UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Certification of New Interstate Natural Gas Facilities	**)** **)**	**Docket No. PL18-1-000**

COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") February 18, 2021 Notice of Inquiry[1] ("February 2021 NOI") and March 31, 2021 Notice Extending Time for Comments,[2] the Environmental Defense Fund ("EDF") respectfully submits the following comments in the above-captioned proceeding. The February 2021 NOI seeks input on whether, and if so how, the Commission should revise the currently effective policy statement on the certification of new interstate natural gas transportation facilities under Section 7 of the Natural Gas Act.[3] Building upon the questions posed in its April 19, 2018 Notice of Inquiry in this proceeding ("April 2018 NOI"),[4] the Commission has identified the following general areas of examination: (1) the reliance of precedent agreements to demonstrate need for a proposed project; (2) the potential exercise of eminent domain and landowner interests; (3) the Commission's evaluation of alternatives and environmental effects under the National Environmental Policy Act and the Natural Gas Act; (4) the efficiency and effectiveness of the Commission's certificate process; and (5) the Commission's identification and addressing of any disproportionately high and adverse human health or environmental effects of its programs,

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1 *Certification of New Interstate Natural Gas Facilities*, Notice of Inquiry, 174 FERC ¶ 61,125 (February 18, 2021).

2 *Certification of New Interstate Natural Gas Facilities*, Docket No. PL18-1, Notice Extending Time for Comments (March 31, 2021).

3 15 U.S.C. § 717f.

4 *Certification of New Interstate Natural Gas Facilities*, Notice of Inquiry, 163 FERC ¶ 61,042 (April 19, 2018) ("April 2018 NOI").

policies, and activities on environmental justice communities and the mitigation of those adverse impacts and burdens.

I. BACKGROUND

On September 15, 1999, the Commission issued a Policy Statement on the Certification of New Interstate Pipeline Facilities ("Certificate Policy Statement") to provide guidance concerning how the Commission would evaluate certificate applications to determine whether such proposals meet the public convenience and necessity test of Section 7 of the Natural Gas Act.[5] The purpose of the Policy Statement was to determine how best to balance "market demand against potential adverse environmental impacts and private property rights" in order to decide whether a project was in the public convenience and necessity.[6] Its goals and objectives were "to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas" and "provide appropriate incentives for the optimal level of construction and efficient customer choices."[7]

On April 19, 2018, the Commission issued the April 2018 NOI, which solicited comments regarding whether and how the Commission should revise the Certificate Policy Statement. The April 2018 NOI noted that nearly two decades had passed since the issuance of the Certificate Policy Statement.[8] The April 2018 NOI explained that, in that time, the industry has seen unprecedented change, including: "(1) a revolution in natural gas production technology

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5 *Certification of New Interstate Natural Gas Pipeline Facilities*, Statement of Policy, 88 FERC ¶ 61,227 (September 15, 1999), modified by, Errata Notice, 89 FERC ¶ 61,040 (October 8, 1999); Order Clarifying Statement of Policy, 90 FERC ¶ 61,128 (February 9, 2000); Order Further Clarifying Statement of Policy, 92 FERC ¶ 61,094 (July 28, 2000).

6 Certificate Policy Statement at p. 61,737.

7 *Id.* at p. 61,743.

8 April 2018 NOI at p. 2.

leading to dramatic increases in production; (2) new areas of major natural gas production; (3) flows on pipeline systems becoming bidirectional or reversing; (4) customers routinely entering into long-term precedent agreements for firm service during the formative stage of potential projects and the use of those precedent agreements as applicants' principal evidence of the need for their projects; and (5) the increased use of natural gas as a fuel source for electric generation, resulting in a closer relationship between natural gas transportation and natural gas-fired electric generation."[9]

EDF submitted comments in response to the April 2018 NOI making a number of recommendations.[10] In particular, EDF recommended that the Commission should: (1) incent increased utilization of existing capacity and analyze utilization capacity on recently constructed pipelines; (2) establish market rules and structures that delineate and price non-ratable just-in-time delivery services and non-ratable "packing" to support both pre-ramping and de-ramping of gas-fired electric generation; (3) require applicants to robustly demonstrate support for the proposed economic useful lives of their proposed facilities; (4) apply heightened review requirements to applications by pipeline developers supported by affiliated utilities and their captive customers; and (5) conduct a more robust and detailed cost benefit analysis of proposed projects. Consistent with the direction in the Commission's February 2021 Notice of Inquiry, EDF has offered new information and recommendations in these comments rather than repeating those recommendations, but EDF continues to adhere to those recommendations and encourages the Commission to review and adopt them.

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9 *Id.*

10 *Certification of New Interstate Natural Gas Pipeline Facilities*, Docket No. PL18-1 Comments of the Environmental Defense Fund (July 25, 2018).

Subsequently, on February 18, 2021, the Commission issued the February 2021 NOI, which solicited "new information and additional stakeholder perspectives to help the Commission explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities." The February 2021 NOI recognized that further changes had occurred since the April 2018 NOI. In addition to the questions and topics included in the April 2018 NOI, it included several new questions as well as an additional topic, regarding environmental justice communities.

II. SUMMARY OF RECOMMENDATIONS

In these comments, EDF makes the following recommendations regarding the Commission's regulations, policies, and practices:

1. The Commission should modify the threshold "no financial subsidies" requirement to require a more detailed review of the justification for the proposed project and should apply this requirement to all applications (A1 and A2);
2. As part of this modified threshold requirement, the applicant should be required to demonstrate that any asserted "need" cannot be met by existing infrastructure, including through more efficient utilization of existing infrastructure, and the Commission should create incentives for such efficient utilization (A1 and A2);
3. The Commission should conduct a more thorough balancing of the potential benefits of the proposed project against its potential adverse impacts and Commission Staff should issue a Draft Balancing Analysis for comment prior to the Commission rendering a decision, similar to the Draft Environmental Impact Statement issued for comment as part of the National Environmental Policy Act review process (A1 and A2);
4. The Commission should update the requirements for Exhibit I of the application, regarding market data, and should strictly apply the informational requirements for Exhibit I and other required exhibits (A3);
5. The Commission should consider all information relevant to the useful life of a pipeline in its need and depreciation analyses, including federal and state decarbonization requirements (A3 and A6);
6. The Commission should require that applicants filing precedent agreements with affiliated shippers, particularly where those affiliated shippers have captive customers, provide evidence that the proposed pipelines provide material cost savings to customers of the affiliated shipper, based on alternatives solicited through a fair and open process (A4);

7. The Commission should employ a comparative hearing process when faced with multiple pipeline applications to provide service in the same geographic area (A9);
8. The Commission should give greater weight to the concerns of impacted landowners and communities and should use the Office of Public Participation ("OPP") to ensure that those stakeholders have effective outreach and opportunity to participate in Commission proceedings (B3);
9. The Commission should impose more detailed certificate conditions related to impact on and remediation of land affected by pre-construction, construction, and post-construction activities (B4);
10. The Commission should increase monitoring of remediation activities and take action when remediation is insufficient (B4); and
11. The Commission should recognize its past failures to appropriately address environmental justice issues and work with environmental justice communities and advocates to improve its identification of and response to adverse impacts and place greater weight on environmental justice concerns (E1 and E2).

The comments below expand upon the need for and proper implementation of these recommendations.

EDF also provides the following as Attachments to its Comments:

- EDF-1: Affidavit of James Murchie, CEO of Energy Income Partners
- EDF-2: Recommended Edits to Exhibit I (Market Data) in Redline
- EDF-3: Testimony of Alexander Kirk on behalf of Columbia Gas Transmission, Docket No. RP20-1060
- EDF-4: 2021 Vision Forward issued by the Interstate Natural Gas Association of America (INGAA)
- EDF-5: Comments of Environmental Defense Fund and New Jersey Conservation Foundation in New Jersey BPU Docket Nos. GO20010033 and GO19070846
- EDF-6: Analysis of Excess Capacity in St. Louis Region
- EDF-7: Standing Addendums from EDF v. FERC, Case No. 20-1016 *et al.*

III. COMMENTS

A1. Should the Commission consider changes in how it determines whether there is a public need for a proposed project?

The Natural Gas Act gives the Commission the responsibility of managing the expansion and maintenance of the natural gas system by determining whether proposed pipelines and other natural gas facilities are required "by the present or future public convenience and necessity."[11] Any proposed facilities not in the public convenience or necessity may not be built.[12] This is a fact-specific inquiry that must be informed both by the details of the project and by prevailing and forecasted market conditions. The current Certificate Policy Statement was adopted in 1999.[13] Since then, the natural gas market and the energy system as a whole have gone through substantial changes and they are on the cusp of an even greater shift. To appropriately evaluate applications for a certificate of public convenience and necessity under the Natural Gas Act, the Commission must update the Certificate Policy Statement in a manner informed by those conditions.

Under the current Certificate Policy Statement, the Commission first evaluates whether the project meets a "threshold requirement" of demonstrating that the project is financially supportable without subsidization from existing customers.[14] In practice, this is usually accomplished through the filing of precedent agreements between the applicant and natural gas shippers demonstrating that most of the project's capacity is subscribed to by new customers or by current customers purchasing additional capacity; it is the Commission's policy not to "look behind" such agreements to consider the shipper's reasons for subscribing to the capacity or otherwise evaluate what need for gas they reflect.[15] Under the Certificate Policy Statement, the threshold requirement does not apply to new pipeline companies, since they have no existing

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11 15 U.S.C. § 717f.

12 *Id.*

13 Certificate Policy Statement.

14 *Id.* at p. 61,746.

15 *Id.* at pp. 61,748-9; *Spire STL Pipeline LLC,* Order Issuing Certificates, 164 FERC ¶ 61,085 at p. 61,485 (August 3, 2018) ("Spire Certificate Order").

customers;[16] however, in practice, the Commission generally conducts a similar review of filed evidence of need, particularly precedent agreements, for applications by new pipeline companies before moving on to the next stage of review.[17]

Second, if the threshold requirement is satisfied, the Commission balances adverse effects of the proposed facilities, with a focus on impacts on existing customers of the applicant, other existing pipelines and their captive customers, and impacted landowners and communities, against public benefits of the proposed facilities.[18] Under the Certificate Policy Statement, a certificate is only granted where public benefits outweigh adverse impacts; the Commission may also impose conditions to minimize adverse effects.[19] In practice, the analysis of public benefits also relies principally on precedent agreements in most cases, with the Commission accepting statements by the applicant or shippers about the benefits of those contracts with minimal further analysis, or even describing the mere existence of precedent agreements as a "benefit."[20]

At present, where the proposed facility meets the threshold requirement and public benefits outweigh adverse impacts, the certificate is granted.[21] This current process continues to reflect the historic, strong, presumption of demand growth coupled with the historic view of relative supply constraints that was reasonably justified by prevailing market conditions in 1999. Those presumptions significantly differ from current and forecasted market conditions. Accordingly, the Commission must update these elements of the Certificate Policy Statement in

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16 Certificate Policy Statement at p. 61,746. ("For new pipeline companies, without existing customers, this requirement will have no application.")

17 Spire Certificate Order at p. 61,476.

18 Certificate Policy Statement at pp. 61,745-7.

19 *Id.* at p. 61,745-6.

20 Spire Certificate Order at pp. 61,495-6.

21 Certificate Policy Statement.

light of current conditions to prevent the issuance of certificates that do not reflect genuine "public convenience and necessity" and that will have significant adverse impacts, particularly on pipeline customers, impacted communities, landowners, and the environment.

In particular, EDF recommends that the Commission modify how it determines whether there is a public need for a proposed project in three ways:

(1) the Commission should modify the threshold "no financial subsidies" requirement to include a more detailed review of the justification for the project, and in particular should enhance review of precedent agreements, as well as explicitly applying the threshold requirement to new pipeline companies;

(2) as part of this modified threshold requirement, the applicant should be required to demonstrate that any asserted "need" cannot be met by existing infrastructure, including through more efficient utilization of existing infrastructure, and the Commission should create incentives for such efficient utilization; and

(3) the Commission should conduct a more thorough balancing of the potential benefits of the proposed project against its potential adverse impacts, clearly separated from the threshold requirement, and should only find public need if the potential benefits as analyzed by the Commission clearly outweigh the potential adverse impacts, including the risk of creating stranded assets. To increase transparency and opportunities for stakeholder input, including the input of impacted landowners and communities, Commission Staff should issue a Draft Balancing Analysis for comment prior to the Commission rendering a decision, similar to the Draft Environmental Impact Statement issued for comment as part of the National Environmental Policy Act review process.

In response to this question and the following questions in section A, EDF explains why these changes are necessary and provides specific details on how they should be implemented.

At the time of the development of the 1999 Certificate Policy and until relatively recently, the development, regulation, and operation of the natural gas system has been rooted in the assumption that demand for natural gas grows with population and the economy while natural domestic gas supply was relatively constrained and would grow much more slowly than domestic demand. Based on these assumptions, the Commission established a presumption that the willingness of businesses to bear the risk of the cost of new facilities, including through signing a pre-construction precedent agreement to purchase its capacity, was sufficient evidence that the facilities were needed.

This assumption of growing demand and the approval process established based on it has precipitated the Commission's approval of over 500 pipeline applications since 1999.[22] The Commission accepted, based on the limited evidence of precedent agreement(s), that both market need and public need existed as new pipeline projects would support growing demand; and, even in cases where intervenors demonstrated flat demand and sufficient existing supply, the prevailing presumption shifted to the asserted view that new pipeline projects would ensure longer-term supply sufficiency and provide access to lower prices. In addition, the view that North American natural gas resources were finite and insufficient to meet projected and experienced demand growth led to the proposal, approval, and development of a number of new LNG import terminals expected to operate as baseload supply facilities.

However, over the last decade, massive changes have uprooted these long-held presumptions. The development of new and expanded domestic resources, particularly through fracking, led to supply growth well beyond what was forecasted and projected supplies well beyond past limits. At the same time, public policy and the falling costs of renewable energy and electrification technologies have led to forecasts of flat or falling annual natural gas demand in much of the country. The new supply has already resulted in the proposals and refashioning of LNG import terminals to LNG export terminals and the reversals of historic flow on substantial portions of the nation's gas transmission system, as well as development of greenfield pipeline projects to support both shifting domestic demand and emergence of substantial export functions.

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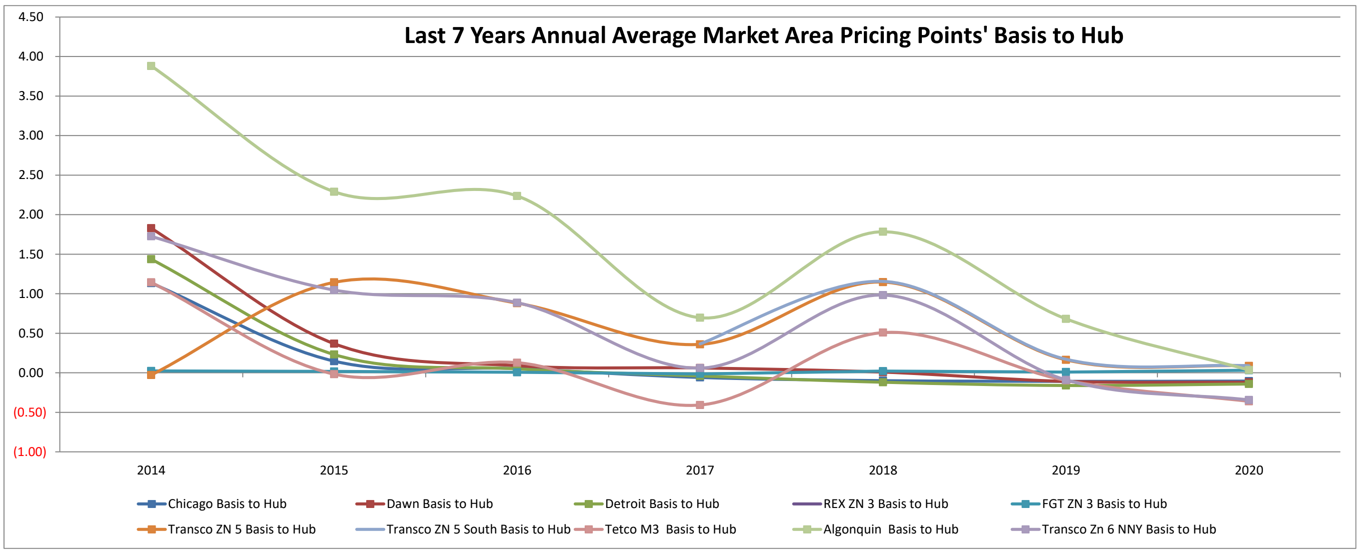
22 FERC, Approved Major Pipeline Projects (1997-Present), available at https://www.ferc.gov/industries-data/natural-gas/approved-major-pipeline-projects-2015-present.

Geographic regions that were formerly just "market areas" have now been transformed into dominant supply areas, seeking demand outlets elsewhere. As the Commission has recognized,[23] one consequence of this significant buildout is that gas prices have largely converged across the different supply and demand areas in the United States.

As seen below, most of the market area prices have, on an annual basis, essentially converged with the Henry Hub's prices:



If producing basins' prices and market areas' prices are nearly the same, the economic rationale for spending millions of dollars on new facilities in order to "promote competition" or "enhance market functioning" is diminished because commodity prices in the respective areas have converged.

Over the last two decades, as natural gas supply in the United States began to substantially increase, the simultaneous demand increases, including for significantly increased natural gas generation and partly driven by falling natural gas prices, allowed for the question of "market need" to be definitively answered in the positive because "these developments created

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23 Spire Certificate Order at p. 61,493

an acute need for new natural gas infrastructure to transport gas to serve customers."[24] However, looking forward, it is reasonable to project diminished annual demand for gas in many regions.[25] Both "market need" and "public need" take on new meanings in an era of a built-out system with flat or declining annual demand. Few if any projects will be justified by actual supply shortage, demand growth, or the potential for increased competition to lower prices; instead, the Commission will increasingly be asked to certificate projects on the basis that those projects will enhance reliability or resiliency, replace existing infrastructure, or meet specific functional needs, such as peak demand. Going forward, the Commission will need a durable framework that can accurately assess whether projects offered to replace or duplicate existing infrastructure will actually enhance reliability or resilience, and will actually meet the evolving needs of retail gas utilities and thus, in fact, satisfy the public convenience and necessity standard.

Governing in an era of uncertainty will require heightened review of new certificate applications. The Commission must reevaluate the information it requires be provided by pipeline applicants to ensure a complete record upon which an informed decision can be made. A growing list of Commissioners have criticized the Commission's approach, some even describing Section 7 reviews as "anemic" and "patently insufficient."[26] A flurry of recent

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24 *Millennium Pipeline Co., L.L.C.*, Order Issuing Certificate, 140 FERC ¶ 61,045 at p. 61,219 (July 17, 2012) (Commissioner LaFleur, dissenting).

25 *See., e.g.*, *Dominion Cove Point LNG, LP*, Docket No. RP17-197, Section 4 General Rate Case, Exhibit No. DCP-0088 at p. 19, lines 17-22 (November 23, 2016) ("There are many items that contribute to future uncertainty about natural gas demand in the long-run, including the technological development of alternative energies and renewable energies, potential gains in energy efficiency, and laws and policies that support the adoption of these technologies, alternatives, and efficiencies. These changes could reduce the demand for natural gas in the long-run, negatively impacting the demand for all of DCP's services. . . .").

26 Spire Certificate Order at p. 61,527 (Commissioner Glick, dissenting).

appellate decisions have also made clear that the Commission needs to "do better" in reviewing certificate applications:

- In *City of Oberlin v. FERC*, the D.C. Circuit found that the Commission failed to adequately justify its determination that it is lawful to credit Nexus's contracts with foreign shippers serving foreign customers as evidence of market demand for the interstate pipeline.[27]
- In *Birkhead v. FERC*, the D.C. Circuit stated that "[w]e are troubled, as we were in the upstream-effects context, by the Commission's attempt to justify its decision to discount downstream impacts based on its lack of information about the destination and end use of gas in question."[28]
- In *Allegheny Defense Project v. FERC*, the D.C. Circuit described the Commission's tolling order practice as "fundamentally unfair," at least when it "allows a pipeline developer to build its entire project while simultaneously preventing opponents of that pipeline from having their day in court[,] ensur[ing] that irreparable harm will occur before any party has access to judicial relief."[29]

Although the Commission has since corrected some of these deficiencies, these statements make clear that the Commission's role as "the guardian of the public interest" demands more. Going forward, the Commission must be prepared to request additional information from the applicant, invite a paper or comparative hearing to develop a complete record, or be willing to deny a project without prejudice until the pipeline meets its burden of proof. This approach will allow the Commission to make better informed and supported decisions, thereby reducing its litigation risk in certificate cases.

As explained in the Attachment EDF-1, the affidavit submitted by Energy Income Partners CEO James Murchie, the Commission must also take a hard look at how existing infrastructure is used and identify opportunities for incentives to drive more efficient use of the

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27 937 F.3d 599 (D.C. Cir. 2019).

28 925 F.3d 510, 520 (D.C. Cir. 2019).

29 964 F.3d 1 (D.C. Cir. 2020) (citing *Spire STL Pipeline*, 169 FERC ¶ 61,134 (Glick, Comm'r, dissenting)).

capital already invested in the existing pipeline network.[30] Going forward, the gas system will be called upon to serve as a facilitator of renewable deployment through the provision of hourly variable supply to electric generators performing balancing services to supplement and complement renewable generations' variable hourly output. The ability of natural gas to continue facilitating renewable deployment rests far more on using the incumbent infrastructure more efficiently and effectively than on greenfield gas infrastructure development. As renewable energy deployment continues, the total annual volume of natural gas used in power generation is likely to decline over time, but peak demand may remain stable or increase. This, coupled with the need to balance variable renewable generation, will increase the value of ancillary services provided by gas infrastructure, such as the provision of hourly non-ratable deliveries, the holding and storing of the ratable supply-receipts-into-the-pipe during hours of "no-burn" by generators, and the accommodation of ever steeper ramps and de-ramps to accommodate ever increasing renewable integration.[31] Rewarding pipelines for ***that*** value creation, as opposed to the simple building of new infrastructure, will drive cost efficiency for consumers and better overall returns for investors by avoiding duplicative investment.[32]

For a facility to be justified by "public convenience and necessity," it must be additive to the natural gas system and meet a need that cannot be met by the current system. If the pipeline applicant is not a new entrant, it should first have to demonstrate that its existing infrastructure is being utilized to its fullest extent. This would require the pipeline, in its application, to provide a

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30 Attachment EDF-1, Affidavit of James J. Murchie (May 26, 2021).

31 *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7, Reply Comments of Environmental Defense Fund (May 9, 2018).

32 Attachment EDF-1, Affidavit of James J. Murchie at ¶ 29.

comparison of the shape of the proposed new demand (over the extent of the proposed facilities) as compared to the shape of the currently existing demand on its system (over the extent of the proposed facilities) and present both against the shape of current contracts whose primary path(s) traverse the proposed facilities. The Commission has in the past required pipelines to provide steady state and transient hydraulic pipeflow simulation studies for both winter and summer seasons to demonstrate how the pipeline will be able to contractually meet all swing, no-notice, quick notice, and hourly delivery commitments on its physical system after abandonment.[33] This information, coupled with the exposition of actual facility utilization, would similarly demonstrate whether there is an opportunity for the turnback of seasonal or hourly contract rights on its system. At present, many customers, especially local distribution companies ("LDCs") and shippers serving LDC loads, have annual contracts whose utilization is at a low to non-existent load factor during extended portions of each year and/or predictable hours of each day over portions of each year.[34]

To the extent the projected peak demand associated with a proposed expansion coincides with the period of fallow utilization of an incumbent shipper, an opportunity for optimizing the contracting and utilization of existing facilities could exist. Where hourly or seasonal turnback by an incumbent is operationally feasible and desirable to the incumbent, FERC should allow the

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33 *Trunkline Gas Company, LLC*, Docket No. CP12-491, Trunkline Gas Company, LLC Response to Data Request (February 26, 2013).

34 *See, e.g.*, NYPSC Case No. 19-G-0678, National Grid Natural Gas Long-Term Capacity Report at p. 26 (February 24, 2020) (Figure 12: Downstate NY Gas Daily Demand Variability Over a Twelve-Month Period in 2013-2014 (colder year) and 2018-2019 (warmer year)).

pipeline to charge (and retain the revenues[35] from) the new customer for the turned-back, legacy capacity, at the unit price it would have cost to build the new capacity.

Allowing pipelines to receive Capacity Optimization Revenue would provide incentive revenue to the pipeline, relieve the incumbent of associated reservation charges, allow for more efficient contracting and use of existing assets, and eliminate the environmental impacts associated with new infrastructure build. In addition, even where the applicant is a new entrant, the Commission should be open to evidence from intervenors that the need the new facilities would serve could be met by more efficient utilization of the facilities of other incumbents, and those incumbents should have the same opportunity to earn revenue through serving those needs.

To the extent the pipeline applicant has exhausted opportunities for capacity optimization, it should be required to present evidence to demonstrate that new infrastructure is in fact needed; and, to propose how that new infrastructure will be depreciated over time consistent with imperative to decarbonize. Additionally, in those applications where the shippers that have signed precedent agreements have captive customers such that their shareholders are not solely at risk for cost recovery (such as in the case of LDC or electric utility shippers), such evidence could include: (1) the results of a competitive RFP process offered by the utility that selected the pipeline applicant as the best choice among other supply and demand relief options, (2) an evaluation of available, existing capacity in the region to demonstrate there is no available

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35 Similar to Commission treatment of revenues from negotiated rate contracts, where revenues are neither considered "discounted" transactions when revenues are below maximum rates, nor are revenues in excess of maximum rates credited to cost of service in Section 4 cases, such Capacity Optimization Revenues should also be excluded from consideration as general revenues in Section 4 rate cases. Instead, they should be treated like revenues from other incrementally-priced projects where the project has its own standalone cost of service and revenue stream.

capacity on neighboring pipelines, or (3) a detailed response to the information required in Exhibit I (Market Data).

A2. In determining whether there is a public need for a proposed project, what benefits should the Commission consider? For example, should the Commission examine whether the proposed project meets market demand, enhances resilience or reliability, promotes competition among natural gas companies, or enhances the functioning of gas markets?

As described above, the current Certificate Policy Statement gives short shrift to the issue of "public need," despite the fact that it is core to the Commission's statutory obligation under the Natural Gas Act. The threshold requirement formally applies only to pipelines with existing customers and asks only about the impact on those customers.[36] The second requirement, that benefits outweigh adverse impacts, does include a role for need in identifying and analyzing benefits, but does not require an explicit finding that need exists for the project.[37] The Commission's test, over time, has also conflated the issue of "need" with benefits.

Notably, the Certificate Policy Statement does include a list of potential project "benefits" that appear to constitute reasons a project may be needed: "meeting unserved demand, eliminating bottlenecks, access to new supplies, lower costs to consumers, providing new interconnects that improve the interstate grid, providing competitive alternatives, increasing electric reliability, or advancing clean air objectives."[38] However, the Commission has not strictly adhered to that list in approving projects, but has instead described factors like the mere

36 Certificate Policy Statement at p. 61,746.

37 *Id.* at pp. 61,745-7.

38 *Id.* at p. 61,748.

existence of a precedent agreement as a "benefit" of the project and then accepted this "benefit" as sufficient evidence of need.[39]

In practice, the Commission purports to address the issue of need but only in a limited manner that is highly deferential to the applicant. For example, in the Spire Order, the Commission followed a brief section titled "Subsidization" in which it finds the threshold requirement to be inapplicable with a significantly longer section titled "Need for the Project," in which it ultimately finds the existence of a precedent agreement for most of the project's capacity sufficient to demonstrate need, without "looking behind" the agreement to determine whether the contract reflects a genuine need on the shipper's part.[40]

The Commission effectively delegates the question of whether public need exists to private corporations, with the Commission finding need so long as two companies, the applicant and a shipper willing to sign precedent agreement, assert there is need. This has even been extended to the situation where only ***<u>one</u>*** company has asserted a claim of need, in cases where all of the applicant's subscribed capacity precedent agreements are with affiliated shippers.

To be fair, in 1999 and for a number of years thereafter, market need was largely synonymous with "market demand," as demand for natural gas continued to increase year-over-year and new greenfield facilities were generally proposed for the purpose of serving that new demand. However, as demand for natural gas diminishes over time, sole reliance on precedent agreements to establish "market need" no longer answers the question of whether the project is required by the public convenience and necessity.

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39 Spire Certificate Order at p. 61,526 (Commissioner LaFleur, dissenting) (explaining that the adverse effects of the project "clearly outweigh the only benefit articulated, a precedent agreement").

40 *Id.* at pp. 61,476-88.

For these reasons, the Commission should modify the threshold requirement to make it a test of "public need" and make it applicable to all applications. This will require that the applicant provide a specific basis for public need. That basis could be one of the items listed in the Certificate Policy Statement or could be an alternative basis accompanied by a justification from the applicant of why that basis reflects need. The applicant should also be required to provide specific evidence that the need identified exists and that the proposed facilities will serve that need. The applicant should further be required to demonstrate that the identified need cannot be met by existing infrastructure, including through more efficient utilization of existing infrastructure.

For example, in determining whether a project enhances resilience or reliability, the Commission needs to set clear guideposts, particularly because, unlike the Federal Power Act, the Natural Gas Act does not provide for the development of mandatory reliability standards. In the absence of such a framework, the applicant is left with unbounded discretion to assert, on its own behalf or based on statements by shippers, what is and is not needed to maintain reliability or increase resiliency. For example, the applicant and shipper in the Spire case asserted that the Spire STL pipeline would enhance reliability, as it provided an additional transportation path that partly circumvented a seismic zone.[41] However, intervenors presented record evidence demonstrating that there is a 0.00005 percent chance of a large magnitude earthquake occurring in the region,[42] portions of the shipper's own service territory are within the same seismic zone rendering illogical the notion that a pipeline must avoid that zone to be reliable,[43] and the shipper

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41 *Id.* at p. 61,484.

42 *Spire STL Pipeline LLC*, Docket No. CP17-40, Protest of Enable Mississippi River Transmission LLC at page 42 (February 27, 2017).

43 *Id.*

already had a transportation path that avoided the seismic zone.[44] Despite this evidence, the Commission, asserting that it would not "look behind" contracts, treated claims of reliability as a benefit of the project. If an applicant seeks to rely on an assertion of "enhanced reliability" as evidence of project need or a project benefit, it must assemble a record that actually quantifies and validates such benefits.

Assessing any reliability benefit must also take into account pipeline tariff provisions that apply when there is an outage on a stretch of pipe or compressor station. Several pipeline tariffs' General Terms and Conditions, including Algonquin's, provide for the proration of impaired deliveries.[45] 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. In other words, no incremental service, or addition of a lateral service or delivery point, overcomes the fact that all suffer equally when an emergency arises. Therefore, if a project is offered to meet a "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, or that the benefit is sufficient to justify the project even given those provisions. The pipeline applicant should be required to demonstrate with sufficient detail the resilience problem asserted to be addressed and how the project would solve that problem. Where some or all of the shippers subscribing to a project purportedly designed for a resilience need are affiliates of the applicant and therefore beneficiaries of project revenues, the

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44 *Spire STL Pipeline LLC*, Docket No. CP17-40, Laclede Gas Company Motion for Leave and Statement in Support of Application at p. 4, n.1 (February 27, 2017).

45 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.

Commission should conduct a heightened review, including a hearing or other processes allowing for data requests and cross examination by intervenors.

As another example, arguably any new pipeline project could claim to meet a need of "promoting competition among natural gas companies" or "enhancing the functioning of gas markets." Therefore, if an applicant relies on such a need to justify its project, the applicant should be required to provide more detailed information in support of either. For instance, a new pipeline to promote competition should be required to qualitatively and quantitatively demonstrate how customers would benefit from increased competition, including demonstrated cost savings; especially in light of evident price convergence. The Commission must also have a means of measuring how the functioning of the gas market is enhanced. Given prevailing market conditions and collapsing basis price differentials, it is unlikely that new greenfield projects could offer meaningful benefits in this area.

Beyond the initial question of whether "public need" exists for a proposed facility, the Commission should continue to conduct a balancing test to determine whether the potential benefits of the proposed facility outweigh the potential adverse impacts caused by the facility. The potential benefits considered should include both the primary justification of the project's need, such ability to serve increased demand, improved reliability, or enhanced competition, as well as secondary benefits such as number of jobs created. The potential adverse impacts considered should include, as discussed below, the impact on landowners who will have their property taken by eminent domain, and on communities near the facilities, as well as adverse environmental impacts. The impacts on other pipelines should also be considered; while it is true that the Commission's role is not to protect incumbent pipelines from fair competition, the

Commission's role is to prevent overbuilding of the system.[46] Indeed, at the foundation of utility regulation is the recognition that overbuilding of the utility system is not in the public interest, along with the recognition that this will result in monopolies that require careful regulation. While the fact that a proposed facility will cause financial harm to existing pipelines is not, on its own, definitive proof that the proposed facility will result in an overbuilt system, the Commission should carefully consider such impacts in its analysis. As described further below using the case study of the Spire STL pipeline, a failure to fully consider the impacts of a new pipeline on existing facilities can result in a substantially overbuilt system.

In balancing potential benefits and potential adverse impacts of a proposed facility, the Commission should both consider the benefits and adverse impacts in a qualitative matter and perform a quantitative balancing of the benefits and adverse impacts. While the Commission described the existing balancing test as an "economic test," in practice the Commission has not conducted a detailed quantitative analysis in its certificate orders. Rather, the Commission has briefly reviewed the "benefits" described by the applicant and any commenting shippers, including "benefits" of questionable value like the mere existence of an affiliate precedent agreement, and the adverse impacts described by intervenors, and then summarily stated that the "benefits" outweigh the adverse impacts. ***Naming*** public benefits and adverse effects is not the same thing as ***weighing*** them. As demonstrated in the chart below, the Commission's balancing analysis contains very little analysis at all:

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46 *See, e.g.*, Certificate Policy Statement at p. 61,737.

Case	Balancing Analysis
Eastern Shore Natural Gas Co., 132 FERC ¶ 61,204 (2010)	P 35 Based on all the above, the Commission finds that the proposal will serve a demonstrated market need and provide a new regional supply source without adverse impacts on existing customers, other pipelines, landowners, or communities.
Dominion Transmission, Inc., 141 FERC ¶ 61,240 (2012)	P 21 The proposed Allegheny Storage Project will increase the transportation and storage capacity available on DTI's system. All of the proposed capacity has been subscribed under long-term contracts, demonstrating the existence of a market for the project. Based on the benefits the project will provide and the minimal adverse effects the project will have on the economic interests of existing shippers, other pipelines and their captive customers, landowners and surrounding communities, we find, consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, that the public convenience and necessity requires approval of DTI's proposal, as conditioned in this order.
Millennium Pipeline Co. L.L.C., 140 FERC ¶ 61,045 (2012)	P 15 Based on the benefits the project will provide and the minimal adverse effect on existing shippers, other pipelines and their captive customers, landowners and surrounding communities, we find, consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, that the public convenience and necessity requires approval of Millennium's proposal, as conditioned in this order.

NEXUS Gas Transmission, LLC, 160 FERC ¶ 61,022 (2017)	P 51 Based on the benefits the project will provide and the minimal adverse impacts on existing shippers, other pipelines and their captive customers, and landowners and surrounding communities, we find, consistent with the Certificate Policy Statement and NGA section 7(c), that the public convenience and necessity requires approval of NEXUS's proposal, subject to the conditions discussed below
Mountain Valley Pipeline, 161 FERC ¶ 61,043 (2017)	P 64 We find that the benefits that the MVP Project will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and landowners or surrounding communities
Spire STL Pipeline LLC, 164 FERC ¶ 61,085 (2018)	P 123 We find that the benefits that the Spire STL Project will provide to the market, including enhanced access to diverse supply sources and the fostering of competitive alternatives, outweigh the potential adverse effects on existing shippers, other pipelines and their captive customers, and landowners or surrounding communities.

In order to increase the transparency of its review and ensure that it has appropriately represented and considered the public benefits and adverse impacts of a project, the Commission should direct Commission Staff to prepare a Draft Balancing Analysis for each application and release that Draft Balancing Analysis for public review and comment in advance of issuing the Initial Order. This would allow intervenors, including in particular impacted landowners and communities, to see whether the adverse impacts they will face have been fully identified and given appropriate consideration, as well as to offer evidence that the magnitude of the adverse impacts will be greater than the Draft Balancing Analysis estimates. The Commission should establish a specific timeline for the Draft Balancing Analysis that allows for Commission Staff to have the benefit of initial filings before preparing the analysis, but that also offers intervenors (as well as the applicant) a reasonable comment period after the Draft Balancing Analysis is published and ensures that the Commission has a reasonable amount of time to review those comments before rendering a decision. This process could be generally similar to the NEPA analysis process used to develop an Environmental Impact Statement (EIS), which includes the following steps:[47]

1. An agency publishes a Notice of Intent in the Federal Register. The Notice of Intent informs the public of the upcoming environmental analysis and describes how the public can become involved in the EIS preparation. This Notice of Intent starts the scoping process, which is the period in which the federal agency and the public collaborate to define the range of issues and potential alternatives to be addressed in the EIS.
2. A draft EIS is published for public review and comment for a minimum of 45 days. Upon close of the comment period, agencies consider all substantive comments and, if necessary, conduct further analyses.
3. A final EIS is then published, which provides responses to substantive comments. Publication of the final EIS begins the minimum 30-day "wait period," in which agencies are generally required to wait 30 days before making a final decision on a proposed action.
4. The EIS process ends with the issuance of the Record of Decision (ROD). The ROD:
    - explains the agency's decision,
    - describes the alternatives the agency considered, and
    - discusses the agency's plans for mitigation and monitoring, if necessary.

The Commission could borrow from this process as it updates its review of public benefits and adverse effects. This reform would promote transparency, confidence and public participation in the Commission's decision making process. This process should also be informed by consultation with the OPP regarding landowner and community impacts.[48]

A3. Currently, the Commission considers precedent agreements, whereby entities intending to be shippers on the contemplated pipeline commit contractually to such shipments, to be strong evidence that there is a public need for a proposed project. If the Commission were

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47 Environmental Protection Agency, National Environmental Policy Act Review Process , available at https://www.epa.gov/nepa/national-environmental-policy-act-review-process.

48 The appropriate role of the OPP in certificate proceedings is discussed further below.

to look beyond precedent agreements, what types of additional or alternative evidence should the Commission examine to determine project need? What would such evidence provide that cannot be determined with precedent agreements alone? How should the Commission assess such evidence? Is there any heightened litigation risk or other risk that could result from any broadening of the scope of evidence the Commission considers during a certificate proceeding? If so, how should the Commission safeguard against or otherwise address such risks?

Although the burden of proof in certificate proceedings falls squarely upon the applicant,[49] it has been observed that FERC's unwillingness to "look behind" precedent agreements and take protesting parties' arguments seriously "has the effect of flipping that burden on its head."[50] While one tool to return the burden to its proper place is to require applicants to provide a more detailed explanation and more evidence of need, as discussed above, the Commission should also make greater use of existing tools, including requiring the submission of, and carefully evaluating, all parts of the certificate application required by current regulations. For instance, 18 C.F.R. Section 157.14 specifies the exhibits that must accompany a certificate application, which include, among other exhibits, Exhibit I (Market Data) and Exhibit O (Depreciation). Over time, the Commission has repeatedly granted waivers of several of these requirements. The consequence of granting such waivers is that a significant portion of Section 7(c) information and data filing "requirements" are casually wiped away.

The below chart summarizes what was provided by the applicant for a number of recently approved pipeline certificates in the following categories: (a) whether, pursuant to 18 C.F.R. § 157.6(b)(8), the applicant provided "an analysis reflecting the impact of the fuel usage resulting

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49 *See Texaco Inc. v. FERC*, 148 F.3d 1091, 1093 (D.C. Cir. 1998) ("To satisfy section 7's 'public convenience and necessity' requirement, an applicant must prove that the facility it proposes to build 'is or will be required by the present or future public convenience and necessity'") (quoting 15 U.S.C. § 717f(e)); *Atl. Ref. Co. v. FPC*, 316 F.2d 677, 678 (D.C. Cir. 1963) ("The burden of proving the public convenience and necessity is, of course, on the natural gas company.")

50 Spire Certificate Order at p. 61,531 (Commissioner Glick, dissenting).

from the proposed expansion project;" (b) whether, pursuant to 18 C.F.R. § 157.6(a)(5) and 18 C.F.R. § 157.14, the applicant provided an Exhibit G showing "[a] flow diagram showing daily design capacity and reflecting operating conditions with only existing facilities in operation" and "[a] second flow diagram showing daily design capacity and reflecting operating conditions with both proposed and existing facilities in operation;" (c) whether, pursuant to the same sections, the applicant provided an Exhibit H describing "[t]hose production areas accessible to the proposed construction that contain sufficient existing or potential gas supplies for the proposed project;" (d) whether, pursuant to those same sections, the applicant provided an Exhibit I including "[a] system-wide estimate of the volumes of gas to be delivered during each of the first 3 full years of operation of the proposed service, sale, or facilities and during the years when the proposed facilities are under construction, and actual data of like import for each of the 3 years next preceding the filing of the application" and "[a] copy of each market survey made within the past three years for such markets as are to receive new or increased service from the project applied for."

No.	Pipeline, Docket No., and Application Date	Analysis of Impact of Fuel Usage	Selected Info from Exhibit G	Selected Info from Exhibit H	Selected Info from Exhibit I
1	Spire STL CP17-40 1/26/2017	Requirements not met.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided documents relating to open season and confidential contract.
2	PennEast CP15-558 9/25/2015	Requirements not met. Information is provided regarding applicant's LAUF rate but not on destination markets' LAUF.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided confidential contracts.
3	Mountain Valley Pipeline CP16-10 10/23/2015	Requirements not met. Information is provided regarding applicant's LAUF rate but not on destination markets' LAUF.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided confidential contracts.
4	MVP Southgate CP19-14 11/6/2018	Requirements not met. Information is provided regarding applicant's LAUF rate but not on destination markets' LAUF.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Provided third-party study of market demand.

5	Algonquin (Weymouth Compressor) CP16-9 10/22/2015	Requirements not met.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided confidential contracts.
6	Transco CP17-101 3/27/2017	Requirements are addressed at a high level in Exhibit Z-1..	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided confidential contracts.
7	Florida Gas CP19-474 5/31/2019	Requirements are addressed at a high level on pages 11-12 of the application.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided confidential contracts.
8	Gulf South CP19-125 3/29/2019	Requirements not met. Information is provided regarding applicant's LAUF rate but not on destination markets' LAUF	Purportedly provided but designated as CEII.	Expressly omitted.	Requirements not met. Only provided confidential contract.
9	Gulfstream CP19-475 6/3/2019	Requirements not met.	Purportedly provided but designated as CEII.	Expressly omitted on the grounds that shippers obtain their own gas.	Requirements not met. Only provided confidential contracts.
10	Texas Eastern CP19-509 9/4/2019	Requirements not met.	Expressly omitted on the grounds that the project maintains system design.	Expressly omitted on the grounds that shippers obtain their own gas.	Expressly omitted because the project maintains existing service.

In particular, Exhibit I requires detailed information that would be informative with respect to the need for a project, regardless of whether the project's capacity is subscribed to by precedent agreements. In practice, however, pipeline applicants usually submit only precedent agreements and assert that this exhibit's requirements are therefore satisfied. While it is clear that certain information contemplated to be filed as part of Exhibit I is no longer germane and can reasonably be revised or eliminated from filing requirements, much of the information is relevant to the Commission's decision-making and should therefore be required as part of application submissions. In Attachment EDF-2, EDF proposes edits to the Exhibit I requirements in redline. Once the Exhibit I requirements are updated, the Commission should require every applicant to fully comply with those requirements and should only grant waivers if the stringent standard for a waiver request has been satisfied.[51]

In addition to no longer waiving much of the data requirements in and revising Exhibit I, the Commission must also revisit its review of Exhibit O, regarding depreciation. Historically, the Commission regularly relied on the potential exhaustion of natural gas resources in determining the economic life in Natural Gas Act Section 7 cases. In these cases, depreciable life was based on the estimated gas reserves at the upstream end of a pipeline's system, while demand for natural gas, and thus the pipeline's services, at the downstream end were assumed to be permanent.[52] As described above, supply is no longer subject to the same limits as were previously anticipated, while annual demand, as a result of public policy and declining costs of renewable energy and electrification technologies, is likely to decline.

Going forward, depreciation rates must reflect an economic useful life that is consistent with the imperative to decarbonize, as well as specific federal, state, and local requirements for

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51 The Commission has granted waiver of tariff provisions where: (1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties. *See, e.g.*, *Florida Gas Transmission Company,* LLC, 174 FERC ¶ 61,170 at ¶ 6 (March 3, 2021); *Calpine Energy Servs., L.P.*, 154 FERC ¶ 61,082 at ¶ 12 (February 4, 2016); *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059 at ¶ 14 (January 29, 2016); *New York Power Auth.*, 152 FERC ¶ 61,058 at ¶ 22 (July 17, 2015).

52 *Iroquois Gas Transmission System, L.P.*, 84 FERC ¶ 61,086 at p. 61,348 (July 29, 1998); *see also Tallgrass Interstate Gas Transmission, LLC*, Docket No. RP16-137, Section 4 Rate Case Filing, Direct Testimony of Patrick R. Crowley (October 30, 2015).

greenhouse gas ("GHG") reductions. The Commission recently had to grapple with an appropriate amortization period for a proxy unit used to establish the New York Independent System Operation ("NYISO") ICAP Demand Curve.[53] In his partial dissent, Chairman Glick explained that, in light of New York's greenhouse gas reduction goals, fundamental reforms to the NYISO tariff recognizing the more limited future of gas generators would likely be necessary.[54] The Commission must acknowledge the need to similarly align the useful life of gas infrastructure with climate commitments and science-based GHG reduction targets.[55]

States are already recognizing the need to align gas infrastructure with climate goals and mandates. For example, the New York Public Service Commission Staff Gas System Planning Process Proposal details information gas utilities should provide in comparing non-pipeline alternatives with traditional gas infrastructure solutions, including a "scenario that assumes that the full value of new gas assets will be depreciated by 2050."[56] Many states have passed legislation requiring sharp declines in carbon emissions over the next decade, which is likely to reduce gas usage in all sectors of the economy, particularly for generation and building heating. The Commission should ensure that its regulatory oversight of new gas infrastructure aligns with these state objectives.

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53 *New York Independent System Operator, Inc.*, Order Accepting, in Part, Subject to Condition and Directing Compliance Filing, 175 FERC ¶ 61,012 (April 9, 2021).

54 *Id.* (Chairman Glick, dissenting in part at ¶ 3).

55 In a March 22, 2021 order in Docket No. CP20-487, the Commission found that "when states have GHG emissions reduction targets we will endeavor to consider the GHG emissions of a project on those state goals." *Northern Natural Gas Co.*, 174 FERC ¶ 61,189 at ¶ 35 (2021). As explained in this section, state GHG emission reduction targets are also relevant to the economic useful life of proposed gas facilities.

56 *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, NYPSC Case No. 20-G-0131, Staff Gas System Planning Process Proposal (February 12, 2021).

Unlike certificate applications, in Section 4 rate cases, pipelines provide detailed testimony in support of their requested economic lives. As detailed in Attachment EDF-3, the Testimony of Alexander Kirk on behalf of Columbia Gas Transmission in Docket No. RP20-1060 concludes that state and local government policies, economics, technological developments, and consumer demand could cause substantial uncertainty over the long-run for natural gas:

> The combination of declining costs of renewable energy and battery storage will cause natural gas to be a relatively high marginal cost source of energy in the future. Such a development would lead to the future underutilization of natural gas pipeline capacity due to a lack of demand for natural gas-fired generation as well and other uses due to electrification . . . Since declining demand results in a lower willingness-to-pay by shippers, a decline in demand (but stable supply) presents a situation where a pipeline will be unable to effectively increase its rates to reflect reduced billing determinants that would allow it to recover its cost of service (inclusive of recovery of the net book cost of plant).[57]

Witness Kirk concludes that a reasonable economic life for Columbia is limited to 35 years, as "market forces due to the dramatic declines in the projected prices of wind and solar power and battery storage are likely to reduce the demand for Columbia's services."[58] Similar types of analyses should be provided in certificate applications as part of a pipeline's Exhibit O demonstration.

A4. Should the Commission consider distinguishing between precedent agreements with affiliates and non-affiliates in considering the need for a proposed project? If so, how?

EDF's prior comments detailed the prevalence of affiliate-backed capacity expansions and offered suggestions for how the Commission could apply heightened review to certain

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57 *Columbia Gas Transmission, LLC*, Docket No. RP20-1060, Section 4 Rate Case, Direct Testimony of Alexander Kirk at p. 40 (July 31, 2020) (included as Attachment EDF-3).

58 *Id.* at p. 41.

categories of affiliate precedent agreements.[59] As offered in those prior comments, when posed with the threat of affiliate abuse between a pipeline developer and a retail gas utility affiliate, the Commission should: (1) invite a paper hearing to ensure a sufficient factual record that the market will support the expense of the new facilities over the contract term; and/or (2) impose a rate condition, requiring 50% of the pipeline applicant's recovery of return and taxes to be assigned to the usage rate.

As part of the paper hearing process, an affiliate gas utility could offer evidence that it engaged in an RFP type process that clearly and transparently evaluated alternatives. For example, in *Florida Southeast Connection*, the retail gas utility held an RFP to seek proposals for a new pipeline to accommodate Florida's long-term natural gas needs.[60] In the order finding that FPL's decision to enter into long-term natural gas transportation contracts was based on a fair and open process, the Florida Public Service Commission found that "the contracts are projected to save up to $450 million over the term of the contracts when compared to the next most cost-effective proposal."[61] Going forward, the Commission should similarly require evidence demonstrating that any affiliate-backed expansion will provide material cost savings to customers of the affiliated shipper, based on alternatives solicited through a fair and open process.

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59 *Certification of New Interstate Natural Gas Pipeline Facilities*, Docket No. PL18-1 Comments of the Environmental Defense Fund at pp. 29-35 (July 25, 2018).

60 *Florida Southeast Connection*, Order Issuing Certificates and Approving Abandonment, 154 FERC ¶ 61,080 at ¶ 9 (February 2, 2016).

61 In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company, FPSC Docket No. 130198-EI, Order No. PSC-13-0505-PAA-E1 (October 28, 2013).

The need for heightened review of affiliate contracts is especially necessary because the standards of conduct adopted in FERC Order 717 apply to ***existing*** interstate natural gas pipelines.[62] 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 the Commission's jurisdiction, only "[u]pon the receipt of its requested certificate authorizations and commencement of pipeline operations."[63] 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 (or to be 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. Another way to look at this structure is that where a corporate entity uses its monopsony power to the benefit of its shareholders is, in fact and function, as undesirable as an entity using its monopoly position to benefit its shareholders.[64]

The Commission's requirement that pipeline applicants conduct an open season process similarly does not cure this regulatory gap, as newly formed pipeline developers routinely offer

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62 18 C.F.R. § 358.1.

63 Spire Certificate Order at ¶ 3; *see id.* at ¶ 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*).

64 *Maritimes & Northeast Pipeline, LLC*, 154 FERC ¶ 61,084 at ¶ 31 (2016) (While the NGA primarily protects the public against the monopoly power of pipelines, it also protects the public against the monopsony power of shippers. NGA section 4(b)(1) charges the Commission with prohibiting pipelines from offering a shipper 'any undue preference or advantage.' Thus, we will not permit, let alone compel, Maritimes to treat Repsol's capacity requests preferentially, simply because it is the largest shipper on Maritimes' system.").

precedent agreements with their affiliate gas utilities that were not connected to, or a result of, the open season process.[65] For example, in the Mountain Valley Pipeline proceeding, the Commission acknowledged that Consolidated Edison became an affiliate of Mountain Valley Pipeline and a shipper of the project three months after the initial certificate application was filed.[66] The Commission reiterated that its open season policy "only requires that a pipeline applicant conduct a fair and transparent open season, prior to filing its application, for potential shippers to seek and obtain firm capacity rights."[67] Thus, the Commission's sole focus regarding affiliates in certificate proceedings is whether there may have been undue discrimination against a non-affiliate shipper.[68] This concern completely ignores the threat of affiliate abuse posed when a newly formed pipeline developer enters into a negotiation with its affiliate gas utility (as monopsony buyer) and uses that precedent agreement to justify need for (and whose shareholders receive the benefit of) a major infrastructure project, as well as the potential that the shipper engaged in undue discrimination against other pipelines or even non-pipeline alternatives.

A5. Should the Commission consider whether there are specific provisions or characteristics of the precedent agreements that the Commission should more closely review in considering the need for a proposed project? For example, should the term of the precedent agreement have any bearing on the Commission's consideration of need or should the Commission consider whether the contracts are subject to state review?

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65 Spire Certificate Order at ¶ 77 (noting that "the precedent agreement was not the direct result of the open season, but stemmed from prior discussions between Spire, Spire Missouri, and their corporate parents . . .").

66 *Mountain Valley Pipeline, LLC*, Order Issuing Certificates and Granting Abandonment Authority, 161 FERC ¶ 61,043 at ¶ 49 (October 13, 2017).

67 *Id.* at ¶ 54.

68 *Id.* at ¶ 45.

The Commission should pay particular attention to whether the state commission has conducted any review of the precedent agreements or need for the proposed project prior to the Commission's consideration of the application. While some states provide avenues for a prior review process,[69] many states do not. The Commission's position—to defer any meaningful review of a precedent agreement to the state regulator—has created rippling effects of harm for state commissions, consumer advocates, retail ratepayers and other interested stakeholders.

When the Commission declines to meaningfully review the terms of and circumstances surrounding precedent agreements, state commissions are left as the sole source of regulatory oversight. FERC has repeatedly found that "any attempt by [FERC] to look behind the precedent agreements [in a certificate] proceeding might infringe upon the role of state regulators in determining the prudence of expenditures by the utilities that they regulate."[70] This finding presumes that such state oversight is occurring, while overlooking the significant extent to which state commissions are limited by statute and law as to their review of these agreements.

In Missouri, for example, the state's prudency review takes place in a Purchased Gas Adjustment ("PGA")/Actual Cost Adjustment ("ACA") process. This is an after-the-fact review, whereby the Missouri Commission is limited to reviewing whether the retail gas utility was prudent in contracting with the pipeline when compared to other alternatives.[71] As explained by Dr. Sue Tierney, state regulators' hands are tied in these proceedings by two factors:

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69 See, e.g., In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company, FPSC Docket No. 130198-EI, Order No. PSC-13-0505-PAA-E1 (October 28, 2013).

70 *Mountain Valley Pipeline, LLC*, Order Issuing Certificates and Granting Abandonment Authority, 161 FERC ¶ 61,043 at ¶ 53 (2017).

71 *Pike County Light and Power Co. v. Penn. Pub. Util. Comm'n*, 77 Pa. Cmwlth 268 (1983).

> First, states cannot undo a Commission-approved rate when the states incorporate the costs, like gas transportation service, as part of retail rates. Second, any attempt to deny cost recovery results in lowering the LDCs' credit rating, which raises their costs of equity capital or debt for all capital investments and will result in higher charges to consumers to cover this cost. Thus, the Commission's attempt to duck a fulsome Gas Act review—which it portrays as necessary to avoid trammeling PUCs' jurisdiction—is backwards. In fact, PUCs' reliance on the Commission to conduct its statutorily mandated need determination is another compelling reason for the Court to ensure that the Commission begins doing just that. *Spire* lays bare this truth; the state regulators apprised the Commission of their limited regulatory reach, and the Commission again abdicated its Gas Act mandate to protect the public interest.[72]

All of these factors point to a significant gap in regulatory oversight between FERC and state commission review of affiliate transportation agreements. The Commission has an obligation under the Natural Gas Act to address these deficiencies. Where captive customers are asked to be the ultimate bearer of the costs of long-term transportation contracts, FERC must "address the question of whether the interests of the customers are sufficiently likely to be congruent with those of the ultimate consumers that will bear the cost of the agreed upon rates in their monthly energy bills."[73]

In addition, where the state commission, ratepayer advocate, or a similar state entity protests the project, the application should be subject to particular scrutiny and review. Where, in particular, one or more precedent agreements are with LDCs, these state entities have responsibility for protecting the captive customers of those LDCs and, based on the details of the project and applicable state law, may be best able to do so through participation in the Commission proceeding rather than through a separate state proceeding. In comments in generic Commission dockets and specific pipeline proceedings, state commissions and ratepayer

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[72] *EDF v. FERC*, D.C. Circuit Case No. 20-1016, Brief of Dr. Susan Tierney as Amicus Curiae in Support of Petitioner the Environmental Defense Fund at page 26 (July 1, 2020).

[73] *Mo. Pub. Serv. Comm'n v. FERC*, 337 F.3d 1066, 1076 (D.C. Cir. 2003).

advocates have submitted comments requesting the Commission consider their viewpoints and, in particular, have requested more thorough reviews of precedent agreements with affiliated shippers.[74] The Natural Gas Act contemplates an elevated role for state commissions and their input should be given sufficient weight and deference.[75] In particular, the Commission should consider making use of the provisions of the Natural Gas Act that enable it to create Joint Boards with state-nominated members or to confer with state commissions, including through joint hearings, as well as inviting state participation in technical conferences and other more informal engagement.[76]

A6. In its determinations regarding project need, should the Commission consider the intended or expected end use of the natural gas? Would consideration of end uses better inform the Commission's determination regarding whether there is a need for the project? What are the challenges to determining the ultimate end use of the new capacity a shipper is contracting for? How could such challenges be overcome?

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74 *See, e.g.*, Certificate Policy Statement at p. 61,740 ("Ohio [Public Utilities Commission] states that pipelines should shoulder the increased risk and that [FERC] should look behind contracts with affiliates"); *E. Shore Natural Gas Co.*, 132 FERC ¶ 61,204, at ¶ 31 (2010) ("The Delaware [Public Service Commission] suggests the mere fact that the agreements are with affiliates of Eastern Shore somehow raises questions regarding the shippers need for the service"); *Spire STL Pipeline LLC*, Docket No. CP17-40, Conditional Protest of the Missouri Public Service Commission at p. 9, n.18 (February 27, 2017) (disputing that an affiliate precedent agreement reflects fair competition); Docket No. PL18-1, Comments of the Public Utilities Commission of the State of California (July 25, 2018) (asking FERC to examine whether affiliate precedent agreements contain perverse incentives); Docket Nos. CP15-117 and CP15-118, Request for Rehearing of the North Carolina Utilities Commission and the New York State Public Service Commission (August 8, 2016); Docket No. CP15-138, Request for Rehearing of the North Carolina Utilities Commission and the New York State Public Service Commission (March 6, 2017); Docket No. CP15-554, Request for Rehearing of the North Carolina Utilities Commission (November 13, 2017); Docket No. CP15-555, Request for Rehearing of the North Carolina Utilities Commission (November 13, 2017); Docket No. CP15-558, Request for Rehearing of the New Jersey Division of Rate Counsel (February 20, 2018).

75 15 U.S.C. § 717p.

76 *Id.*

In order to determine whether a project is in the public convenience and necessity, the Commission must consider the intended or expected end use of the natural gas. The Commission cannot evaluate an assertion of a need that a project will serve without understanding what shippers will be using the pipeline's capacity and what purposes they will use it for. In many cases, this will be relatively obvious: a pipeline between a production area and an LNG export terminal is clearly designed for export, while a pipeline with a precedent agreement with an LDC shipper is most likely designed for the provision of gas to the LDC's end use customers. In any case where precedent agreements exist, the applicant will have an understanding of who is purchasing the gas and what its end use is, and therefore can be required to provide that information. In the unlikely scenario of an applicant who has no precedent agreements, whatever information that applicant files as evidence of need, including market studies, should have sufficient information to identify likely users and end-uses.

Notably, pipelines are already providing end use assessments as part of their Section 4 rate case filings. As detailed in Attachment EDF-3, Columbia Gas provided an analysis of the substantial amount of renewable energy potential that exists within its footprint that could reduce the demand for natural gas. Looking to an assessment put forth by the National Renewable Energy Laboratory ("NREL"), Columbia Gas witness Kirk identified 21,819,833 gigawatt hours of potential renewable energy production in the states Columbia serves and a total of 950,322 gigawatt hours of sales across all sectors (residential, commercial, industrial, and transportation):[77]

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[77] Attachment EDF-3 at p. 30.

Table 1
Columbia States Renewable Energy Potential and 2019 Total Sales

Potential Energy from Renewable Sources	Gigawatt Hours
Urban Utility-scale Photovoltaics	408,520
Rural Utility-scale Photovoltaics	14,962,087
Rooftop Photovoltaics	183,570
Concentrating Solar Power	0
Onshore Wind	216,636
Offshore Wind	3,130,407
Biopower-Solid	56,961
Biopower-Gaseous	25,207
Geothermal Hydrothermal	0
Enhanced Geothermal Systems	2,801,567
Hydropower	34,877
TOTAL	**21,819,833**
2019 Total Retail Sales (All Sectors)	**950,322**

Witness Kirk concludes that "[i]n the long run, since most end-use consumption of natural gas can be substituted with electricity, this shows the potential for renewable energies to significantly diminish demand for natural gas . . . The data indicates that if renewable energy is price-competitive, ample renewable energy potential exists within the Columbia States alone to displace all energy consumption within these states."[78]

Pipeline analyses also make clear that battery storage technology will support increased reliance on renewable sources in the long run. Columbia Gas witness Kirk observes that many battery storage facilities are located in the Columbia footprint and that "the continued decline in battery storage costs combined with renewable generation from solar and wind will cause renewable energy to be significantly more competitive by 2030 or earlier."[79] He cites the

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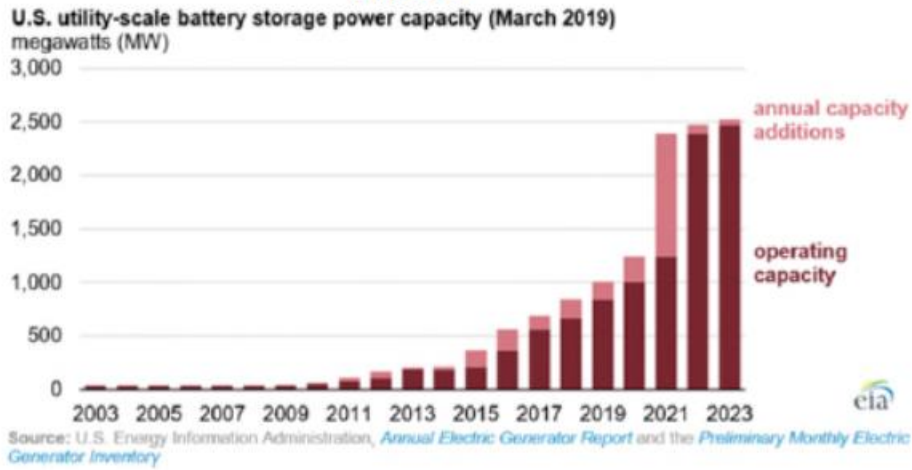
78 *Id.*

79 *Id.* at p. 36.

following Energy Information Administration data, which shows that U.S. utility scale battery storage is expected to grow substantially by 2023:

Chart 6



The testimony also makes clear that the adoption of renewable energy can displace gas demand in the residential, commercial, and industrial sectors.[80] Witness Kirk, citing to a study by NREL, explains that "air-source heat pump and heat pump water heaters, offering electric-based space-heating and water-heating, are likely to be at cost-parity with natural gas space-heating and water-heating between 2020 and 2030, and are likely to be 'substantially lower cost' between 2040 and 2050."[81]

These cost predictions and technological assessments must also be viewed in light of the imperative to decarbonize. Consistent with science-based targets making clear the need for regulation to swiftly and dramatically reduce emissions, climate change policies are entering into effect at various levels of government in the United States. On his first day in office, President

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80 *Id.* at pp. 36-37.

81 *Id.* at p. 38.

Biden acted to bring the United States back into the Paris Climate Agreement.[82] Recently, the Biden-Harris Administration set an ambitious and necessary target for the U.S. to achieve a 50-52% reduction in economy-wide greenhouse gas pollution by 2030 (below 2005 levels).[83] The Administration recognizes that part of the comprehensive strategy to achieve this target will include reducing short-lived climate pollutants such as methane that can deliver fast climate benefits.[84] Currently, 25 states, the District of Columbia and Puerto Rico have established GHG emissions targets. For instance, the Climate Leadership and Community Protection Act mandates that the State of New York adopt measures to reduce state-wide GHG emissions by 40% by 2030 and 85% by 2050 (from 1990 levels), with an additional goal of achieving net zero emissions across all sectors of the economy by 2050.[85] Pipelines are acknowledging the impact of these state climate goals in Section 4 rate case testimony and conclude that "[t]o achieve reductions in greenhouse gas emissions of these magnitudes will require a significant decrease in natural gas use, and a consequent decrease in use of natural gas transportation and storage services."[86]

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82 The White House, Fact Sheet: President-elect Biden's Day One Executive Actions Deliver Relief for Families Across America Amid Converging Crises (Jan. 20, 2021), available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/20/fact-sheet-president-elect-bidens-day-one-executive-actions-deliver-relief-for-families-across-america-amid-converging-crises/.

83 The White House, Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies (Apr. 22, 2021), available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

84 *Id.*

85 Climate Leadership and Community Protection Act ("CLCPA"), 2019 N.Y. Sess. Laws 106.

86 *Columbia Gas Transmission, LLC*, Docket No. RP20-1060, Direct Testimony of Alexander Kirk at p. 27 (July 31, 2020) (included as Attachment EDF-3).

Considering the intended or expected end use of natural gas is also critical in light of ongoing state efforts. Several state public utilities commissions have taken the important first step of opening broad, state-wide proceedings to evaluate the future role of natural gas and how best to reconcile their climate goals with existing gas utility policies and business models. The California PUC predicts that, "[o]ver the next 25 years, state and municipal laws concerning greenhouse gas emissions will result in the replacement of gas-fueled technologies and, in turn, reduce the demand for natural gas."[87] The Massachusetts Department of Public Utilities has found that the energy transition requires it "to consider new policies and structures that would protect ratepayers as the Commonwealth reduces its reliance on natural gas. . . ."[88] The New York State Public Service Commission has observed that gas planning "must be conducted in a manner consistent with [the state's climate legislation]."[89]

Gas utilities are also starting to perform assessments of how state climate goals will translate into action. In Massachusetts, for example, the gas utilities are evaluating both high electrification and low electrification scenarios. The high electrification scenario assumes a significant reduction in 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

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87 *Long-Term Gas Planning Rulemaking*, CPUC Rulemaking 20-01-007, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning at p. 3 (January 16, 2020).

88 *Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals*, Mass. D.P.U. 20-80, Vote and Order Opening Investigation at p. 2 (October 29, 2020).

89 *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, NYPSC Case 20-G-0131, Order Instituting Proceeding at p. 3 (March 19, 2020).

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.[90]

Similarly, New York City, in a joint study with the City's major electric and gas utilities, projects that total natural gas demand across all sectors will fall more than 60% by 2050, even under a "low carbon fuels" pathway.[91]As these examples illustrate, achieving economy-wide climate goals will require massive transformation across all sectors and will necessitate a diminished role for natural gas in our future energy system.

In response to the imperative to decarbonize the energy system, the gas industry has committed to taking specific action to reduce GHG emissions. The Interstate Natural Gas Association of America ("INGAA") has committed to "reaching net zero GHG emissions from natural gas and storage operations by no later than 2050 . . ."[92] Gas utilities, such as National Grid and Southern California Gas Company, have committed to net zero GHG emissions by 2050 or earlier.[93] GHG assessments are becoming integral to business transactions, as customers

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90 Massachusetts Dept. of Pub. Utilities, Request for Proposal: The Role of Gas Distribution Companies in Achieving the Commonwealth's 2050 Climate Goals at p. 7 (Feb. 5, 2021), available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13209897.

91 City of New York Mayor's Office of Sustainability, Con Edison, & National Grid, *Pathways to Carbon-Neutral NYC: Modernize, Reimagine, Reach* at p. 75 (Apr. 2021), available at https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf ("NYC Pathways Study").

92 Interstate Natural Gas Association of America, 2021 Vision Forward, available at https://www.ingaa.org/File.aspx?id=38523&v=6553c6c8. This commitment is included as an attachment at EDF-4.

93 National Grid, National Grid Releases Net Zero by 2050 Plan (October 2, 2020), available at https://www.nationalgridus.com/News/2020/10/National-Grid-Releases-Net-Zero-by-2050-Plan/; SoCalGas, Aspire 2045 (March 2021), available at https://www.socalgas.com/sites/default/files/2021-03/SoCalGas_Climate_Commitment.pdf.

demand more detailed information about the GHG footprint of LNG cargoes.[94] It is against this backdrop of change spurred by new technologies, evolving customer expectations, and climate goals designed to meet science-based targets that the Commission should consider the expected—and evolving—end use of natural gas.

Given these factors, the expected end use of natural gas is an important component of the need analysis due to the quickly changing uses of the gas system in many states. Similar to the information pipelines already provide in Section 4 proceedings, pipeline applicants should be required to conduct these end use assessments for the states in which they operate in support of their Section 7 applications. The Commission should not approve an application where the use cases are inconsistent with legal requirements, including federal, state, and local greenhouse gas emission requirements. In addition, as described above, in reviewing an application, the Commission must consider the depreciation applicable to the proposed facilities. This must be informed by the timeline for the facility's usage; the depreciation analysis would look very different for a facility that will become unused within five years based on current state law than for a facility that has an end use purpose consistent with a longer lifespan.

A7. Should the Commission consider requiring additional or alternative evidence of need for different end uses? What would be the effect on pipeline companies, consumers, gas prices, and competition? Examples of end uses could include: LDC contracts to serve domestic use; contracts with marketers to move gas from a production area to a liquid trading point; contracts for transporting gas to an export facility; projects for reliability and/or resilience; and contracts for electric generating resources.

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94 Isla Binnie, Reuters, Repsol makes first delivery of carbon-compensated LNG (March 12, 2021), available at https://www.reuters.com/article/us-repsol-lng-carbonoffset/repsol-makes-first-delivery-of-carbon-compensated-lng-idUSKBN2B41DT; Ben German, Axios, Natural gas exporters race to have the least polluting fossil fuels (February 25, 2021), available at https://www.axios.com/fossil-fuels-pollution-green-energy-ffe221d8-aaa8-4a26-bb21-990e244aa4e0.html.

The Commission should tailor its review and analysis of an application based on the expected end use and identified need. A project designed to serve new demand should require different evidence than a project designed to offer reliability benefits or than a project designed to increase competition; similarly, a project designed to serve an LDC shipper should require different evidence than a project designed to ship gas from a production area to a trading point or a project designed to transport gas to an export facility.

For example, where a project is primarily or exclusively serving one or more LDC shippers, the Commission should invite the applicant to submit the results of the LDC's analysis of its various supply and demand relief options and the reasons for choosing to take service from the pipeline applicant. As the Commission has previously acknowledged, its lack of jurisdiction over shippers and end users does not preclude or foreclose it from further developing the record by requesting additional data from the project applicant.[95]

Retail gas utilities' gas supply planning choices have become subject to increased scrutiny in the past few years. To help bring transparency and accountability to these decisions, EDF has suggested—at the state level—that retail utilities be required to submit an RFP to compare alternatives that could either provide natural gas supply or demand relief.[96] An example of EDF's recommendations, filed with the New Jersey Board of Public Utilities, is appended to

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95 *Birkhead v. FERC*, 925 F.3d 510, 520 (D.C. Cir. 2019).

96 *Gas Planning Procedures*, NYPSC Case No. 20-G-0131, Comments of Environmental Defense Fund on Staff Gas System Planning Process Proposal; *Natural Gas Commodity and Delivery Capacities in the State of New Jersey – Investigation of the Current and Mid-Term Future Supply and Demand*, NJBPU Docket No. GO20010033 *et al.*, Comments of the Environmental Defense Fund and New Jersey Conservation Foundation at pp. 19-22 (May 13, 2021) (included as Attachment EDF-5).

this document as Attachment EDF-5. This type of evidence has been offered in prior Commission cases[97] and would help demonstrate that a project is in fact needed.

A8. How should the Commission take into account that end uses for gas may not be permanent and may change over time?

As described above, the Commission should take federal, state, and local requirements for decarbonization into account as a factor in considering an application. To the extent that, based on those requirements or other factors like contract term, the end use planned for the gas is unlikely to be necessary for the entire asserted useful life of the project, the Commission should require the applicant to provide additional information on potential future end uses of the gas. This should also inform the depreciation analysis of the project.

A9. Should the Commission assess need differently if multiple pipeline applications to provide service in the same geographic area are pending before the Commission? For example, should the Commission consider a regional approach to a needs determination if there are multiple pipeline applications pending for the same geographic area? Should the Commission change the way it considers the impact of a new project on competing existing pipeline systems or their captive shippers? If so, what would that analysis look like in practice?

Yes, the Commission should consider a comparative hearing process when faced with multiple pipeline applications to provide service in the same geographic area. In the past, the Commission has used a comparative hearing process to assess numerous competing applications to provide new transportation service to specific new customers in the northeast and where only one pipeline was needed to provide a specified increment of service to a given customer.[98]

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97 *See Ruby Pipeline, L.L.C.*, Preliminary Determination on Non-Environmental Issues, 128 FERC ¶ 61,224 at ¶ 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").

98 *Millennium Pipeline Co.*, 97 FERC ¶ 61,292 at p. 62,315 (2001) (explaining the Commission's process in *Northeast U.S. Pipeline Projects*, 40 FERC ¶ 61,087 (1987)).

Employing a similar process could avoid the pitfalls that followed the Commission's approval of both the Atlantic Coast Project and the Mountain Valley Project. Commissioner LaFleur's dissent in the Mountain Valley Pipeline order observed the similarities in respective routes, impact, and timing of the Atlantic Coast Project and Mountain Valley Pipeline project:

ACP and MVP are proposed to be built in the same region with certain segments located in close geographic proximity. Collectively, they represent approximately 900 miles of new gas pipeline infrastructure through West Virginia, Virginia and North Carolina, and will deliver 3.44 Bcf/d of natural gas to the Southeast. The record demonstrates that these two large projects will have similar, and significant, environmental impacts on the region. Both the ACP and MVP cross hundreds of miles of karst terrain, thousands of waterbodies, and many agricultural, residential, and commercial areas. Furthermore, the projects traverse many important cultural, historic, and natural resources, including the Appalachian National Scenic Trail and the Blue Ridge Parkway. Both projects appear to be receiving gas from the same location, and both deliver gas that can reach some common destination markets. Moreover, these projects are being developed under similar development schedules, as further evidenced by the Commission acting on them concurrently today. Given these similarities and overlapping issues, I believe it is appropriate to balance the collective environmental impacts of these projects on the Appalachian region against the economic need for the projects. In so doing, I am not persuaded that both of these projects as proposed are in the public interest.[99]The ultimate cancellation of the Atlantic Coast Pipeline suggests that a more thorough review of need and weighing of public benefits and adverse effects for the region was warranted. When the Commission is faced with multiple

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[99] *Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043 (2017) (Commissioner LaFleur, dissenting at p. 2)

pipeline applications to provide service in the same geographic area, it should consider utilizing a comparative hearing approach to assess all applications simultaneously. This approach could help to streamline the review process, significantly reduce costs for all parties, and avoid the cancellation of major projects.

A10. Should the Commission consider adjusting its assessment of need to examine (1) if existing infrastructure can accommodate a proposed project (beyond the system alternatives analysis examined in the Commission's environmental review);[7] (2) if demand in a new project's markets will materialize; or (3) if reliance on other energy sources to meet future demand for electricity generation would impact gas projects designed to supply gas-fired generators? If so, how?

As described above, analysis of certificate applications should consider whether more efficient use of existing infrastructure, including both the applicant's existing facilities and other facilities serving the relevant geographic areas, could serve the need identified by the applicant. The applicant should be required to provide specific information about its existing facilities as part of the application, including comparing the shape of proposed new demand, demand on its existing system, and current contracts. This information, along with pipeflow simulation studies and information on actual facility utilization, would demonstrate whether there is an opportunity for the turnback of seasonal or hourly contract rights on its system to serve the needs identified. There are likely to be particular opportunities in cases where LDC shippers and shippers serving LDC loads have annual contracts with low to non-existent load factors during much of the year and high demand only during certain, relatively predictable hours. The Commission should also ensure that the applicant's market survey and other information submitted as part of Exhibit I identifies other facilities serving the relevant area.

Commission Staff could also have a role in reviewing available, excess capacity on neighboring pipelines. For example, in the Nexus remand order, "Commission staff used publicly-available information from NEXUS' application and other pipeline company's electronic bulletin boards to determine that there is similarly no unsubscribed capacity available to serve the 625,000 Dth per day subscribed by NEXUS' domestic shippers."[100] This type of analysis could serve as a protection against approval of unnecessary capacity.

Conducting a thorough review of available, excess capacity on neighboring pipelines could serve as a protection against overbuilding and the risk of stranded assets. For instance, in Attachment EDF-6, EDF presents an analysis of the excess capacity in the St. Louis region resulting from the Commission's approval of the affiliate-backed Spire STL Pipeline. Attachment EDF-6 includes: 1) the 2011 to 2021 history of Spire Missouri's capacity subscriptions, showing the impact of the Spire STL Pipeline on the existing and past subscribed capacity of Enable MRT to the St. Louis area; 2) the posting of unsubscribed capacity by neighboring pipeline MOGAS showing capacity available to serve the St. Louis market; and, 3) the posting of unsubscribed capacity by another neighboring pipeline Enable MRT showing the capacity available to serve the St. Louis Market. This analysis demonstrates that the construction of the Spire STL Pipeline, and subsequent turnback of existing capacity by Spire Missouri, has resulted in a significant amount of unsubscribed capacity available on other pipelines in the St. Louis area—approximately 576,948 Dth per day on the Enable MRT and MOGAS interstate pipelines. This amount of excess capacity is greater than the entire capacity of the Spire STL pipeline—400,000 Dth per day. If a primary objective of the Commission is to prevent overbuilding, then it must develop the analytical tools to confirm that its approval of new pipeline infrastructure will not result in significant amounts of excess capacity.

A11. In its determination of need, should the Commission consider the economic, energy security and social attributes of domestic production and use of natural gas as detailed in

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100 *Nexus Gas Transmission, LLC*, 172 FERC ¶ 61,199 at ¶ 27 (2020).

the letter dated February 11, 2021 from the Chairman of the Senate Energy and Natural Resources Committee, Senator Joe Manchin III, to President Biden?

Both the market need analysis and the comparison of benefits and adverse impacts must be specifically focused on the proposed project, rather than hypothetical or general benefits of natural gas production and usage. As described above, these reviews should also be separated. To the extent that an individual project demonstrates economic benefits, energy security benefits, or other societal benefits, those could be considered as part of the weighing of benefits and adverse impacts. However, those benefits would have to be supported by specific information demonstrating that those benefits will be associated with the facilities proposed. For example, any potential economic benefits of a proposed project must be considered in context of the project costs, with recognition of the fact that project costs will ultimately be paid by end-use consumers, who would spend that money differently were the project not built. Similarly, any justification related to energy security would need to demonstrate what specific energy security benefits the proposed project would offer, how those benefits compare to alternatives, and that those benefits, along with any other potential benefits of the project, outweigh the potential harms of the project.

B3. For proposed projects that will potentially require the exercise of eminent domain, should the Commission consider changing how it balances the potential use of eminent domain against the showing of need for the project? Since the amount of eminent domain used cannot be established with certainty until after a Commission order is issued, is it possible for the Commission to reliably estimate the amount of eminent domain a proposed project may use such that the Commission could use that information during the consideration of an application?

As with many other issues discussed above, the Commission should recognize that the applicant has the burden of demonstrating that adverse impacts of the proposed project do not outweigh the benefits of the project. The Commission should recognize that the use of eminent domain represents a significant adverse impact and should require the applicant to provide information on how much land might need to be taken through eminent domain. Specifically, the applicant should be expected to provide information on how much of the pipeline route it can acquire without eminent domain, including through contracts, letters of intent, and other evidence that the applicant is able to obtain the right to build the project without eminent domain, and how much of the pipeline route it has been unable to acquire through voluntary methods. The Commission should assume that any land the applicant has not been able to voluntarily acquire the right to build on or pass through will need to be acquired through eminent domain and should evaluate adverse impacts in accordance with that assumption.

B4. Does the Commission's current certificate process adequately take landowner interests into account? Are there steps that applicants and the Commission should implement to better take landowner interests into account and encourage landowner participation in the process? If so, what should the steps be?

The current certificate process fails to adequately take landowner interests into account. As part of the Spire Pipeline appeal, EDF offered the affidavit of several of its members whose land was taken by eminent domain. Affidavits by those landowners are attached as Attachment EDF-7. Those affidavits demonstrate the difficulty that landowners have in engaging with the Commission process and describe the harm inflicted on landowners by pipeline companies. For example, Jacob Gettings, Jr. explained that pipeline construction on his land resulted in a loss of topsoil, soil compaction, and damage to subsurface drain tiles, which make the land less productive for crops and result in standing water on the property, potentially impairing a plan to install solar panels on the property.[101] Gregory Stout described the damage that the pipeline construction process did to a conservation prairie he established and maintained as part of a United States Department of Agriculture conservation program, as well as the destruction of

[101] Attachment EDF-7, Decl. of Jacob Gettings, Jr. at ¶¶ 17-21.

mature trees he had planted and damage to his driveway.[102] Kenneth Davis explained that he and his wife had planned to build a home on their land but have since abandoned those plans as the pipeline passes close to the area with road access and where they had installed a water line.[103] Patrick Parker described the impairment of ability to farm the land and use it for cattle during the construction process and the long-term detrimental effects that pipeline construction caused.[104] In addition to this evidence, a number of other landowners and members of impacted communities offered detailed descriptions of the harm done to them and of the difficulty of participating in the Commission process during the listening sessions held by the Commission regarding the establishment of the OPP.[105]

The Commission should not, as it has in some cases, assume that the lack of landowner protests indicates that a project will not have meaningful adverse impact on any landowners. As two Commissioners recently recognized, successful participation in a Commission proceeding requires timely compliance with the "sometimes byzantine set of rules and regulations that can make up a FERC proceeding."[106] Instead, the Commission should assume that any landowners who have not voluntarily entered into a contract, letter of intent, or similar agreement for their

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102 *Id.*, Decl. of Gregory Stout at ¶¶ 15-24.

103 *Id.*, Decl. of Kenneth Davis at ¶¶ 20-21.

104 *Id.*, Decl. of Patrick Parker at ¶¶ 14-20.

105 *The Office of Public Participation*, Docket No. AD21-9, Transcript of the 03/17/2021 Public Comment Meeting re Landowners and Communities Affected by Infrastructure Development (March 26, 2021); Transcript of the 03/22/2021 Public Participation Listening Session (April 5, 2021); Transcript of the 03/24/2021 Public Participation Listening Session (April 5, 2021); Transcript of the 03/24/2021 Public Participation Listening Session (April 6, 2021).

106 *Spire STL Pipeline LLC*, Order Dismissing Complaint, 174 FERC ¶ 61,058 (January 19, 2021) (Commissioners Glick and Clements, concurring) (internal citations omitted).

use of the land will be adversely impacted by the project against their will and should consider their interests accordingly.

There is the potential for this situation to be significantly improved by the establishment of the OPP. EDF's comments regarding the design and role of the OPP contain a number of recommendations on how the OPP can best serve impacted landowners and communities in NGA Section 7 cases, as do a number of other comments filed in that docket.[107] Robust outreach and support from the OPP could improve notice to landowners and impacted communities, understanding of the procedural steps, and ability of landowners and impacted communities to intervene and participate. In addition, the OPP should help impacted landowners and communities connect with each other, with legal and technical experts interested in assisting them, and with other intervenors. However, as the Commission has not yet acted to establish the OPP and the actual establishment of the OPP will take, at minimum, a number of months after the Commission acts, the Commission should recognize that, for applications already filed or filed within the next several years, support from the OPP for impacted landowners and communities will limited, at best, as compared to applications where a fully established OPP is able to engage from the start. Thus, the Commission should establish a policy of robust consideration of landowner interests that will be sufficient to protect landowners even in the absence of the additional protection of the OPP.

B5. Should the Commission reconsider how it addresses applications where the applicant is unable to access portions of the right-of-way? Should the Commission consider changes in how it considers environmental information gathered after an order authorizing a project is issued?

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107 *The Office of Public Participation*, Docket No. AD21-9, Comments of the Environmental Defense Fund (April 23, 2021); Comments of Public Citizen, Inc. (April 23, 2021); Comments of Earthjustice (April 23, 2021).

Yes. In particular, the Commission should use certificate conditions to ensure that the impacted landowners and communities are treated fairly during the pre-construction, construction, and post-construction period. As detailed in the affidavits attached as Attachment EDF-7, landowners often face adverse impacts at all stages of the process, including intrusions and threats of eminent domain during the pre-construction process, disturbances to their use and enjoyment of their property during the construction process, often beyond what the pipeline company had told them to expect, failures of remediation after construction is complete, and long-term damage to and loss of use of their property.[108] However, even where the pipeline company has violated its certificate conditions, landowners often find it difficult to get relief from the Commission.

For example, in a recent decision, the Commission dismissed complaints filed by a consultant to several landowners on the bases that the consultant had not clearly identified itself as a representative of those landowners and that the complaint was not timely but was rather a time-barred request for rehearing of delegated decision by Commission Staff.[109] In concurrence, two Commissioners acknowledged that there were "serious concerns about whether [the pipeline company] has adequately restored the lands affected by the construction of the pipeline" and that the decision turned on the "sometimes byzantine set of rules and regulations that can make up a FERC proceeding."[110] Indeed, only two months later, the Commission issued an order finding in response to a report by a state regulator that there were a number of remediation failures

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108 Attachment EDF-7, Decls. of Jacob Gettings, Jr., Gregory Stout, Kenneth Davis, and Partick Parker.

109 *Spire STL Pipeline LLC*, Order Dismissing Complaint, 174 FERC ¶ 61,058 (January 19, 2021).

110 *Id.* (Commissioners Glick and Clements, concurring) (internal citations omitted).

associated with the same pipeline and directing action by the pipeline company.[111] The Commission similarly found a number of serious remediation failures in the Midship case.[112]

Treatment of landowners and successful remediation could be improved by a combination of enhanced certificate conditions, improved outreach, and more robust oversight. First, the Commission should impose more detailed certificate conditions such that the applicant's obligations are clear to the applicant, to impacted landowners and communities, and to Commission Staff tasked with oversight and enforcement. These conditions will likely need to be tailored to each project and should be informed by the impacts that the project is expected to have on landowners, communities, and the natural environment. The input of impacted landowners and communities will be especially valuable in crafting these conditions; as described above, the OPP should be used as a tool to solicit such input. The Commission, as well as the OPP in seeking input, should also review past cases involving remediation failures and landowner complaints to support consideration of where enhanced certificate conditions might be most necessary. For example, the recent Spire STL and Midship orders both involved issues with topsoil remediation, suggesting that as an issue that requires heightened Commission attention.[113] This sort of review could also inform the analysis of potential adverse impacts of future pipelines. The Commission should also ensure that pipeline provides full detail on its proposed route as part of Exhibit F and F-I[114] and updates those exhibits when any changes are made to the route prior to the issuance of a certificate. Furthermore, the Commission should

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111 *Spire STL Pipeline LLC*, Order on Environmental Compliance, 174 FERC ¶ 61,219 (March 18, 2021).

112 *Midship Pipeline Co., LLC*, Order on Environmental Compliance, 174 FERC ¶ 61,220 (March 18, 2021).

113 *Id.*; *Spire STL Pipeline LLC*, Order on Environmental Compliance, 174 FERC ¶ 61,219.

114 18 C.F.R. § 157.14(6).

ensure that proposed route changes, before or after the issuance of a certificate, are subject to appropriately rigorous notice and review.

Second, Commission Staff should conduct more robust oversight and monitoring during the pre-construction, construction, and post-construction process, particularly with regard to remediation. This should include both improvements to the process of receiving and considering landowner complaints, which should be a function of the OPP, as well as an increase in proactive inspections, which could also be done by the OPP or could be a function of oversight and enforcement Staff. Inspectors should also consult directly with landowners. Finally, the Commission should build on its appropriate efforts in the recent Spire STL and Midship orders to ensure that pipeline companies are held accountable for compliance with certificate conditions and completion of appropriate remediation, including considering penalties or other appropriate remedies for egregious or repeated violations.

C6. Does the NGA, NEPA, or other federal statute authorize or mandate the use of Social Cost of Carbon (SCC) analysis by the Commission in its consideration of certificate applications? If so, how does the statute direct or authorize the Commission to use SCC? Does the statute set forth specific metrics or quantitative analyses that the Commission must or may use and/or specific findings of fact the Commission must or may make with regard to SCC analysis of a certificate application? Does the statute set forth specific remedies the Commission must or may implement based on specific SCC findings of fact?

EDF has joined comments filed by the Institute for Policy Integrity regarding the use of the Social Cost of Carbon in consideration of certificate applications and refers to those comments for its position on questions C6 through C9.

E1. Should the Commission change how it identifies potentially affected environmental justice communities? Why and if so, how? Specifically, what criteria should the Commission consider?

The Commission currently considers impacts to environmental justice communities through its NEPA review. FERC's Environmental Impact Assessments often refer to Executive Order 12898 *Federal Action to Address Environmental Justice in Minority Populations and Low-*

Income Populations, which requires federal agencies to consider if impacts on human health or the environment (including social and economic aspects) would be disproportionately high and adverse for minority and low-income populations and appreciably exceed impacts on the general population or other comparison group. While this assessment is critical, and currently done in a deficient manner as discussed immediately below, it is far from sufficient. There are other important dimensions to ensuring equitable outcomes, including an evaluation of energy access and affordability, procedural justice and democracy, and economic participation and community ownership.[115] Going forward, the Commission should invite, encourage, and enable participation in the regulatory process by environmental justice communities and consider equity in all of its regulatory decisions. The additional comments offered below are not exhaustive and the recommendations and voices of environmental justice advocates and communities should be prioritized in developing any specific reforms.

E2. Are there concerns regarding environmental justice communities' participation in past Commission proceedings? If so, what are the concerns? Please provide concrete examples.

The Commission has failed to appropriately consider the adverse impacts of projects on environmental justice communities in a number of past cases, despite participation by members of those communities and organizations representing them in the proceeding. Two particularly glaring examples are the Commission's certificate orders regarding the Rio Grande LNG facility, the Rio Bravo Pipeline, and two other adjacent LNG facilities, and regarding the Atlantic Coast Pipeline.

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115 Talia Lanckton and Subin DeVar, Initiative for Energy Justice, Justice in 100 Metrics, Tools for Measuring Equity in 100% Renewable Energy Policy Implementation (January 2021), available at https://iejusa.org/wp-content/uploads/2021/03/Justice-in-100-Metrics-2021.pdf.

With respect to the Atlantic Coast Pipeline, the Commission both failed to appropriately identify environmental justice communities and failed to sufficiently consider the impact on environmental justice communities it did identify. For example, the Commission found that a compressor station in Buckingham County, Virginia was not in or near an environmental justice community based solely on the fact that the three nearest census tracts did not qualify as minority communities, ignoring the fact that the community immediately surrounding the compressor station is a historic African-American community.[116] The Commission must ensure that its review appropriately identifies environmental justice communities, rather than relying on a single limited methodology to deny their existence. Where the Commission did identify an environmental justice community that would suffer health impacts from air emissions, it found that, because the emissions "would not exceed regulatory permittable levels," the health were not sufficiently severe to constitute a disproportionate impact.[117] This ignores the purpose of environmental justice reviews. *All* projects must comply with "regulatory permittable levels" in all areas; any project that failed to would have its permits denied or would be in violation of the law. Environmental justice review must recognize that environmental justice communities have faced and continue to face disproportionate cumulative impacts even when all individual projects are operating within "regulatory permittable levels" and must consider disproportionate impacts to environmental justice communities in that context.

With respect to the Rio Grande facility and related facilities, the Commission recognized that environmental justice communities were impacted by the projects but then conducted an analysis that turned the purpose of environmental justice reviews on its head. After

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116 *Atlantic Coast Pipeline, LLC*, Order Issuing Certificates, 161 FERC ¶ 61,042 at p. 61,266 (October 13, 2017).

117 *Id.* at p. 61,267.

acknowledging that all of the communities impacted by the project were environmental justice communities, the Commission determined that finding meant the project had no disproportionate impact on environmental justice communities, since there was no non-environmental justice community that faced a lower impact.[118] The conclusion should have been the opposite: that the fact that only environmental justice communities would be impacted by the project demonstrated an environmental justice problem. Bizarrely, the Commission's decision suggests that the safest route an applicant concerned about environmental justice review can take is to ensure the entire project is sited such that only environmental justice communities are impacted. In addition, as in the Atlantic Coast Pipeline case, the Commission found the fact that emissions would not exceed a legal limit sufficient to demonstrate that there was no disproportionate impact.[119]

These examples alone demonstrate that the Commission must reform its review of impacts on environmental justice communities. Environmental justice communities also face barriers to participation in Commission proceedings, similar to barriers faced by impacted landowners described above. Furthermore, even when they do bring their concerns to the Commission, as occurred in both the Rio Grande and Atlantic Coast cases, those concerns are often dismissed or ignored. The Commission should work with environmental justice advocates and communities, both in this proceeding and through the OPP, to reform the process in a way that meets the needs of those communities.

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118 *Rio Grande LNG, LLC*, Order Granting Authorizations Under Sections 3 and 7 of the Natural Gas Act, 169 FERC ¶ 61,131 at ¶ 98, Commissioner Glick dissenting at ¶ 7 (November 22, 2019); Order on Rehearing and Stay, 170 FERC ¶ 61,046 at ¶¶ 63-77, Commissioner Glick dissenting at ¶¶ 11-13 (January 23, 2020).

119 *Rio Grande LNG, LLC*, Order on Rehearing and Stay, 170 FERC ¶ 61,046 at ¶ 74.

IV. Conclusion

EDF respectfully recommends that the Commission modify the Certificate Policy Statement, related regulations, and its practices in conformance with recommendations provided above, as well as the recommendations in EDF's July 25, 2018 comments in this proceeding.

Dated: May 26, 2021

Respectfully submitted,

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Attachment EDF-1

UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Certification of New Interstate Natural Gas Facilities	**)** **)**	**Docket No. PL18-1-000**

AFFIDAVIT OF JAMES J. MURCHIE
on behalf of
The Environmental Defense Fund

I. Introduction

1. My name is James J. Murchie.[1] I am Co-founder and CEO of Energy Income Partners, LLC (EIP). EIP is a Registered Investment Adviser that oversees about $4.1 billion[2] of client assets. EIP advises or sub-advises seven mutual funds (five of which are New York Stock Exchange listed funds), two investment partnerships and hundreds of separately managed accounts for individuals and institutions. EIP invests all of these client assets in equity securities of publicly traded energy infrastructure companies located primarily in the U.S. with some investments in Canada and nominal investments overseas. EIP invests in companies that operate natural gas and petroleum pipelines and related storage and terminals and regulated power generation, transmission and distribution facilities, as well as developers and operators of renewable energy selling power on long term contracts. Our investment strategy seeks stable cash flows being generated by regulated assets with modest growth.

2. EIP was established in 2003 and is an outgrowth of my personal investments in energy

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[1] This Affidavit represents solely the views of James Murchie as of the submittal date. The views expressed herein address certain matters set forth in the May 26, 2021 Comments of the Environmental Defense Fund, but do not address all of the matters covered therein. No inferences should be drawn regarding the views of Mr. Murchie or Energy Income Partners, LLC, regarding any matter not specifically addressed in this Affidavit.

[2] As of March 31, 2021.

infrastructure dating back to the late 1990s. My experience includes 8 years at British Petroleum and its predecessor company the Standard Oil Company of Ohio, 5 years at the Wall Street research house Sanford C. Bernstein and 2 years at Julian Robertson's Tiger Management. EIP's original fund, started in 2003, has generated a double digit compounded annual growth rate that exceeds the returns of the S&P 500, the PHLX Utility Sector Index, the Alerian MLP Index and the NAREIT REIT Index over the same time period.[3] Such outperformance is rare; recent studies by Standard & Poor's have shown that, on average, about 94% of active fund managers have underperformed their benchmarks over the last 15 years.[4] EIP's success in achieving these returns is a result of three main factors. The first is our long-term investment horizon, the second is our focus on investing in companies with stable and predictable earnings and the third is EIP's emphasis on the track record and capabilities of the management teams that run our portfolio companies.

3. This affidavit was prepared at the request of the Environmental Defense Fund (EDF) to present the view of a successful long-term investor whose clients provide the capital that funds North America's energy infrastructure. In my experience, EDF has a deep understanding of the energy sector, and its approach is informed by evidence to develop market-based solutions, values that we share. My comments and recommendations focus on the importance of optimizing the efficient use of capital invested in natural gas pipeline infrastructure in a manner that supports system reliability while minimizing end-

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[3] Bloomberg. The references to the performance of accounts is not representative of other EIP accounts that may not have experienced the same performance described above. Past performance is no guarantee of future results.

[4] SPIVA ® U.S. Scorecard, S&P Global, Year-End 2017.

user costs and environmental impact. In my experience, optimal and efficient use of energy infrastructure is not only the best way to achieve those objectives, but also the best way to achieve superior returns on capital invested in that infrastructure.

4. I am attaching the following exhibit to my affidavit:

- Exhibit JJM-01: July 12, 2018 Testimony of James J. Murchie Before the U.S. Senate Committee on Energy and Natural Resources Regarding Natural Gas Pipeline Development

II. Summary of Recommendations

5. The Federal Energy Regulatory Commission's ("Commission") February 18, 2021 Notice of Inquiry ("Notice of Inquiry")[5] seeks input on whether, and if so how, the Commission should revise the currently effective policy statement on the certification of new interstate natural gas transportation facilities (Policy Statement). I believe this inquiry is an appropriate venue to consider pipeline economic incentives and regulatory compensatory structures and have three specific observations from the perspective of a seasoned energy infrastructure investor:

6. The first is that among the greatest risks associated with investing in any form of infrastructure are redundancy and obsolescence. Historically, this risk was addressed by sustained growth in both supply and demand for gas as well as a regulatory regime where rewards were based on costs incurred rather than value created. Today, rising development costs, slowing growth in new shale supplies, and public opposition have elevated the risk of financial impairment, as reflected in the over $5 billion write-off of a recently canceled gas pipeline project in Appalachia. There is a risk that investor capital

[5] *Certification of New Interstate Natural Gas Facilities*, Notice of Inquiry, 174 FERC ¶ 61,125 (2021).

dedicated to other Commission certificated projects that currently lack necessary state and federal permits will face a similar fate.

7. Less than fulsome use of a capital asset drives lower investment returns, write-off of project development costs, or both. *It can also drive higher customer rates with no attendant benefit.* Conversely, well-crafted incentives that recognize the value created by, not just the costs incurred for, new investment would likely drive more efficient use of incumbent infrastructure, lower costs to consumers, reduced environmental impact, and reduced risk of redundancy, yet still reward the private capital provided by investors.

8. My second observation is that while the need to build new large-scale pipeline infrastructure may have waned, the industry's need to access capital on favorable economic terms has not. Ongoing investment is needed to address safety and reliability and to address issues such as fugitive methane emissions. A regulatory regime that lowers the cost of financing this capital benefits consumers who ultimately bear the cost of these needed investments. The core utility regulatory construct should be preserved to maintain capital access on affordable terms.

9. My third observation is that to align the interests of the public, ratepayers and investors, returns should be permitted to vary from the Base ROE to provide incentives for companies to perform better in terms of cost, reliability, safety and environmental impact. The current ROE methodology descends from a long line of legislative, judicial and regulatory guidance intended to incentivize new investment. While this remains a central reason for providing a just and reasonable return, the increased complexity of the energy delivery system, the new demands being placed on that system by state-level initiatives, rapid growth of renewable and natural gas generation (and the attendant need for

increased coordination), and growing demand for reduced environmental impact calls for a more flexible approach to incentivizing energy delivery solutions other than simply putting more steel in the ground. At the state level, going back decades, electric and natural gas utilities have been rewarded for investing in conservation if that conservation is a cheaper alternative to new capacity. Likewise, there may be opportunities for pipelines to utilize existing infrastructure more efficiently, providing better investor returns without simply adding new capacity, thereby lowering costs to customers and mitigating environmental impact. The product that pipeline utilities should provide is more than just the delivery of energy, it is the delivery of safe, reliable, clean and low-cost energy. The ROEs allowed should not only reflect these public benefits but should further incentivize and reward the companies who best deliver them above a baseline of average performance, while penalizing those that fall short.

III. Historical Context and Investor Perspective

10. The natural gas industry, once underpinned by sustainable growth, today faces a different sustainability challenge that requires adaptation of the business model to meet changing end-user needs as well as pressing social, environmental and economic issues. The U.S. natural gas system is responding to many of these needs as evidenced by its critical supporting role in facilitating significant penetration of renewable energy in the U.S., without the attendant harsh economic penalties imposed by the same transition in some European nations.

11. What is lacking is an alignment of desired outcomes (e.g. renewable balancing, fugitive methane abatement and reduced environmental impact, lowering costs to end-use

consumers) with a regulatory framework that appropriately compensates gas pipeline companies, protects consumers, and attracts investor capital.

12. My perspective on capital formation, pricing, and allowed ROEs for utility businesses is informed by the history of utility regulation as detailed in my July 12, 2018 testimony before the Senate Committee on Energy and Natural Resources, provided as Exhibit JJM-01 to my affidavit.

13. Natural monopolies are a rarity and somewhat of an anomaly in classical economics, but their existence was made evident during the railroad boom in the middle of the 19th century. During that time Charles Francis Adams Jr., the grandson of John Quincy Adams, head of the Massachusetts Railroad Commission (and later the Union Pacific Railroad) observed that the railroad industry was a natural monopoly where "competition and the cheapest possible transportation are wholly incompatible" and that "the cheapest possible transportation [results from] the largest possible volume of movement through the fewest possible channels."[6]

14. Subsequently, regulatory constructs evolved at the state and federal levels to provide the power of eminent domain and a "just and reasonable return" on privately sourced energy infrastructure capital in exchange for limited competition, an obligation to serve, open access, reliability and safety. Regulators are charged with approving new capital investment upon a determination that these conditions have been met and that an investment's public benefits exceed the public's costs.

15. The downside of the utility model, as history has demonstrated, is the moral hazard that

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[6] Prophets of Regulation: Charles Francis Adams; Louis Brandeis; James M. Landis; Alfred E. Kahn, by Thomas K. McCraw, 1984, Harvard University Press.

comes from a return on investment to a private enterprise that may view that allowed return as a *guarantee*. These hazards have included over-leverage, cost inflation and forays into highly risky businesses because of the comfort provided by the base business being perceived by management as guaranteed. The challenge for society is to reap the benefits of the privately funded regulated monopoly business model while avoiding the accompanying hazards.

16. Despite this moral hazard, the investor-owned utility has proven the superior model relative to the alternative of government ownership as can be seen in today's critical lack of capital available for publicly owned civil infrastructure in the United States. But this is not to say that regulation cannot be improved by blending the benefits of competition in terms of operating efficiency while retaining the characteristics that lower the cost of financing by reducing investor risk. As articulated by Alfred E. Kahn:

> Merely permitting all regulated companies as a matter of course to earn rates of return in excess of the cost of capital does not supply the answer; there has to be some means of seeing to it that those…returns are earned, some means, for example, of identifying the companies that have been unusually enterprising or efficient and offering higher profits to them while denying them to others.[7]

I will further address this concept in Section IV.

17. Perhaps the most important concept that emerges in separating the cost of equity from allowed ROE is that regulators can use this spread as a tool to achieve policy goals:

> Many in the regulatory community appear to believe that the utility's rate of return is the sole value driver, and that rates of return are set at the cost of equity. Neither of these perceptions is correct. Instead, the financial "value engine" – the difference between a utility's return on investment and its cost of capital – drives shareholder returns. Regulators should use this value engine to align utilities' financial motivations with delivering value to customers and society. They can offer utilities and regulated pipelines opportunities to earn increased revenues when they provide value-based products and

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[7] The Economics of Regulation, Alfred E. Kahn, 1988, MIT Press.

services. Regulators can also influence utilities' cost of capital by taking actions that increase the predictability of returns on valuable investments.[8]

I next turn to aligning financial motivations with delivering value to customers and society.

IV. Aligning Incentives with Desired Outcomes

18. Our nation's energy system is undergoing profound change. The prominent role of natural gas in power generation initially stemmed from to its lower cost resulting from shale drilling, but is today increasingly reflective of the critical role gas plays in balancing the intermittency of renewables. As a result, the electricity and natural gas systems are becoming ever more interdependent, as was amply demonstrated by the loss of electricity service in California in August of 2020 and more recently in Texas during the extreme winter events of February 2021. This interdependency calls for a more synchronized coordination between the gas transportation and power generation segments of the business that operate under different regulatory constructs. The growth in the use of intermittent renewables, battery storage, and the emergence of a more distributed model are also driving significant changes. These are just a few of the technological changes occurring at a time when the public is demanding a lower cost, more resilient energy system with less environmental impact.

19. Traditional cost-of-service regulation (COSR) has provided a return sufficient to finance and build essential pipeline and utility infrastructure, but it offers few incentives to achieve higher levels of reliability and safety and lower levels of cost and environmental

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8 "You Get What You Pay For: Moving Toward Value in Utility Compensation – Part 2 Regulatory Alternatives" Dan Aas and Michael O'Boyle. America's Power Plan, Energy Innovation and U.C. Berkeley, https://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf..

impact being demanded today:

> This regulatory model works reasonably well to align utility motivation with public interest when rapid system build-out is the top goal for policy makers. In fact, without a rate of return above the cost of equity for utilities, the system would stagnate – no activities would be profitable. But when capital-based solutions are not preferred, or new technology creates room for competition, COSR may create a disconnect between utility shareholder value and outcomes that most benefit society.[9]

20. The impetus for restructuring of electric generation was a series of events that led to cost overruns for new power plants at a time of lower demand that drove up customer prices to levels that were uncompetitive with non-utility independent alternatives. While restructuring did lower the cost of wholesale electricity by introducing competition, a significant portion of those savings were then offset by a substantially higher cost of equity and debt financing as markets correctly perceived greater risk to these assets in a competitive versus a regulated construct. By some estimates, the cost of capital for merchant power producers is about twice the levels of regulated utilities.

21. Of course, power generation does not exhibit the same natural monopoly characteristics as transmission infrastructure, but many parts of the natural gas transmission network have sufficient alternative routes to be deemed competitive. While still operating with regulatory oversight, arms-length agreements ("black-box settlements") between shippers and pipeline operators have generally been approved with a wide range of resulting returns on equity.

22. In the non-competitive markets, however, the challenge is to incentivize efficiency without risking cash flow stability and undermining those efficiencies with a higher cost of equity and debt financing. Even if competition could be introduced, it is not clear that

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[9] *Id.*

competitive markets would provide greater reliability and safety and lower environmental impact. For this reason, many state regulators have developed "patches" to the competitive markets to incentivize ample capacity, supply diversity and carbon-free generation. Of course, the inability of any competitive market to deal with externalities is not new and drives a wide range of regulation across many industries. For natural monopolies, cost of service regulation can broadly penalize negative externalities such as environmental impact, inattention to safety, or inadequate storm recovery, but it cannot specifically target performance differences in these negative externalities among utility companies nor reward positive externalities such as reliability and capital and operational efficiency. The Connecticut Public Utility Regulatory Authority's recent order directing a reduction in allowed utility ROE stems from inadequate storm preparedness and response, but it also opens the door to the identification of outcomes (e.g. better storm preparedness) tied to financial incentives to reward desired behavior.[10] In a separate natural gas local distribution utility company (LDC) rate proceeding approving a performance-based ratemaking model, the Massachusetts Department of Public Utilities determined that "…the LDC industry is rapidly changing and that a PBR plan is the appropriate ratemaking model to allow the Company to adapt to this change."[11]

23. Incentive ratemaking providing higher equity returns for better performance in reliability, safety, cost efficiency and environmental impact would impart the benefits of competition and accounting of externalities while preserving the lower cost of financing

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[10] *Investigation into Electric Distribution Companies' Preparation For and Response to Tropical Storm Isaias*, Conn. PURA Docket No. 20-08-03, Decision (April 28, 2021).

[11] *NSTAR Gas Company d/b/a Eversource Energy*, Mass. DPU Docket No. 19-120, Order Approving a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism (October 30, 2020).

owing to lower risk and stable cash flows that are lacking in a purely competitive construct.

24. An incentive approach, for example, could be applied to the challenge of better allocating contracted but unused capacity in interstate pipelines when merchant power generators have a higher short-term willingness to pay for that capacity. I would caution against any changes that would be viewed by the capital markets as tantamount to converting a regulated utility into a trading/cyclical merchant business with a correspondingly higher cost of equity and debt financing. As this Commission is aware, allowing some competitive precepts into a COSR marketplace, can and does foster more efficient allocation of capital serving the interests market participants, investors and public welfare.[12]

25. Incentivizing higher utilization of existing assets by such methods might reduce the need for new pipelines, improving the capital efficiency of the entire network and reducing externalities such as environmental impact. Sharing some of those benefits with the pipeline company in the form of a higher allowed ROE would stimulate more efficient use of the assets without raising the cost of equity and debt financing. As an investor, I believe pipeline companies should be working to improve efficiency of existing assets. Building unnecessary pipelines exposes investors to risks of inferior returns on capital,

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[12] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs. ¶ 30,939 (1992) (the Commission's primary aim in issuing Order No. 636 was "to improve the competitive structure of the natural gas industry"); *Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy*, 88 FERC ¶ 61,227 at p. 61,743 (1999) (in issuing the 1999 Certificate Policy Statement, the Commission explained that an effective certificate policy "should further the goals and objectives of the Commission's natural gas regulatory policies" and "should be designed to foster competitive markets.").

write-offs, or both.

26. An important starting place could be FERC's 1996 Incentive Ratemaking Policy Statement.[13] That policy stated:

> Where companies have market power, market-based rates are not appropriate. However, in order to enhance productive efficiency in non-competitive markets, the Commission will allow utilities to propose incentive rate mechanisms as alternatives to traditional cost-of-service regulation. Such proposals should result in lower rates to consumers and provide utilities the opportunity to earn higher returns.[14]

Although certain updates may be needed to that policy, its observation that "ratemaking flexibility would permit pipelines to tailor natural gas transportation rates for electric generators to meet the swings in gas consumption often experienced by such generators"[15] can help inform the challenges faced by the Commission today in this evolving regulatory environment.

V. Conclusion

27. The nation's natural gas pipeline infrastructure and regulatory policy are rooted in the context of development and capital investment driven by a need to reliably and affordably meet growing demand for natural gas as a heating and industrial fuel. Today, electricity generation has become the largest end-use of natural gas, and the nation's gas and power systems have become highly intertwined and interdependent. Expanding deployment of renewable wind and solar resources may diminish natural gas usage over time, but not necessarily the need for the capacity to transport that gas, as peak levels of demand may be higher in the future than today as the natural gas and pipeline

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[13] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines (1996 Incentive Ratemaking Policy Statement),* 74 FERC ¶ 61,076 (1996).

[14] *Id.* at p. 61,237.

[15] *Id.* at p. 61,226.

infrastructure's role in balancing renewable intermittency grows.

28. Infrastructure of any kind achieves greatest cost and capital efficiency when utilized to its optimal potential. Underutilization of any capital asset drives up its cost on a per-unit basis, wastes capital, drives higher costs to end-users, and can contribute needless negative environmental and social externalities. Investor, consumer, and social interest are aligned when an infrastructure system is optimally sized and utilized. The companies regulated by the Commission today face a changing energy landscape in which future profitability will derive more from optimal use of what is already built—and attendant identification of new revenue opportunities—than from simply putting new steel in the ground as was done in the past.

29. Better alignment of interests among pipeline and utility shareholders, regulated energy infrastructure companies and their many stakeholders can be achieved with a regulatory system that incentivizes monopolies toward the efficiency of a competitive business while retaining the lower cost of equity and debt financing attendant to stable cash flows and lower market risk embodied in the regulatory construct to ultimately serve the public with safe, reliable, low-cost energy with the least environmental impact. In such a system the utilities that provide the most public benefits will enjoy better returns on invested capital at a lower cost of debt and equity financing. Capital would then flow to those companies creating the most value for all stakeholders and away from those that create the least. The certification process for *new* pipeline capacity is an appropriate venue to address the economic incentives that drive use of *existing* capacity.

UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Certification of New Interstate Natural Gas Facilities	**)** **)**	**Docket No. PL18-1-000**

I, James J. Murchie, declare under penalty of perjury that I am the author of the foregoing Affidavit and that the facts set forth herein are true and correct to the best of my knowledge.

/s/ James J. Murchie
James J. Murchie
Chief Executive Office
Energy Income Partners, LLC

TESTIMONY OF
JAMES J. MURCHIE
CEO AND CO-FOUNDER
ENERGY INCOME PARTNERS, LLC

BEFORE THE
U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

REGARDING
NATURAL GAS PIPELINE DEVELOPMENT

JULY 12, 2018

Madam Chair and Members of the Committee:

My name is Jim Murchie. I am Co-founder and CEO of Energy Income Partners, LLC or EIP for short. EIP is a Registered Investment Adviser that oversees about $6 billion[1] of client assets. EIP advises or sub-advises six mutual funds (five of which are New York Stock Exchange listed funds), two investment partnerships and hundreds of separately managed accounts for individuals and institutions. EIP invests all of these client assets in equity securities of publicly traded energy infrastructure companies located primarily in the U.S. with significant investments in Canada and nominal investments overseas. EIP invests in companies that operate natural gas and petroleum pipelines and related storage and terminals, regulated power generation, transmission and distribution as well as developers and operators of renewable energy selling power on long term contracts. Our investment strategy seeks stable cash flows being generated by regulated assets with modest growth.

EIP was established in 2003 and is an outgrowth of my personal investments in energy infrastructure dating back to the late 1990s. My firm and I appreciate the opportunity to present testimony to the Committee today.

I am joined here today by my colleague Sam Brothwell. The investment team at EIP is comprised of six individuals, including myself and Sam; we all have extensive energy and financial industry experience. My own experience includes 8 years at British Petroleum and its predecessor company the Standard Oil Company of Ohio, 5 years at the well-known Wall Street research house Sanford C. Bernstein and 2 years at Julian Robertson's Tiger Management. Sam

[1] As of June 30,2018

has worked in the industry at Public Service of New Mexico and Questar as well as on Wall Street at Merrill Lynch and Wells Fargo and has testified before the Federal Energy Regulatory Commission on pipeline ratemaking policy.

EIP's original fund which started in 2003 has generated a double digit compounded annual growth rate that exceeds the returns of the S&P 500, the PHLX Utility Sector Index, the Alerian MLP Index and the NAREIT REIT Index over the same time period.[2] Such outperformance is rare as recent studies by Standard & Poor's have shown that, on average, about 94% of active fund managers have underperformed their benchmarks over the last 15 years.[3] We believe EIP's success in achieving these returns is a result of three main factors. The first is our long-term investment horizon, the second is our focus on investing in companies with stable and predictable earnings and the third is that EIP does not adhere to the typical asset allocation guardrails imposed on most money managers by institutional investors that would pigeonhole us into being either a "utility" manager or an "MLP" manager.

One of the tenets of EIP's approach is a focus on total or absolute investment returns rather than returns relative to index benchmarks. In assessing both past and forecasted returns, we disaggregate the portion of the investment return contributed by dividend yield from the portion of the return contributed by share price appreciation. Separating these two components is critical to understanding how we invest and what factors we seek in our portfolio companies to maximize our returns. The yield component of our returns is about 6%, the balance has come from appreciation of the underlying share prices.

While share prices fluctuate daily, the long-term driver of share price appreciation is growth in per-share earnings and dividends. For investment managers with a short investment horizon, these fluctuations are far more important to their strategy and approach. Since those short-term fluctuations are caused so often by transient factors in the news for the economy, an industry or a particular company, it is those short-term factors that most investment managers focus on. Watching most portfolio managers speak on television business programs provides a good window into this investing style.

The higher yield of our portfolio over time versus the stock market averages (the yield on the S&P 500 is currently 1.9%[4]) is mostly a result of a higher dividend payout ratio, which is the portion of a company's earnings paid to its shareholders each quarter. Higher payout ratios tend to be found in companies with more stable earnings and in slower-growing mature industries. Stability of earnings matter because dividends are viewed by investors a little like the coupon payment of a bond. A dividend cut is a broken promise and often indicates more serious problems at a company. As a result, company boards of directors strive to set dividends at a level they will never have to cut. The more stable the earnings, the higher the payout ratio can

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[2] Source: Bloomberg. The references to the performance of account is not representative of other EIP accounts that may not have experienced the same performance described above. Past performance is no guarantee of future results.

[3] Source: SPIVA ® U.S. Scorecard, S&P Global, Year-End 2017.

[4] Source: Bloomberg. Data as of July 3, 2018.

be. Slower growing industries also tend to have higher payout ratios because there are fewer growth opportunities requiring reinvestment of earnings.

We believe that pipelines and related storage as well as certain electric and natural gas utilities possess both of these attributes. Energy is a mature business (U.S. primary energy demand grows less than 1% per year[5]) and these businesses tend to operate under federal or state jurisdiction that earn allowed rates of return on their invested capital.[6] That means that they are less subject to the cycles of the economy, commodity prices or changes in the rate of inflation. Businesses that have these allowed rates of return are often referred to as Regulatory Asset Base businesses or RAB for short.

In the early history of the electric and natural gas industries, these regulated asset base businesses represented an alternative to public ownership. Today, the vast majority of electric and natural gas transportation infrastructure in the United States is owned by publicly traded corporations and publicly traded partnerships. By contrast, over 85% of water and sewer infrastructure is owned by municipalities and special government districts.[7] That U.S. energy consumers enjoy some of the lowest electricity and natural gas rates in the OECD is partially the result of an abundance of available capital to build and maintain energy infrastructure at reasonable cost, in our view. Again, by contrast, many municipal water systems are today reaching the end of their useful life and are increasingly being sold to investor-owned publicly traded utilities that can access the capital needed to modernize their pipes and related equipment without unduly increasing rates charged to consumers. Infrastructure assets have long—but not infinite—lives, and over time face stricter safety and environmental standards as well as ongoing technological evolution in the sources and uses of the products they transport that require constant reinvestment.

This RAB model in the U.S. traces its history back to a famous speech given by Sam Insull at the June 1898 (that's **eighteen**-ninety-eight) meeting of the National Electric Light Association, the forerunner of today's Edison Electric Institute. Insull had left the General Edison Electric Company (now General Electric) as Thomas Edison's right-hand man to head up what became Commonwealth Edison in Chicago. He was arguing for a regulated investor-owned utility framework that would benefit all stakeholders, including the customers buying the electricity during a time when the electric industry was in its "Wild West" infancy. Here's the essence of his message:

"Acute competition necessarily frightens the investor, and compels corporations to pay a very high price for capital….The best service at the lowest possible price can only be obtained….by exclusive control of a given territory being placed in the hands of one undertaking…..The more certain this protection is made, the lower the rate of interest and the lower the total cost of

[5] Sources: BP Statistical Review of World Energy: June 2018; U.S. Energy Information Administration (EIA)
[6] Sources: BP Statistical Review of World Energy: June 2018; U.S. Energy Information Administration (EIA).
[7] Source: American Water Investor Presentation: June 2018.

operation will be, and consequently the lower the price of the service to public and private users."[8]

Recognizing that regulation has since evolved to bring the benefits of competition to utility consumers, the essence of Insull's message remains as relevant today as it was 120 years ago; *that risk and cost of capital are highly correlated*. The regulatory framework under which pipelines and utilities operate reduces risk, takes advantage of scale, and is critical to achieving reliable, low cost service to customers, while providing reasonable and competitive returns to investors. The regulatory model articulated by Insull has resulted in an extensive U.S. energy infrastructure system that provides abundant energy to businesses and consumers at prices that are among the lowest in the developed world.[9]

The yield component of EIP's returns for its clients is a direct result of a regulatory framework that provides stable and more predictable earnings that allows for a payout ratio well above that for other industries or the stock market as a whole. As most of the investors in our funds and other investment products are individuals, this higher yield is a critical component of the investment return they are seeking.

Nonetheless, the growth component has been a larger contributor to our returns. At first glance it seems incongruous to have enjoyed growth in earnings and dividends from an industry whose unit demand grows at less than 1%.[10] There are two factors that explain the difference. The first is that unit demand growth of about 1% might still result in sales growth of 2-4% depending on the rate of inflation. This matches the average dividend growth over the last 15 years for the utility and MLP indices of about 4%.[11] The second factor is our successful stock selection as we have been able to identify companies with higher than average growth rates.

In assessing our own track record, we have found that higher growth rates result from our ability to select companies with good management teams operating under consistent and balanced regulation. If we can get these two parts right, a third component kicks in, which is a lowering of the company's cost of debt and equity financing also referenced in Insull's 1898 speech.

While we analyze financial statements and valuation like all other fund managers, our extreme focus on the quality of management is unusual among investment managers but consistent with our long-term approach. It is the management teams that determine where their competitive advantages lie and how to best allocate capital. It is the management teams that work with the regulators at the state and federal levels. It is the management teams that hire and retain the best employees. It is the management teams that determine the safety and environmental record of the company. All these activities determine a company's ability to deliver energy to its customers in

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[8] Source: Insull, Samuel. "Standardization, Cost System of Rates, and Public Control" (1898). Reprinted in S. Insull, Central-Station Electric Service, 34–47. Chicago: Privately Printed, 1915.

[9] Based on electricity pricing data sourced from U.S. Energy Information Administration as of December 2017 and the European residential electricity prices sourced from Eurostat as of December 2017.

[10] BP Statistical Review of World Energy: June 2018; U.S. Energy Information Administration (EIA).

[11] Source: Bloomberg. MLPS are represented by the Alerian MLP Index. Utilities are represented by the PHLX Utility Sector Index.

an economical, safe, reliable and responsible manner. Companies that consistently do this well over time tend to have superior shareholder returns. Companies that give short shrift to issues of worker safety, system reliability and environmental stewardship also tend to be poor allocators of capital, have higher operating costs and usually have poor relationships with regulators and other stakeholders. They also tend to have lower shareholder returns.

Just as the quality of management teams varies, so does the tenor of regulation, so all else equal, we seek the best regulatory constructs that we can find. One recent success is reflected in a portfolio shift we made several years ago to increase our weighting in state-regulated natural gas utilities also known as Local Distribution Companies or LDCs.

The leak and tragic explosion of a natural gas utility pipeline in San Bruno, California in 2010 and a similar incident in New York City in 2014 led many state regulators to encourage the accelerated replacement of old pipe through the use of incentives and rate tracking mechanisms that added regulatory certainty, facilitating a step change in the pace of investment. This, in turn, has driven improved worker and public safety, system reliability and perhaps even a reduction in fugitive releases of methane, a potent greenhouse gas. Shareholders also benefitted from lower regulatory risk and higher rates of earnings and dividend growth, and as those higher growth rates were recognized in the market, these stocks traded at higher valuations. Those higher valuations reduce the cost of equity just as a higher credit rating lowers the cost of debt. Lower capital costs benefit consumers, who ultimately bear the cost of utility financing.

The case of accelerated pipe replacement for LDCs and the regulatory structures that enabled them at the state level are a great example of the Regulatory Asset Base regulated model working for all stakeholders.

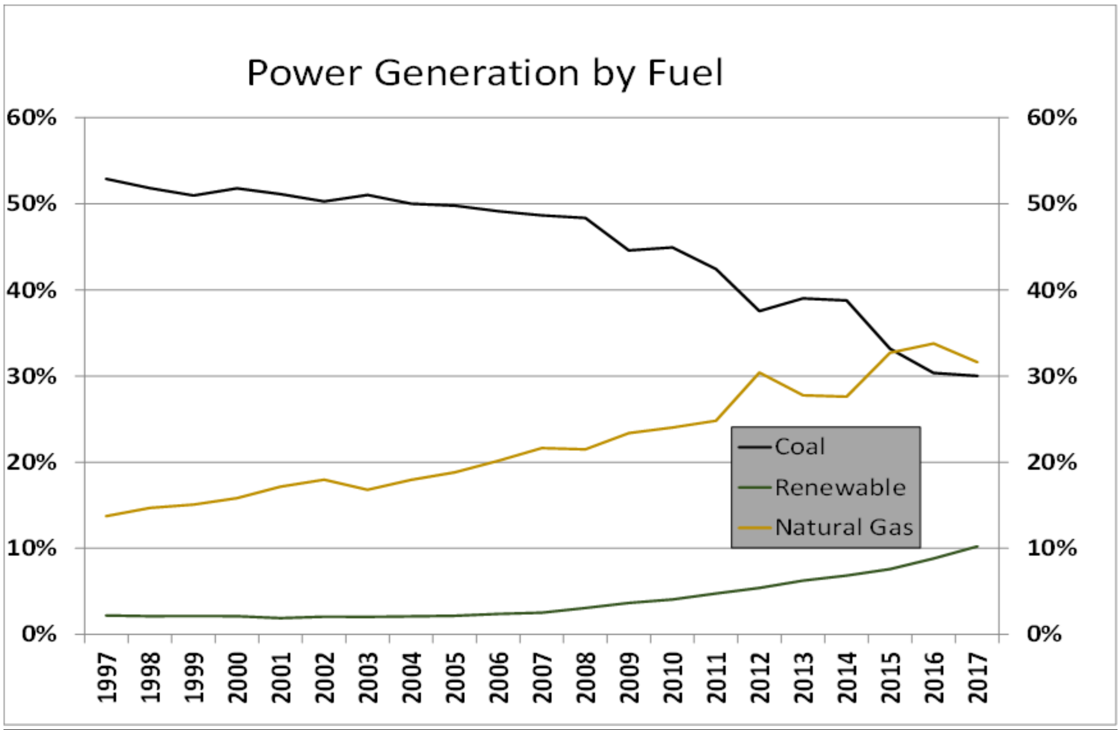
I once met a financial adviser who derided regulation as “a lot of red tape.” My response was that so-called “red tape” consists of extensive public hearings, the consideration of all relevant testimony by regulators and oversight by an independent judiciary that insures that regulatory decisions have considered all the evidence and are arrived at by reasoned judgment and are therefore neither arbitrary nor capricious. This process, *so long as it follows established law and procedures*, protects all stakeholders including customers, the environment, as well as investors.

The 120-year history of these industries is also one of technological advancements that have driven lower costs, better worker and public safety, increased reliability and lower emissions of pollutants of all kinds. That holds true today as technological advances continue improving the performance and cost-effectiveness of renewable energy resources such as wind, solar, and energy storage the costs of which have declined about 70% over the last 8 years and have emerged as the most cost-effective source of new supply in many regions of the U.S.

Increased use of renewables, however, has actually been facilitated by another technological advancement: shale gas. The dramatically lower cost of natural gas has shifted electricity generation away from coal in favor of natural gas and increasingly, renewables. Contrary to the public debate pitting fossil fuels against renewables, natural gas and renewables actually complement each other because of the intermittent and variable output of wind and solar and the flexibility of gas-fired generation to respond quickly to the rapid changes in output from wind and solar that coal and nuclear generation lack. As battery costs decline, more of this back up function can be borne by storage of electricity in the future. But cleaner generation of electricity is *happening now* in large part because of the availability of cheap natural gas.

The graph in Exhibit 1 shows how electricity generated by natural gas and renewables has grown while generation from coal has declined. These changes have led to a 13.2%[12] decline in U.S. CO_2 emissions since their peak in 2005. Emission of other pollutants such as sulfur dioxide, nitrous oxides and mercury are also lower.[13]

<u>Exhibit 1 – Electricity Generation: Coal, Natural Gas and Renewables</u>



Sources: U.S. Energy Information Administration, Electric Power Monthly, February 2018.

Germany, by contrast, embarked on a bold strategy which accelerated in 2011 with Fukishima to eliminate nuclear power and fully embrace renewable wind and solar. While on a path to achievement, this initiative came at great cost to the country's electricity consumers as German residential electricity prices have risen nearly 45% in the past decade. Retail customers in Germany today pay about 35 cents per kilowatt hour vs around 13 cents in the U.S. and 22 cents for the rest of Europe.[14] Germany's initiative has had another almost surely unintended consequence; lacking access to abundant and reliable sources of natural gas as a back-up fuel for renewables, Germany continues to rely on lignite, a domestic but environmentally hostile fuel.

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[12]Source: BP Statistical Review of World Energy: June 2018
[13] Source: US Environmental Protection Agency Website
[14] Eurostat, UBS Research, U.S. Energy Information Administration Electric Power Monthly, December 2017.

Since these goals were laid out in 2011, Germany's CO_2 emissions have actually increased by 0.4% while over this same time frame the U.S. has lowered its CO_2 emissions by 5.3%.[15]

It is in this context that we view the debate about the Greenhouse gas (GHG) impact of permitting new natural gas pipelines. To be direct, we view the debate as a false choice. When regulators and the courts are asked to address the impact of a particular new natural gas pipeline on GHGs, the discussion centers around considering the impact upstream of the pipeline (more natural gas production) and downstream of the pipeline (more natural gas usage). Missing from the discussion, in our view, is recognition that natural gas pipeline infrastructure enables natural gas to reduce coal usage, reducing power plant emissions of all kinds, including CO_2 and further facilitates adding more renewables to the mix.

From a portfolio management perspective, we see uncertainty surrounding pipeline certification and approval as a growing risk that we must factor into how and where we allocate our investor's capital. These risks affect primarily the growth component of our returns but in the rare case of an existing pipeline being shut down, the impact could also affect the dividend payments of the company that owns that pipeline.

Perhaps more important than any changes we would make to the EIP portfolios are fund redemptions by investors as they see the cancellation of new pipeline projects due to objections by regulators as well as some of the recent rulings by FERC as risks that outweigh the rewards of a 6% portfolio yield. We believe that this flight of capital from the equity securities of companies that own federally regulated pipelines has had a negative effect on valuation and therefore a negative effect on the cost of capital for building new pipelines which is ultimately paid for by consumers.

As investors in a capital-intensive commodity industry we recognize that lower costs ultimately win out. And in our analysis, we include the costs of externalities like pollution and safety because under our system of government the cost of those externalities are eventually paid for by those who cause them. *In short, we want to own the low-cost way of shipping the lowest-cost form of energy.*

While natural gas pipelines are a significant part of our portfolio, so too are operators and developers of low cost renewable power, including a growing number of utilities that recognize the opportunity in aligning their strategy with the direction of public policy. In the future we expect to have a significant investment in companies providing infrastructure for electric vehicles as we see them as eventually being the low-cost, higher performance means of transportation.

We believe our investment success in the future will be directly impacted by policy makers' and regulators' ability to use our existing regulatory construct to facilitate rather than frustrate the increased adoption of these new technologies that improve the reliability, cost, safety and environmental impact of our domestic energy system. Because adoption of these new

[15] Source: BP Statistical Review of World Energy: June 2018

technologies cuts across industries and therefore the mandate of the relevant regulatory agencies, there is an important role to play for policy makers as well as regulators.

Our investors have benefitted from great management teams operating essential businesses under a consistent rule of law administered by regulation that balances consumer and investor interests to the benefit of all. We will continue to manage the allocation of the capital we are entrusted with to seek fair returns and minimize risk by investing in well-run companies operating under the guidance of balanced, reasoned and predictable regulation.

This concludes my testimony. Thank you for the opportunity to share my Firm's views on these very important issues.

(12) Exhibit I — Market data. A system-wide estimate of the volumes of gas to be delivered to each delivery point operator's aggregated delivery locations during each of the first 3 full years of operation of the proposed service, sale, or facilities and like data during the years when the proposed facilities are under construction, and actual data of like ~~import~~ character for each of the 3 years ~~next~~ preceding the filing of the application, together with:

(i) Names ~~and locations~~ of customer companies and municipalities and the counties where applicant makes deliveries to those entities, plus ~~showing~~ the number of residential, commercial, firm industrial, interruptible industrial, residential space-heating, commercial space-heating, and other types of customers for each distribution system served and to be served ~~at retail or wholesale~~; and the names and locations of each firm and interruptible direct industrial customer whose estimated consumption totals 10,000 Mcf or more in any calendar month or 100,000 Mcf or more per year together with an explanation of the end use to which each of these industrial customers have and will put the gas.

(ii) Applicant's total annual and peak day gas requirements by delivery point operator ~~classification of service in paragraph (a)(11)(i) of this section, divided as follows: Gas requirements for each distribution area where gas is sold by applicant at retail; for each wholesale customer; for all main line direct industrial customers;~~ and company use and unaccounted-for gas, for both the applicant and each delivery point operator (excluding interstate natural gas company operators and intrastate pipeline operators)~~wholesale customer~~.

(iii) Total ~~past and expected~~ curtailments of service in the prior 3 years by the applicant and each wholesale customer proposing to receive new or additional supplies of gas from the project, all to be listed by ~~the classifications of service in paragraph (a)(12)(i) of this section~~delivery point operator.

(iv) Explanation and derivation of basic factors used in estimating future requirements, including, for example: Peak-day and annual ~~degree-day~~deliveries ~~deficiencies~~, annual load factors of applicant's system and of its deliveries to its proposed customers; individual consumer peak-day and annual consumption ~~factors~~ for each ~~class of consumers~~delivery point operator, peak-day and annual consumption by gas-fired generators receiving service from applicant's customer companies and municipalities all with supporting historical data; forecasted saturation of gas-fired space-heating as related to past experience; and full detail as to all non-geologic ~~other~~ production sources of gas supply available to applicant's system and to each of its ~~customers~~delivery point operators, including ~~manufacturing facilities~~biologically sourced gas, hydrogen, LNG, ~~,~~ and liquid petroleum gas.

(v) Conformed copy of each contract, letter of intent or other agreement for sale or transportation of natural gas proposed by the application. Indicate the rate to be charged. If no agreements have been made, indicate the basis for assuming that contracts will be consummated and that service will be rendered under the terms contemplated in the application. When one or more contracts, letters of intent or other agreements for sale or transportation of natural gas proposed by the application is with an affiliate of applicant~~,~~ and such affiliate is a state regulated delivery point operator, provide evidence that the applicable state regulator has approved the proposed contract, letter of intent or other agreement for sale or transportation of natural gas proposed by the application; or, that such affiliate has conducted a competitive RFP process with proposals for service to such affiliate in the quantity(ies) proposed in the application prior to selection by the of service from the applicant.

(vi) A full description of all facilities, other than those covered by the application, necessary to provide service ~~in the communities~~ to the customers to be served, the estimated cost of such facilities, by whom they are to be constructed, and evidence of economic feasibility.

(vii) A copy of each market survey made by applicant or applicant's proposed customer(s) within the past three years for such markets as are to receive new or increased service from the project applied for.

(viii) A statement showing the franchise rights of applicant or other person to distribute gas in each community ~~in~~ to which service is proposed.

~~**(ix)** When an application requires a statement of total peak-day or annual market requirements of affiliates, whose operations are integrated with those of applicant, to demonstrate applicant's ability to provide the service proposed or to establish a gas supply, estimates and data required by this paragraph (a)(12)(ix) shall also be stated in like detail for such affiliates.~~

~~**(x)** When the proposed project is for service which would not decrease the life index of the total system gas supply by more than one year, the data required in paragraphs (a)(12)(i) to (ix), inclusive, of this section need be submitted only as to the particular market to receive new or additional service.~~

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Columbia Gas Transmission, LLC) Docket No. RP20-___-000

Summary of Prepared Direct Testimony of
Alexander Kirk
on behalf of Columbia Gas Transmission, LLC

Mr. Alexander Kirk is a Vice President of Brown, Williams, Moorhead & Quinn, Inc. and advises and assists energy industry clients on matters relating to natural gas supply and demand, rate design and cost of service modeling, and economic life determinations for natural gas pipelines. The purpose of Mr. Kirk's testimony is to present an analysis of the gas supplies available to Columbia Gas Transmission, LLC ("Columbia"), to discuss the demand for Columbia's transportation and storage service, and support Columbia's proposed economic life. His analysis is used in support of Columbia witness Crowley's testimony regarding depreciation.

To analyze gas supplies available to Columbia, Mr. Kirk presents estimates of the non-speculative gas resources available within the Eastern U.S. Region. Next, Mr. Kirk examines production projections by the U.S. Energy Information Administration and compares the amount of production under these scenarios with the estimates of non-speculative resources within the Eastern U.S. Region. Mr. Kirk's comparison shows that non-speculative gas supplies within the Eastern U.S. Region should be available to Columbia for at least a 35-year period if sufficient demand exists.

Mr. Kirk also discusses factors that affect the demand for Columbia's services, which must be considered in determining Columbia's remaining economic life. The factors that will impact demand for Columbia's services and its remaining economic life are: (1) energy and environmental legislation/regulation to reduce greenhouse gas emissions; and (2) technological development in alternative energies and energy storage. Mr. Kirk provides examples regarding how evolving government energy and environmental policies are promoting significant changes to the energy mix utilized across Columbia's footprint. Mr. Kirk concludes that while sufficient natural gas supply may be available to Columbia over the next 35 years, the issues he discusses that impact natural gas demand support limiting the economic life of Columbia to 35 years.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Columbia Gas Transmission, LLC	)	Docket No. RP20-___-000

PREPARED DIRECT TESTIMONY OF ALEXANDER KIRK ON BEHALF OF COLUMBIA GAS TRANSMISSION, LLC

July 31, 2020

Table of Contents

Glossary of Terms

AEO	Annual Energy Outlook
BWMQ	Brown, Williams, Moorhead & Quinn, Inc.
Columbia	Columbia Gas Transmission, LLC
Commission	Federal Energy Regulatory Commission
DOE	Department of Energy
Dth	Dekatherms
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
MMcf/d	Million cubic feet
NREL	National Renewable Energy Laboratory
PGC	Potential Gas Committee
PGC Report	July 2019 PGC report entitled “Potential Supply of Natural Gas in the United States”
PPA	Power purchasing agreement
PV	Photovoltaic
QST	Questar Southern Trails Pipeline Co.
RMI	Rocky Mountain Institute
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
Tcf	Trillion cubic feet

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Columbia Gas Transmission, LLC	)))	Docket No. RP20-___-000

PREPARED DIRECT TESTIMONY OF ALEXANDER KIRK

I. INTRODUCTION

Q. Please state your name, job title and business address.

A. My name is Alexander Kirk and my business address is 1155 15th Street N.W., Suite 1004, Washington, D.C. 20005. I am a Vice President of Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"), an energy consulting firm in Washington, D.C.

Q. What is the nature of the work performed by your firm?

A. We offer technical, economic, and policy assistance to the various segments of the natural gas pipeline industry, oil pipeline industry, and electric utility industry on business and regulatory matters.

Q. On whose behalf are you submitting your prepared testimony in this proceeding?

A. I am submitting testimony on behalf of Columbia Gas Transmission, LLC ("Columbia").

Q. Are you sponsoring any exhibits with your prepared direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit No. TCO-038	*Curriculum Vitae* of Alexander Kirk
Exhibit No. TCO-039	Eastern U.S. Region Non-Speculative Resources
Exhibit No. TCO-040	Production Projections and Scenario Descriptions by the EIA

Exhibit No. TCO-041	Carbon Dioxide Emissions Projections by the EIA
Exhibit No. TCO-042	National Renewable Energy Laboratory Report "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018" (November 2018)
Exhibit No. TCO-043	National Renewable Energy Laboratory Report "Q3/Q4 2019 Solar Industry Update" (February 2020)

Q. Please briefly state your professional experience and qualifications.

A. I earned a Bachelor of Science degree with majors in Mathematics and Economics from Linfield College in 2005, and a Master of Arts in Economics from the University of Washington in 2008. From September 2008 to May 2010, I was an instructor for Principles of Microeconomics and Natural Resource Economics courses at the University of Washington. I have been employed by BWMQ since June 2007, where I have assisted clients with analyses of gas supply, natural gas pipeline rate cases, storage and pipeline market-based rate applications, business risk, rate design and both traditional and levelized cost-of-service modeling.

Q. Have you previously testified before the Federal Energy Regulatory Commission ("Commission" or "FERC")?

A. Yes, a list of the cases in which I have provided testimony and/or testified during my career is included in my curriculum vitae attached as Exhibit No. TCO-038.

Q. What is the purpose of your prepared direct testimony in this proceeding?

A. The purpose of my testimony is to discuss the gas supplies available to Columbia and the demand for Columbia's services, and to support Columbia's economic life. My analysis is used in support of the depreciation testimony of Columbia witness Crowley.

Q. What is the "economic life" for a natural gas pipeline asset?

A. The economic life for an asset refers to the time period for which the asset is expected to be economically profitable. To be economically profitable, a natural gas pipeline asset must receive both the *return of* its fixed costs through depreciation as well as a *return on* the investment of its fixed costs. A natural gas pipeline asset has reached the end of its economic life when it is no longer expected to return an economic profit. The economic life of a natural gas pipeline asset is used as a "truncation" in the calculation of its depreciation rate, as explained by Columbia witness Crowley.

Q. What factors influence the economic life of a natural gas pipeline?

A. Part 201 of FERC's regulations sets forth an accounting system for natural gas companies under the Natural Gas Act that lists economic life concepts which are to be considered in determining depreciation rates. In relevant part, the definition of depreciation in Part 201 provides that "[a]mong the causes to be given consideration [in determining depreciation] are wear and tear, decay, action of the elements, inadequacy, *obsolescence,* changes in the art, *changes in demand and requirements of public authorities*, and, in the case of natural gas companies, *the exhaustion of natural resources*." 18 C.F.R. pt. 201, Definitions, ¶ 12.B (2020) (emphasis added).

Q. How is your testimony organized?

A. To address each of the elements discussed above, I discuss numerous factors relating to gas supply and the demand for Columbia's services. In Section II, I review gas supplies available to Columbia to determine whether sufficient gas supplies are likely to be available to Columbia over a 35-year horizon under numerous scenarios. In Section III, I discuss factors affecting the demand for Columbia's services. In Section IV, I explain why a 35-year economic life is conservative, yet appropriate, for Columbia.

II. GAS SUPPLY

Q. Please briefly describe your understanding of the Columbia system.

A. Columbia is a large interstate pipeline system located in Delaware, Ohio, Kentucky, West Virginia, Virginia, Maryland, North Carolina, Pennsylvania, New Jersey, and New York. The Columbia system also includes significant storage assets located across its footprint.

Q. Please explain how you selected the appropriate regions to analyze as the basis of your gas supply study?

A. Historically, the Commission has required pipelines to file gas supply information supporting the economic life of their pipeline systems by analyzing the potential recoverable natural gas reserves in a pipeline's gas supply area. *See, e.g., Trunkline Gas Co.*, 90 FERC ¶ 61,017, 61,057 (2000). Given the footprint of Columbia, and after reviewing the regions used by the Energy Information Administration ("EIA") and Potential Gas Committee ("PGC") (described more fully later), I determined that Columbia's supply regions should include what the EIA defines as the East, Midcontinent, Southwest, and Gulf Coast Regions. See the EIA region Map 1 below.

Map 1

Source: U.S. Energy Information Administration, Office of Energy Analysis.

These EIA regions very closely overlap with the PGC's North Central, Mid-Continent, Atlantic, and Gulf Coast Regions. I use the term "Eastern U.S. Region" to describe the supply region that I used for Columbia's supply analysis, which is the summation of these EIA and PGC regions.

Q. If natural gas markets are fully integrated and natural gas from supply basins across North America compete to serve end-use markets, would it be appropriate to use the total gas supplies from North America, or some subset thereof, in addition to Eastern U.S. Region supplies, in determining the resource base available to Columbia?

A. No. There are several primary reasons why such an analysis would be improper and why my gas supply analysis focuses on the future availability of Eastern U.S. Region supplies. First, Commission precedent in depreciation practice provides that gas supply studies should be focused on the areas of supply that are in reasonable proximity and connectivity to the pipeline system being analyzed. For example, in *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,057 (2000), the Commission adopted a gas supply analysis that included supplies located in areas near the footprint of Trunkline Gas Company, including Railroad Commission of Texas Districts 2, 3, and 4, onshore South Louisiana, and Federal Offshore Louisiana. In *Williston Basin Interstate Pipeline Co.*, 107 FERC ¶ 61,164 (2004), the Commission adopted a gas supply analysis that included the Western Canadian Sedimentary Basin and the Rocky Mountains, areas that could reasonably be expected to provide supplies to Williston Basin Interstate Pipeline Company in the future, and excluded more distant supplies. Second, although it is likely that gas supplies from other areas will impact Columbia, much of this impact will be from displacement or exchanges, or such supplies may provide a competitive alternative to supplies located on Columbia. Third, my analysis of the Eastern U.S. Region is, in part, based on

Commission precedent that holds that gas supply forecasts in excess of 35 years are speculative. I have significant reservations regarding forecasts or projections of both gas supply and demand beyond a 35-year horizon, which I will explain in detail later. Fourth, I conclude that gas supplies from the Eastern U.S Region will be available to Columbia for 35 years. As such, consideration of gas supplies from other areas would not change my conclusion that gas supplies will be available to the Columbia system for the entirety of the maximum 35-year period that the Commission, as discussed below, has found is appropriate to include in a depreciation analysis.

Q. What methodology did you use to analyze the gas supply availability in the Eastern U.S. Region?

A. I analyzed the total amount of non-speculative resources in the Eastern U.S. Region, as I discuss in Section II.A and II.B. Next, I examined the EIA's Annual Energy Outlook ("AEO") 2020 projections to show what I describe as plausible projections of natural gas production. I then confirmed that sufficient non-speculative gas resources will be available over a 35-year horizon to satisfy natural gas production projections under the EIA's various scenarios. While I discuss why these scenarios are likely to overestimate production (and, therefore, consumption) later in my testimony, utilizing these scenarios allows me to determine whether or not supply is likely to constrain Columbia's economic life over the next 35 years.

Q. Why did you examine a 35-year horizon for gas supply?

A. I examined a 35-year horizon based, in part, on Commission precedent that provides that projections beyond 35 years are speculative. Specifically, in *Portland Natural Gas Transmission Sys*., 134 FERC ¶ 61,129 at P 127 (2011), the Commission noted:

> The ALJ rejected [Portland Shippers Group's] recommended end-life of 40 years for [the pipeline's] system, finding it extended beyond the Commission's standard of 35 years, and is inconsistent with Commission precedent indicating that reserve estimates projected beyond 35 years are speculative.

The Commission affirmed the Administrative Law Judge's ("ALJ") rejection of the Portland Shippers Group's and Staff's recommended life beyond 35 years. Illustrating uncertainty regarding Portland Natural Gas Transmission System-related supply, Sable Island natural gas production in Nova Scotia had previously been planned to produce for 25 years following its initial in-service date in 1999, however was plugged and abandoned by 2018. *See* https://www.cnsopb.ns.ca/offshore-activity/offshore-projects/sable-offshore-energy-project. I discuss numerous factors in Section III that cause both demand and supply projections over long horizons, such as beyond 35 years, to be highly uncertain as well.

A. Description of Data Used for the Eastern U.S. Region

Q. What states and areas comprise the regions you analyzed?

A. The Eastern U.S. Region encompasses many states and basins. The states, which are shown in the EIA Region Map earlier in Section II, are listed in Exhibit No. TCO-039. The EIA regions overlap closely with the PGC's North Central, Mid-Continent, Atlantic, and Gulf Coast regions. The specific PGC basins that are located in the Eastern U.S. Region are also provided in Exhibit No. TCO-039.

Q. What is the source of the data you used to analyze gas supply?

A. I examined proved reserves data from the EIA's Form EIA-23L and estimates of probable and possible resources from the PGC's July 2019 report entitled "Potential Supply of Natural Gas in the United States" ("PGC Report"). I provide further detail with respect to these data sources in Section II.B. I also analyzed projections from the

EIA's AEO 2020. Complete details regarding all EIA sources are available on the agency's web site, www.eia.gov.

Q. What is the PGC?

A. The PGC is an independent organization that works closely with the Potential Gas Agency at the Colorado School of Mines and consists of volunteer members from all segments of the oil and gas industry, government agencies, and academic institutions. The PGC offers biennial estimates of the potential gas supply of the United States which can be used to estimate the long-term gas supply. As discussed later below, the Commission has previously relied upon PGC estimates to assess gas supply.

B. Discussion of Remaining Non-Speculative Resources

Q. What is the estimated quantity of remaining natural gas resources in the Eastern U.S. Region?

A. I calculated an estimate of what I term remaining "non-speculative resources" by summing dry proved reserves, probable resources, and possible resources, using the latest available data. Estimated total non-speculative resources equal 2,231.5 trillion cubic feet ("Tcf"), which is derived by adding: (1) the EIA's estimate of remaining proved reserves for the Eastern U.S. Region of 389.0 Tcf; and (2) the PGC's latest independent estimate of probable and possible resources for the Eastern U.S. Region of 1,842.5 Tcf. The tabulation of resources by state (proved reserves) and basin (probable and possible resources) is shown in Exhibit No. TCO-039.

Q. Would you please describe the PGC estimates?

A. The estimates of the PGC represent potential gas resources that, in the judgment of its members, can be recovered by future drilling under: (a) adequate economic incentives in terms of price and cost, and (b) current foreseeable technology. The PGC projects resources based on knowledge of areas of proved reserves. The PGC's estimates included in this study represent "Most Likely" values derived from statistically aggregated mean values.

Q. You said the PGC's "Most Likely" estimates are statistically aggregated mean values. What does this mean?

A. The "Most Likely" estimates, as described by the PGC, "represent the best judgment of individual Committee members and are considered the most credible assessments for purposes of analysis, planning and exploration." *See PGC Report* at 2. The Commission has explicitly relied upon PGC estimates in *Trunkline Gas Co*., 90 FERC ¶ 61,017 at 61,057 (2000).

Q. What is the difference between proved reserves, probable resources, and possible resources?

A. Proved reserves are defined by the EIA as "the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." See Form EIA-23L, *Annual Survey of Domestic Oil and Gas Reserves*. Probable, possible, and speculative resources are estimated by the PGC. As defined by the PGC:

> Probable resources are associated with known fields and are the most assured of potential supplies. Relatively large amounts of geologic and engineering information are available to aid in the estimation of resources existing in this category. Probable resources bridge the boundary between discovered and undiscovered resources. The discovered portion includes the supply from future extensions of *existing pools* in known productive reservoirs … Although the pools containing this gas have been discovered, their extent has not been completely delineated by development drilling. Therefore, the existence of quantity of gas in the undrilled area of the pool are as yet *unconfirmed*. The undiscovered part is expected to come from

> future new pool discoveries within existing fields either in reservoirs productive in the field or in shallower or deeper formations known to be productive elsewhere within the same geologic province or subprovince.
>
> (See *PGC Report* at 82. Emphasis in original. Endnotes omitted.)

By contrast,

> Possible resources are a less assured supply because they are postulated to exist outside known fields, but they are associated with a productive formation in a productive province. Their occurrence is indicated by a projection of plays or trends of a producing formation into a less well explored area of the same geologic province or subprovince. The resources are expected to arise from *new field* discoveries, postulated to occur within these trends or plays under both similar and different geologic conditions—that is, the types of traps and/or structural settings may be either the same or different in some aspect.
>
> (*See PGC Report* at 82. Emphasis in original. Endnotes omitted.)

The PGC defines speculative resources as:

> Speculative resources, the most nebulous category, are expected to be found in formations or geologic provinces that have not yet proved productive. Geologic analogs are developed in order to ensure reasonable evaluation of these unknown quantities. The resources are anticipated from *new pool* or *new field* discoveries within a productive province or sub-province and from *new field* discoveries within a *province not previously productive*.
>
> (*See PGC Report* at 82. Emphasis in original. Endnotes omitted.)

Summing proved reserves, probable resources, and possible resources, I calculated total remaining non-speculative resources. I excluded speculative resources from my analysis due to the "nebulous" nature of their existence. The Commission has stated that it is appropriate to rely on "the PGC's most likely estimates for probable and possible resources in [a pipeline's] gas supply areas." *See Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,057 (2000). Speculative resources should only be included in a gas supply analysis if and when the resources are reclassified as proved, probable, or possible.

C. Production Projections

Q. Why did you examine production projections?

A. The estimates for non-speculative resources I discussed in Section II.B are measurements of the stock of resources that may be available for production, but further context is required in order to understand the magnitude of the stock and for how long the stock might be available.

Q. Which production projections did you examine for the Eastern U.S. Region?

A. I examined the 22 scenarios projected by the EIA's AEO 2020. I discuss how the EIA and PGC's regions overlap within the Eastern U.S. Region's geographic area in more detail below. The EIA is specific in that it only produces projections—which are estimates that may occur given specific hypothetical assumptions (*see, e.g.*, the EIA's "Annual Energy Outlook Retrospective Review" https://www.eia.gov/outlooks/aeo/retrospective/, noting that "[t]he projections presented in the AEO are not statements of what will happen but of what may happen given the assumptions in the underlying National Energy Modeling System"). Alternatively stated, the EIA does not place any expectation that any one outcome, such as its Reference Case, is any more likely to occur than any of its alternate scenarios. Furthermore, there is no expectation by the EIA that any of the scenarios will necessarily occur. I used the combination of scenarios to evaluate whether sufficient non-speculative resources exist to fulfill such production and will be available for at least a 35-year horizon.

Q. Why did you separately examine non-speculative resources and compare them to EIA's projections?

A. The EIA's AEO uses its proved reserves estimates in addition to estimates of "unproved resources," which may include resources that can be classified as speculative. By comparing the EIA's resource projections to the amount of non-speculative resources available in each region, I can ensure that such projections will not require the existence of speculative resources to come to fruition.

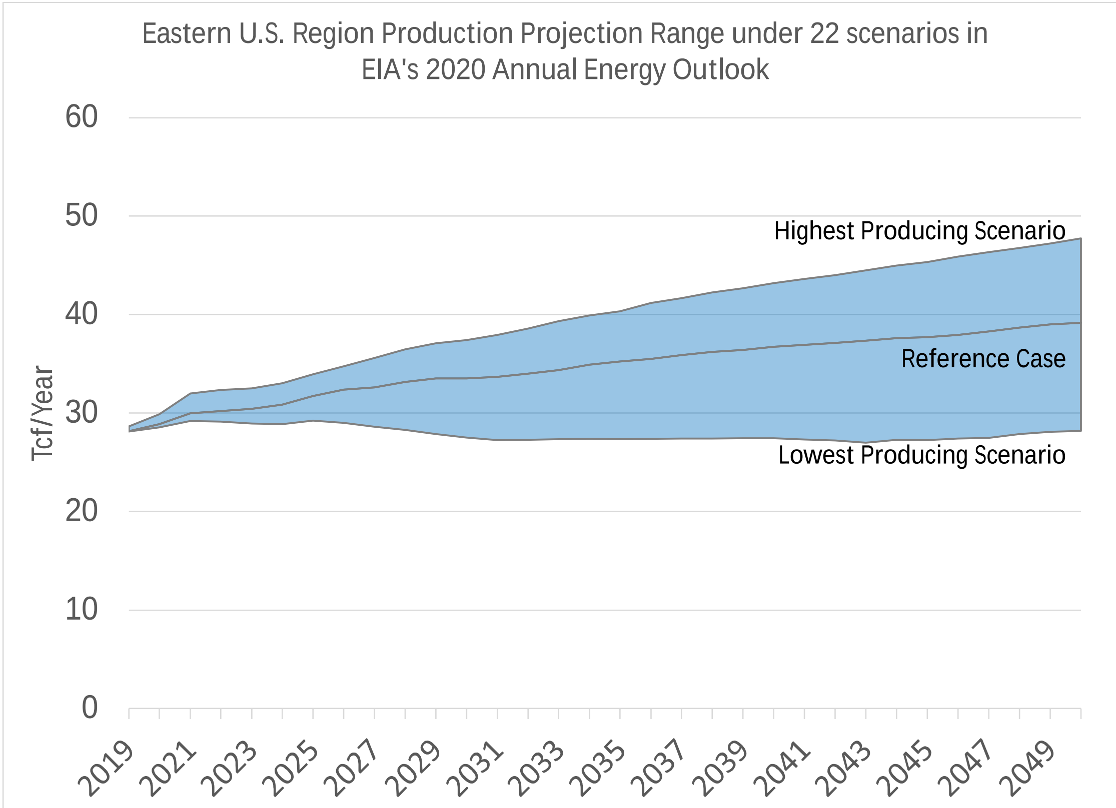
Q. How do the EIA regions differ from the PGC regions you used to define the Eastern U.S. Region?

A. There is large overlap. The only substantial amount of land area that is located in the EIA regions, but not the PGC regions, is western Nebraska. The only substantial amount of land area that is located in the PGC regions, but not the EIA regions, is a portion of eastern South Dakota. Neither of these areas are gas production areas, so the lack of perfect overlap is inconsequential to my analysis.

Q. What do the Eastern U.S. Region production projections show?

A. The range of the EIA's 22 projections for the Eastern U.S. Region is shown in Chart 1 below, with the reference case explicitly shown (the tabulated data with scenario names as well as EIA's scenario descriptions can be found in Exhibit No. TCO-040).

Chart 1



As I explained earlier, the Commission has previously used 35 years for a pipeline's economic life, even when additional years of supplies may have been available. Furthermore, there is growing uncertainty with respect to the demand for Columbia's services the further into the future we examine. My purpose here is therefore to confirm whether supplies will be available for 35 years. Since the EIA's projections only extend to 2050, I use the annual average growth (or decline) rates of each scenario in its last five years to project production for 2051 to 2055, in order to reach 35 years from present day. The total aggregate production from 2019 to 2055 is 1,508.2 Tcf from the highest-production scenario and 1,308.5 Tcf from the Reference Case, which is about 68 percent and 59 percent of the approximately 2,231.5 Tcf of estimated remaining non-speculative resources in the region. This comparison demonstrates that sufficient levels of non-speculative resources, and therefore sufficient gas supply, in the Eastern U.S. Region are likely to be available over a 35-year period.

Q. You mentioned that the EIA's figures are projections, and that the EIA does not state an expectation that any particular projection is likely to occur. How do you view the likelihood of the EIA's projections?

A. Due to several considerations of demand discussed in Section III, all of the projections are likely to overestimate natural gas consumption, and consequently production, in the long run. For instance, technical advancement in alternative energy and electric storage technologies, as well as government policy goals regarding energy and the environment in the future, could result in the EIA projections overstating the production that will occur. Uncertainty with respect to the EIA projections is discussed further in Section III.

Q. What are your primary findings with regard to natural gas supply as it pertains to the Columbia system?

A. If demand for the services provided by Columbia exists, sufficient supplies will likely be available from Columbia's supply areas within a 35-year horizon. Factors discussed in Section III and throughout this section suggest that there will be significant uncertainty regarding the demand for Columbia's services over time, and such uncertainty in market demand supports truncating Columbia's economic life to 35 years or less.

III. DEMAND FOR COLUMBIA'S SERVICES

Q. Why is it important to consider the demand for Columbia's services?

A. Even if sufficient gas supplies exist, factors affecting demand may limit the amount of *available* supplies that could be expected to be produced and utilize Columbia's services. Conclusions that rely on long-run forecasts or projections must be considered speculative due to these inherent uncertainties over long horizons.

Q. Are most energy projections limited to a 20- to 30-year time frame?

A. Yes. For example, the EIA AEO currently only projects a 30-year time frame, with an end date of 2050. The Canada Energy Regulator only projects over a 20-year time frame, with an end date of 2040. *See, e.g.,* https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html. The International Energy Agency also only projects to 2040. *See, e.g.,* https://www.iea.org/reports/world-energy-outlook-2019/. The 20- to 30-year time frames allow these entities to avoid the added speculation that would be required under even longer horizons.

Q. Why are factors that affect the demand for natural gas and for Columbia's services relevant to a determination of Columbia's depreciation rates?

A. As mentioned earlier, a change in market demand is specified in Part 201 of FERC's regulations as a factor to consider in setting depreciation rates, as are the requirements of public authorities. There are, as I will discuss later, requirements of state and local public authorities that directly affect the demand for natural gas and affect demand for Columbia's services as a direct consequence. It follows then that the regulations and requirements of public authorities may directly impact a pipeline's economic life, and thereby impact depreciation rates.

Q. Why is it important to consider the demand for Columbia's services, rather than just gas supply?

A. An assessment of Columbia's economic life should consider the produced supplies *that will be expected to actually flow on Columbia's system*. Even if available supplies exist, factors affecting demand may limit the amount of *available* supplies which could be expected to flow to Columbia's system. A depreciation rate based on evidence that failed to forecast the future reserves "which actually may be expected to be added to [the pipeline's] system" was rejected by the United States Court of Appeals for the District of

Columbia Circuit in *Memphis Light, Gas and Water Division v. Federal Power Commission*, 504 F.2d 225, 232 (D.C. Cir. 1974) ("*Memphis*").

Q. Can you please outline the connection between the demand for natural gas, the demand for Columbia's services, and Columbia's economic life?

A. The demand for Columbia's services is driven by the demand for natural gas, the natural gas price dynamics over time, the market regions that Columbia serves, and competition from alternative energy sources and from competing pipelines. Pipeline competition is addressed in Columbia witness Isherwood's business risk testimony, while I focus on other long-run demand factors. A decline in the demand for natural gas broadly will reduce price differentials and shippers' willingness to pay for the transportation and storage of natural gas. As discussed in more detail earlier in my testimony, a pipeline's economic life is over once it is unlikely to recover its remaining fixed costs. The consumption of natural gas need not fall to zero for this to occur. Long before natural gas consumption falls to zero, increasing competition from alternative energy sources and excess capacity will prevent pipelines from charging maximum recourse rates. Increasingly, pipelines will enter into discounted and negotiated rate contracts until they are able to cover only marginal costs. The pipeline may even cease to have shippers willing to contract for firm service. At such a point, even though there may still be natural gas available to be transported or stored in pipeline and storage facilities, and even some natural gas supplies that still are transported and stored, the pipeline's economic life is effectively over.

Q. Can you provide an example of an interstate natural gas pipeline which had reached the end of its economic life from such circumstances?

A. Yes, Dominion Energy, Inc.'s Questar Southern Trails Pipeline Co. ("QST") reached the end of its economic life under such circumstances. QST began transportation services into California from the San Juan Basin in 2002. At the time, natural gas consumption was expected to continue to increase for the foreseeable future. Data from the EIA shows that pipeline capacity into California grew from 7,542 million cubic feet ("MMcf/d") in 1998 to 10,701 MMcf/d in 2016. However, the California Public Utility Commission now projects that demand for natural gas will diminish through 2035 (the end of the projection period) as renewable energy production increases. *See* California Gas and Electric Utilities, *2018 California Gas Report*, at 17-18, at https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf. The result of the declining California demand in combination with excess pipeline capacity caused firm contracts to California on QST to fall to zero.

On December 22, 2017, QST filed an application with FERC (Docket No. CP18-39-000) to abandon, partially by sale and partially in-place, all of its certificated facilities dedicated to providing jurisdictional transportation service, including approximately 488 miles of natural gas pipeline and related facilities in California, Arizona, Utah, and New Mexico. The facilities to be sold were those that had provided service to QST's one remaining firm shipper, the Navajo Tribal Utility Authority, which had a contract for only 1,000 dekatherms ("Dth")/day. The Navajo Tribal Utility Authority contract had a negotiated rate of $0.10 per Dth/day, significantly below QST's 100 percent load factor rate of approximately $0.38 per Dth/day. QST stated that it could no longer justify continued operation of its 80,000 Dth/day system based on this one remaining contract, coupled with the projected declining demand for natural gas in California. The

Commission issued an order on May 9, 2018, authorizing QST to abandon the pipeline. *See generally Questar Southern Trails Pipeline Co.*, 163 FERC ¶ 62,086 (2018). This is a prime example of how a pipeline's economic life may be over, even when some quantity of natural gas may still be consumed in its destination markets and gas supply may still be available.

A. Factors Impacting Natural Gas Demand

Q. Please explain some of the factors that will influence natural gas demand in the future.

A. The demand for any good or service is influenced by the prices of alternatives and substitutes, as well as other factors called "demand shifters." There are two factors that will negatively affect the market demand for natural gas: (1) energy and environmental legislation/regulation; and (2) technological development in alternative energies and energy storage.

Government policy at the state and local level can have a large impact on the future of natural gas demand within Columbia's markets. There are several local and state policies that are likely to reduce the demand for natural gas considerably in the long run, as well as a recent FERC order regarding energy storage that may significantly advance the adoption of energy storage and alternative energies.

Alternative energies are likely to provide significant competition to natural gas in the next 35 years. Large declines in the price of energy produced by wind and solar facilities are likely to lead to increased wind and solar capacity in Columbia's markets. Large declines in the cost of battery storage technology will also support increased reliance on renewable energy in the long run. Increases in the availability and capacity of renewable resources driven by governmental policies and competitive prices, combined with increases in battery storage capacity, will likely decrease the demand for natural gas as a fuel source.

Q. What do you mean by the phrases "short-run" and "long-run"?

A. These terms are economics concepts. The "long-run" refers to a period of time over which no factors of production are fixed. The "short-run" refers to a period of time during which some factors of production may be fixed but others are variable. In the short-run, it is economic to continue to sell a good or service as long as the price is above variable cost, even if the price is not high enough to recover the large "sunk" investments involved in production. In the long-run, since all factors of production are variable, there is flexibility in the mix of energy sources utilized in each region. For purposes of this testimony, and consistent with the Commission precedent discussed earlier, I generally refer to a time period of 35 years or more when I refer to the "long-run." A 35-year time period should be sufficient to consider most productive inputs in the economy to be considered variable. This is also extremely conservative, since most productive inputs may be considered variable much sooner than 35 years from now and it may therefore be reasonable to use a shorter horizon to define "long-run".

B. Impact of Government Energy and Environmental Policies on Natural Gas Demand

Q. You indicated that there are local and state policies that are likely to reduce the demand for natural gas in the long run. Can you provide examples of those local and state policies?

A. There are numerous states across Columbia's footprint and downstream of Columbia that have enacted Renewable Portfolio Standards ("RPS"), among other policies. An RPS typically sets a minimum required percentage of a state's energy portfolio to be derived from renewable resources by a stated year. These standards reflect a goal of reducing fossil fuel use and typically emphasize the construction of renewable energy infrastructure in some of Columbia's markets. The percentage or amount of renewable energy that utilities are required to sell thus represents market demand for energy for which Columbia cannot compete. An RPS is an example of a state policy that negatively impacts demand for natural gas and natural gas transportation and storage services.

There are many requirements of public authorities located across the Columbia States (defined here as Delaware, the District of Columbia, Kentucky, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Virginia and West Virginia) regarding energy and environmental policy:

i. Delaware

1. Statewide: Renewable Portfolio Standard. Delaware's RPS requirements include that 25% of the energy portfolios of Delaware's utilities must come from renewable sources by 2025. *See* https://dnrec.alpha.delaware.gov/climate-coastal-energy/renewable/portfolio-standards/.

2. Newark, Delaware: Sustainable Newark. Some of the goals included in the Sustainable Newark plan include procuring 30% of renewable generation resources for its distributed electricity mix by 2025, and 100% by 2045. Other goals include facilitating pilot renewable energy projects such as community solar and other energy storage technologies and reducing the GHG emission rate to net zero by 2060. *See* https://newarkde.gov/DocumentCenter/View/12803/SustainableNewark_FINAL_30OCT19?bidId=.

ii. New Jersey

1. Statewide: Executive Order No. 100. Goal to achieve 100% clean energy by 2050, reducing state greenhouse gas emissions by 80% below 2006 levels. Some strategies included within the plan will include a build-out of offshore wind turbines and solar panels. Plan to reduce energy consumption and emissions from the building sector by utilizing electrification programs for new construction, allowing buildings to utilize clean electricity, and laying the groundwork for an in-state workforce to retrofit existing structures.

Projects New Jersey's electricity load to double by 2050, and plan to have New Jersey's natural gas use decline to less than 1/5 of today's levels by 2050, 'likely reducing the need for gas distribution system expansion'. *See* https://nj.gov/governor/news/news/562020/approved/20200127a.shtml.

2. Statewide: Renewables Portfolio Standard/A.B. 3723 (May 2018) increased the RPS standard to 50% by 2030, increased offshore wind carveout, increased solar carveout. This standard requires that energy providers that sell electricity to retail customers in New Jersey shall generate a certain percentage of their energy from renewable resources. Specifically, 50% Class I renewable energy by 2030, 2.5% Class II renewable energy each year, and 5.1% solar-electric by energy year 2021 – gradually reduced to 1.1% by energy year 2031 (as Class I increases). *See* https://casetext.com/regulation/new-jersey-administrative-code/title-14-public-utilities/chapter-8-renewable-energy-and-energy-efficiency/subchapter-2-renewable-portfolio-standards/section-148-23-amount-of-renewable-energy-required.

iii. New York

1. Statewide: The Climate Leadership and Community Protection Act will require the state to cut greenhouse gas emissions to 40% below 1990 levels by 2030, and 85% below 1990 levels by 2050, explicitly excludes stationary electric source emissions from being offset. This act also requires that 70% of statewide electricity generation be from renewable energy systems by 2030, and 100% statewide electricity generation come from carbon-free sources by 2040. Some of the measures to achieve these goals include 6 gigawatts of solar energy capacity installed by 2025, 9 gigawatts of offshore wind capacity installed by 2035, and 3 gigawatts of statewide energy storage capacity by 2030. This Act also establishes a climate action counsel that shall establish advisory panels on transportation, energy intensive and trade-exposed industries, land-use and local government, energy efficiency and housing, power generation, and agriculture and forestry. *See* https://legislation.nysenate.gov/pdf/bills/2019/s6599.

2. Statewide: Clean Energy Standard. The Clean Energy Standard (CES) states that 70% of New York State's electricity will come from renewables such as solar, wind, and hydro by 2030. This standard's goal is to support New York State's goals of reducing GHG emissions 40% by 2030 and ~80% by 2050. *See* https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard.

3. New York City: OneNYC 2050 (New York City's Green New Deal). Outlined in OneNYC 2050, New York City is setting a goal of 30% GHG reduction by 2030, and 100% reduction in net GHG emissions by 2050, and to utilize 100% clean electricity. The city will also be pursuing 100% carbon-free electricity supplies for City government operations utilizing hydropower. *See* https://www1.nyc.gov/office-of-the-mayor/news/209-19/action-global-warming-nyc-s-green-new-deal#/0.

iv. North Carolina

1. Statewide: North Carolina Clean Energy Plan. This plan details goals to reduce greenhouse gas emissions by 70 percent below 2005 levels by 2030, to attain carbon neutrality by 2050, and to accelerate clean energy development. *See, e.g.*, https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

2. Statewide: Renewable Energy and Energy Efficiency Portfolio Standard. This RPS requires all investor owned utilities in the state to supply 12.5% of retail electricity sales from renewable energy resources by 2021. Rural electric cooperatives and municipal electric suppliers are subject to a slightly lower 10% REPS requirement. *See, e.g.*, https://www.ncleg.net/Sessions/2007/Bills/Senate/PDF/S3v6.pdf.

3. Charlotte, NC: Sustainable and Resilient Charlotte by 2050 Resolution. This resolution sets a goal to lower city-wide greenhouse gas emissions by, e.g., source 100 percent of its energy use for its building and fleet from zero carbon sources by 2030. Charlotte will strive to bring city-wide greenhouse gas emissions to below two tons of carbon dioxide per person annually by 2050. *See, e.g.*, https://cleanaircarolina.org/wp-content/uploads/2019/10/Sustainable-and-Resilient-Charlotte-Resolution.pdf.

4. Raleigh, NC: Climate Energy Action Plan. On May 21, 2019, the Raleigh city council adopted a community-wide goal of an 80 percent reduction of greenhouse gas emissions by 2050. *See, e.g.*, https://raleighnc.gov/environment/content/AdminServSustain/Articles/ClimateAction.html.

5. Apex, NC. The Apex Town Council endorsed a goal of transitioning to 80% clean energy by 2035 and 100% clean energy by 2050. *See, e.g.*, http://www.apexnc.org/DocumentCenter/View/26210/newbusiness

01?bidId= and https://www.newsobserver.com/news/local/article225610415.html.

6. Chapel Hill, NC. The Council of the Town of Chapel Hill committed to creating a Climate Action and Response Plan to begin transitioning to 80% clean, renewable energy community-wide by 2030, and to reach 100% by 2050. *See*, *e.g.*, https://chapelhill.legistar.com/LegislationDetail.aspx?ID=4143409&GUID=C84850B1-0266-437F-AE4F-0BEC1DF63B37&FullText=1.

7. Hillsborough, NC: the Hillsborough Town Board adopted a resolution that endorses the transition of the town to 80% clean, renewable energy by 2030, and 100% clean, renewable energy by 2050. *See, e.g.*, https://assets.hillsboroughnc.gov/media/documents/public/resolution-supporting-the-goal-of-100-percent-clean-energy-by-2050.pdf.

8. Ashville, NC and Buncombe, County, NC: Resolution 18-279 and Buncombe County Resolution 17-12-06. Asheville's Resolution states that they will transition the municipal operations from fossil-fueled energy to 100% renewable energy by the end of 2030, in line with county goals to reach 100 percent renewable energy by 2042. *See, e.g.*, https://www.ashevillenc.gov/department/sustainability/sustainability-initiatives/100-renewable-energy-initiative/.

9. Orange, NC. The Board of Orange County Commissioners adopted a resolution to transition to 100% renewable energy by the year 2050. *See, e.g.*, http://server3.co.orange.nc.us:8088/weblink/0/doc/47637/Page1.aspx.

10. Wake County, NC. The Wake County Board of Commissioners endorsed the goal of 100% clean energy by 2050, in order to reduce greenhouse gas emissions and increase energy efficiency. *See, e.g.*, http://www.wakegov.com/energy/Documents/2018%20Clean%20Energy%20by%202050%20-RES.pdf.

v. Ohio

1. Statewide: Renewable Energy Portfolio Standard. Ohio's RPS requires that 8.5% (previously 12.5%) of electricity sold by electric services companies or distribution utilities be generated from renewable energy sources by 2026. (Side note- this is a reduction,

recently reduced in 2019 by HB 6, sources noted in updates. *See* http://codes.ohio.gov/orc/4928.64v1.

2. Cincinnati, Ohio: Clean Energy Commitment. In this plan, Mayor Cranley of Cincinnati commits to shifting the city to 100% renewable energy by 2035, and to develop 25 MW of solar power during the first phase of this plan. *See* https://www.cincinnati-oh.gov/oes/assets/File/CincinnatisCleanEnergyCommitmentPhase1.pdf.

3. Cleveland, Ohio: Cleveland Climate Action Plan. Cleveland has committed to having 25% of electricity use in the city provided by renewable sources by 2030, and 100% of electricity demands from clean, renewable energy sources by 2050. *See* https://www.sustainablecleveland.org/climate_action.

4. Lakewood, Ohio: Resolution 9099-19. Lakewood, Ohio has committed to using 100% clean, renewable energy in its facilities by 2025, and 100% clean, renewable energy community-wide by 2035. *See* http://www.onelakewood.com/wp-content/uploads/2016/02/CouncilMinutes_102119.pdf.

vi. Pennsylvania

1. Statewide: Pennsylvania Climate Action Plan. This plan sets greenhouse gas reduction goals of 26% by 2025, and 80% by 2050. It also plans to increase Alternative Energy Portfolio Standards (AEPS) from 8% Tier 1 renewables by 2020 to 30% Tier 1 by 2030, and 50% by 2050, including a 6% solar carve out. *See* http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=1454161&DocName=2018%20PA%20CLIMATE%20ACTION%20PLAN.PDF%20%20%20%3cspan%20style%3D%22color:blue%3b%22%3e%28NEW%29%3c/span%3e.

2. Statewide: Alternative Energy Portfolio Standards Act. Pennsylvania's AEPS currently requires that electric distribution companies and electric generation suppliers to retail electric customers in Pennsylvania supply 18% of their electricity using alternative-energy resources by 2021. *See* https://www.legis.state.pa.us/cfdocs/Legis/LI/uconsCheck.cfm?txtType=HTM&yr=2007&sessInd=0&smthLwInd=0&act=35.

3. Philadelphia, Pennsylvania: Resolution 190728. The City of Philadelphia has resolved to transition to the use of 100% clean, renewable energy for electricity in municipal operations by 2030, for electricity city-wide by 2035, and for 100% of energy (including heat and transportation) city-wide by 2050 or sooner.

See https://phila.legistar.com/LegislationDetail.aspx?From=RSS&ID=4142523&GUID=BA06CC3B-7B43-4743-A07E-515A145C4A2A.

4. Pittsburgh, Pennsylvania: Climate Action Plan 3.0. The Pittsburgh Climate Action Plan outlines climate goals of municipal operations using 100% renewable electricity and a 100% fossil fuel free fleet by 2030. City-wide, their goals include a 50% energy use reduction, among other goals. The Climate Action Plan also outlines goals of 80% greenhouse gas reduction by 2050, and a pursuit of a carbon neutral goal in the future. *See* https://apps.pittsburghpa.gov/redtail/images/7101_Pittsburgh_Climate_Action_Plan_3.0.pdf.

5. Pittsburgh, Pennsylvania: Executive Order Committing City to Paris Climate Accords. This Order commits to continuing to work on 2030 climate objectives, which include 100% renewable electricity consumption for municipal operations, a development of a fossil fuel fleet, and 50% reduction of energy consumption city-wide. *See* https://apps.pittsburghpa.gov/mayorpeduto/Climate_exec_order_06.02.17_(1).pdf.

vii. Virginia

1. Statewide: Virginia Clean Economy Act (HB1526/SB851). Approved by the governor in April 2020 and effective as of July 2020, this law requires Dominion Energy Virginia to be 100% carbon-free by 2045 and Appalachian Power to be 100% carbon-free by 2050. It also requires nearly all coal-fired plants to close by the end of 2024. The act establishes that 5,200 megawatts of offshore wind generation is ‘in the public interest’, that 16,100 megawatts of solar and onshore wind is ‘in the public interest’, expands net metering to make it easier for rooftop solar to advance, and requires Virginia’s largest energy companies to construct or acquire more than 3,100 megawatts of energy storage capacity. *See* https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html.

2. Statewide: Virginia Electric Utility Regulation Act. This law states that by the year 2025, 15% of total electric energy sold by a utility must be obtained from renewable energy resources. *See* https://lis.virginia.gov/cgi-bin/legp604.exe?091+sum+HB1994.

3. Statewide: EO-43 EXPANDING ACCESS TO CLEAN ENERGY AND GROWING THE CLEAN ENERGY JOBS OF THE

FUTURE. This Executive Order states that the Director of Department of Mines, Minerals and Energy (DMME), with the Secretary of Commerce and Trade, the Secretary of Natural Resources, and the Director of the Department of Environmental Quality (DEQ) will create a plan of action that will produce 30% of Virginia's electricity from renewable energy sources by 2030, and 100% of Virginia's electricity from carbon-free sources by 2050. This includes ensuring the development of at least 3,000 megawatts of solar and onshore wind by 2022, and 2,500 megawatts of offshore wind to be fully developed by 2026. *See* https://www.governor.virginia.gov/media/governorvirginiagov/executive-actions/EO-43-Expanding-Access-to-Clean-Energy-and-Growing-the-Clean-Energy-Jobs-of-the-Future.pdf.

4. Alexandria, VA: Environmental Action Plan 2040. The Environmental Action Plan (EAP) sets goals including reducing community greenhouse gas emissions 50% by 2030 and 80-100% by 2050, and offsetting municipal electricity use with 100% renewable energy credits by 2020 and directly purchasing renewable electricity for 100% of City operations by 2035. *See* https://www.alexandriava.gov/news_display.aspx?id=110544.

5. Arlington, VA: 2019 Community Energy Plan (CEP). Arlington County's 2019 CEP includes goals such as Arlington County Government operations achieving 100% renewable electricity by 2025, having 100% of Arlington's electricity from renewable sources by 2035, and carbon neutrality by 2050. *See* https://arlingtonva.s3.amazonaws.com/wp-content/uploads/sites/13/2019/10/Final-CEP-CLEAN-003.pdf.

viii. Maryland

1. Statewide: Clean Energy Jobs Act. This law raises Maryland's renewable electricity requirement from 25% by 2020 to 50% by 2030 and will require the state to examine pathways for achieving 100% clean energy by 2040. It also provides incentives for the offshore wind industry, supporting an additional 1,200 megawatts of offshore wind development. The law does not, however, remove incineration being considered a renewable power source. *See* http://mgaleg.maryland.gov/mgawebsite/legislation/details/sb0516?ys=2019rs.

2. Annapolis, Maryland: Community Action Plan. The Annapolis Community Action Plan outlines climate action goals which include: a 75% reduction in emissions by 2025 for both municipal and county operations, and eventual carbon neutrality for both

municipal and community operations by 2050. *See* https://www.annapolis.gov/402/Community-Action-Plan.

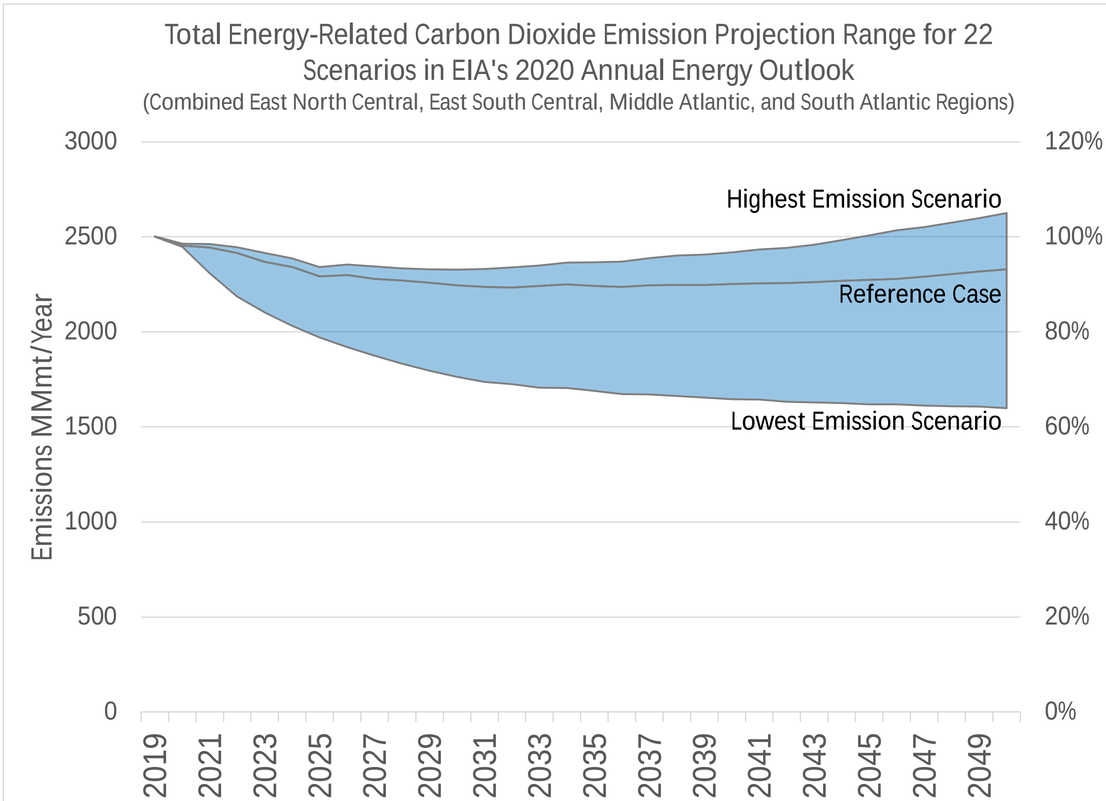
ix. Washington, D.C.: Clean Energy DC Omnibus Amendment Act of 2018. This law increases the Renewable Portfolio Standard to 100% by 2032 and establishes a solar energy standard by 2032. It also requires that electricity suppliers obtain a certain percentage of energy from long-term purchase agreements with renewable energy generators (Beginning January 1, 2022, at least 70% of renewable energy credits from long-term purchase agreements with tier one renewable source). It also states that funds will be used to assist low-income residents with energy bill assistance, energy efficiency, and fuel-switching programs. *See* http://lims.dccouncil.us/Download/40667/B22-0904-Introduction.pdf.

In addition to the Columbia States listed above, other downstream markets that may utilize throughput on Columbia located in New England and Eastern Canadian provinces have set an ultimate goal of achieving a greenhouse gas reduction of 75 to 85 percent of 2001 emissions by 2050, as well as other interim goals, via an agreement entitled the New England Governors and Eastern Canadian Premiers Climate Action Plan. *See* https://www.coneg.org/wp-content/uploads/2019/04/39-1-Climate-Change.pdf. To achieve reductions in greenhouse gas emissions of these magnitudes will require a significant decrease in natural gas use, and a consequent decrease in use of natural gas transportation and storage services.

Q. When analyzing gas supply, you mentioned that the EIA provides 22 different scenarios, including projections such as a Low Renewable Cost case, a 50 Percent Carbon Free Generation Standard case, and a $35 Carbon Dioxide Allowance Fee case. Why are these scenarios unlikely to meet many of the environmental and energy policies that you discussed?

A. The EIA projects carbon dioxide emissions as part of its 2020 AEO. The carbon dioxide emission projections under all scenarios do not approach the declines required by the policies listed above. I have combined the emissions projections for the regions underlying the Columbia States, including East North Central, East South Central, Middle Atlantic and South Atlantic Regions, and present the greenhouse gas emissions projections for the EIA's 22 scenarios below in Chart 2.

Chart 2



Under the Reference Case, energy-related carbon dioxide emissions decrease a total of 6.8% by 2050. The projected percent decrease from 2019 emissions by 2050 for the three other scenarios mentioned above are:

- Low Renewable Cost: 11.5% decrease
- 50 percent carbon free generation: 8.8% decrease
- $35 carbon dioxide allowance: 36.1% decrease ("Lowest Emission Scenario" shown in Chart 2 above)

See Exhibit No. TCO-041 for the EIA's carbon dioxide emission projections tabulated for each of its scenarios. As seen above, none of these scenarios are likely to approach an 80 percent reduction in carbon dioxide emissions, and are therefore likely to overestimate the amount of carbon-emitting energy resources, including natural gas, that would be consumed in the Columbia States when considering many of the requirements of the public authorities within these states. Additionally, none of the EIA cases are designed to meet the requirements that many local authorities have as detailed above either requiring 100 percent renewable energy or net zero carbon emissions by 2050 or earlier.

Q. Do you expect there to be an increase in capacity of renewable resources?

A. Yes. The combination of technological developments, governmental policies, including the Commission's policies, and consumer interests are driving the addition of renewable resources to displace fossil-fuel consumption.

C. Impact of Technological Development on Natural Gas Demand

Q. Please explain how technological development of alternative energies and energy storage can diminish demand for natural gas in the long-run?

A. As technology advances and the prices of alternative energies and energy storage decline, alternative energies may become the economic choice for many energy consumers. Alternative energies, such as wind and solar, are likely to offer viable competitive alternatives to natural gas, particularly over a 35-year period.

Q. Does an opportunity exist for a substantial amount of renewable energy to be built in Columbia's footprint that could diminish demand for firm deliveries of natural gas?

A. Yes. A substantial amount of renewable energy potential exists in the Columbia States that could reduce the demand for natural gas, as well as firm transportation and storage of natural gas, in the long-run. The NREL assessed the amount of potential alternative energy generation in each U.S. state (https://www.nrel.gov/gis/re-potential.html). As I show in Table 1 below, the NREL identified 21,819,833 gigawatt hours of potential renewable energy production in the Columbia States, while EIA data for 2019 indicated that the Columbia's markets had a total of 950,322 gigawatt hours of sales across all sectors (residential, commercial, industrial, and transportation).

Table 1

Columbia States Renewable Energy Potential and 2019 Total Sales

Potential Energy from Renewable Sources	Gigawatt Hours
Urban Utility-scale Photovoltaics	408,520
Rural Utility-scale Photovoltaics	14,962,087
Rooftop Photovoltaics	183,570
Concentrating Solar Power	0
Onshore Wind	216,636
Offshore Wind	3,130,407
Biopower-Solid	56,961
Biopower-Gaseous	25,207
Geothermal Hydrothermal	0
Enhanced Geothermal Systems	2,801,567
Hydropower	34,877
TOTAL	**21,819,833**
2019 Total Retail Sales (All Sectors)	950,322

In the long-run, since most end-use consumption of natural gas can be substituted with electricity, this shows the potential for renewable energies to significantly diminish demand for natural gas. Furthermore, EIA data regarding total energy use in 2017 across the Columbia States amounted to an equivalent 6,354,250 gigawatt hours. The data indicates that if renewable energy is price-competitive, ample renewable energy potential exists within the Columbia States alone to displace all energy consumption within these states.

Q. How much wind generation has been produced in the Columbia States in recent years?

A. Energy generation data has shown a substantial increase in wind generation across the Columbia States in the last two decades. EIA-923 annual survey data (https://www.eia.gov/electricity/data/state/annual_generation_state.xls) shows that wind generation from these markets has increased from 20 gigawatt hours in 2000 to 12,226 gigawatt hours in 2018.

Q. Do you have any recent examples of how advancements in technology have lowered the cost of alternative energy?

A. Yes. The price of solar power from photovoltaic ("PV") systems have fallen significantly over time. The NREL, in an November 2018 report titled "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018," stated "from 2010 to 2018, residential PV LCOE ["levelized cost of energy"] declined 71%, …resulting in an unsubsidized LCOE of $0.12/kWh ["kilowatt hour"] ($0.08 to $0.10 when including the federal ITC ["income tax credit"])." Exhibit No. TCO-042 at 36.

Commercial and utility scale PV systems have similarly fallen in price and are cheaper than residential PV. While underlying technology may be similar for residential, commercial, and utility scale PV, both commercial PV and utility scale PV benefit from growing economies of scale, driven by hardware, labor, and related markups. See, *e.g.*, Exhibit No. TCO-042 at 31, 39, and 45. Commercial PV systems have "an unsubsidized LCOE of $0.09–$0.12/kWh ($0.06–$0.08/kWh when including the federal ITC)" and utility-scale PV systems have "an unsubsidized LCOE of $0.04–$0.06/kWh ($0.03–$0.04/kWh when including the federal ITC)." Exhibit No. TCO-042 at 43 and 51. The NREL notes that its current goals are to reduce the unsubsidized cost of energy by 2030 to 0.03/kWh, $0.04/kWh, and $0.05/kWh for utility-scale PV, commercial PV, and residential PV respectively in nominal USD. *See* Exhibit No. TCO-042 at 34. For illustrative purposes, the EIA states that the average price of electricity for residential electricity was 0.13043/kWh in the United States in 2019 (https://www.eia.gov/electricity/data/browser/).

Wind power prices have also fallen significantly and are projected to become increasingly competitive in the years to come. A report by the DOE titled “2018 Wind Technologies Report” (August 2019) at p. 60 shows declining costs (illustrated by falling power purchasing agreement (“PPA”) prices) in Chart 3 (Figure 54 in the report).

Chart 3

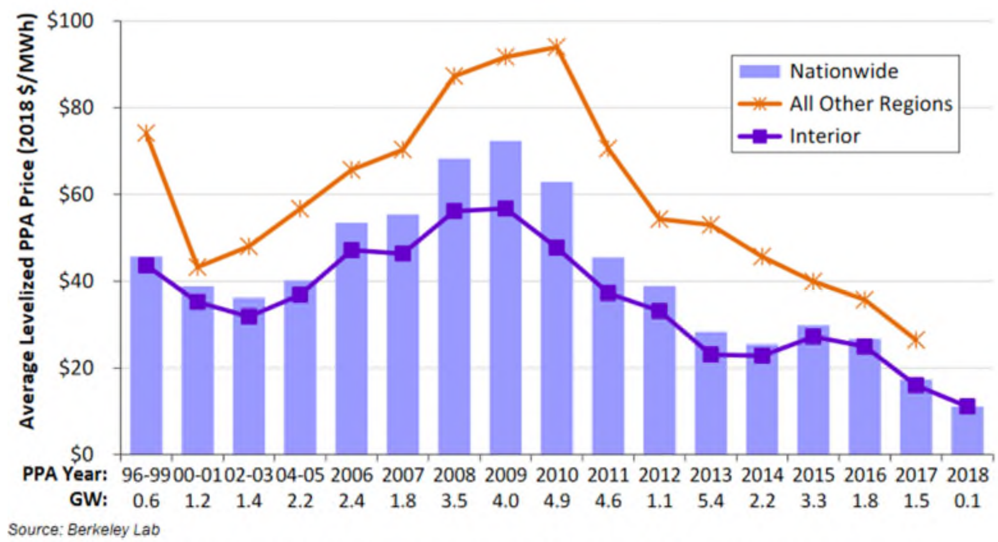
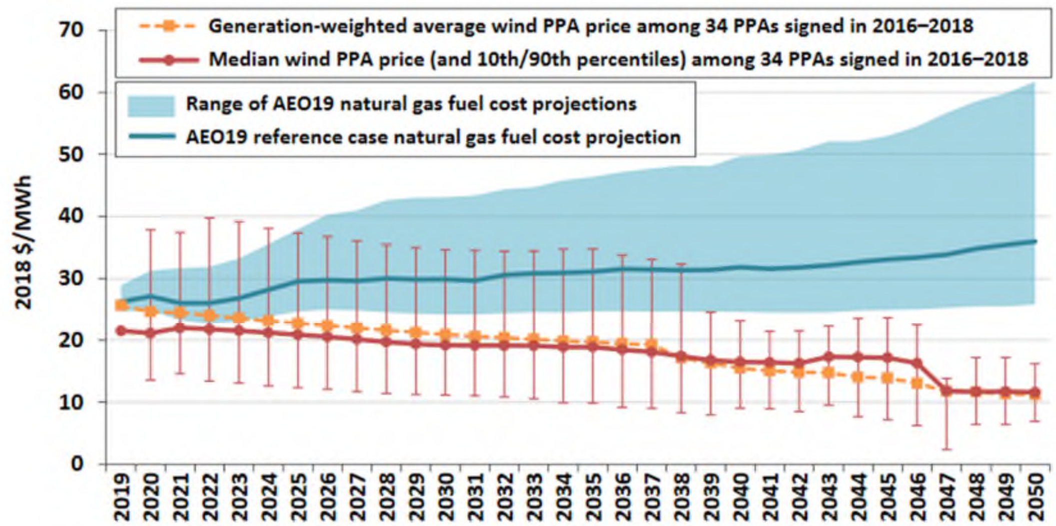


Figure 54. Generation-weighted average levelized wind PPA prices by PPA execution date and region

See https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf. DOE compared the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown, along with a generation-weighted average) and compared this to the EIA’s 2019 AEO projections of just the fuel costs of natural gas generation in Chart 4 (Figure 57 in the report).

Chart 4



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration

Figure 57. Wind PPA prices and natural gas fuel cost projections by calendar year over time

As shown in Chart 4, DOE's report shows that even the 90th percentile of wind PPA prices are lower than the entire range of the 2019 AEO natural gas fuel cost projections by 2039.

Q. Wind and solar offer only variable generation and cannot always be dispatched as needed. How are these sources of generation going to compete with natural gas?

A. Currently, the variability of wind and solar generation can require that other dispatchable sources of generation, such as from natural gas, be available to stabilize the electricity grid. The solution to the variability of wind and solar generation is battery storage, which is now being installed at a significantly increased rate. Battery storage resources allow wind and solar generation to be stored during times of peak production and dispatched when needed. Thus, battery storage can allow variable generation to potentially serve both peak and baseload demand. The Commission recently recognized the importance of battery storage and acted to reduce existing barriers to enable battery storage operators to compete within wholesale electric markets in *Electric Storage Participation in Markets*

Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 162 FERC ¶ 61,127 (February 15, 2018) ("Order No. 841"). *See also Electric Storage Participation in Markets. Operated by Regional Transmission Orgs. and Independent System Operators,* Order No. 841-A, 167 FERC ¶ 61,154 (2019).

Q. How does Order No. 841 reduce barriers to battery storage participating in the wholesale electric market?

A. Order No. 841 amends the Commission's regulations to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by Regional Transmission Organizations ("RTO") and Independent System Operators ("ISO"). The FERC requires that each RTO and ISO establish a participation model that must:

> (1) ensure that a resource using the participation model is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing in the RTO/ISO markets;
>
> (2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price;
>
> (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and
>
> (4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.
>
> (5) Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price.
>
> *Order No. 841*, 162 FERC ¶ 61,127 at P 4 (2018).

These changes will allow electric storage operators to capture additional value within RTO/ISO markets previously unavailable and increase their profitability.

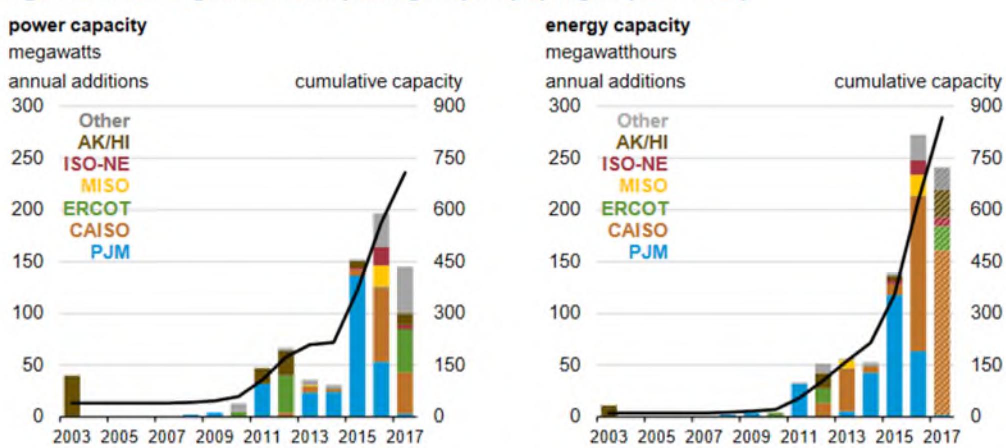
Q. Is the cost of battery storage declining, similar to the declining cost of wind and solar energy?

A. Yes. The NREL report "Q3/Q4 2019 Solar Industry Update", published February 18, 2020, explains that the average lithium-ion battery pack price from 2010 to 2019 fell 87 percent, dropping 13 percent from 2018 to 2019 alone. The NREL reports that 2019 average battery pack price was $156/kWh and that "BNEF expects average battery price to fall to $93/kWh by 2024 and $61/kWh by 2030." *See* Exhibit No. TCO-043 at 48.

The benefits of battery storage coupled with declining costs have led to an increasing amount of battery storage capacity across the U.S. in recent years. A chart published by the EIA in a report titled "U.S. Battery Storage Trends" (May 2018, https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf) shows a significant increase in battery storage capacity within the last decade.

Chart 5

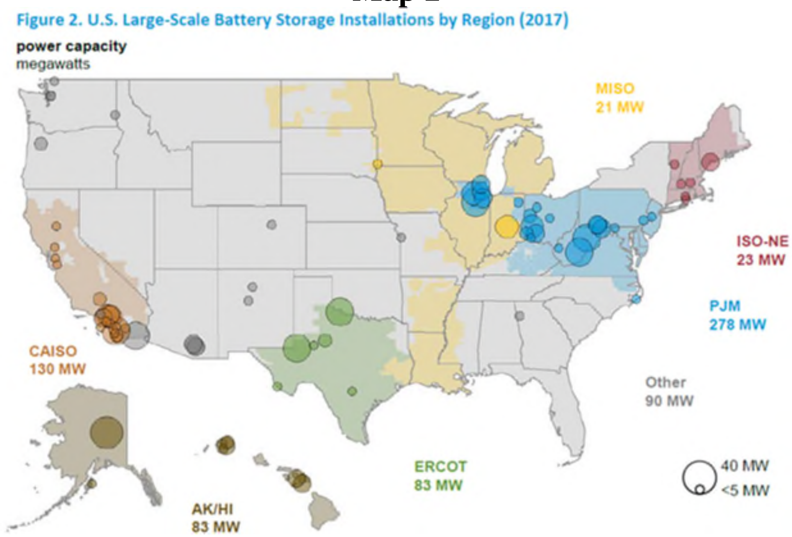
Figure ES1. U.S. Large-Scale Battery Storage Capacity by Region (2003–2017)



Notes: 2017 energy capacity data for large-scale battery storage are based on preliminary estimates; energy capacity annual additions do not include 26 MW of since-retired batteries because energy capacity is not reported for retired generators
Sources: U.S. Energy Information Administration, Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*; U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*.

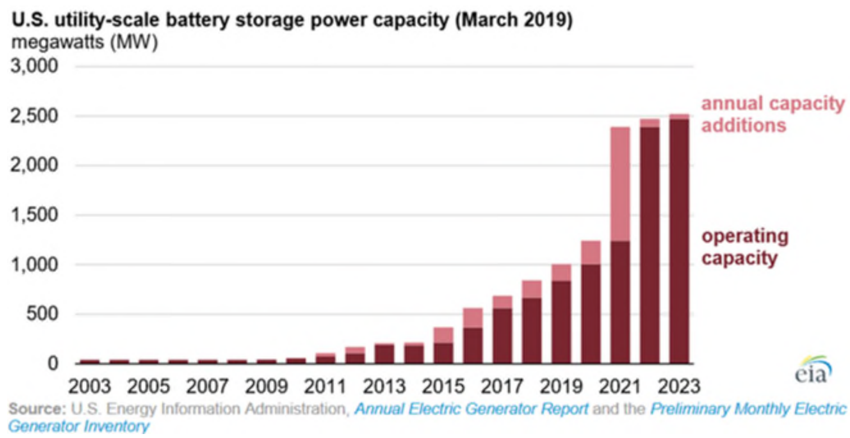
The report also shows that many battery storage facilities are located in or near the Columbia footprint:

Map 2



Furthermore, on July 10, 2019, the EIA noted that "U.S. utility-scale battery storage is expected to grow substantially by 2023" (https://www.eia.gov/todayinenergy/detail.php?id=40072), as illustrated in Chart 6 below.

Chart 6

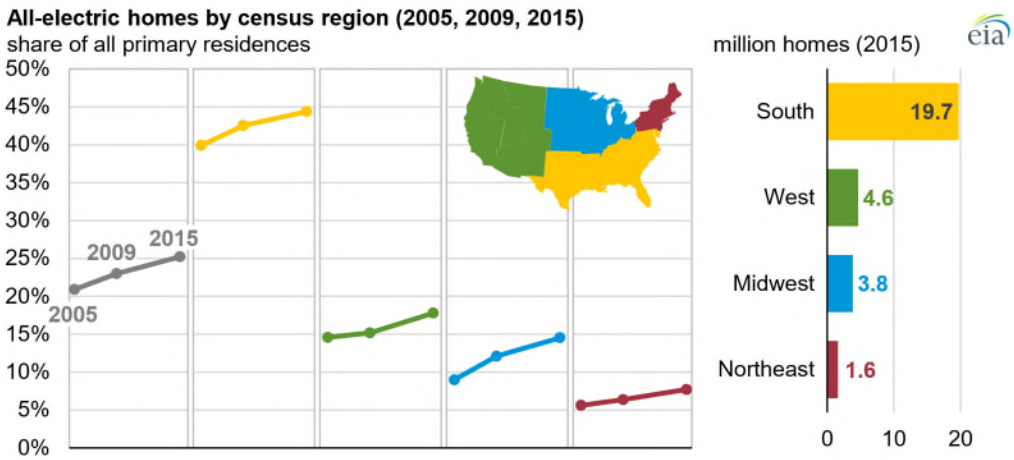


The continued decline in battery storage costs combined with renewable generation from solar and wind will cause renewable energy to be significantly more competitive by 2030 or earlier.

Q. Is there reason to believe that the adoption of renewable energy can displace natural gas demand in the residential, commercial and industrial sectors?

A Yes. Renewable energy sources can already displace a multitude of traditional sources of natural gas demand. Regarding residential demand for natural gas, an EIA article from May 2019 illustrates that one out of four homes in the United States are *all electric* (i.e., they do not directly consume any natural gas), and this percentage has been growing as shown on Chart 7 below:

Chart 7



See https://www.eia.gov/todayinenergy/detail.php?id=39293.

The EIA data demonstrates that not only is it possible for members of the residential sector to directly consume no natural gas, the percentage of the sector that utilizes no natural gas is growing.

NREL has also done significant research regarding the electrification of all sectors of the U.S. Economy. A report by NREL released December 2017 titled "Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050" (accessible at https://www.nrel.gov/docs/fy18osti/70485.pdf) was "designed to examine electric technology advancement and adoption for end uses in all major economic sectors as well as electricity consumption growth and load profiles, future power system infrastructure development and operations, and the economic and environmental implications of widespread electrification." Regarding the residential sector, NREL found:

> "[f]or the two residential end uses, the LCOSs [levelized cost of services] based on the cost and performance projections demonstrate that even with moderate near- to mid-term improvements, ASHPs [air-source heat pumps] and HPWHs [heat pump water heaters] could achieve cost parity with existing technologies by the beginning to end of the next decade, and with continued improvements could become substantially lower cost in the 2040–2050 timeframe.
>
> *Id*. at 51.

Thus, NREL finds that air-source heat pumps and heat pump water heaters, offering electric-based space-heating and water-heating, are likely to be at cost-parity with natural gas space-heating and water-heating between 2020 and 2030, and are likely to be "substantially lower cost" between 2040 and 2050. NREL projects there to be substantial economic benefits for the residential sector to electrify its energy consumption within the next 10 to 30 years.

NREL also finds electrification possibilities in the commercial sector. NREL states that in the commercial sector "heat pump technologies for space heating applications in warm or moderate climates can become cost-competitive by the end of 2040 with only limited improvement and within the next 10 years with faster improvements." *Id.* at 51. NREL concludes:

> The LCOSs … demonstrate that with only modest improvements in cost and performance, residential and commercial heat pump technologies could achieve cost parity with incumbent technologies. Cost parity would likely result in substantial increases in adoption. Of course, cost parity is not the sole determinant of adoption, and other beneficial attributes of heat pumps could induce increased their uptake, including their dual functionality (both heating and cooling services), superior safety relative to combustion based technologies, and increased

> controllability, while additional barriers to adoption, such as lack of customer awareness and installer knowledge of heat pump systems, and split-incentive or landlord-tenant problems could limit adoption even with achievement of cost parity.
>
> *Id.* at 52.

NREL notes several additional non-cost related benefits to electrification.

The NREL report also examined the DOE's Industry Assessment Center's database in its evaluation of the industrial sector. NREL found that most electrification-relevant offered a simple payback within 5 years:

> - Use Immersion Heating in Tanks, Melting Pots, etc.: **2 Years**
> - Convert Liquid Heaters from Underfiring to Immersion or Submersion Heating: **3 Years**
> - Replace Fossil Fuel Equipment with Electrical Equipment: **2 Years**
> - Use Electric Heat in Place of Fossil Fuel Heating System: **1 Year**
> - Replace Hydraulic/Pneumatic Equipment with Electrical Equipment: **2 Years**
> - Replace Gas- Fired Absorption Air Conditioners with Electric Units: **4 Years**
> - Use Heat Pump for Space Conditioning: **5 Years**
>
> *Id*. at 60.

Thus, NREL did identify possible areas for the economic electrification of many sources of industrial energy demand, though it did note that "the literature on future electric technologies ("electrotechnologies") is insufficient to develop informed and plausible cost and efficiency sensitivity cases" and it did find that electric boilers were not economic under 2015 electric and natural gas prices. *Id.* at 66 and 63.

Q. You previously presented EIA AEO projections that generally show increased natural gas production in future years, as opposed to declining production (and consumption). How does this reconcile with your evidence regarding natural gas demand and its uncertainty?

A. I acknowledge that natural gas is currently a useful and integral part of U.S. energy infrastructure and will continue to be so in the short-run. However, just as state and local government policies, economics, technological developments, and consumer demand are currently responsible for the increasing capacity of both renewable energy and natural gas-fired-generation as it displaces coal-fired generation, those factors, at a minimum, also cause substantial uncertainty over the long-run demand for natural gas. The cost trends that I presented earlier suggest that the combination of declining costs of renewable energy and battery storage will cause natural gas to be a relatively high marginal cost source of energy in the future. Such a development would lead to the future underutilization of natural gas pipeline capacity due to a lack of demand for natural gas-fired generation as well and other uses due to electrification. Unlike a situation where a decline in natural gas supply (but stable demand) can result in a reevaluation of a pipeline's economic life and allow for an earlier recovery of a pipeline's fixed costs, there is no equivalent possibility in the event that natural gas demand begins to decline. Since declining demand results in a lower willingness-to-pay by shippers, a decline in demand (but stable supply) presents a situation where a pipeline will be unable to effectively increase its rates to reflect reduced billing determinants that would allow it to recover its cost of service (inclusive of recovery of the net book cost of plant). And at some point, as discussed above for example in the case of Dominion Energy, Inc.'s Questar Southern Trails pipeline, the pipeline must file for abandonment when the remaining demand is insufficient to enable it to operate economically.

Furthermore, there are examples that illustrate the great uncertainty involved in the EIA's AEO under even relatively short time horizons. In its "Annual Energy Outlook

Retrospective Review," (https://www.eia.gov/outlooks/aeo/retrospective/) the EIA shows that its 2006 Annual Energy Outlook overestimated 2017 coal production by a whopping 83.4 percent, a significant difference over only a 10-year period. While it is true that much of the projected coal consumption was likely displaced by natural gas during this period, many of the factors that caused natural gas to displace coal may be similar to those that will eventually cause renewable energy to displace natural gas in the future. Another example that illustrates the uncertainty which underlies projections of the future is that the EIA's AEO had not incorporated battery storage into its projections until 2018 (*see, e.g.*, "Assumptions to AEO 2018" in the "Electricity Market Module" section and compare to past years at https://www.eia.gov/outlooks/archive/aeo18/assumptions/ noting that "battery storage" is not mentioned prior to the 2018 AEO). Given battery storage's importance to the adoption of renewable energy, projections of renewable energy adoption are likely to be highly sensitive to assumptions on battery storage.

Q. What are your conclusions concerning the future demand for Columbia's services?

A. Although my review of gas supply in Section II demonstrates that sufficient supply may be available to Columbia over the next 35 years across the Eastern U.S. Region, the factors discussed throughout Section III demonstrate that natural gas demand is highly uncertain. In addition to government policies and the RPS discussed earlier, market forces due to the dramatic declines in the projected prices of wind and solar power and battery storage are likely to reduce the demand for Columbia's services.

IV. ECONOMIC LIFE OF COLUMBIA

Q. Based on the factors you have discussed, what is Columbia's economic life?

A. While there are natural gas resources that can support 35 years of supply, there is also significant risk to Columbia's economic life in the coming decades due to diminished demand caused by the requirements of the public authorities of the state and local governments on and near Columbia's footprint, and significant competitive pressure from renewable sources of energy and battery storage within the next three decades. Local, state, and federal regulations, such as RPS and FERC's Order No. 841 will place downward pressure on the demand for natural gas. Based on these factors, there is reliable evidence to support an economic life for Columbia limited to 35 years. Furthermore, there is significant asymmetry in a pipeline's ability to recover its fixed costs if an unreasonably long economic life (one which does not consider the significant demand uncertainty over time) is adopted, while there is no possibility to over-recover a pipeline's fixed costs where a more conservative economic life is utilized. For these reasons, I conservatively support a 35-year economic life for Columbia.

Q. Regarding the asymmetry you mentioned, if the Commission accepts a remaining economic life that, once more years have passed, turns out to be too long due to unanticipated falling demand, can the pipeline simply make a section 4 rate filing to increase its rates based on a shorter economic life?

A. While a pipeline could make such a rate filing, if demand for Columbia's services has fallen, so too would the shippers' willingness to pay for Columbia's services, all else being equal. If Columbia were to file a new rate case in an attempt to increase its rates to reflect a shorter economic life due to declining demand after demand is already declining, Columbia's ability to receive its filed recourse rates become less and less likely. Increasing rates in a declining demand scenario risks setting up a reinforcing feedback loop where unit costs rise as throughput declines, which in turn leads to further cost increases and further loss of throughput. Any foregone depreciation accruals would also most likely never be recovered.

Q. If the Commission accepts an economic life that, once more years have passed, turns out to be too short, will the pipeline over-collect its plant investment through depreciation?

A. A pipeline cannot recover more than its plant investment through depreciation in a scenario where a more conservative economic life is initially adopted that later turns out to be too conservation. This is because the economic life determines, in part, the amount of depreciation dollars that a pipeline can collect each year, dollars that can only be booked as depreciation once. Depreciation accruals cease when an asset becomes fully depreciated. If such a scenario occurs, the pipeline's economic life can be revisited in future rate cases such that there is intergenerational equity among the customers expected to utilize the pipeline's services.

Q. Does this conclude your Prepared Direct Testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Columbia Gas Transmission, LLC) Docket No. RP20-____-000

District of Columbia)
) ss.
District of Columbia)

AFFIDAVIT OF ALEXANDER KIRK

Alexander Kirk, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Alexander Kirk"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Alexander Kirk's sworn testimony in this proceeding.

Alex Kirk
Alexander Kirk

SWORN TO AND SUBSCRIBED BEFORE ME THIS 21st DAY OF JULY, 2020.

STEPHANIE J. WILKERSON
NOTARY PUBLIC
EXP. 9-14-24
DISTRICT OF COLUMBIA

Stephanie Wilkerson
Notary Public

STEPHANIE J. WILKERSON
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires September 14, 2024

2021 Vision Forward:
Addressing Climate Change Together

Interstate Natural Gas Association of America

As America's energy leaders, INGAA's members recognize the need to build upon our efforts and to continue to act to address global climate change by advancing our commitment to minimize and reduce greenhouse gas (GHG) emissions, including methane emissions. INGAA members are determined to lead the effort to modernize our nation's interstate natural gas delivery network infrastructure with a goal of reducing emissions and helping minimize the impact on our climate.

Our commitments will include an active effort to do even more to address climate change by supporting renewables, as well as new and innovative technologies and process enhancements that will further reduce emissions. Working together, we are determined to support sound public policies that protect the environment while ensuring a safe, reliable and resilient energy transmission system that provides the affordable energy so many of our businesses and families need.

LOOKING AHEAD: THE ROLE OF NATURAL GAS

Addressing the problem of climate change requires us to recognize how best to reduce emissions while meeting the growing energy needs of our communities and the nation. Natural gas is and will remain a critical partner to building a cleaner energy future. Natural gas not only empowers critical energy services vital to our current and future economy, it also serves as the energy foundation to every aspect of our daily life. Because of our collective action, the adoption of natural gas has contributed to historic reductions in emissions.

Key Fact

In 2019, natural gas was the largest source of electric power generation in the U.S. (38%).[1] Fuel switching to natural gas has allowed the country to make rapid reductions in carbon dioxide emissions. According to the EIA, between 2005 – 2019, carbon dioxide emissions from the U.S power sector declined by 33%, with natural gas accounting for more than half of those reductions.[2]

Building on these environmental benefits, natural gas also continues to provide a more reliable and affordable energy source for tens of millions of homes and small businesses. Natural gas, and the infrastructure that delivers this vital fuel, is used to support critical business and industries such as restaurants, pharmaceutical research, refining, plastics, and electric power plants. During periods of both economic crisis and prosperity, these business and industries use natural gas to produce the products and services that our communities and hard-working families rely on such as electricity, food preparation, cars, cell phones, computers, prescription drugs, and so much more.

Natural gas is and will continue to be the back-bone fuel for America's economy, delivering 1/3 of the total energy in the U.S.[3] Even as INGAA's members recognize the important societal benefits of natural gas, we know that more must be done to reduce emissions that contribute to climate change. We are committed to working together and developing more innovative policies and practices with a goal of significantly reducing emissions even further over the next several decades.

Solving Problems Together

Overcoming the dual challenges of addressing climate change while continuing to deliver affordable and reliable energy will require governments, industry, consumers, non-government organizations, and all stakeholders to work together like never before to develop and implement sustainable, practical and near- and long-term solutions that benefit our shared goals.

2021 Vision Forward: Our Clean Energy Commitments

As part of our commitment to building a cleaner energy future, INGAA's members commit to the following:

1. Reducing their individual GHG emissions from their natural gas transmission and storage operations and to setting and meeting their individual emission reduction goals.
2. Identifying and continuing to implement long-term strategies to transition the industry and the individual INGAA member companies to lower emissions, while working as an industry towards reaching net-zero GHG emissions from natural gas transmission and storage operations by no later than 2050, supported by necessary technology advancements and sound public policy initiatives.
3. Providing consistent and transparent data collection, measurement, and reporting of GHG emissions from operations to support that INGAA members are making actionable progress to achieve our shared climate goals.
4. Reducing both the carbon intensity of our natural gas infrastructure, as well as supporting the reduction of net global GHG emissions by adopting and investing in more innovative technologies such as renewable natural gas (RNG), carbon capture, and other carbon solutions and transporting low or no-carbon fuels.
5. Working together with customers, governments, non-governmental organizations, and other stakeholders to accelerate efforts to reduce and minimize all GHG emissions across the entire natural gas value chain through the adoption of innovative solutions.
6. Investing in responsible environmental stewardship and practices as part of our efforts to modernize our nation's natural gas infrastructure, including supporting meaningful and positive engagement with the communities in which we operate.

Providing cleaner, safer, reliable, and more affordable energy is achievable, and our nation's natural gas transmission infrastructure is central to achieving these essential goals. Our vision forward is defined by our shared commitment to our environment, our communities, and all our families.

We recognize that sustainability and protecting our environment is not simply a choice; it is goal that can be achieved by working together with a clear belief that building a stronger and more equitable economy goes hand in hand with creating a cleaner world. Now, more than ever, INGAA is committed to supporting its members and their efforts to reduce GHG emissions as we all work together to address the issue of climate change.

—

1. https://www.eia.gov/todayinenergy/detail.php?id=43035#.
2. https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T11.06#/?f=A&start=1973&end=2019&charted=0-1-6.
3. https://www.eia.gov/energyexplained/us-energy-facts/.

2021 Vision Forward:

Innovating Towards a Cleaner Energy Future

INGAA
Interstate Natural Gas Association of America

As part of our vision forward, INGAA's members commit to investing in and undertaking a wide variety of initiatives as we strive to help build and support the adoption of more innovative technologies and smarter energy policies.

Through the use of more innovative technologies and process improvements, the United States is continuously advancing its ability to produce, transport, store, and deploy natural gas, a vital and foundational fuel, while further reducing GHG emissions.

Going forward, INGAA's members are further committed to supporting continued innovation which will be essential and necessary to achieve our long-term GHG emission reduction goals.

Reducing GHG Emissions: The Role of Innovative Technologies

By investing in and adopting innovative technologies and encouraging and working with other portions of the natural gas value chain to do the same, we can drive emissions even lower. INGAA's members are committed to reducing both the carbon intensity of the natural gas network and supporting the reduction of the absolute quantity of global GHG emissions derived from the energy we deliver. Reducing both the carbon intensity and the overall emissions will be important as economies around the world convert to a lower carbon future. INGAA's policies and innovative practices going forward are based on the following principles:

Innovating Our Delivery Infrastructure

While batteries may be able to address some energy storage needs, finding a solution that is scalable, cost-effective, addresses long-term and seasonal needs and that keeps energy affordable and reliable, is essential. Our nation's natural gas infrastructure has the capacity to safely, cost-effectively transport and store vast amounts of alternative energy. Over the coming decades, our nation's natural gas infrastructure network is well-suited to deliver lower-carbon fuels even as we grow our use of more renewable energy.

1. To support the growth of renewable energy and generation technology, we are committed to providing the services necessary for flexible, fast-ramping generation and reliable energy storage to help minimize the risk of power disruptions and black/brown outs during periods of peak demand.
2. To further reduce GHG emissions, we will continue to transport renewable natural gas (RNG) across our delivery infrastructure. RNG provides a beneficial use of waste methane from other sectors, such as methane from agriculture and food waste, resulting in an impactful reduction in GHGs. Increasing the access to and use of RNG will help provide carbon-neutral/potentially carbon-negative fuel and accelerate our progress toward a clean energy future through infrastructure largely already in place.
3. We are evaluating the potential application for hydrogen blending in existing natural gas systems. We are encouraged by the results of research and development programs that are exploring the potential to deliver new lower-carbon fuels through existing, repurposed or new delivery systems.
4. We are prepared to expand the natural gas transmission system which can affordably provide the long-term energy storage across an energy system that is safe, flexible, and reliable, which supports the increased investment in renewable energy.
5. We are committed to the further research and development of promising new technologies, such as RNG sources, renewable hydrogen, carbon capture, utilization, and sequestration (CCUS), and power to gas technologies to even further reduce emissions.

2021 Vision Forward:
Developing More Constructive Energy Policy

Interstate Natural Gas Association of America

As part of our ongoing commitment to the environment and addressing climate change, members of INGAA have taken many significant steps to minimize methane emissions across our operations. As part of our 2021 vision forward, we are renewing our public commitment to build a cleaner energy future.

Across INGAA, our members will continue to advance constructive ideas and positions that are beneficial to our shared environment, as well as our customers, communities, and employees.

To meet these critical climate change goals, we are committed to active and constructive engagement with government officials, investors, and a wide variety of other public and private stakeholders. Developing more constructive energy policy that utilizes our national gas transmission infrastructure, benefits our environment, and reduces emissions can be accomplished through policies and practices that support and encourage more innovation while ensuring that the cleaner energy our nation needs remains safe, reliable, and affordable.

For INGAA's members, the principles that should shape constructive energy policy include the following:

1. Investments in natural gas infrastructure should enable citizens and businesses to benefit from stable and affordable energy costs, which will help our nation recover from the negative economic impacts of the Covid-19 pandemic, support the creation of jobs, fuel economic growth, and encourage implementation of projects to minimize GHG emissions.
2. We support equitable, efficient, effective, and flexible federal policy designed to minimize and reduce emissions across the entire economy, and a recognition that all sectors of the economy should contribute to any new federal emission reduction policies. Policies to address climate, including any policies that include a price on carbon or clean energy standards, must also diminish potential adverse financial impacts on consumers and avoid harm to the U.S. economy.
3. New energy and climate policies should avoid or mitigate adverse climate, environmental and economic impacts on disadvantaged communities and should be based upon meaningful engagement with such populations.
4. Funding for new energy innovations should include investment into research, development, demonstration and deployment of additional technologies to address climate change, such as renewable natural gas (RNG) sources, renewable hydrogen, carbon capture, utilization, and sequestration (CCUS), and gas to power technologies.
5. Efforts to address climate change should recognize the immediate emissions reductions derived from utilizing natural gas, and should recognize how natural gas is an energy partner that will enable the expansion of renewable and other energy technologies.
6. To help improve air quality and reduce carbon emissions globally, policy makers should recognize that through liquefied natural gas (LNG) exports, the U.S. is well-positioned to help other countries significantly and immediately reduce their reliance on higher carbon intensity fuels.
7. More constructive energy policies should support the modernization of natural gas infrastructure, which is key to minimizing GHG emissions and ensuring the development of safer, more reliable, and resilient infrastructure. Energy policies should not only promote greater development and use of RNG, hydrogen, CCUS, and other innovative technologies, but should also recognize and encourage the use of the natural gas system that will support the growth of both renewables and future energy storage capabilities.
8. The development of more effective public policy that reduces GHG emissions should also provide consumers with the option of utilizing natural gas and preserving customer choice of energy. Given the vital partnership between natural gas and the adoption of more renewable energy, it is critical that policies strengthen this foundational relationship as we develop more comprehensive and equitable climate change solutions.

Record of Emissions Reduction

INGAA members have historically implemented measures to minimize GHG emissions. According to data reported to USEPA, these efforts have resulted in a reduction of CO2-equivalent emissions from transmission and storage compressor stations that is the equivalent of removing more than one million passenger vehicles from the road. Many INGAA members are also members of EPA's Natural Gas STAR and Methane Challenge Programs, ONE Future, and various state GHG reduction programs.

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-

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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]

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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;
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> (2) evaluate both secured capacity[8] and available capacity[9] to meet demand and reliability targets; and
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> (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

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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.

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[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

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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:

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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 Statement F

Current and Proposed Parameters

Vintage Group Procedure

		Current Parameters						Proposed Parameters					
	Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	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

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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.

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-

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[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:

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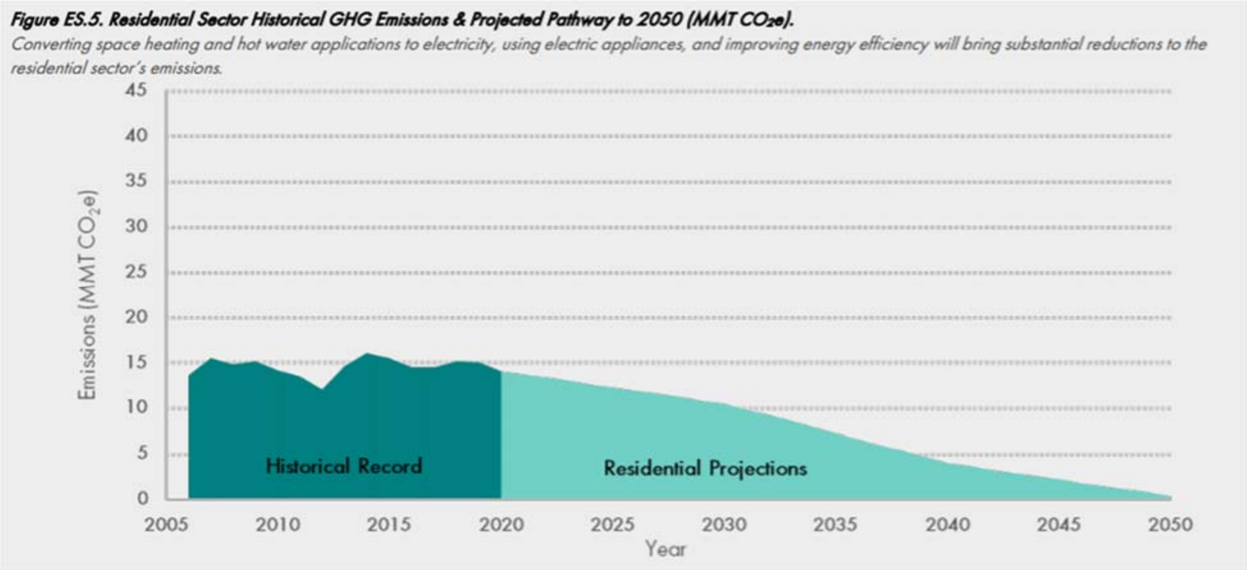
[25] *In the Matter of the Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2020*, Motion of the Environmental Defense Fund, BPU Docket No. GR19050676 at page 3 (June 17, 2019) (explaining 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.



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

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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

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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

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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

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[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

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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]

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[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 <u>existing</u> 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:

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[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.

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[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

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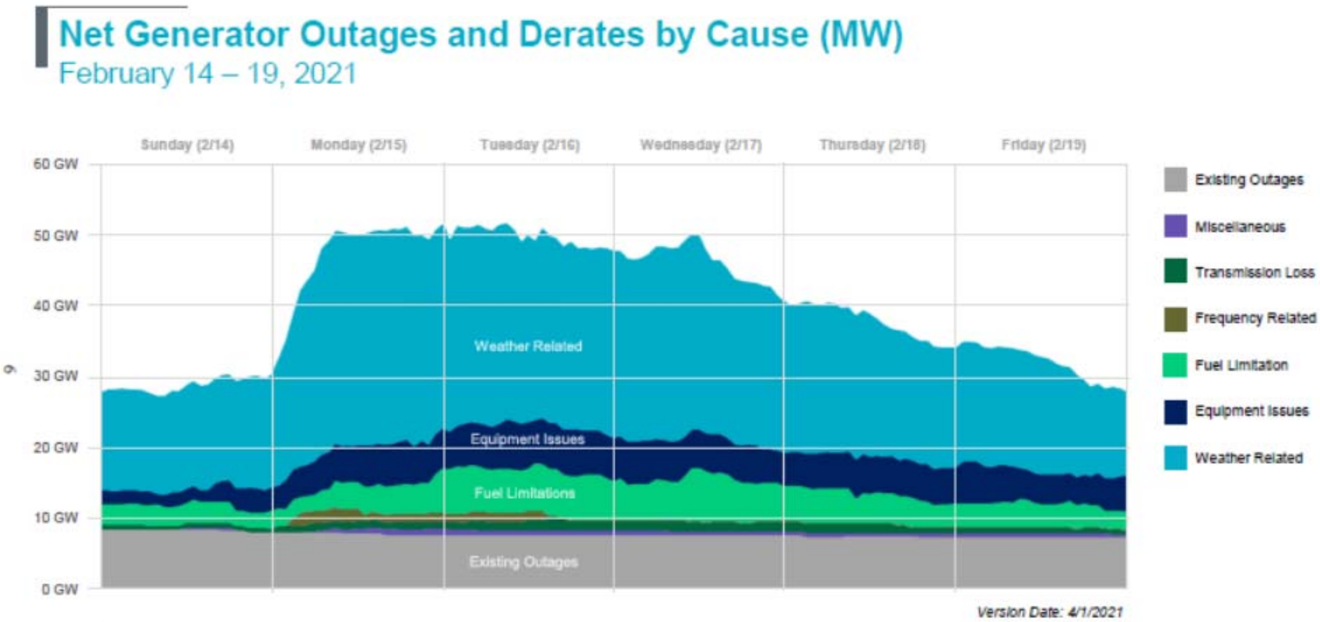
[59] EDF, Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California at p25 (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

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.

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[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

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EDF-6

Part 1

History of Laclede/Spire Firm Interstate Capacity Holdings

Mkt Area	Direct Connect	Jan 2021	Jan 2017	2021 v. 2017	Pctg Change	Jan 2011	2020 v. 2011	Pctg Change
Spire St. Louis	MRT	480,779	660,329	(179,550)	-27.2%	664,738	(183,959)	-27.7%
Spire St. Louis	MOGAS	145,600	62,800	82,800	131.8%	62,800	82,800	131.8%
Spire St. Louis	SSCGP	30,502	30,502	0	0.0%	31,508	(1,006)	-3.2%
Spire St. Louis	STL	350,000	0	350,000	infinite	0	350,000	infinite
Spire St. Louis	**Total**	**1,006,881**	**753,631**	**253,250**	**33.6%**	**759,046**	**247,835**	**32.7%**
Spire Rest of MO.	SSCGP	795,282	757,188	38,094	5.0%	757,188	38,094	5.0%
Spire Rest of MO.	Tallgrass	110,000	145,000	(35,000)	-24.1%	150,000	(40,000)	-26.7%
Spire Rest of MO.	PEPL	22,062	22,062	0	0.0%	22,062	0	0.0%
Spire Rest of MO.	Total Capacity	**927,344**	**924,250**	**3,094**	**0.3%**	**929,250**	**(1,906)**	**-0.2%**
Addl Supply Area	Feeder Capacity	415,165	639,937	(224,772)	-35.1%	606,918	(191,753)	-31.6%
All Spire Mo. Delivery Capacity		1,934,225	1,677,881	256,344	15.3%	1,688,296	245,929	14.6%

Firm, contracted, direct connect capacity serving the St. Louis market of Spire the LDC declined slightly from 2011 to 2017 (from 759,046 Dth per day to 753,631 Dth per day) before increasing to 1,006,881 after the introduction of Spire STL; an increase of 33.6% in contracted capacity.

Firm, contracted, direct connect capacity serving the rest of Spire Missouri's market declined slightly from 2011 to 2017 (from 929,250 Dth per day to 925,250 Dth per day) before increasing slightly to 927,344 Dth per day an increase of 0.3% from 2017 but still below 2011 levels.

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Part 2

Unsubscribed Capacity Available to Serve the St. Louis Market.

TSP Name:	MoGas Pipeline, LLC						
TSP:	2595932						
Posting Date/Time:	March 3, 2021 01:39 AM CT						
Eff Gas Day	3-Mar-21						
End Eff Gas Day:	4-Mar-21						
Capacity Type Description	Unsubscribed capacity available from the pipeline						
<< Previous Day	Next Day >>						
Location Name	Loc	Loc Purp Desc	Loc/QTI	Design Capacity	Unsub Cap		
Ameren Zone2 AP	1130	Delivery Location	RDQ	16,000	8,625		
Cuba	1100	Delivery Location	RDQ	11,000	9,250		
Fort Leonard Wood	1180	Delivery Location	RDQ	41,000	34,800		
From MRT	2010	Receipt Location	RDQ	51,000	49,309		**Lesser of Receipt or Delivery**
From REX	2020	Receipt Location	RDQ	450,000	410,750	From	
Laclede AP	1010	Delivery Location	RDQ	537,000	391,400	To	**391,400**
Highway N	1040	Delivery Location	RDQ	41,000	23,163		
PEPL	2000	Receipt Location	RDQ	140,000	89,124		
To MRT	2011	Delivery Location	RDQ	100,000	100,000		
Spire STL Pipeline	2040A	Receipt Location	RDQ	0	-90,600		
St. James	1120	Delivery Location	RDQ	11,000	9,320		
St. Robert	1160	Delivery Location	RDQ	11,000	10,150		
Waynesville	1170	Delivery Location	RDQ	11,000	9,875		
Willard	1150	Delivery Location	RDQ	4,000	4,000		
Winfield	1000	Delivery Location	RDQ	41,000	41,000		
Change date to:							
March 4, 2021							
Measurement Basis Description: Million BTU's (Dth)					391,400	To Laclede From Rex on **MOGAS**	
					135,548	To Laclede from NGPL Shattuck on **MRT** (See Attachment Part 2a)	
					50,000	Potential Add'l to Laclede on **MRT** from **MOGAS** or **Illinois Intrastate** (owned by MRT) (See Attachment Part 2a)	
					576,948	Total of all Sources	
					526,948	Total without Potential Add'l on MRT	

The yellow highlighted lines are MOGAS posting of unsubscribed capacity.

The green highlighted and aqua highlighted capacities are from the Enable MRT posting of unsubscribed capacity presented on this Attachment's Part 2a

EDF-6 Part 2a

UNSUBSCRIBED CAPACITY
TSP Name: ENABLE MISSISSIPPI RIVER TRANSMISSION, LLC
TSP: 006968077
Posting Date/Posting Time: 02/24/21 4:01:18 PM
Effective Gas Day: 02/25/21
Ending Effective Gas Day: 02/26/21
Meas Basis Desc: MMBtu

Note: Most Locations eliminated that do not relate to Capacity Available to serve to Laclede:

Loc	Location Name	Loc Purp	Loc/QTI	Loc Zone	Unsubscribed Capacity		
805523	TRIGEN ENERGY-ST LOUIS	Delivery Location	DPQ	M	12,500		
805526	SPIRE MO AGGREGATE	Delivery Location	DPQ	M	349,116		**This is the "To"**
805527	HAZEN, CITY OF	Delivery Location	DPQ	M	757		
805549	PERRYVILLE-CEGT/ANR	Delivery Location	DPQ	F	750,000		
805588	NGPL @ SHATTUC/CLINTON	Receipt Location	RPQ	M	238,379		**This is the "From" on the East Line that feeds Spire in Missouri**
805589	NGPL @ HARRISON	Receipt Location	RPQ	F	100,000		
805824	WEST LINE CAPACITY	Mainline	MLQ	F	0	(2)	
808396	LACLEDE AGGRET RECEIPT	Receipt Location	RPQ	M	22,000		
808471	EAST LINE CAPACITY	Mainline	MLQ	M	135,548	(5)	**This is the limit of Capacity between the "From"and the "To".**
808472	MAIN LINE NORTH	Mainline	MLQ	M	0	(3)	
808473	MAIN LINE SOUTH	Mainline	MLQ	F	0	(4)	
808478	WESTLINE BACKHAUL	Mainline	MLQ	F	50,000	(1)	
808754	RETICULATED	Mainline	MLQ	M	50,000	(6)	
808760	GULF SOUTH PERRYVILLE	Receipt Location	RPQ	F	111,339		

COMMENTS AND NOTES

MRT may also have available primary capacity for transportation under Rate Schedule FT from time to time along various segments of the above Main Line North capacity. Interested shippers should review receipt and/or delivery point unsubscribed capacity amounts and locations. Any such capacity will be subject to the general terms and conditions of MRTs currently effective tariff, including provisions of Section 8 which addresses nominations, scheduling, constant flow rate obligations and other conditions contained therein. Interested shippers should contact their designated Commercial representative at 636-812-7123 or 636-812-7121.

(1) West Line Capacity, westbound to EGT Dixie and/or EGT AM-200
(2) West Line Capacity, eastbound to storage and/or Field Zone Main Line
(3) Main Line Capacity, northbound to Field Zone or Market Zone delivery points
(4) Main Line Capacity, southbound from EGT Glendale receipt point to Main Line delivery points
(5) East Line receipt points to certain Market Zone delivery points **Market Zone here is Spire MO Aggregate**
(6) MoGas and/or Illinois Intrastate Transmission receipts to certain Market Zone delivery points **This could be additional capacity to fill the 349,116 of Spire MO Aggregate from MOGAS at REX**

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DECLARATION OF JACOB GETTINGS, JR.

I, Jacob Gettings, Jr., declare as follows:

1. My name is Jacob Gettings, Jr. I am over the age of 18 and competent to give this declaration. The following information is based on my experience and personal knowledge.

2. I am a member of Environmental Defense Fund. I have been a member since before the commencement of this lawsuit.

3. I primarily reside at 3471 Lollar Branch Road, Sullivan, Missouri.

4. I reside part-time in Jerseyville, Illinois, where I own a home that is connected to my family farm. I own the home on six acres of land, and my wife Patricia Gettings and I are part owners—through a family trust—of a 280-acre tract of land that has been in the family since 1965 (with the exception of 20 acres that we purchased later in the 1960s). In consultation with my parents and siblings, I oversee the day-to-day management of the land. My wife and I stay at our Jerseyville home three to four times per month. We check on the property to make sure things are running smoothly on the farm and we enjoy visiting our home.

5. The Spire STL Pipeline crosses our Jerseyville property for a distance of approximately half a mile. When I first heard about the project, I was opposed to the pipeline crossing my land because it would disrupt farming, violate the integrity of the property by transecting the land, negatively affect my family's

future plans for the land, and pose a safety risk to me, my family, my house, and my land. Those concerns have become a reality, and in some ways the construction process was even more disruptive and harmful to my property than I expected. I continue to be opposed to the Spire STL Pipeline crossing my land and suffer continuing harms from the presence of the pipeline on my land.

History and Use of the Property

6. The property has historically been used for agriculture. In my experience it is highly productive farmland with high-quality topsoil. My family has grown corn, soybeans, and wheat on the property. We have been good stewards of the land, and I did everything I could to build our soil productivity. I began implementing organic practices and crop rotations in the 1990s, and we previously maintained a section of the farm where we grew certified organic soybeans and corn.

7. Currently, an individual leases most of the land from me and farms it. He grows corn and soybeans. I have great confidence that our tenant exercises care and attention to be a good steward of our agricultural land.

8. In the future, I expect that the property will become part of a solar farm. I entered an agreement with Orion Renewable Energy Group in 2016, a company that is planning to develop a solar energy generation field in southwest Illinois. It is my understanding that Orion is in the process of finalizing its

approvals and funding for the solar project. When the project is fully approved and funded, Orion will install solar panels on my family property and it will be part of a 1,000-acre solar field. Under the agreement with Orion, the developer will lease my land for at least 30 years, with the option to extend for another 20 years. I am excited to see my family's land contribute to the production of clean energy.

Effect of the Spire STL Pipeline

9. I was first approached by a representative of Spire STL in spring 2018. The representative offered a contract to buy out the section of my land where Spire STL planned to build the pipeline. I did not want to sell because I did not want my property to be disrupted by the construction process and the ongoing operation of a pipeline. The representative emphasized to me from the beginning that Spire STL could file an eminent domain lawsuit to take my land if I declined to sell it to them outright. I was upset and concerned.

10. From my research and knowledge as a resident of this region, it does not seem like a new pipeline was necessary to serve St. Louis. I am not opposed to all pipelines, but I do not think my land should be damaged to construct something that is not actually needed.

11. Because I am opposed to the pipeline crossing my property, I did not allow Spire STL staff or contractors onto my land to conduct surveys or any other work until I was required to. I am aware that the Federal Energy Regulatory

Commission approved Spire STL's application to build the pipeline in August 2018. I am aware that later that month, Spire STL filed a condemnation action in the U.S. District Court for the Southern District of Illinois, seeking possession of my land and the land of others in the area who did not want to accept the developer's buyout offer. Through the condemnation action, Spire STL seeks to take title to approximately seven acres of land on my family's property.

12. I am aware that on December 12, 2018, the court issued an order granting Spire STL's request for a preliminary injunction, allowing the developer to take immediate possession of parcels of land. As a result of that order, Spire STL was allowed to take possession of a section of my land, 90 feet wide and about half a mile long. The 90-foot width includes a 50-foot permanent easement and a 40-foot temporary easement for use during construction.

13. Spire STL began construction of the pipeline on my property in March 2019, and the work was ongoing until September 2019. The construction process caused long-term damage to the land that I continue to cope with now, and the presence of the pipeline is harmful.

14. The pipeline route is within approximately 200 feet of my home and grain storage bins located next to the house. I feel uneasy knowing that a pipeline is that close to my house. Especially now that I am aware there is gas running through the pipeline, I do not feel comfortable being there. I am worried about the

possibility, even if unlikely, of a catastrophic pipeline failure. If such a failure occurred, I am worried that the explosion could damage or destroy my house and grain bins, and result in death or serious injury to anyone inside the house. Since the Spire STL Pipeline was constructed across my family's farmland, this is a new risk I have to live with that wasn't there before.

15. The pipeline crosses my property along the edge near Grafton Lane, a county road. My family has considered the idea of developing that segment of our land into residences or businesses that could be sectioned off into smaller lots and sold. It would make sense to do this along Grafton Lane because houses or businesses there would be easily accessible from the road, and it would be easy to section off that area on the edge of our property into individual lots. As long as the pipeline is on our land, we cannot pursue this opportunity. The route of the pipeline is close to Grafton Lane, and therefore poses safety concerns. I also do not think it would be a good investment because I would not expect potential buyers to be interested in purchasing a home or business in such close proximity to a natural gas pipeline, due to safety concerns. This section of our property is now essentially unavailable for development.

16. Additionally, most of the Spire STL pipeline route on my property cuts through farmland, and the construction of the pipeline caused a significant loss of topsoil on the fields. The topsoil on my land has accumulated over decades, and

is important to its health, productivity, and value as farmland. Topsoil is where nutrient transfer takes place between soil and plants, and the roots of crops will grow deeper if there is a deeper layer of topsoil with more organic matter.

17. Spire STL did not preserve topsoil or otherwise restore the land to its prior condition, as I understand they were required to do. Based on assessments of my soil conducted in January 2019 with assistance from the local farm cooperative, and in June 2020 with assistance from the Illinois Department of Agriculture, I have approximately 21 to 28 inches of topsoil on my undamaged land—approximately two feet. I observed the construction crew set aside a much smaller depth of topsoil in piles along the pipeline route—ostensibly so that it could be added back as the top layer of soil after the pipeline was installed in the ground. But this process was not completed correctly, causing the topsoil to be mixed in with the other soil layers and lost. I conducted additional soil assessments in April and May 2020 at several points along the pipeline route, with the assistance of a soil scientist and land consultant, and those assessments show that in the aftermath of the Spire STL construction I have less than a foot of topsoil remaining.

18. The construction process also resulted in serious soil compaction along the path of the pipeline. Compacted soil contains less organic activity, making it less productive for crops. Additionally, compacted soil cannot absorb water, and can cause flooding in surrounding areas as water flows away from the

most compacted area to find a place to go. In periods of rainfall, for example, the land along either side of the pipeline route is adversely affected by this deluge of water. It makes the surrounding soil vulnerable to erosion and flooding.

19. The photo below, which was taken in November 2019, shows compacted soil and a large area of standing water on my property along the path of the Spire STL pipeline:

20. Additionally, we have subsurface drain tiles installed on my farm. The installation cost tens of thousands of dollars, and the tiles ensure good water flow across my property and prevent crops from being flooded, improving the productivity of our farmland. The tiles were installed every 50 feet, and each tile extends about a quarter of a mile across the fields. Spire STL damaged our

subsurface drain tiles where it dug into the earth and installed the pipeline. Although Spire STL installed a "bridge" that is supposed to reconnect my drain tiles across the pipeline, I do not expect the bridge to be effective in the long term as the pipeline settles into the ground.

21. The damage to the drain tiles causes me to expect that the land on either side of the pipeline will be less productive for crops. Furthermore, Orion, the solar developer that has contracted to lease my land and install a solar field in the coming years, was impressed by the subsurface drain tile system. I know that Orion viewed my drain tiles as a positive attribute of the land, because it is important to avoid standing water in the area where the solar panels will be installed. I am concerned that the damage to my drain tiles caused by Spire STL could create complications for the installation of solar panels in the future.

22. I feel that the presence of the pipeline on my family's property is invasive and harmful. The path of the pipeline is a scar on the land, a muddy dirt track where plants are only growing in very slowly right now. It will take years to return that soil to its natural state. And I feel less safe on my own property, staying at my house, because I know that a pipeline with natural gas flowing through it is buried in my backyard. For these reasons, among others, the pipeline is interfering with my enjoyment of my land.

23. Because of the ongoing injury I am dealing with from the Spire STL pipeline, I am opposed to the pipeline. I believe that the withdrawal of Spire STL's certificate under the Natural Gas Act would reduce or eliminate the risk of a pipeline rupture that could harm me, my family, and property. I would sleep better at night knowing that there is not gas flowing through the pipeline.

24. I am aware that the condemnation action, whereby Spire STL has taken possession and seeks to take title to an easement across my land, is premised upon FERC having issued a Certificate of Public Convenience and Necessity for the project. I am concerned that the harms I have detailed to the farmland—loss of topsoil, soil compaction, and damage to drain tiles—could recur in the future because the Certificate and corresponding condemnation action allow Spire STL to access its easement across my property at any time. Even if the soil is remediated in the near term, the damage could recur if Spire STL drives equipment on the pipeline route to conduct repairs or monitor the pipeline.

25. I anticipate that I will be in a better position to regain full possession of my land and avoid losing any property through condemnation if the FERC certificate is vacated. I anticipate that I will be in a better position to seek remediation of the damage to my farmland if the FERC certificate is vacated. My family and I will be in a better position to make full use and enjoyment of the land if there is no longer an easement and an active pipeline crossing the property. We

will feel much safer staying at our house, we will have more land available to use for the solar farm, and it will be easier to restore proper drainage to the fields and develop the land close to Grafton Lane.

I declare that the foregoing is true and correct.

Dated: June 23, 2020

Jacob Gettings, Jr.

DECLARATION OF GREGORY STOUT

I, Gregory Stout, declare as follows:

1. My name is Gregory Stout. I am over the age of 18 and competent to give this declaration. The following information is based on my experience and personal knowledge.

2. I am a member of Environmental Defense Fund. I have been a member since before the commencement of this lawsuit.

3. My wife, Connie Stout, and I own 40 acres of land in Jersey County, Illinois. We purchased the property in 1995, built our home, and have lived and farmed there ever since. The property includes a conservation prairie area, a pond, a barn, the house, and a wooded area behind the house. Our driveway is about half a mile long, and the house is set back from the road, making it secluded and peaceful.

4. The property is essentially made up of two parts: the front half is a conservation prairie area, and the back half consists of a yard around the house, a barn, and an approximately one-acre pond. The driveway runs the length of the property, from front to back.

5. The Spire STL Pipeline runs across the front of our property along the road, bisecting the conservation prairie and our driveway, including a stand of trees that I planted along the driveway for our aesthetic enjoyment. I have been opposed

to the pipeline crossing my land because of the damage to the conservation prairie area—including the underlying soil—and the disruption the construction has caused to my family. After the Federal Energy Regulatory Commission (FERC) issued the Certificate approving the pipeline, Spire STL has been dismissive of my concerns and requests for remediation. I remain opposed to the pipeline and my wife and I suffer continuing harms from the presence of the pipeline on our land.

Front of Property: Conservation Prairie Area

6. The front tract, closest to the road, was historically used for agriculture. We used to grow corn and soybeans, and occasionally leased the land to tenants who continued to use it for agriculture, growing similar crops. In 2015, we converted that section of our property to a conservation prairie area through programs with the United States Department of Agriculture (USDA) that compensate landowners who create and maintain habitat areas for pollinators. Of the 20 acres, a 19-acre tract is enrolled in a conservation prairie program with USDA, and a separate one-acre tract is part of a different USDA program to promote monarch butterfly populations. The distribution of plant species in these areas is similar, but we grow more milkweed in the one-acre tract since monarch caterpillars rely on milkweed as a food source.

7. I invested considerable time, energy, and resources to convert our farmland to a conservation prairie. I reviewed guidance from the USDA and took

classes to learn how to develop the conservation prairie in order to ensure compliance with the USDA's regulations, including traveling to a nursery in Minnesota for a training class. Now I also help to train other people who want to participate in the USDA Conservation Reserve program. I started preparing my land for the conservation prairie program months in advance, dedicating a growing season to preparing the soil by tilling it through the spring and summer, preventing weed growth, and then planting oats and rye at the end of summer to prevent erosion. The following winter I planted the seeds for the prairie. I used a seed mix that contains about 30 different plant species, with a few grasses and primarily flowering forbs, which are good for the pollinators. During the first year that the prairie plants sprouted, they only grew to a few inches tall, so it was very important to control the weeds during the summer. I spent up to two hours each day, five days a week, weeding the land with my hands during the first summer the prairie plants were growing. Some of the plant species take several years to start blooming, and therefore the prairie on my property was improving year-over-year before the pipeline was built. For example, last year—before construction began on the pipeline—one of my compass plants, a prairie wildflower that is native to Illinois, bloomed for the first time.

8. I am proud of my work and it is important to me to continue to maintain the conservation prairie and provide habitat for native plants and

pollinators. Plants on the prairie typically start blooming as early as May, and different species will bloom sequentially through October or until the first frost. As my conservation prairie tract has developed, I see more pollinators, including several native bee species, monarch butterflies, other butterfly species, and hummingbirds. The property is along a monarch butterfly migration route that runs along the Mississippi River, and last year we saw populations of monarchs pass through our prairie as late as the first week of October heading south.

9. The USDA provides compensation on an annual basis through the Conservation Reserve program for the acreage that I maintain up to the agency's standards for pollinator-friendly prairie land. Regardless of my continued eligibility and participation in the USDA program, I would like to maintain the prairie habitat on my land for its aesthetic and ecological value.

Rear of Property: House, Pond, Driveway

10. On the back half of the property, we have our home, barn, and a pond. From the front of the house, you can see across the pond to the prairie, and around the sides and back of the house is forested. We like that our home provides a peaceful retreat. When our kids were younger, they would fish in the pond out front. Our driveway runs from the house out to the road, and about 20 years ago I planted tulip poplar trees to line either side of the driveway for their aesthetic

value, to create shade, and because tulip poplars are great trees for pollinators, producing abundant nectar and pollen.

11. My wife and I purchased this land with the intent of keeping it in the family and passing it on to our children, but we have discussed whether to sell it as a result of the harms we have experienced and continue to experience, described herein. On the other hand, we feel concerned that the presence of an operational pipeline running through the property would lower the property value and make it more challenging to sell.

Impact of Spire STL Pipeline

12. I am aware that FERC approved Spire STL's application to build the pipeline in August 2018. I am aware that later that month, Spire STL filed a condemnation action in the U.S. District Court for the Southern District of Illinois, seeking possession of my land and the land of others in the area who did not want to accept the developer's buyout offer. Through the condemnation action, Spire STL seeks to take title to approximately three acres of land out of my family's property.

13. I am aware that on December 12, 2018, the court issued an order granting Spire STL's request for a preliminary injunction, allowing the developer to take immediate possession of parcels of land. As a result of that order, Spire STL was allowed to take possession of a piece of my land that is 115 feet wide,

which includes a 50-foot permanent easement and a 65-foot wide temporary easement and workspace for use during construction. Spire STL's temporary easement on my property is narrower at the point where it crosses the driveway, but is otherwise 65 feet wide.

14. When Spire STL initially contacted me about the project, the company promised not to cut the tulip poplar trees down, committed to bore underneath the driveway and avoid damaging it, and committed to remediate any impact to the prairie caused by construction. Representatives of Spire STL assured me that the construction process would not change the look of the property. But Spire STL never put those commitments in their written offers to purchase my land, which, in addition to the fact that I did not want a pipeline to cut across my property, was part of why I did not want to accept their offers. Ultimately, Spire STL failed to follow through on its commitments, and the construction process has unquestionably altered the appearance of the land and threatens my eligibility for the USDA programs.

15. Spire STL began construction on my property in early May 2019. On the very first day Spire STL representatives were on my property for construction, they cut down eight of the tulip poplar trees. Because I had planted all of those poplars at the same time twenty years ago, we had a beautiful line of trees that were all approximately the same size and height along the length of the driveway.

The loss of those trees is a harm to my enjoyment of the land and the aesthetics that my family and I cultivated on the property. Spire STL has not replaced these trees. Even if Spire STL did so, it would take years for the trees to grow to the size and height of the trees that Spire STL cut down—and the replaced trees would never match the size of the original tulip poplars that I planted twenty years ago. Furthermore, as long as Spire STL has an easement across my land, I will be concerned that they could return with construction equipment and harm or remove any replacement trees that are planted.

16. On multiple occasions during the construction of the Spire STL pipeline, I saw large construction equipment parked or driving on my paved driveway, including once when the contractor had parked a large crane on my driveway well outside of the designated easement granted to the company. On several occasions, I arrived home and there was construction equipment blocking my driveway, so I had to sit and wait for the crew to move out of the way before I could get to my house, disrupting access to my own property.

17. As a result of the practices of Spire STL and its construction crew, my driveway was damaged and has not been adequately repaired, with the result that it is now in worse condition than before the pipeline was built. Spire STL's heavy equipment penetrated my driveway up to a foot and a half deep during construction of the pipeline. They later repaved a section of the driveway with an asphalt patch,

but as a former manager of design and construction projects at Boeing, I believe that Spire STL's repairs are not up to the standards that I would have followed. There are cracks in the driveway and it is no longer even in certain parts. In my assessment, my driveway now needs to be dug out and the base needs to be recompacted. I anticipate that this will cost tens of thousands of dollars. Additionally, I am concerned that damage to my driveway could happen again because the FERC Certificate and corresponding condemnation action allow Spire STL to access its easement across my property at any time.

18. The process of constructing the Spire STL pipeline and its aftermath also caused significant, long-term damage to the conservation prairie on the front section of my property. This is distressing, because my wife's and my enjoyment of the conservation prairie has been disrupted, and our participation in the USDA conservation program could be threatened in the long term. The path of the pipeline through the conservation prairie we have been cultivating is now a roadway of compacted soil, mud, standing water, and weeds. This path of destruction is at least 95 feet wide, and wider in some parts. Because a large section of the conservation prairie area was destroyed by Spire STL crews, there is less habitat available for pollinator species such as monarch butterflies.

19. The topsoil on my land is important because it is nutrient-rich soil that facilitates growth of agricultural crops or, more recently, native prairie species that

support pollinators. I am aware that the Spire STL construction crew was required to make a separate pile of the topsoil while digging to lay the pipeline so that they could restore the topsoil layer after the pipe was installed. The construction crew did separate about 6-8 inches of topsoil, but they failed to till the topsoil mound to prevent weeds from going to seed, and when the soil was restored after the pipeline had been laid in the ground, the construction crew mixed all of the topsoil in with the subsoil during the grading process.

20. A soil scientist working with Diamond Consulting recently visited my property to test the soil in February 2020. The test indicated that I have an average of 8 inches of topsoil in the prairie that was undamaged by the pipeline, and that I have zero inches of topsoil where the soil is disturbed due to the pipeline. As a result of the pipeline construction and related activities, I lost valuable topsoil that was mixed with the subsoil, and all of the soil along the pipeline route was compacted. This has resulted in an ongoing problem of standing water on the front land tract. It also means that the soil will have to go through a considerable restoration process before it can grow prairie plants that were previously thriving.

21. Below is a photo of the front section of my property—the conservation prairie area—taken in September 2017 before the pipeline was built.

22. Below is a photo of the same area, taken in January 2020 after the Spire STL pipeline was constructed and went into operation.

23. The construction crew appeared to complete construction on my property in June 2019, but they continued to use the easement as a roadway to travel on with heavy equipment through late September 2019. Thus, the blooming season was lost and I also lost time that could have been spent restoring the soil. That ongoing traffic was disruptive to my use and enjoyment of my property.

24. More recently, in April 2020, a representative of Spire STL came out and planted seeds in the easement area, using a tractor and a seed drill. This is presumably part of Spire STL's effort to restore my land as they are required to, but the effort has been unhelpful and incomplete. First, because Spire STL previously neglected the soil, weeds have already gone to seed, which is a major obstacle to re-growing the prairie plants that were destroyed by the pipeline construction. Furthermore, the Spire STL representative used a seed drill, which plants the seeds too deep and not properly dispersed. Finally, I don't know what seeds were planted, so I don't know if the seeds are the correct prairie plant seed mix that I requested the company replant on my land. I tried to approach the tractor operator as he was seeding and he waved me away and would not stop—it was hard to tell what he was saying, but I perceived that he was unwilling to speak with me directly. Since those seeds were planted in April I have walked the land ten times and have seen only a few dozen prairie plants come up—while there should be roughly 60,000 plants over the three acres of Spire STL's easement. This is an

indication that Spire STL's construction process caused long-term damage to my prairie that is not being remediated.

25. I am concerned that this disruption of my land—soil compaction, soil mixing, and destruction of the prairie—could recur in the future. Spire STL has a continuing right to access my property under the Certificate and the condemnation action, and I worry that any restoration efforts I might undertake could be undermined if representatives of the pipeline reentered my property to conduct maintenance, repairs, or other activities related to the operation of the pipeline. As I stated previously, I purchased my property because I wanted a peaceful and quiet place that my family and I enjoy. For many years, it was just that. But the construction of the Spire STL pipeline disrupted our daily life as we dealt with the presence of heavy equipment and construction crews, and the operation of the pipeline feels like a constant unwelcome presence on my land.

26. I am aware that the condemnation action, whereby Spire STL has taken possession and seeks to take title to an easement across my land, is premised upon FERC having issued a Certificate of Public Convenience and Necessity for the project. I anticipate that my wife and I will be in a better position to regain full possession of our land and avoid losing any property through condemnation if the FERC Certificate is vacated. I anticipate that my family and I will be able to make full use of the land if there is no longer an easement and an active pipeline crossing

the property. We will be able to pursue restoration of the section of the conservation prairie that has been destroyed and continue to improve that habitat for pollinators, and we will be able to pursue restoration of our tulip poplars through replanting of the lost trees.

I declare that the foregoing is true and correct.

Dated: June 25, 2020

Gregory Stout

DECLARATION OF KENNETH DAVIS

I, Kenneth Davis, declare as follows:

1. My name is Kenneth Davis. I am over the age of 18 and competent to give this declaration. The following information is based on my experience and personal knowledge.

2. I am a member of Environmental Defense Fund. I have been a member since before the commencement of this lawsuit.

3. I reside in Scott County, Illinois.

4. My wife Kelly and I own a 40-acre property in Scott County, Illinois that I, along with family and friends, use for hunting and other outdoor recreation. I live just up the road, about six miles away, so I frequently visit the property. We purchased this tract of land 14 years ago because I wanted to be able to have my own land for hunting, and because Kelly and I planned to eventually build a home here in a more secluded area.

5. The Spire STL Pipeline crosses our property for a distance of approximately 1,500 feet, and the pipeline route runs through the middle of the property. I am opposed to the pipeline crossing my land. The presence of the Spire STL pipeline affects my use and enjoyment of the land because the construction process altered my hunting grounds and damaged the soil, and my wife and I have abandoned our plans to build a home on this land due to the presence of the

pipeline. I don't feel comfortable going back to the land the way I used to before the pipeline was installed and went into operation, and I would prefer that the pipeline be removed and my land restored.

History and Use of the Property

6. I am an outdoorsman who loves to be in the timber or out on the water. I love deer hunting, turkey hunting, and bass fishing. When I first started hunting, I could go anywhere in Scott County, but over the years access to property has become more restricted as more people lease out land specifically for hunting. I decided that it would be best to be able to enjoy my own land, so I bought the 40-acre property. It is primarily wooded, which is ideal for hunting, and there are some open fields that I essentially use as food plots for the deer. I typically invite a friend to mow the fields for hay three times per year, because mowing exposes the clover and chicory underneath, which are rich in nutrients and attract deer.

7. I use the property for bow hunting and shotgun hunting for deer during October through January. I usually take two or three does each year for meat, though my main passion is buck hunting. In the spring I go turkey hunting on the property. In the summer I like to hike around on the land, especially with my grandchildren.

8. My family also uses and enjoys the land. My uncle and cousins go foraging for mushrooms, and my two young grandsons have also come mushroom

hunting. I taught my 16-year-old and 8-year-old granddaughters to hunt on this property, and they come with me occasionally. I try to introduce my grandchildren to nature, and we walk around and find snakes and turtles. They like to walk through the creek that runs through the property and collect rocks to bring home. I am also teaching them to recognize itchweed and poison ivy. I derive great enjoyment from spending time outdoors on the land with my family.

Effect of the Spire STL Pipeline

9. I was first approached by a land agent on behalf of Spire STL in 2016, and was subsequently approached by other representatives of the company. The land agent and representatives offered to buy an easement on the section of my land where Spire STL planned to build the pipeline. I did not accept any offer because I did not want a pipeline constructed on my land. Representatives of Spire STL began accessing my land to conduct surveys in 2017, before Spire STL had received approval from FERC to construct the pipeline. They arrived to conduct the surveys without advance notice during deer season. I informed the crews that I did not want them on the property during hunting season, because I was frequently using the land at that time and their presence was both disruptive and unsafe.

10. I am aware that the Federal Energy Regulatory Commission approved Spire STL's application to build the pipeline in August 2018. I am aware that later that month, Spire STL filed a condemnation action in the U.S. District Court for

the Central District of Illinois, seeking possession of my land and the land of others in the area who did not want to accept the developer's buyout offer. Through the condemnation action, Spire STL seeks to take title to approximately 3.6 acres of land on my property.

11. I am aware that on December 14, 2018, the court issued an order granting Spire STL's request for a preliminary injunction, allowing the developer to take immediate possession of parcels of land. As a result of that order, Spire STL was allowed to take possession of a 1,500-foot-long strip of land across my property ranging from 90 to 140 feet wide. This includes a 50-foot permanent easement and a temporary easement ranging from 40 feet to 90 feet in width for use during construction.

12. Spire STL began construction of the pipeline on my property in January 2019, and the work was ongoing until June 2019. Spire STL construction crews have continued to access my land occasionally after construction appeared to be done. The construction process has caused long-term damage to the land. I feel less safe visiting my land when I know that the pipeline is present and operating.

13. My use and enjoyment of the land for its recreational and aesthetic value is diminished by the Spire STL pipeline. I love this land, but it does not feel the same to spend time here now that the pipeline is present. The construction of the pipeline resulted in significant deforestation, soil compaction, and

destabilization of land formations on my property. For example, there is a ridge on the property that was perfect for buck hunting. Deer have an excellent sense of smell, so it is important to be able to position yourself where they won't smell you while you are hunting. On the ridge, I had a good spot to watch an acorn patch where the bucks like to gather but they were unlikely to catch my scent. In that spot, I used to be able to see up to 20 bucks in one day. Now, as a result of the construction process and the presence of the pipeline, my hunting grounds are diminished because many of the trees in that area were removed and there is a big open strip of land through the middle of the woods. The exposed open air makes it easier for the bucks to catch my scent. The pipeline route goes along the acorn patch, so the wooded area where I would stake out and watch for bucks is exposed as a result of the deforestation.

14. The quality of my hunting experience has diminished since the Spire STL pipeline was built. When I am on the land, I prefer to stay away from the pipeline route because I find it sad and upsetting to look at, so now I try to hunt on other sections of the property. During the 2019-2020 hunting season, I never got close to a big buck. One day earlier this year, for example, I went buck hunting and only saw three bucks. I was watching a doe when a Spire STL helicopter flew low overhead—I am aware that they do flyovers sometimes to monitor the pipeline—and scared off the doe. I didn't see another deer for hours.

15. The construction of the pipeline was highly damaging to my land and soil. I tried to convince Spire STL to at least choose a different route across my property that would be less damaging to my hunting grounds and the trees, but they declined to do so; and Spire STL did not provide the 45-day notice that I understand they were required to provide before cutting down trees on the property. I believe that at least 90 large trees were removed from my property, in addition to some small trees.

16. The photo below, taken in January 2020, shows the open land where the pipeline runs through my property. The area that is now open, empty ground used to be forested.

17. The Spire STL construction crews also failed to preserve the topsoil on my land during the construction process, so the topsoil was mixed in with the

subsoil, which makes it harder for new plants to grow and hold the soil in place. Additionally, the Spire STL crews used a bulldozer to flatten the soil after the pipeline was covered up, resulting in severe soil compaction. Because the soil is so compacted, there is often standing water in the fields along the route of the pipeline that is unable to drain for days at a time. Another result of the compacted soil is that all of the standing water creates deep voids in the ground, because the water has to flow somewhere and forms channels and ditches that continue to deepen over time. When I was turkey hunting this spring, I fell into one of the ditches. I am concerned about the worsening condition of the ground, which could continue to destabilize over time.

18. The photo below, taken in January 2020, shows an area where standing water is sitting on the heavily compacted soil.

19. There is a creek that runs through my property, and the bank on one side of the creek is eroding and slipping because the Spire STL construction crews removed the trees that were helping to hold the bank in place. Part of the bank has already come off since the Spire STL crews removed the nearby trees, and now the bank is very steep. I am concerned that the bank will continue to erode, which will alter the landscape of my property and could interrupt the flow of the creek.

20. My wife Kelly and I have decided not to move forward with building a home on our 40-acre property because of the presence of the Spire STL pipeline. We had a water line installed on the property about 10 years ago because we were planning to build a house and live on this property full time. There is a road that

provides access to an open field on the north end of the property, and we had the water line installed there because we intended to build the house in the field near the road. The Spire STL pipeline crosses that road and the water line is roughly 50 feet from the pipeline, just barely outside the permanent easement. My wife and I have decided not to build a house here because we would not feel safe living in such close proximity to an operational pipeline. It makes me sad to think about the plans we had for a secluded home on this land, but it would not be the same to build a house here now that the pipeline is here. I am concerned that there could be a catastrophic failure of the pipeline that could cause harm to me and my family if we were living nearby.

21. I have decided not to build any permanent structures on the property due to the presence of the Spire STL pipeline. There is currently a lean-to shed on the property, but I had planned to build a nicer shed to house my tractor. Now that the pipeline crosses my land, I am reluctant to spend money to construct any permanent structure, and I am reluctant to store my nice tractor nearby because I am concerned about the possibility of a gas explosion. I am also concerned that the land has lost its value due to the presence of the pipeline, limiting my ability to sell it if I no longer derive enjoyment from the land.

22. I am opposed to the Spire STL pipeline. I believe that the withdrawal of Spire STL's certificate under the Natural Gas Act would reduce or eliminate the risk of a pipeline rupture that could harm me, my family, and property.

23. I am aware that the condemnation action, whereby Spire STL has taken possession and seeks to take title to an easement across my land, is premised upon FERC having issued a Certificate of Public Convenience and Necessity for the project. I am concerned that loss of trees, loss of topsoil, soil compaction, and erosion could all worsen in the future because the Certificate and corresponding condemnation action allow Spire STL to access its easement across my property on an ongoing basis. Even if the soil was remediated and cover crops were planted, the damage could recur if Spire STL drives equipment on the pipeline route to conduct repairs or monitor the pipeline. And there is no way for me to replant the trees that were removed from my property as long as the pipeline is present with a permanent easement.

24. I anticipate that I will be in a better position to regain full possession of my land and avoid losing any property through condemnation if the FERC certificate is vacated. I anticipate that I will be in a better position to seek remediation of the damage to my land if the FERC certificate is vacated. I love this land and I do not want to give up on it. The property is a place where I enjoy spending time outside in the woods, and I enjoy exploring with my family. But I

don't feel comfortable going to the property the way I used to, and every time I visit, I think about the pipeline. My family and I will be able to enjoy the land more fully again if there is no longer an easement and an active pipeline crossing the property.

I declare that the foregoing is true and correct.

Ken Davis

Dated: June 23, 2020 Kenneth Davis

DECLARATION OF PATRICK PARKER

I, Patrick Parker, declare as follows:

1. My name is Patrick Parker. I am over the age of 18 and competent to give this declaration. The following information is based on my experience and personal knowledge.

2. I am a member of Environmental Defense Fund. I have been a member since before the commencement of this lawsuit.

3. I primarily reside in Jersey County, Illinois.

4. I am one of the owners of a 350-acre tract of land in Jersey County, Illinois. The property is held in a limited liability company, or LLC, owned by myself, my wife Mary, and our three sons. My family and I have been farming in the area since 1973, and we acquired this property more than 20 years ago. We also own and farm other property in the area, but we refer to this 350-acre tract as the Home Place because it is central to our farming operation and our family life. It is a place where we oversee farming operations and also where we gather to enjoy the land and explore.

5. The Spire STL pipeline has disrupted my and my family's enjoyment of the land for its beauty and recreation, as well as our use of the land for ranching and farming. I am opposed to the pipeline. It makes me sad to see the path of the pipeline cutting across our property as far as the eye can see.

History and Enjoyment of the Land

6. The property consists of a house; fields used for agriculture; grain bins to store crops; machine sheds for equipment; grazing pasture for our cattle; loafing sheds for the cattle to shelter from bad weather; a climate-controlled finishing barn where we wash and prepare cattle for shows; and a pond, wooded areas, and several creeks that we enjoy for recreation.

7. My son, Pat Parker, Jr., and his wife and kids live in the house on the property, which we built about eight years ago. The pond is close to the house, and the kids—my grandchildren—use the pond for recreation, such as occasionally hunting ducks there. I live just up the road, about three miles away, so I am regularly at the Home Place to help work on the farm or to visit the family.

8. We keep between 50 to 90 head of Herford cattle on the land at any given time. They are well-bred show cattle, and the bulls are worth about $30,000 each. We do not butcher our cattle, we take them to shows and sell them as breeding stock. Generally, the cattle are free-range and grazing out in the fields, and sometimes we won't see them for a few days. We bring the cattle into the finishing barn when preparing them for shows, and they can come and go from the loafing sheds to get out of the rain or snow. We recently had high-tensile fences

installed to keep the cattle in the pasture areas, which is expensive, high-quality fencing.

9. The farmland is used to grow corn, soybeans, and hay. We used to farm it ourselves, but we got so busy with the cattle that we leased out the farmland to a friend who lives close by. He grows the same crops that we used to grow.

10. In addition to farming and managing cattle, the Home Place is where my family can gather and enjoy the land. There is a dirt road that runs from the house down along the back of the pasture to a beautiful wooded area with walnut and chestnut trees. The grandkids will ride four wheelers down the road to the wooded area. I like to hunt deer back there, and my kids and grandkids also use that area for hunting. There are creeks back there that are fun to explore, and you can find arrowheads. This is basically our family's big backyard.

Effects of the Spire STL Pipeline

11. I am aware that the Federal Energy Regulatory Commission approved Spire STL's application to build the pipeline in August 2018. I am aware that later that month, Spire STL filed a condemnation action in the U.S. District Court for the Southern District of Illinois, seeking possession of my land and the land of others in the area who did not want to accept the developer's buyout offer. Through the condemnation action, Spire STL seeks to take title to approximately eleven acres of land on my family's property.

12. I am aware that on December 12, 2018, the court issued an order granting Spire STL's request for a preliminary injunction, allowing the developer to take immediate possession of parcels of land. As a result of that order, Spire STL was allowed to take possession of a piece of my land that is 90 feet wide, which includes a 50-foot permanent easement and a 40-foot temporary easement for use during construction. In some sections, the temporary easement is even wider than 40 feet.

13. Spire STL first contacted my family in November 2017 looking to purchase the right of way through a section of our property. They offered us about $65,000 for an easement that would cut right through the middle of the property. This is not about the money for me: I decided not to sell an easement to Spire STL

because this land is important to me and my family and I didn't want to see it divided up by construction.

14. The route of the Spire STL pipeline cuts through the middle of our pastures and farmland. The pipeline construction caused long-term damage to our soil and pasture. First, it took a long time for Spire STL to get the pipeline covered up—for months the construction crew left open trenches across our land with the pipeline exposed in the trench. This disrupted my family's aesthetic enjoyment of the land as well as our cattle operation. Second, when Spire STL finally covered the pipeline, the soil along the pipeline route and surrounding areas is compacted and looks very muddy. Due to the construction crew's handling of our soil—letting the soil sit for a long time while the trenches were open, mixing the soil layers, failing to seed the soil with a cover crop—we have lost topsoil throughout our farm and have to deal with removing weeds. It's a big deal that the construction crew let the weeds go to seed in the soil and grow out. We previously invested thousands of dollars to regularly apply herbicide to keep our cropland and pastureland free of weeds. My family has had to mow down the weeds that Spire STL and its construction crew left behind.

15. Spire STL began construction on our property in spring 2019. Spire STL was supposed to notify me when construction crews would be accessing the property. Instead, Spire STL representatives came onto our land without advance

notice and cut through the high-tensile fence that we recently had installed. Our cattle were grazing in the pasture where the Spire STL representatives cut the fence, so the cattle dispersed, and we had to track them down because they had wandered to different parts of the property. One heifer was injured and broke her leg, which devalued her as a show cattle and we had to give her up for slaughter.

16. My family put up a temporary fence around the front section of the pasture, at our own expense, to replace the high-tensile fence that was damaged by the Spire STL construction crew. We are still using the temporary fence.

17. Due to the pipeline construction and the resulting unstable soil, my family was unable to use the back section of pasture beyond the pipeline for many months. We kept our cattle within the smaller front pasture area bounded by the temporary fence. During construction, there was no way for us to use the back pasture because the cattle could not walk across the open trenches. And even with pipeline construction complete, the land still has not been restored to its original state. The soil is muddy and compacted along the pipeline route, and there is no cover crop so it cannot be used as pasture for the cattle. For a long time it was dangerous for the cattle to walk across because there was a risk that the cattle might break a leg or suffer another injury in the mud. Only recently have we been able to start bringing the cattle across the pipeline.

18. Some of our high-tensile fencing has been damaged by the ongoing erosion of soil resulting from the pipeline construction. The ground is less stable because there is so much bare, compacted soil along the route of the pipeline. In one section, several fenceposts were displaced. Spire STL representatives ostensibly repaired the fence, but their repair work was inadequate—our high-tensile fence is partially electrified, but their repairs failed to restore the electrification to that section of the fence, so we ended up fixing it ourselves. I am concerned that this issue will recur in the future because there continues to be erosion on the land that could undermine our fencing. Weaknesses in the fencing of our pastures can result in loose cattle, which means the cattle could be lost or get injured. This is a source of ongoing stress for me and my family to deal with.

19. In addition to the disruptions caused to our cattle operation, agriculture has also been disrupted by the pipeline, particularly because of the open construction trenches, soil compaction, and loss of topsoil. Spire STL built a sort of temporary wooden bridge to allow our tenant farmer to drive equipment over the pipeline to access the back section of farmland that was cut off by the pipeline route. This made it more challenging for our tenant farmer to access that land. And there were a few smaller sections of farmland that became too challenging to access with the pipeline in place, so our tenant farmer let those areas go and did not attempt to plant crops there.

20. Overall, the Spire STL pipeline has a lasting, detrimental effect on my and family's enjoyment and use of our land. As I have described, the construction and presence of the pipeline across the property disrupted our cattle ranching activities and disrupted our tenant's farming activities. But this isn't just about the economic harms that we suffer. Our experiences on the land—the Home Place—as a family feel different now. My sons and I don't even like going back there to see the pipeline route. The grandkids used to get on four-wheelers and take the road along the pasture to the forest where we hunt and explore. Now, to access that part of our property we have to cross the pipeline, and it isn't the same. It doesn't feel like it did before, and it makes me sad to go to that section of our land and see the destruction caused by the pipeline. Our land is cut in two. You can stand where the pipeline is, look in both directions, and all you can see for miles is the path of the Spire STL pipeline.

21. There is a lot of history on this land, for my own family and before us. The people that owned this property before us farmed it for their entire lifetimes. I want to be able to enjoy the land, and I wanted the Home Place to stay in our family for as long as possible. I recognize that my grandkids might not want to continue farming and ranching, and I always figured that they might decide to sell the land. I expect that the presence of the Spire STL pipeline has reduced the value of the property if future generations in my family choose to sell it.

22. I understand that, under the FERC certificate and the permanent easement granted to Spire STL by the court, construction crews can continue to come onto our land and access the pipeline in the future. I also understand that there is a possibility Spire STL could use the easement across our land to install additional pipelines in the future. The possibility of having to deal with further disruptions and construction, which would harm my family's recreation and enjoyment of the land as well as our cattle operation, is of great concern to me.

23. As I described, the Home Place is my family's backyard. It is a source of income and a place of sanctuary for us to gather. All of that has been negatively affected by the operation of the Spire STL pipeline on our land. My use and enjoyment of the land continues to be negatively affected by the Spire STL pipeline.

24. I am aware that the condemnation action, whereby Spire STL has taken possession and seeks to take title to an easement across my land, is premised upon FERC having issued a Certificate of Public Convenience and Necessity for the project. I anticipate that my family and I will be in a better position to regain full possession of our land and avoid losing any property through condemnation if the FERC Certificate is vacated. I anticipate that we will be able to make full use of the land if there is no longer an easement and an active pipeline crossing the property.

I declare that the foregoing is true and correct.

Dated: June 23, 2020

Patrick Parker