -40.0 |
| 363.20 Vaporizing Equipment | 2068 | 35-R5 | 35.22 | 23.61 | 49.6 | 50.0 | 2068 | 35-R5 | 35.55 | 21.95 | 49.6 | 50.0 |
| 363.30 Compressor Equipment | 2068 | 35-R5 | 35.73 | 19.06 | -4.9 | -5.0 | 2068 | 35-R5 | 35.94 | 17.41 | -4.9 | -5.0 |
| 363.40 Measuring and Regulating Equipment | 2068 | 35-R5 | 35.13 | 29.61 | -5.1 | -5.0 | 2068 | 35-R5 | 35.24 | 27.79 | -5.1 | -5.0 |
| 363.50 Other Equipment | 2068 | 35-R5 | 37.50 | 5.09 | -4.5 | -5.0 | 2068 | 35-R5 | 39.88 | 4.35 | -4.5 | -5.0 |
| **Total Storage and Processing Plant** | | | | | | | | | 39.25 | 25.86 | 2.4 | 3.1 |
| **TRANSMISSION PLANT** | | | | | | | | | | | | |
| 366.00 Structures and Improvements | 2034 | 200-SC | 39.18 | 15.18 | -9.8 | -10.0 | 2034 | 200-SC | 39.30 | 13.26 | -9.8 | -10.0 |
| 367.00 Mains | 70.00 | S4 | 69.92 | 53.94 | -58.9 | -60.0 | 70.00 | R3 | 70.10 | 54.86 | -92.1 | -90.0 |
| 369.00 Measuring and Regulating Equipment | 50.00 | L0 | 50.24 | 43.51 | -74.5 | -75.0 | 46.00 | L1 | 45.99 | 36.99 | -70.1 | -70.0 |
| **Total Transmission Plant** | | | | | | | | | 63.66 | 50.00 | -87.5 | -86.0 |
| **DISTRIBUTION PLANT** | | | | | | | | | | | | |
| 375.01 Structures and Improvements | 65.00 | L1.5 | 65.39 | 46.76 | -3.0 | -5.0 | 70.00 | L1.5 | 70.30 | 52.82 | -3.3 | -5.0 |
| 376.00 Mains - Steel | 77.00 | S1.5 | 77.09 | 55.88 | -87.6 | -93.0 | 75.00 | S2 | 74.96 | 55.28 | -112.0 | -90.0 |
| 376.26 Mains - Plastic | 70.00 | S4 | 69.96 | 59.50 | -59.6 | -60.0 | 65.00 | S2 | 65.00 | 55.12 | -92.3 | -90.0 |
| 378.00 Meas. and Reg. Station Equip. - General | 35.00 | L0.5 | 35.23 | 26.13 | -78.8 | -75.0 | 37.00 | L0.5 | 37.05 | 29.94 | -78.1 | -75.0 |
| 380.01 Services - Steel | 70.00 | L0 | 72.26 | 51.31 | -38.7 | -60.0 | 65.00 | R0.5 | 67.01 | 41.89 | -176.5 | -90.0 |
| 380.21 Services - Plastic | 70.00 | S3 | 69.85 | 56.17 | -58.0 | -60.0 | 60.00 | S3 | 59.85 | 46.17 | -97.6 | -90.0 |
| 381.00 Meters | 35.00 | L2 | 35.07 | 27.40 | -3.8 | | 38.00 | L1.5 | 38.08 | 29.99 | -3.4 | |
| 382.00 Meter Installations | 38.00 | L1.5 | 38.22 | 28.54 | -54.4 | -50.0 | 38.00 | L1 | 38.39 | 29.12 | -59.8 | -50.0 |
| 383.00 House Regulators | | | | | | | | | | | | |
| 384.00 House Regulator Installations | | | | | | | | | | | | |
| 385.00 Meas. and Reg. Equipment - Industrial | 40.00 | L2 | 41.92 | 19.78 | -10.4 | -10.0 | 40.00 | L2 | 42.38 | 18.92 | -10.4 | -10.0 |
| 387.00 Other Equipment | 15.00 | L0 | 19.07 | 8.33 | -14.1 | -15.0 | 15.00 | L0 | 20.08 | 7.95 | -14.7 | -15.0 |
| **Total Distribution Plant** | | | | | | | | | 59.89 | 47.52 | -91.7 | -82.7 |

While an assumed useful life of 67 years or longer may have been appropriate in a pre-climate crisis paradigm, the mismatch between the time horizon of these new investments and climate goals exposes both gas utilities and their customers to new risks of under-collecting or even needlessly stranding infrastructure. Utilities are starting to recognize the incompatibility between continued investment in long-lived infrastructure and achievement of climate objectives. Consolidated Edison Company of New York Inc.'s Joint Proposal, approved by the New York Public Service Commission, obligates the Company to file a study on "the potential depreciation impacts of climate change policies and laws on its gas, electric, steam, and common assets."[22] Corning Natural Gas Corporation in New York states that, as a consequence of New York's climate law, Corning's assets (and improvements that reduce GHG emissions) should be

[22] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Case 19-G-0066 Joint Proposal at 113 (Oct. 18, 2019), [http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=234578&MatterSeq=58902](http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=234578&MatterSeq=58902).

permitted to have "depreciable lives [that] match the expected economic lives of utility assets."[23] The Board will have to carefully assess this issue going forward, with particular focus on protecting low-income customers from the death-spiral effect of contracting throughput and the collection of fixed costs associated with the same or even a contracting gas system.

Another process in need of enhancement is the Basic Gas Supply Service ("BGSS") proceedings. Since the 1999 restructuring of the gas distribution business to allow competition in providing gas supply, the gas utility provision of gas supply is through the BGSS. BGSS rate petitions are filed by each gas utility annually around June 1. The filings and proceedings follow provisions of the applicable utility tariff. Those tariffs place the focus of those proceedings on the costs to be recovered through the new proposed BGSS rate – not planning.[24] BPU does not currently require GDCs to submit long-term planning information in the BGSS proceedings to place any of the rate requests into broader context. For example, none of the GDCs provided comprehensive information on the planning or justification for their investment in the affiliate-

---

23 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service*, Case 20-G-0101, Direct Testimony of Firouzeh Sarhangi at FS-5 (Feb. 27, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=241529&MatterSeq=62108.

24 For example, the Elizabethtown Gas Company tariff defines the BGSS process as follows:

> The filing shall provide for a review of the actual costs and recoveries for the previous period ending April 30 and projections of costs and recoveries through September 30. The filing shall also propose a new BGSS-P rate to be implemented on October 1. The proposed BGSS-P rate shall be based upon the projected cost of purchased gas and storage utilization to serve projected demand for gas service for the period October 1 through September 30 and an adjustment to recover or credit prior period under or over recovered gas costs as projected to exist on the preceding September 30. The Company shall provide the basis for its projected costs and the NYMEX projection of monthly gas prices for the projected period. In its annual filing the Company shall calculate the CCC-P component, as defined above, of the BGSS-P rate. Adjustments, if any, resulting from the Board's review of this filing shall be made following a Board Order.

Elizabethtown Gas Company B. P. U. NO. 17 – GAS ORIGINAL SHEET NO. 108 (Nov. 14, 2019).

backed PennEast Pipeline.[25] To address these deficiencies, the Board will need to update and refine implementation of its existing regulatory tools to ensure that they align with the State's climate objectives.

### C. New Jersey Needs a Long-Term Gas Planning Process that is Transparent, Holds GDCs Accountable, and Ensures Alignment with Climate Objectives

In July 2019, Governor Murphy signed into law amendments to the Global Warming Response Act ("GWRA"). First passed in 2007 and since amended, the GWRA introduced a fixed goal of reducing GHG emissions by 80% from their 2006 levels by 2050. The New Jersey Department of Environmental Protection issued its 80x50 report, as required by the GWRA, on October 15, 2020. One of the key findings from the report is that:

> Residential and commercial buildings account for the second largest share of (26%) of the state's GHG emissions, accounting for 24.6 MMT CO2e in 2018. In order to achieve the 80x50 goals, emissions from the residential and commercial sectors must be reduced by 89% to 2.7 MMT CO2e by 2050. Space and water heating account for the majority of the emissions, with 87% of residential buildings and 82% of commercial building relying predominately on natural gas.[26]

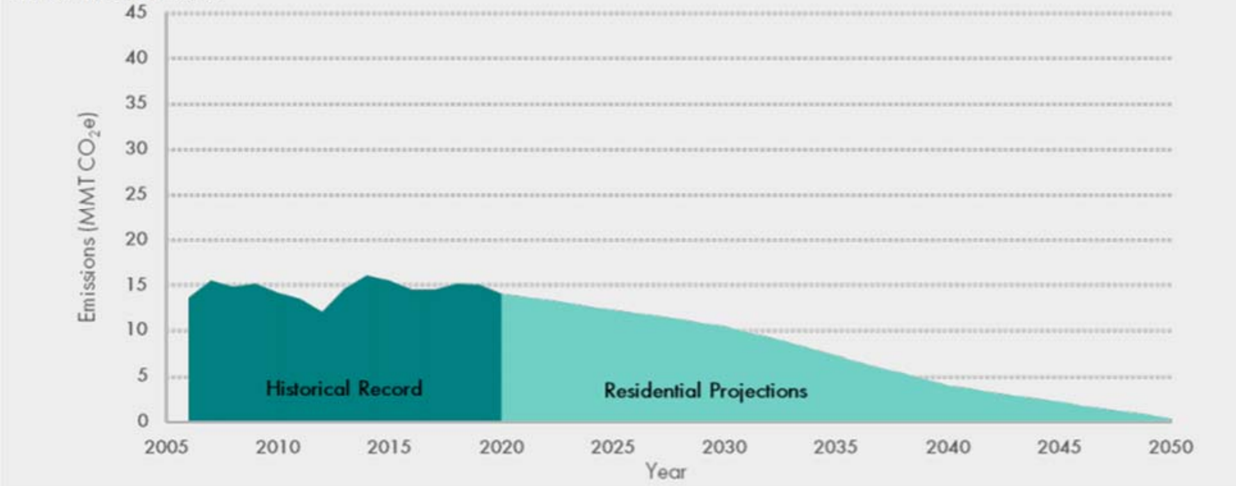
As shown in the graph below depicting the residential sector, the least cost scenario modeling performed for the 2019 Energy Master Plan ("EMP") calculated that 90% of buildings must be converted to 100% clean energy systems to meet the 2050 emissions goals:

---

25 *In the Matter of the Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2020*, Motion of the Environmental Defense Fund, BPU Docket No. GR19050676 at page 3 (June 17, 2019) (explaining that the petition was conspicuously silent on NJNG's contractual commitment for service on its affiliate's PennEast Pipeline).

26 New Jersey's Global Warming Response Act 80x50 Report, https://www.nj.gov/dep/climatechange/docs/nj-gwra-80x50-report-2020.pdf.

***Figure ES.5. Residential Sector Historical GHG Emissions & Projected Pathway to 2050 (MMT $CO_2e$).***
*Converting space heating and hot water applications to electricity, using electric appliances, and improving energy efficiency will bring substantial reductions to the residential sector's emissions.*




The 80x50 Report asserts that it is necessary for New Jersey to implement both a unified energy policy as set forth in the 2019 EMP and sector-specific policies to achieve the level of GHG reductions called for by the GWRA.[27]

One of the key inquiries in this proceeding is consideration of how the EMP will impact natural gas use in the state going forward.[28] The EMP sets forth a strategic vision for the production, distribution, consumption, and conservation of energy in the state.[29] It incorporates rigorous climate goals and spans multiple sectors and governmental agencies, including the Board. Various strategies in the EMP could have significant implications for the management of gas supply portfolios, including, among others:

- The finding that "the building sector should be largely decarbonized and electrified by 2050 with an early focus on new construction and the electrification of oil- and propane-fueled buildings" (Page 13); and

- The development of a "transition plan to a fully electrified building sector, including appliances like electrified heat pumps and hot water heaters" (Page 14).

---

[27] *Id.* at page vii.

[28] May 2020 Order at page 3, 4.

[29] https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf.

Such strategies and goals underscore the importance of considering the impact of current and future state policies on prospective gas demand and supply needs. Rigorous electrification policies will impact gas capacity needs and uses, which will in turn require thoughtful planning of the rate recovery of gas infrastructure, including whether creative financing mechanisms such as accelerated depreciation are needed in order to calculate the appropriate useful life of an asset.[30] The EMP strategies also underscore the importance of requiring gas utilities to demonstrate that their gas portfolio decisions conform to and are consistent with State climate policy and greenhouse gas reductions goals. As the Board has previously found, the "actions, decisions, determinations and rulings of State government entities with respect to energy 'shall to the maximum extent practicable and reasonable and feasible conform' with the provisions of the EMP.'"[31]

Going forward, the Board should take the foundational step of improving its gas supply planning processes to ensure that gas supply decisions comply with the state's ambitious climate goals. The Board has previously found that the annual BGSS proceedings should involve review of gas utility "overall gas purchasing strategies."[32] To fulfill this objective, the Board needs an enhanced planning framework with which it can assess whether a GDC gas portfolio "provides maximum benefit" to customers, as specified in the statute.[33] Below is a list of critical components for a successful planning framework, informed by the recommendations set forth in

---

30 *See generally* Environmental Defense Fund, Managing the Transition – Proactive Solutions for Stranded Gas Asset Risk in California (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

31 *In the Matter of the Petition of New Jersey Natural Gas Company for a Determination Concerning the Southern Reliability Link Pursuant to N.J.S.A. 40:55D-19 and N.J.S.A. 48:9-25.4*, Decision and Order, Docket No. GO15040403 at pages 118-119 (March 18, 2016) (citing N.J.S.A. 52:27F-15(b)) (emphasis supplied).

32 *In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities*, Docket No. GA05121062 (Feb. 25, 2009).

33 N.J.S.A. §48:3-58u.

EDF's White Paper "Aligning Gas Regulation with Climate Objectives"[34] as well as proposals offered before other state commissions, such as the New York Public Service Commission Staff's Gas Planning Proposal.[35]

### 1. Long-Term Plan tied to BGSS Process

To date, GDCs are not required to submit any kind of long-range plan. This is in stark contrast to other state practices, which require detailed planning documents as a core feature of regulatory oversight.[36] GDCs should be required to submit a long-range plan,[37] which would set forth projections of demand, by peak hour by operational "division" and by day by operational "division." Against that demand, the resources to meet that demand should be set based upon the contracts and the on-system supply capabilities of the GDC. GDCs should then identify the cost of each resource (fixed costs and projected or known variable costs) and the projected load factor utilization of the resources so that all-in costs (discussed in detail immediately below) can be reviewed and alternatives that might result in lower all-in cost(s) be evaluated. An agreed-upon long range plan would become the basis for the annual BGSS proceedings. Then, in the annual BGSS proceedings, the long range plan would provide the baseline. Differences between the

---

[34] Environmental Defense Fund, Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators, (Jan. 2021), http://blogs.edf.org/energyexchange/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf.

[35] *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Case 20-G-0131, Staff Gas System Planning Process Proposal (Feb. 12, 2021).

[36] *See, e.g.*, Boston Gas Company d/b/a National Grid Long-Range Resource and Requirements Plan (November 1, 2018), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10008562.

[37] Narragansett Electric Company's recent Gas Long-Range Resource and Requirements Plan could serve as a helpful model: http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf.

baseline and the actuals/projections in the gas cost reconciliation proceeding would be evaluated as "variances from plan."[38]

A joint proposal submitted by Rhode Island Staff and the utility to the Rhode Island Public Utilities Commission ("RIPUC") employs a similar process to align the gas utility's long-term plan with its annual gas cost recovery. Under this framework, Narragansett Electric Company (the GDC d/b/a National Grid) submits a long-range plan that is subject to approval by the RIPUC and uses the same forecasts from the long-range plan in its annual gas cost reconciliation filings, such that the gas cost reconciliation will be "a proceeding that effectively reconciles costs from known and supported commitments."[39] The utility "shall prepare a comparison of volumes and costs presented in its GCR [gas cost reconciliation] filing in the same form (i.e., presentation format) as its annual LRP [long-range plan] filing from June of the same year and identify any differences," which ensures that "[b]y the time the GCR is filed, these items found in the Company's LRP submission will have already been fully vetted."[40]

Connecting the long-range plan to the information presented in the BGSS proceedings will allow for the presentation of potential resources, their timing, all-in costs, and capabilities to assist the Board in both understanding the available alternatives and the trade-offs involved with each.

**2. All-in Cost Metric**

As New Jersey works to achieve its climate objectives, there is a need for a transparent demonstration of the true demands of the gas system and the all-in costs of meeting that demand

---

[38] *Id.* at pages 40-41.

[39] *Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27*, RIPUC Docket No. 4816, Joint Memorandum of the Narragansett Electric Company d/b/a National Grid and the Division of Public Utilities and Carriers at page 3 (Feb. 20, 2019).

[40] *Id.* at page 7.

with various resources, being mindful not to lock-in greenhouse gas emissions from unnecessary long-lived and possibly stranded infrastructure. To ensure that the planning process facilitates fulsome consideration of these issues, GDCs should be required to calculate and report the all-in costs of different proposals.

Existing metrics do not allow for easy comparison of the varied supply and demand options GDCs might consider. To address this deficiency, the Board should require the use of the all-in cost metrics to compare the true costs of different supply provision and/or demand reduction options. This will help the Board, BPU Staff, GDCs, and interested stakeholders compare different options and ensure that costs to ratepayers are minimized appropriately.

There are two related all-in cost metrics. One is the Design Day all-in cost per Dth metric. The other is the load factor sensitive all-in cost per Dth of estimated use metric. The Design Day all-in cost is determined by looking at the pertinent facility's/asset's fixed costs (including fixed O&M, if any) divided by the Design Day quantity of Dth provided (or saved) by the pertinent facility/asset/program; plus, the pertinent facility's/asset's/program's variable commodity/O&M cost per unit of demand to be met on a peak day.

Similarly, the all-in cost per Dth of estimated use (i.e., annual demand) to be met (i.e., taking into account the load factor of the annual demand to be met), looks at the same total annual fixed costs (including fixed O&M, if any) plus the annual variable commodity/O&M cost of the annual load served divided by the quantity of annual load met by the pertinent facility/asset/program. The two metrics, applied to capital projects, capacity plus supply contracts, delivered service contracts, energy efficiency and/or demand response measures allows for an apples-to-apples comparison of different supply-side and demand-side options based on how often over the course of a year they will actually be used (as well as based on design day use). The formulas are provided below:

$$\text{All-In Cost (Design Day)} = \left( \frac{\text{the sum of the fixed cost per year of the project + the fixed O\&M cost (if any) of the project (i.e., total annual non-gas cost)}}{\text{the projected Design Day Dth of use (i.e., quantity) of project (to arrive at modeled per Dth of use non-gas cost)}} \right) + \text{the variable commodity cost per Dth of the project} + \text{the variable O\&M cost per Dth (if any)}$$

$$\text{All-In Cost (Estimated Use)} = \left( \frac{\text{the sum of the fixed cost per year of the project + the fixed O\&M cost (if any) of the project (i.e., total annual non-gas cost)}}{\text{the projected annual use (i.e., quantity) of/by or through the project (to arrive at modeled per Dth of use non-gas cost)}} \right) + \text{the variable commodity cost per Dth of the project} + \text{the variable O\&M cost per Dth (if any)}$$

The example below shows how the all-in cost of estimated use metric could be used in comparing the costs of a CNG facility versus new pipeline capacity:

| | Annual Facilities' / Fixed Costs | Annual O&M / Commodity Costs | Peak Hour Demand (Dth/Hr) | Annual Incremental Demand Met | All-in Cost ($/Dth) |
|---|---|---|---|---|---|
| Ex. 1 | $5,000,000 | $1,800,000 | 1,000 | 150,000 | $45.33 |
| Ex. 2 | $15,768,000 | $420,000 | 1,000 | 150,000 | $107.92 |

Ex. 1 Assumptions: Annual Cost of CNG Facility is $5 MM; CNG $/Dth $12;
Ex. 2 Assumptions: Annual Cost of New build PL Capacity at $1.80/Dthd; $/Dth $2.80;

Common Asssumptions: 1,000 Dth/Hr (24,000 Dthd); and 150 Hours/Yr Equivalent Full use.

The all-in cost metrics are critical to weighing the cost of new long-term investment such as new pipeline capacity, which is not used on every day of the year. Solving seasonal constraints with a pipeline solution, as compared to an alternative such as CNG or LNG, would come at significant cost to ratepayers. This is because the annual fixed costs of new pipeline capacity are significantly higher than these other alternatives; especially when capacity is not needed to meet firm demand every day of the year. The result of high annual fixed costs coupled with low annual use means that the per Dth cost of gas actually used to meet firm demand is quite high. Therefore, the all-in cost metrics can serve as valuable tool in elucidating the least cost option for customers and should be incorporated into an updated planning framework.

### 3. Framework to Compare Non-Pipeline Alternatives with Traditional Solutions

The Board should consider employing a more systemized approach to comparing alternatives that could either provide natural gas supply or demand relief. EDF/NJCF propose a framework that builds on Consolidated Edison's December 21, 2017 Request for Proposals submitted in the Smart Solutions proceeding before the New York PSC in Case No. 19-G-0606 and borrows from other state processes used to discipline affiliate transactions.[41] In brief, the GDC would issue a Request for Proposals ("RFP"), seeking a broad array of innovative solutions that could either provide natural gas supply or demand relief.

This competitive-type process would not only protect against affiliate abuse—see discussion immediately below—but would also incentivize Capacity Service Providers[42] to

---

41 *See Application of Pacific Gas and Electric Company for Authorization to Enter into Long-Term Natural Gas Transportation Arrangements with Ruby Pipeline, for Cost Recovery in PG&E's Gas and Electric Rates and Nonbypassable Surcharges, and for Approval of Affiliate Transaction*, California Public Utilities Commission ("CPUC"), Decision 08-11-032, November 6, 2008 Order at 85-93, 118-122 (citing CPUC D.04-09-022; CPUC D.06-12-029, Appendix A-3, Rule III.B.1; CPUC D.04-12-048) (explaining that the CPUC's rules require utilities to use an open and transparent solicitation process when involving affiliates and have a neutral independent evaluator review solicitations that involve affiliates); Direct Testimony of Greg Lander, Missouri Public Service Commission Case No. GR-2017-0215, GR-2017-0216 at Schedule EDF-06 (September 8, 2017) (proposing modifications to the gas supply and transportation standards of conduct).

42 A Capacity Service Provider is an entity that provides, for a price, one or more Capacity Service(s). Capacity Service is defined as one or more asset(s), service(s), product(s) or any combination of same that enables the ultimate need (as defined below) to be met. Examples of Capacity Service Providers

develop solutions that are narrowly tailored (in terms of size and cost) to the ultimate need[43] while minimizing costs, GHG emissions, and adverse impacts on communities and the environment.[44] As a result of this robust and competitive process, the GDC would have several options to choose from and its selection process would be transparent and apparent to the Board and interested stakeholders.

1. [Retail Gas Utility] will use a competitive bidding process in which requests for proposals (RFPs) are submitted by [Retail Gas Utility] to Capacity Service Providers to provide either natural gas-supply or natural gas-demand relief. For any exceptions to the competitive bid and award process, [Retail Gas Utility] will have a documented process for the approval and award process, including (a) justification requirements, (b) authorization process, (c) contemporaneous documentation requirements (for internal Company information and external communications), and (d) effective monitoring and controls. [Retail Gas Utility] will maintain internal controls such that no information regarding the content or subject of communications by and between non-affiliate potential bidders and [Retail Gas Utility] personnel with access to such information shall be communicated or made accessible to personnel of [Retail Gas Utility] affiliate(s).

2. The RFP process shall be open to all Capacity Service Providers who wish to bid and shall be publicly posted on the [Retail Gas Utility's] website and filed with the Commission. The intent is to gain the broadest practical participation by eligible Capacity Service

---

would include: (1) a pipeline that provides firm transportation service to the Retail Gas Utility or end market served by the Retail Gas Utility; (2) an entity that sells CNG, RNG and/or LNG delivered into the Retail Gas Utility and/or into a pipeline able to effectuate firm incremental delivery to the Retail Gas Utility or end market served by the Retail Gas Utility; (3) an entity that provides a firm, bundled capacity and commodity service to the Retail Gas Utility or end market served by the Retail Gas Utility; (4) demand response providers whose demand response reduces demand of specified end use customers during hours of peak demand – typically early morning and evening periods on peak demand days; and (5) Energy Efficiency providers whose energy efficiency measures reduce demand of specified end use customers during hours of peak demand – typically early morning and evening periods on peak demand days.

[43] The ultimate need must be defined clearly and substantiated by the Retail Gas Utility.

[44] For instance, an interstate pipeline could distinguish its proposal by incorporating additional features that would provide environmental benefit such as enhanced methane reduction measures. *See, e.g.*, Iroquois Spring 2020 Report, https://www.iroquois.com/site/assets/files/1057/spring_2020_safety_issue_web.pdf ("As part of the ExC Project, Iroquois plans to reduce methane and overall emissions at project sites through the installation of low Nitrous Oxide (NOx) turbine units that will reduce NOx emissions by 40% over standard turbine units, as well as adding oxidation catalysts on the newly installed turbines, thereby reducing Carbon Monoxide (CO) emissions by approximately 90%. In addition, Iroquois is proposing to install methane recovery systems at each project site to capture released natural gas from station operations.").

Providers in submitting competitive bids. Once such a process is reasonably developed, appropriately implemented and effectively monitored and controlled, the results of that process are intended to establish the most innovative solutions to provide natural gas-supply or natural gas-demand relief, considering the all-in cost metrics, GHG emissions, as well as impacts on communities and the environment. [Retail Gas Utility] shall require that proposals quantify the GHG emissions associated with their offer, using an agreed-upon methodology such as the Gas Company Climate Planning Tool.[45] [Retail Gas Utility] shall provide the Commission with a report, including an explanation of any credit, performance or other criteria that [Retail Gas Utility] takes into consideration in developing the RFP.

3. No affiliate of [Retail Gas Utility] shall be awarded a capacity service contract where such contract would result from an exception to the competitive bid and award process. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility] as a result of the RFP or other competitive bidding process, the affiliate shall be held to the same performance requirements as non-affiliated Capacity Service Providers.

4. In the event a capacity service contract is awarded, [Retail Gas Utility] shall maintain the following contemporaneous documentation: (a) any diversity, credit, or reliability-related capacity limitations placed on the maximum capacity [Retail Gas Utility] will purchase from an individual Capacity Service Provider (if applicable); (b) an explanation of the diversity, credit and/or reliability-related reasons for imposing such limitations (if applicable); (c) a description of the process used to evaluate bids, and negotiate final prices and terms; (d) a complete summary of all bids received and all prices accepted, together with copies of all underlying documents, contracts and communications; (f) a summary and explanation of Capacity Service Providers disqualified for credit, performance or other criteria, and (g) a copy of the policy or procedure employed by [Retail Gas Utility] for awarding contracts in instances where an affiliate and an unaffiliated Capacity Service Provider have offered identical pricing terms. For phone calls or texts, [Retail Gas Utility] shall maintain contemporaneous logs documenting the discussions and decisions.

5. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility], the [Retail Gas Utility] shall maintain contemporaneous documentation showing that the affiliate's bid price was equal to or lower than the bids received from non-affiliates.

6. In the event a capacity service contract is proposed to be awarded to an affiliate of [Retail Gas Utility] for a capacity path between a supply receipt area and a delivery area along or through which no other bids were received, [Retail Gas Utility] shall re-issue an RFP to the broadest practical set of eligible Capacity Service Providers in order to obtain competitive capacity service bids for the capacity service contract proposed to be awarded to an affiliate of [Retail Gas Utility].

7. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility] for a capacity path between a supply receipt area and a delivery area along or through which [Retail Gas Utility] also received bids for and/or awarded capacity service contract(s) to

[45] M.J. Bradley & Associates, New York Gas Company Climate Planning Tool and New York Gas Planning Greenhouse Gas Framework (May 2021), https://mjbradley.com/mjb_form/Gas-tools.

non-affiliated Capacity Service Providers, the [Retail Gas Utility] shall maintain contemporaneous documentation showing that the price established under the contract awarded the affiliate was within or lower than the range of prices established under contracts awarded to entities other than the affiliate.

8. If the affiliate's bid price or contract price does not meet the criteria in paragraphs 5, 6 or 7, [Retail Gas Utility] may not award the capacity service contract to the affiliate, unless the [Retail Gas Utility] can demonstrate and contemporaneously document that a more favorable bid was rejected for legitimate reasons relating to the rejected bidder or bidders' creditworthiness, performance history (or lack thereof), or other consideration bearing on the fitness and reliability of the bidder to provide the requested service.

9. In the interests of optimizing the competitive benefits of the RFP process, the RFP will explicitly inform potential bidders that [Retail Gas Utility] permits Capacity Service Providers to propose alternative ways of satisfying the ultimate need, including but not limited to basic quantity, reliability, receipt, delivery and pricing terms of the RFP in addition to those specifically contemplated by the RFP. The RFP may also utilize ranges for such quantity, reliability, receipt, delivery, pricing and/or other terms.

This type of proposed framework has numerous benefits. It will bring enhanced clarity and transparency to available supply and demand alternatives, spur innovative solutions to facilitate the objectives of the state's climate goals, and assist the Board, Staff, GDCs, and interested stakeholders in making informed decisions in shaping the future energy system. As noted above, other jurisdictions employ a similar framework, and this type of before-the-fact review of any interstate capacity contracts would also assist the Federal Energy Regulatory Commission in its decision-making at the federal level.[46] This thorough, upfront review will allow the Board to protect against a situation where FERC approves an unnecessary project and the Board is left with limited retroactive regulatory tools to assess prudency.[47]

---

[46] *See* Preliminary Determination on Non-Environmental Issues, *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224 at P 37 (Sept. 4, 2009) (finding the proposed Ruby pipeline and transportation contract "consistent with Commission policy" in part because the California Public Utilities Commission "directed PG&E to replace expiring contracts on GTN in order to diversify PG&E's gas supply, and, after evaluating several options, the CPUC approved PG&E's acquisition of capacity on Ruby's proposed pipeline").

[47] Under the Narragansett doctrine, "state regulatory commissions, in setting retail rates, must allow recovery of the interstate wholesale utility rates that have been made effective by [FERC] in the exercise of its exclusive jurisdiction over the regulation of such rates." Andrea J. Ercolano & Peter C.

### 4. Heightened Review of Affiliate Transactions

One important benefit of the above framework is that it allows for a transparent evaluation of both affiliate and non-affiliate alternatives. The framework provides that, in the event a contract is awarded to an affiliate, the gas utility must maintain contemporaneous documentation showing that the affiliate's bid price was equal to or lower than the bids received from non-affiliated suppliers. This provision will ensure that customers will be protected against any unnecessary costs resulting from an affiliate-backed transaction.

Applying heightened scrutiny to affiliate transactions at the state level is critical because there are no such protections in place at the federal level that govern newly formed affiliate pipeline developers. The standards of conduct adopted in FERC Order 717 apply to existing interstate natural gas pipelines.[48] A newly formed affiliate pipeline developer becomes a natural gas company, as defined by section 2(6) of the Natural Gas Act and subject to FERC jurisdiction, "[u]pon the receipt of its requested certificate authorizations and commencement of pipeline operations."[49] However, during the pivotal period of the open season process and contract negotiation, there are no rules in place governing the interactions between a newly formed pipeline developer and its affiliate gas utility. In practice, this means there is no meaningful separation between the pipeline development personnel and gas supply and operations personnel and that major new infrastructure projects are proposed and designed as the result of "negotiations" within the same corporate family and primarily for the benefit of that same corporate family's shareholders.

---

Lesch, *Narragansett Update: From Washington Gas Light to Nantahala*, 7 Energy L.J. 333, 333 (1986).

48 18 C.F.R. § 358.1.

49 *Spire STL Pipeline LLC*, 164 FERC ¶ 61,085 at P 3 (2018); *see id.* at P 104 (summarizing Spire's argument that it is not yet a "transmission service provider" and therefore not subject to the Commission's Order No. 717, *Standards of Conduct for Transmission Providers*).

FERC's primary concern regarding affiliates in certificate proceedings is whether there may have been undue discrimination against a non-affiliate shipper.[50] This concern completely ignores the threat of affiliate abuse posed when a newly formed pipeline developer enters into a negotiation with its affiliated gas utility and uses that precedent agreement to justify need for a major infrastructure project. Further compounding the problem is the Board's current position that it will not initiate review of such projects before they are built:

> "In New Jersey, regulators do not require pre-approval of precedent agreements by LDCs. There is no regulatory role until after a pipeline is built and LDCs seek cost recovery for transportation contracts from the NJ Board of Public Utilities. Such an outcome would result in a long-term glut in capacity that state regulators have no ability to remedy, and constitutes a significant regulatory gap."[51]

The consequence of this regulatory framework is that stakeholders are left with only one tool to challenge these types of projects before the state: after-the-fact prudency reviews. Ironically, FERC has described such processes as "lengthy, resource-consuming and uncertain in their outcome."[52]

The threat of affiliate abuse in New Jersey is not merely abstract. Stakeholders have been questioning the need for the affiliate-backed PennEast project for years.[53] When EDF attempted to raise concerns regarding this project in several of the GDCs' BGSS dockets, the Board denied EDF's intervention, stating:

---

50 *Id.* at P 45.

51 Request for Rehearing and Motion for Stay on Behalf of New Jersey Conservation Foundation and Stony Brook-Millstone Watershed Association, FERC Docket Nos. CP15-558, at 43-44 (February 12, 2018).

52 *Cove Point LNG Ltd. P'ship*, 68 FERC ¶ 61,128, 61,619 (1994).

53 Lander, Greg, "Analysis of Public Benefit Regarding PennEast Pipeline" at 11 (March 9, 2016), available at: https://rethinkenergynj.org/wpcontent/ uploads/2016/03/PennEastNotNeeded.pdf (estimating that the financial burden created by the glut of capacity the PennEast Project would introduce is estimated at $180 million to $280 million per year on just two legacy pipelines).

> "NJNG … is not seeking any costs related to the PennEast Agreement in this proceeding. Therefore, a review of the PennEast Agreement is not likely to add to a determination on the how NJNG's purchasing strategies affect NJNG's BGSS costs in this proceeding."[54]

As these examples demonstrate, the Board is in need of updated tools to address the threat posed by affiliate contracts and should therefore adopt the framework above.

### 5. Standard Method for Assessing GHG Emissions

Incomplete or insufficiently transparent planning can lead to adverse consequences, including increases in GHG emissions, and contravene the GWRA. Calculating and reporting greenhouse gas emissions associated with all solutions, both supply-side and demand-side, is necessary for transparency when weighing competing alternatives. The Gas Company Climate Planning Tool, developed by M.J. Bradley & Associates, can be used to assess the lifecycle GHG emissions of gas utilities.[55] The tool can be used to evaluate different portfolios of gas supply options against each other, to compare specific discrete options against each other, or to evaluate the effect of a proposed portfolio on state-wide GHG reduction goals. The Gas Company Climate Planning Tool consists of a life cycle approach that accounts for GHGs emitted throughout the entire value chain of natural gas and other fuels, from production all the way through end use[56] and is based on the following six core principles:

1. Account for all combustion-related GHG emissions and fugitive methane emissions.
2. Account for both supply- and demand-side options to manage and meet gas demand.
3. Use the most recent, publicly available data.
4. Identify and incorporate significant uncertainties.

---

[54] *In the Matter of the Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2020*, DECISION AND ORDER APPROVING STIPULATION FOR PROVISIONAL BGSS AND GIP RATES (September 11, 2019). Similar language was in the orders for the other two gas company BGSS cases denying EDF's intervention in those cases.

[55] M.J. Bradley & Associates, New York Gas Company Climate Planning Tool and New York Gas Planning Greenhouse Gas Framework (May 2021), https://mjbradley.com/mjb_form/Gas-tools.

[56] *Id.* at page 4.

5. Align the analysis with economy-wide GHG emission reduction targets under state climate laws.
6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide, the Social Cost of Methane, and the Social Cost of Nitrous Oxide.[57]

The figure below demonstrates a sample results table generated by the tool:


To ensure an accurate assessment of the GHG emissions impact of a given course of action, the Board should build into the planning process requirements that GDCs must use a common methodology to calculate the GHG emissions associated with a proposed project, and to project their overall GHG emissions out to 2050.

[57] *Id.*

### 6. Joint Gas-Electric Planning Assessments

As the Board takes steps to update its gas planning framework, it must ensure that the planning framework is durable enough to accommodate the significant changes on the horizon. As New Jersey pursues its climate targets, infrastructure once deemed to be used and useful may no longer be needed—and that transition will accelerate over the next decade as the State deploys its electrification plans and programs. To prepare for this future, the Board should require a Joint Feasibility Assessment to be conducted by both gas and electric utilities to identify the challenges, opportunities, and barriers to high electrification scenarios.

Other states are conducting similar types of analyses to inform how gas utility operations will need to evolve in light of rigorous climate goals. For example, in Massachusetts, the gas utilities are evaluating both high electrification and low electrification scenarios. The high electrification scenario assumes a significant reduction in Local Distribution Company ("LDC") sales and requires the LDC to conduct a feasibility and impact assessment:

> Building on the 2030 CECP Examination, perform a detailed examination of the feasibility and impact on customers and the LDCs' gas distribution operations through 2050, assuming a pace of building services electrification and required emissions reductions as described in the 2050 Roadmap All Options scenario resulting in an approximately 90% volumetric reduction in total LDC sales.[58]

The Joint Feasibility Assessment should consider hard-to-electrify buildings and industrial applications that are the most likely to continue relying on gas molecules instead of electrification, and conversely should consider the low-hanging fruit areas for electrification. Most critically, the analysis should be conducted in coordination with the corresponding electric utility (or utilities) operating in the gas utility's service territory. For combined gas and electric utilities, this coordination would occur more naturally. Gas-only utilities may need to institute

[58] Massachusetts Dept. of Pub. Utilities, Request for Proposal: The Role of Gas Distribution Companies in Achieving the Commonwealth's 2050 Climate Goals at p7 (Feb. 5, 2021), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13209897.

more formal channels of communication between the gas utility and electric utility counterpart to coordinate respective capabilities and plans.

This type of thoughtful and deliberate planning can help save costs for both utilities and ratepayers, for example through strategic targeting of electrification efforts. "[I]f electrification occurs on a house-by-house basis, both gas pipelines and electricity lines in a neighborhood will be maintained and benefits from electrification could take longer to manifest. The state could therefore miss critical opportunities for market and grid transformation. There may be better bang for the buck to push to electrify entire blocks or subdivisions, both from a marketing perspective and from deployment of grid infrastructure."[59] By requiring a Joint Feasibility Assessment early in the energy transition, the Board can provide greater regulatory certainty to both gas and electric utilities, accelerate the adoption of clean energy technologies, and reduce costs to customers associated with an unmanaged transition.

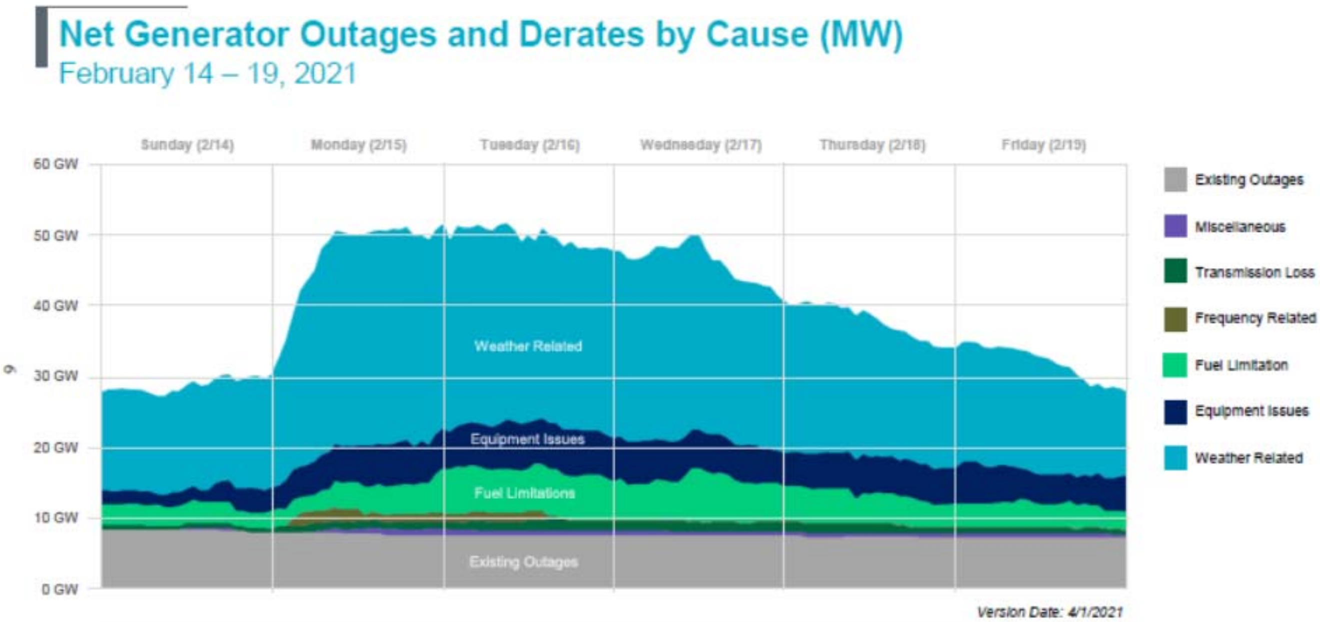
### D. The Texas Reliability Crisis Should Not Be Used as a Justification for Action in this Proceeding

During the public meeting, several stakeholders referred to the February event in Texas to express blanket concerns about reliability in New Jersey and potential risks associated with a "Texas-like" event. The Board should take note of the underlying causes of the Texas event—and the stark differences between that region of the country and the Northeast. Insufficient weatherization affected multiple types of generation during the Texas event. Insufficient weatherization also affected gas production, gathering and processing and thus the total quantity of available gas supply. Between gas supply and un-weatherized generation units, the biggest loss in capacity was among natural gas-fired generators, with approximately 25 GW unavailable

---

[59] EDF, Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California at p25 (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

for the two peak days of the event.[60] Weather and equipment related issues were the primary cause of the outages:




Net generator outages at the beginning of each hour on February 14-19, 2021, by cause category.

Unlike Texas which experiences extreme cold temperatures quite infrequently, the Northeast's gas production and electricity production facilities experience extreme cold frequently, and are substantially and appropriately weatherized. The Northeast has effectively managed reliability through polar vortexes and bomb cyclones. While there may be gas pipeline capacity constraints in pockets of the Northeast, the region is not plagued by frozen gas-production lines, frozen blades on wind-turbines, or gas-fired generators freezing because they are not ready for winter's cold. Given these important distinctions, the Board should carefully weigh any claims regarding the potential risks in New Jersey associated with a "Texas-like" event.

---

[60] ERCOT, Review of February 2021 Extreme Cold Weather Event at page 13 (February 24, 2021), http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf.

### E. Comments in Response to Specific Questions Posed in the Public Notice

#### 1. Should New Jersey be moving towards common design day reliability criteria?

Yes, the Board should establish a 1 day in 30 year ("1-in-30") Design Day as the weather that drives the demand for which the GDCs plan. While the weighting of the temperature values from the weather stations in or proximate to each of New Jersey GDCs' service territories may vary, having the same 1-in-30 standard based on the same 1-in-30 day is recommended.

#### 2. Are there reasons for allowing different GDCs to utilize different design day reliability criteria?

No, the Board should apply a uniform common "design day" and "design hour" to answering the question of "what" is the weather condition that should drive GDC design planning. Once the metric for "what" should be planned for is established, the GDC would present a specific outline of "how" it plans to meet that "design day" and "design hour."

#### 3. How does the selection of higher or lower design day reliability criteria affect the issue of whether, in your view, there are sufficient gas resources into New Jersey to maintain system reliability?

Once the "what" is identified (i.e., the design day and design hour to be planned for), the issue of higher or lower reliability criteria is addressed.

#### 4. Please discuss the costs and the benefits associated with using a 1-in-90 year design basis day versus a 1-in-30 year design basis day, with a focus on impacts to system reliability, customer affordability, and any other tradeoffs.

Extreme temperature data indicatively shows that the 30-year criteria is relevant and sufficient. Three locales' airports were reviewed below—Newark (EWR), Philadelphia (PHL), and Allentown (ABE). From the data reviewed, the (1) lowest recorded temperature in the past 30 years and year of observance for each locale and (2) the record lowest temperature for each locale over the period of the load duration curves and year of record observance are set forth below:

| Locale | Lowest Recorded Daily Average Temp Last 30 Yrs | Year Month and Day of Lowest Temp | Lowest Recorded Temp of Load Duration Curve period | Year and Month of Observation during Load Duration Curve Period |
|---|---|---|---|---|
| **Newark** | -2 | Jan 19, 1994 | 0 | Feb 2016 |
| **Philadelphia** | -5 | Jan 19, 1994 | 4 | Jan 2018 |
| **Allentown** | -11 | Jan 19, 1994 | -8 | Feb 2015 |

Below are the highest demand days for each of the load duration curves and the average Gas Day Temperature for each of the 3 locales.

| Highest Demand day of each of the 5 Load duration curves | NJ Scheduled Qty | Newark Avg Temperature | Philadelphia Temperature | Allentown Temperature |
|---|---|---|---|---|
| **Feb 15, 2015** | 4,869,327 | 10 | 10 | 6 |
| **Feb 13, 2016** | 5,506,327 | 13 | 17 | 12 |
| **Dec 15, 2016** | 5,172,532 | 21 | 21 | 18 |
| **Jan 1, 2018** | 5,359,726 | 15 | 16 | 12 |
| **Jan 31, 2019** | 5,657,207 | 11 | 14 | 5 |

Below is the New Jersey Demand on each of the record lowest temperature days during the Load Duration curve period.

| Date | Locale | Lowest Load Duration Curve Temperature | NJ Scheduled Qty |
|---|---|---|---|
| **Feb 14, 2016** | Newark | 0 | 5,472,628 |
| **Jan 7, 2018** | Philly | 4 | 5,251,314 |
| **Feb 24, 2015** | Allentown | -8 | 4,474,410 |

From the indicative 1-in-30 year data identified in advance of the April 29, 2021 Stakeholder Meeting and the actual data provided with respect to the load duration curve periods,[61] it is clear that more gas was delivered to New Jersey demand locations, in total, than LAI identified as New Jersey GDC capacity. It is also clear that the highest demand days for each of the five load duration curves had demand that was greater than the coldest winter day during the load duration curve period at each of the three locales.

Finally, assuming the LAI-asserted level of GDC pipeline capacity is sufficient to meet their respective design days, and given actual deliveries under all pipeline contracts (including GDC and others) exceeded LAI levels by from 0.5 BCFd to 1.5 BCFd and based upon Mr. Lander's analysis that available (and likely unsecured) capacity could facilitate an additional 1.2 BCFd or greater deliveries beyond historic actuals, moving to the 1-in-30 standard has little prospect of leading the GDCs to either over- or underestimate firm demand. Rather, such a standard will bring consistency to the objective design day (and hour), allowing the BPU Staff to focus on the "factors" the GDCs use to convert from temperature to load for each of its GDC's rate classes.

**5. How have voluntary peak management demand programs been structured in other jurisdictions or related industries? For example, how much would it cost to purchase and install directly controllable thermostats for all firm heating customers? Would smart meters be required as well? What would be the cost of these? Are there other examples of peak management demand programs, and what best practices can the State implement for these programs?**

Issues of peak management demand programs may or may not need to be considered once the GDCs plan for a common design day and design hour. Should there be identified

[61] See chart provided in EDF comments of EDF/NJCF dated October 21, 2019.

current or future firm demand in excess of secured capacity, cost and benefit comparisons can be made to identify how best to meet (and/or reduce) the identified demand.

**6. Consider a program in which smart thermostats controlled directly by the GDC during potential supply disruption were provided to all firm heating customers at no cost to the customer, and the capital cost to the GDC could be included in rate base. Please describe the benefits and consequences of such a program. How should Staff consider the program in terms of cost to provide reliability? Would it be equitable to all customers?**

Issues related to the efficacy or requirement for "smart thermostats" may or may not need to be considered once the GDCs plan for a common design day and design hour. Should there be identified current or future firm demand in excess of secured capacity, cost and benefit comparisons can be made to identify how best to meet (and/or reduce) the identified demand.

**7. What would be the potential uptake and impact of a "time of use" (TOU) program? For example, if a TOU or other peak demand-management program was offered to customers based on smart thermostats, would an opt-out program have a bigger impact than an opt-in program? If so, what would be the magnitude? Would it be more effective to offer an option to customers to opt in or opt out based on a level of emergency (e.g., yellow, orange, or red) where there would be different price incentives based on the level of the emergency?**

TOU is not a price-based approach currently available to the gas business. TOU is only a demand response tool that would be part of the design hour planning and DR/EE implementation. In addition, issues related to the efficacy or utility of one or more TOU programs may or may not need to be considered once the GDCs plan for a common design day and design hour. Should there be identified current or future firm demand in excess of secured capacity, cost and benefit comparisons can be made to identify how best to meet (and/or reduce) the identified demand.

**8. How would the impact of TOU pricing affect a firm heating customer's monthly bill in the winter? What are the ways that this could be mitigated without dampening the incentive to conserve? For example, should peak prices be tied not to the wholesale price of natural gas, which can be extremely volatile, but rather be set as an adder to existing BGSS prices, with the adder tied to projected day-ahead sendout? Should such prices be capped?**

See response to Question 7 above.

**9.What are the limits to the efficacy of peak demand reduction programs?**

See responses to Questions 5 and 6 above.

**10. What are the pros and cons of relying on government emergency orders to cope with a potential emergency (for example, orders shutting down businesses), rather than having peak demand programs in place?**

See response to Question 3 above. In addition, future government emergency orders, their threshold, extent, and public acceptance (i.e., effectiveness) may well: 1) be different in response to similar events, 2) lack speed of event recognition sufficient to address emergency, 3) face resistance by, or inability of, businesses to safely respond (ex. water line freezes, boiler freezes, shelf product loss, loss of animal life etc.). Conversely, demand response programs with implementation plans, contracts, and carrots and sticks do not suffer the same 'government emergency order' shortcomings. That is not to say that one or more government emergency orders in response to a gas system emergency which exceeds the programs' abilities to cope should be avoided or go unused; it is just that organized programs that address all but the most rare and severe of events will make government emergency orders the exception and not a rule likely to have less positive impact with successive uses. Lastly, once the government issues emergency orders, it becomes the government's responsibility as opposed to the GDCs responsibility to plan reasonably to avoid the problem occurring in the first place.

**10. Are there other measures the Board should consider to ensure the reliability of the natural gas system?**

As discussed above, the Board should initiate a new proceeding to establish a Gas Planning Process whereby each GDC files plans identifying future demands, and how they plan to address those demands while meeting the state's climate goals.

## III. Conclusion

The Board has the opportunity in this proceeding to align gas utility planning and operations with New Jersey climate law and policy and give meaning to the GDCs' obligation to serve in a manner that preserves and conserves the quality of the environment. Adopting the recommendations set forth above will allow for a comprehensive planning framework that meets today's needs and is durable enough to accommodate forthcoming state climate policies. EDF and NJCF look forward to continuing to engage with the Board, BPU Staff, GDCs and other stakeholders to ensure that gas utility planning is aligned with climate policy.

Dated: May 13, 2021

/s/ Natalie Karas
Natalie Karas
Senior Director and Lead Counsel, Energy
Environmental Defense Fund
1875 Connecticut Avenue NW, Suite 600
Washington, DC 20009
nkaras@edf.org

/s/ Mary Barber
Director, Regulatory & Legislative Affairs, Energy
Environmental Defense Fund
mbarber@edf.org

/s/ Jennifer Danis
Morningside Heights Legal Services
Columbia Law School
435 W. 116th Street
New York, NY 10027
jdanis@law.columbia.edu
*Counsel to NJCF*

/s/ Barbara Blumenthal
New Jersey Conservation Foundation
barbblumen@gmail.com