

## **People's Dossier: FERC's Abuses of Power and Law**

### **→ Deficient Needs Analysis**

#### **FERC's Failure to Mandate Genuine Demonstration of Need Results In Pipeline Overbuild**

FERC approval of a pipeline requires a demonstration of need. (*Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), clarified, 90 FERC ¶ 61,128, further certified, 92 FERC ¶ 61,094 (2000)). And yet, FERC routinely ignores evidence that there is no genuine public need for a proposed pipeline project. Further, instead of requiring a demonstration of genuine need, FERC allows pipeline companies to assert increased profits, competitive advantage, and self-manufactured claims of need to fulfill the public necessity mandate.

Rather than engage in objective and independent review of the claims of need, “FERC has increasingly relied on information supplied by pipeline operators in making decisions to grant approvals...”<sup>1</sup> The failure to objectively consider claims of “need” results in poorly informed and often inappropriate decision making.

#### **FERC's failure to ensure “need” for a pipeline will result in overbuild**

Industry experts themselves have recognized that there is no need for additional pipeline capacity. For example:

→ Industry expert Rusty Braziel, speaking to attendees at the 21st Annual LDC Gas Forums Northeast conference regarding capacity in the Northeast, said:

*“an evaluation of price and production scenarios through 2021 suggests the industry is planning too many pipelines to relieve the region’s current capacity constraints...What we’re really seeing is the tail end of a bubble, and what’s actually happened is that bubble attracted billions of dollars’ worth of infrastructure investment that now has to be worked off.”*<sup>2</sup>

→ And Elle G. Atme, Vice President, Marketing and Midstream operations for independent producer Range Resources has said:

*“We believe that the Appalachian Basin’s takeaway capacity will be largely overbuilt by the 2016-2017 time frame.”*<sup>3</sup>

#### **When credible and expert evidence is provided that the asserted “need” for a new gas**

---

<sup>1</sup> Deficient Needs Analysis Attachment 1, Tom Pawlicki, *FERC deference to pipeline operators seen contributing to overbuild*, snl.com, March 24, 2016.

<sup>2</sup> Deficient Needs Analysis Attachment 2, Jeremiah Shelor, *Marcellus/Utica on Pace for Pipeline Overbuild, Says Braziel*, Natural Gas Intelligence, June 8, 2016.

<sup>3</sup> Deficient Needs Analysis Attachment 3, *Marcellus-Utica could soon be overpiped*, Kallanish Energy, February 2, 2016.

**project is false, FERC routinely and without explanation ignores that evidence instead embracing pipeline company assertions**

In the following cases, expert analyses have directly contradicted company assertions of “need.” And yet, in each instance, the information was largely ignored by FERC as it continued, instead, relying on the assertions of the pipeline companies:

NorthEast Direct Pipeline (FERC Docket No. CP 16-21): A 2015 study conducted by Analysis Group at the request of the Massachusetts Attorney General that was placed on the FERC docket for the Northeast Energy Direct pipeline, found that new interstate natural gas pipeline capacity is not needed in New England through the year 2030.<sup>4</sup>

Mountain Valley (FERC Docket No. CP16-13) and Atlantic Coast Pipelines (FERC Docket No. CP15-554): According to a 2016 study conducted by Synapse Energy considering the need for the Mountain Valley and Atlantic Coast pipelines that are purported to deliver natural gas from West Virginia to Virginia and the Carolinas: “The region’s anticipated natural gas supply on existing and upgraded infrastructure is sufficient to meet maximum natural gas demand from 2017 through 2030. Additional interstate natural gas pipelines, like the Atlantic Coast Pipeline and the Mountain Valley Pipeline, are not needed to keep the lights on, homes and businesses heated, and industrial facilities in production.”<sup>5</sup> In a separate analysis, Synapse found that Dominion overestimated the Atlantic Coast Pipeline’s economic benefits in reports to FERC and failed to account for any of the environmental and societal costs that the pipeline would impose on local communities.<sup>6</sup>

Constitution Pipeline (FERC Docket No. CP13-499): In the case of the Constitution Pipeline, one detailed report on the record concluded that New York City’s existing infrastructure is “large, dynamic, and more than adequate” to support the City’s needs. The report also provided evidence that the Constitution Pipeline does not, in fact, seek to supply the City with natural gas, but instead seeks to export the natural gas.<sup>7</sup>

PennEast Pipeline (FERC Docket No. CP15-558): The asserted public “need” advanced by the PennEast pipeline company for the PennEast Pipeline Project and accepted by FERC included assertions that the proposed pipeline is necessary to serve New Jersey and eastern Pennsylvania communities and some unstated number of “surrounding states.” However, numerous expert reports on the PennEast docket demonstrate there is in fact no such “need” for the gas that PennEast would transport, and that if the pipeline were to be built there would be an increased gas surplus in both NJ and PA:

---

<sup>4</sup> Deficient Needs Analysis Attachment 4, Power System Reliability in New England, Analysis Group, Inc., November 2015 and Deficient Needs Analysis Attachment 5, Press Release, Mass Attorney General’s office, AG Study: Increased Gas Capacity Not Needed to Meet State’s Electric Reliability Needs, November 18, 2015.

<sup>5</sup> Deficient Needs Analysis Attachment 6, Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? Synapse Energy, September 12, 2016.

<sup>6</sup> Deficient Needs Analysis Attachment 15, Atlantic Coast Pipeline Benefits Review, Synapse Energy, June 12, 2015.

<sup>7</sup> Deficient Needs Analysis Attachment 7, Report on Need for the Constitution Pipeline, April 7, 2014.

- “The proposed PennEast Pipeline would deliver an additional 1 Bcf/d of natural gas to New Jersey potentially creating a 53% supply surplus above the current level of consumption.” “...Pennsylvania has no unfulfilled demand...”<sup>8</sup>
- “Local gas distribution companies in the Eastern Pennsylvania and New Jersey market have more than enough firm capacity to meet the needs of customers during peak winter periods. Our analysis shows there is currently *49.9% more capacity than needed to meet even the harsh winter experienced in 2013.*”<sup>9</sup>

Sabal Trail Pipeline (FERC Docket No. CP14-554): FERC refused to revisit the alleged “need” for the Sabal Trail pipeline through Alabama, Georgia, and Florida, despite admissions by Florida Power and Light (FPL) that the region’s needs had dramatically changed. In 2016, FPL’s Ten Year Plan stated firmly that “FPL does not project a significant long-term additional resource need until the years 2024 and 2025” and, at the same time, acknowledged that growing investments in efficiency and solar power will stave off and reduce Florida’s need for increased natural gas deliveries. Given the predictions that shale gas will peak by 2020, seriously declining thereafter, that FPL’s predictions for its energy needs changed significantly between its 2013 and 2016 energy plans, and the significant advancements in efficiency and clean energy options, FERC’s refusal to reconsider the question of need for the Sabal Trail pipeline is yet another example of irresponsible consideration of “need.”<sup>10</sup>

Atlantic Sunrise Pipeline (FERC Docket No. CP15-138)

In the case of the Atlantic Sunrise Pipeline, FERC took Transco’s word over the word of a Pennsylvania electric utility. FERC’s approval of Transco’s Atlantic Sunrise Pipeline directly negatively affected the public and the electric grid; Transco’s use of a public utility’s right-of-way would condemn the right-of-way, rendering it unusable for the utility’s transmission infrastructure. FERC issued a Certificate to Atlantic Sunrise despite the fact that its interference with the utility’s right-of-way would negatively affect the electric grid’s reliability and resiliency, forcing the utility to intervene before FERC. This approval demonstrates FERC’s skewed definition of public need, which favors natural gas infrastructure over the security of the electric grid.<sup>11</sup>

**Pipeline Claims of Higher Profits or Competitive Advantage are Inappropriately Adopted by FERC as Demonstrating Need**

FERC routinely allows self-serving claims that a proposed project will help the pipeline company increase corporate profits, give them a competitive edge, or otherwise advance

---

<sup>8</sup> Deficient Needs Analysis Attachment 8, Arthur Berman, Labyrinth Consulting Services, Inc., Professional Opinion on the PennEast Pipeline, February 2015 and Deficient Needs Analysis Attachment 9, Arthur Berman, Labyrinth Consulting Services, Inc., PennEast Updated Opinion, September 11, 2016.

<sup>9</sup> Deficient Needs Analysis Attachment 10, Analysis of Public Benefit Regarding PennEast, Skipping Stone, March 9, 2016.

<sup>10</sup> Deficient Needs Analysis Attachment 11, Florida Power and Light, Ten Year Power Plant Site Plan, 2016-2025, April 2016, p.56-62.

<sup>11</sup> Deficient Needs Analysis Attachment 16, Motion to Intervene out-of-time of the PPL Electric Utilities Corporation re the Transcontinental Gas Pipeline Company, FERC Docket No. CP15-138, March 6, 2017.

company goals to stand in lieu of a genuine demonstration of need.

Among the assertions of “need” advanced by the PennEast Pipeline Company and endorsed by FERC, are to “provide low cost natural gas produced from the Marcellus Shale region;” to provide “enhanced competition among natural gas suppliers and pipeline transportation providers;” and to allow “supply flexibility,” “diversity,” better pricing, etc.

By any reasonable definition, none of these are public “needs.” These are very clearly private goals and gains that are sought for the benefit of private industry and should not justify the power of eminent domain and avoidance of state and local regulations in the construction, operation and maintenance of the pipeline.

### **Self-Dealing is Inappropriately Accepted By FERC as Proof of Need**

FERC routinely, and inappropriately, allows companies to put forth themselves as the customers in “need” of a proposed pipeline project and do so using unverifiable data and information.

The PennEast Pipeline Company asserts that the need for its pipeline is demonstrated by contracts for most of the proposed pipeline’s capacity. FERC accepts this “need” demonstration at face value. But, as described by the New Jersey Division of Rate Counsel’s comments on the PennEast Docket these contracts do not in fact demonstrate need:

“PennEast bases its claim of need on “precedent agreements with seven foundation shippers and twelve total shippers, which together combine for a commitment of firm capacity of 990,000 dekatherms per day (‘Dth/d’),” approximately 90% of the Project’s total capacity...In this case, approximately 610,000 Dth/d of the 990,000 Dth/d of capacity has been contracted by affiliates of the Project owners... Of the twelve shippers that have subscribed to Project capacity, five of them are affiliates of companies that collectively own PennEast... **Thus, two-thirds of the demand for the pipeline exists because the Project’s stakeholders have said it is needed. This self-dealing undermines the assertion of need that the DEIS relies upon.**” (emphasis added; citations omitted).<sup>12</sup>

In *Empire Pipeline*, then-Commissioner Norman Bay acknowledged that the Agency’s reliance on precedent agreements to establish need is misplaced. Former Commissioner Bay stated that FERC should consider “whether precedent agreements are largely signed by affiliates; or whether there is any concern that anticipated markets may fail to materialize” among other considerations.<sup>13</sup> Despite these facts, FERC makes no investigation into the legitimacy of the claims resulting from self-dealing.

### **FERC Fails To Provide Independent Assessment or Review of Pipeline “Need” Claims and Thereby Perpetuates Overbuilding**

As reported by the Institute for Energy Economics and Financial Analysis, pipeline companies have an incentive to overbuild, and no reason to self-moderate or limit their construction. The failure of FERC to provide any independent review or oversight over self-serving claims of

---

<sup>12</sup> Deficient Needs Analysis Attachment 14, Comments of the New Jersey Division of Rate Counsel on PennEast Pipeline, FERC Docket No. CP15-558, Sept. 12, 2016.

<sup>13</sup> Deficient Needs Analysis Attachment 13, Commissioner Bay Separate Statement, p.3, FERC Docket No. CP15-115.

“need” undermines the requirements of the law and the actual needs of the public.

- “...current low natural gas prices in the Marcellus and Utica region are driving a race among natural gas pipeline companies .... An individual pipeline company acquires a competitive advantage if it can build a well-connected pipeline network ...; thus, pipeline companies competing to see who can build out the best networks the quickest. This is likely to result in more pipelines being proposed than are actually needed to meet demand in those higher-priced markets.”
- “...[T]he regulatory environment created by FERC encourages pipeline overbuild. The high returns on equity that pipelines are authorized to earn by FERC and the fact that, in practice, pipelines tend to earn even higher returns, mean that the pipeline business is an attractive place to invest capital. And because, as discussed previously, there is no planning process for natural gas pipeline infrastructure, there is a high likelihood that more capital will be attracted into pipeline construction than is actually needed.”
- “The pipeline capacity being proposed exceeds the amount of natural gas likely to be produced from the Marcellus and Utica formations over the lifetime of the pipelines. An October 2014 analysis by Moody’s Investors Service stated that pipelines in various stages of development will transport an additional 27 billion cubic feet per day from the Marcellus and Utica region. This number dwarfs current production from the Marcellus and Utica (approximately 18 billion cubic feet per day). ... pipeline capacity out of the Marcellus and Utica will exceed expected production by early 2017.”
- “The loss borne by the public, businesses, and critical irreparable natural resources when a natural gas pipeline is approved by FERC requires that the Agency sufficiently consider whether an infrastructure project is actually necessary and for the public good. Instead, FERC uses an inappropriate and counterintuitive definition of “need” which is contrary to the historic underpinnings and intent of the Natural Gas Act, and results in the overbuild of unnecessary pipelines to pad companies’ quarterly balance sheets.”<sup>14</sup>

---

**Attachments:**

Deficient Needs Analysis Attachment 1, Tom Pawlicki, *FERC deference to pipeline operators seen contributing to overbuild*, snl.com, March 24, 2016.

Deficient Needs Analysis Attachment 2, Jeremiah Shelor, *Marcellus/Utica on Pace for Pipeline Overbuild*, *Says Braziel*, Natural Gas Intelligence, June 8, 2016.

Deficient Needs Analysis Attachment 3, *Marcellus-Utica could soon be overpiped*, Kallanish Energy, February 2, 2016.

Deficient Needs Analysis Attachment 4, Power System Reliability in New England, Analysis

---

<sup>14</sup> Deficient Needs Analysis Attachment 12, IEEFA, Risks Associated with Natural Gas Pipeline Expansion in Appalachia, April 2016.

Group, Inc., November 2015.

Deficient Needs Analysis Attachment 5, Press Release, Mass Attorney General's office, AG Study: Increased Gas Capacity Not Needed to Meet State's Electric Reliability Needs, November 18, 2015.

Deficient Needs Analysis Attachment 6, Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? Synapse Energy, September 12, 2016.

Deficient Needs Analysis Attachment 7, Report on Need for the Constitution Pipeline, April 7, 2014.

Deficient Needs Analysis Attachment 8, Arthur Berman, Labyrinth Consulting Services, Inc., Professional Opinion on the PennEast Pipeline, February 2015.

Deficient Needs Analysis Attachment 9, Arthur Berman, Labyrinth Consulting Services, Inc., PennEast Updated Opinion, September 11, 2016.

Deficient Needs Analysis Attachment 10, Analysis of Public Benefit Regarding PennEast, Skipping Stone, March 9, 2016.

Deficient Needs Analysis Attachment 11, Florida Power and Light, Ten Year Power Plant Site Plan, 2016-2025, April 2016, p.56-62.

Deficient Needs Analysis Attachment 12, IEEFA, Risks Associated with Natural Gas Pipeline Expansion in Appalachia, April 2016.

Deficient Needs Analysis Attachment 13, Commissioner Bay Separate Statement, p.3, FERC Docket No. CP15-115.

Deficient Needs Analysis Attachment 14, Comments of the New Jersey Division of Rate Counsel on PennEast Pipeline, FERC Docket No. CP15-558, Sept. 12, 2016.

Deficient Needs Analysis Attachment 15, Atlantic Coast Pipeline Benefits Review, Synapse Energy, June 12, 2015.

Deficient Needs Analysis Attachment 16, Motion to Intervene out-of-time of the PPL Electric Utilities Corporation re the Transcontinental Gas Pipeline Company, FERC Docket No. CP15-138, March 6, 2017.

***Complete People's Dossier: FERC's Abuses of Power and Law***

***available at <http://bit.ly/DossierofFERCAbuse>***

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 1**, Tom Pawlicki,  
*FERC deference to pipeline operators seen contributing  
to overbuild*, [snl.com](http://snl.com), March 24, 2016.

[snl.com](http://snl.com)

# SNL: FERC deference to pipeline operators seen contributing to overbuild

Tom Pawlicki

Discoveries of oil and gas in new regions in the U.S. typically bring the need for additional pipelines to take the resources to market. But with natural gas production booming in the past 10 years, industry experts believe that increased use of gas for power generation and deference by regulators may result in a potential overbuild of pipeline infrastructure.

## Signs of pipeline overbuild

The number of interstate natural gas pipelines and compressor stations that have been proposed and approved in recent years is growing.

"In 2014, there were 26 pipelines that were approved and then an additional 20 that were proposed," Carolyn Elefant, a private attorney that represents impacted communities during the pipeline conception process, said at a conference held by the Institute for Energy Economics and Financial Analysis on March 15. "In 2015, there were 54 pipelines proposed and 30 that were approved. There are definitely many more cases."

Elefant said that the increased number of proposed pipelines is a result of growing production in places like the Marcellus.

"Back in 2012 or 2013, maybe production did overwhelm infrastructure, but if you see where we're headed, pretty soon infrastructure is going to overwhelm Marcellus," Elefant said. "There have already been some reports questioning whether there is enough gas in Marcellus to sustain all of these pipelines."

Typically, pipeline operators work with exploration and production companies to guarantee that a new pipeline is needed and will be utilized.

Elefant said that there is a debate at FERC as to whether there is a causal connection between extraction and pipeline development, where increases in one lead to growth in the other, but said that it is arguably case specific.

FERC has increasingly relied on information supplied by pipeline operators in making decisions to grant approvals, and the issue has manifested itself through exports of liquefied natural gas.

"In theory, FERC might be thinking 'well pipelines are not going to overbuild because, if they don't have contracts for the gas, what are they going to do with it?'" Elefant said. "This is what

we're going to do with it. If they have excess capacity, they can use it for export, and so that's another factor that's driving development."

### **Problems with overbuild**

Any overbuild in pipeline infrastructure could have deleterious effects on consumers and private property owners, according to Elefant.

One problem arises from electric companies that lock into long-term contracts to buy gas for power generation. State commissions are either pre-approving or encouraging utilities to enter into long-term contracts for gas. The locked prices typically lock in consumers as well, which does not bode well during a declining price environment.

The Clean Power Plan is contributing to this, as many utilities are substituting cleaner burning natural gas for coal.

Another problem with overbuild is pipeline abandonment, which could leave abandoned infrastructure on private property. Elefant said that FERC does not require pipelines to put up money for potential decommissioning or make plans for abandoning them down the line.

A third problem comes from potential encroachment on an individual's fifth amendment rights to private property. The amendment requires that eminent domain be coupled with just compensation and public need when property is taken.

"If you have companies that are overbuilding, then by definition, there's no need," Elefant said. "The constitution says you can only take private property with just compensation and if there's a public need."

Elefant said that the determination of need and the certificate that authorizes the taking of property are done at FERC, so that once a pipeline company has that certificate and uses it in an eminent domain proceeding, the landowner has little ability to challenge it. Such challenges are considered to be collateral attacks on a FERC decision.

There is also the possibility that getting the certificates has become easier.

"In reading over applications in the past few years, I've noticed that even the support for the need for these projects has really deteriorated over time," Elefant said. "In one of the applications, the company said something like 'it's our hope that we'll get enough subscribers for this project.' There wasn't even an attempt to suggest that there was demand for the project."

The fix for a potential overbuilding of pipeline infrastructure could lie in section 7 of the Natural Gas Act and the public need provision, along with adjudicated hearings.

"FERC really needs to take a closer look at need on a case-by-case basis," Elefant said. "The best way to do that is to have adjudicated hearings again."

A representative at FERC declined to comment but noted that the agency closely reviews each pipeline application to ensure adequate customer support for the project.

*To view operational statistics on interstate natural gas pipelines, go to our [Pipeline Summary Page](#).*

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 2**, Jeremiah Shelor, *Marcellus/Utica on Pace for Pipeline Overbuild, Says Braziel*, Natural Gas Intelligence, June 8, 2016.

# Marcellus/Utica On Pace for Pipeline Overbuild, Says Braziel

Jeremiah Shelor

The need for more takeaway capacity out of the Marcellus and Utica shales has become a common refrain, but with a long list of projects on tap the Northeast could be headed for a pipeline overbuild, according to RBN Energy LLC President Rusty Braziel.

Speaking to attendees at the 21st Annual LDC Gas Forums Northeast conference in Boston Tuesday, Braziel said an evaluation of price and production scenarios through 2021 suggests the industry is planning too many pipelines to relieve the region's current capacity constraints.

"Is it possible that we could build too much takeaway capacity out of the" Marcellus and Utica? "It's certainly happened in about every other segment of the energy business over the last few years," Braziel said.

Braziel said his firm estimated Northeast production through 2021 by taking a range of price scenarios and determining what producers would be likely to drill and how many drilled but uncompleted (DUC) wells they would put into service.

RBN's most aggressive growth scenario, based on 2021 prices of \$4/MMBtu Henry Hub and \$60/bbl West Texas Intermediate, would see the Marcellus and Utica increase production by 11 Bcf/d over the next five years.

Meanwhile, add up all the major proposed Marcellus/Utica takeaway projects headed to the East (3.3 Bcf/d), to the Midwest (4.3 Bcf/d), to the Gulf of Mexico (4.5 Bcf/d), to the South along the Atlantic Coast (5.2 Bcf/d) and to Canada (.65 Bcf/d) and it equals 18 Bcf/d of new capacity by 2019.

"Could prices be higher, and could [the growth scenario] be higher because prices are higher? Yes, it could. Could pipes be delayed? Absolutely," Braziel said. Ultimately the discrepancy between the growth projections and planned capacity "means that there are a lot of things that could go right or wrong depending on your perspective on all of this...If you're looking at this from the standpoint of a company committing or considering commitments to any pipelines, firm pipeline capacity, 20-year deals, you just might want to think long and hard about whether [an overbuild] could happen."

Braziel drew parallels between the current state of shale hydrocarbon commodities markets and the housing market crash during the Great Recession.

“What we’re really seeing is the tail end of a bubble, and what’s actually happened is that bubble attracted billions of dollars worth of infrastructure investment that now has to be worked off,” he said. “It’s entirely possible that that could be the world that we’re into now, that it’s this world of infrastructure investment that we’re dealing with right now and that this has a lot to do with what we’re seeing happening up in the Northeast.”

Basis differentials at Appalachian Basin trading points still point to a need for more pipelines, Braziel said. It may come down to which projects pull from the remaining active areas within the basin, he said.

“Due to localized transportation or capacity constraints, that means a lot of these pipes are going to be needed anyway. Growth is in very narrow pockets, so we’re going to need some of these pipes,” Braziel said. “That means if you’re looking at one of those pipes that is not in one of these narrow pockets, then that pipeline might be at risk.”

Of the 15 counties responsible “for the vast majority” of drilling activity in Pennsylvania, Ohio and West Virginia, “there’s only been nine of those counties that have anything going on today...It’s a very concentrated market with not much drilling going on. Of course, there are the DUCs. So there are certainly DUCs coming back, but the majority of the DUCs, guess what? The good DUCs are coming back in those very same counties...There’s a lot of other DUCs that are scattered about in those other counties that were drilled quite some time ago. They’re probably not coming back. The economics are not so good. We like to call them the dead DUCs.”

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 3, *Marcellus-Utica could soon be overpiped*, Kallanish Energy,  
February 2, 2016.**

[Home](#) > [Topics](#) > [Company News](#) > [Marcellus-Utica could soon be 'overpiped'](#)

# Marcellus-Utica could soon be 'overpiped'

🕒 February 1, 2016   📁 [Company News](#), [Crude Oil](#), [Featured](#), [Natural Gas](#), [News](#), [North America](#), [Pipeline](#)   💬 0



It's a concept rarely, if ever discussed in the Marcellus and Utica Shales region, but was heard uttered by no fewer than two speakers at last week's Seventh Annual Marcellus-Utica Midstream Conference & Exhibition (MUM).

The Pittsburgh program is presented by Hart Energy; **Kallanish Energy** was in attendance.

**FREE 14 DAY NEWS TRIAL**

[GET STARTED](#)

**WEEKLY POLL**

“What if the Marcellus/Utica region is overpiped?” asked Mark Eisenhower, vice president of Strategic Planning and Development for midstreamer Aspire Energy of Ohio. “I’m not saying it is, but it’s something that must be considered.”

Eisenhower said one has to considered the pullback in production in the Marcellus/Utica due to the price plummet in oil and gas.

“Producers scaling back will mean excess pipeline capacity, and excess pipeline capacity will reduce the basis differential and thus reduce/eliminate the value of new pipeline projects,” according to Eisenhower

(Basis is the difference between the benchmark Henry Hub spot price and the corresponding cash spot price for natural gas in a specified location.)

Earlier in the conference day, Dominion Transmission Senior Vice President Don Raikes told his MUM audience that between the years of 2015 and 2018, 21 billion cubic feet per day of new takeaway capacity from the Marcellus/Utica was planned.

“We believe the Appalachian Basin’s takeaway capacity will be largely overbuilt by the 2016-2017 timeframe,” said Elie G. Atme, vice president, Marketing and Midstream Operations for independent producer Range Resources.

Atme said growth in Northeast Pennsylvania’s Marcellus dry gas play had stopped, and growth in Southwest Pennsylvania, where both Marcellus and Utica drilling is underway, “is slowing.”

Aspire’s Eisenhower also played the “what-if” game concerning liquefied natural gas (LNG) exports. Estimates of 9 Bcf/d of LNG exports are seen by many in the industry as a partial fix for the huge natural gas oversupply the U.S. currently suffers from.

“What if LNG exports don’t happen?” Eisenhower asked. “If that occurs, expect lower gas prices beyond 2018.”

Will the U.S. O&G industry working-rig count onshore Lower 48 States drop below 2016?

Yes

No

vote



Advertisement

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 4, Power System  
Reliability in New England, Analysis Group, Inc.,  
November 2015.**

**Power System Reliability in New England**  
*Meeting Electric Resource Needs in an Era of  
Growing Dependence on Natural Gas*

**Analysis Group, Inc.**

**Paul J. Hibbard**

**Craig P. Aubuchon**

**November 2015**

## **Acknowledgments**

This Report presents a review of winter electric resource needs in New England and compares the potential ways to meet those needs, considering both ratepayer cost and regional carbon emissions. This is an independent report by Analysis Group, Inc. (AGI) on behalf of the Massachusetts Office of the Attorney General (AGO), with funding from the Barr Foundation.

Throughout the project, AGI received input from the Office of the Attorney General, a Study Advisory Group comprising a wide spectrum of the region's electric and gas industry stakeholders (listed on the next page), and Dr. Jonathan Raab of Raab Associates (who facilitated the Advisory Group process). The authors wish to thank the Barr Foundation, the AGO, the Study Advisory Group, and Dr. Raab for their input on the analysis presented in this report. The authors also would like to recognize the significant contributions of Pavel Darling, Christopher Llop, Justin Metz, and Dana Niu of AGI for their assistance with this project.

The analytic method, views and observations described in this study, however, are solely those of the authors, and do not necessarily reflect the views and opinions of AGI, the Office of the Attorney General, Dr. Raab, or any members of the Study Advisory Group.

## **About AGI**

AGI provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 700 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

AGI's energy and environment practice is distinguished by expertise in economics, finance, market analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies, among others.

## Study Advisory Group

*The Attorney General's Office and AGI would like to thank the Advisory Group (listed below) for their invaluable feedback and input. The Advisory Group members served as a sounding board for the AGO and AGI throughout the modeling process. However, all of the modeling related decisions (including the modeling framework, assumptions, data choices, analysis, and conclusions) are the sole responsibility of the authors using their best professional judgment. Listing the Advisory Group members is not indicative of their concurrence or support for anything contained in this Report, and they may disagree with inputs, analysis, and observations set forth in it.*

### **Study Advisory Group Members, Listed Alphabetically by Organization**

Peter Shattuck (Acadia Center)

Bob Rio (Associated Industries of Massachusetts)

Greg Cunningham (Conservation Law Foundation)\*

N. Jonathan Peress (Environmental Defense Fund)\*

James Daly (Eversource)

Tony Scaraggi (LNG Importers)

Michael Altieri (Massachusetts Executive Office of Energy and Environmental Affairs)

Charlie Harak (National Consumer Law Center, Inc.)

Marcy Reed (National Grid Massachusetts)

Dan Dolan (New England Power Generators Association, Inc.)

Peter Rothstein, Janet Besser (alternate) (Northeast Clean Energy Council)

Sue Coakley (Northeast Energy Efficiency Partnerships, Inc.)

Tom Kiley (Northeast Gas Association)

Cynthia Arcate (PowerOptions)

Marc Hanks (Retail Energy Supply Association)

David Littell (The Regulatory Assistance Project)

\*shared seat

## TABLE OF CONTENTS

<b>I. Executive Summary</b>	<b>i</b>
<b>II. Introduction and Purpose</b>	<b>1</b>
A. Emerging Challenges to Winter Power Supply	1
B. Purpose of the Study	4
C. Overview of Analytic Method	5
<b>III. Power Supply Deficiency Analysis</b>	<b>6</b>
A. Power Supply Deficiency Analysis	6
B. Deficiency Statement Results	14
<b>IV. Potential Electric Sector Pathways to Ensure Reliability under “Stressed” System Conditions</b>	<b>16</b>
A. Solution Sets	16
B. Infrastructure Scenarios	24
<b>V. Assessment</b>	<b>25</b>
A. Method	25
B. Results	30
<b>VI. References</b>	<b>45</b>
<b>VII. Glossary</b>	<b>47</b>
<b>VIII. Appendices</b>	<b>49</b>

## FIGURES AND TABLES

Figure 1: Historical Relationship of Weather and Gas Demand, 2012-2015	9
Figure 2: Historical Weather Years, 2004-2015	10
Figure 3: Deficiency Duration Curve (2024-25 and 2029-30)	15
Figure 4: Pipeline Utilization and Natural Gas Prices, Winters 2012-2015	27
Figure 5: Forecasted Natural Gas Prices, By Solution Set	29
Figure 6: Evaluation of Electric Reliability Solution Sets, Annualized Impacts	33
Figure 7: Annualized Cost and Emission Impacts, By Solution Set	34
Figure 8: Annual CO <sub>2</sub> Emissions and Potential ISO-NE Climate Goals	38
Figure A1: Scheduled Natural Gas Demand and Total Capacity, ISO-NE System	50
Figure A2: Total Greenhouse Gas Emissions and Potential Targets, New England	69
Table 1: Electric Sector Reliability Deficiency Analysis, 2020-2030	15
Table 2: Summary of Solution Sets	23
Table 3: Evaluation of Electric Reliability Solution Sets, Annualized (\$2015, mil)	31
Table 4: Evaluation of Additional Infrastructure Scenarios, Annualized (\$2015 mil)	36
Table 5: Risk Factors and Other Considerations Associated with Solution Sets	44
Table A1: Electric Sector Reliability Deficiency Analysis Sensitivity, 2020-2030	52
Table A2: Existing Liquefied Natural Gas Capability	56
Table A3: Unit Retirements	66
Table A4: Unit Additions	66
Table A5: Summary of State GHG Goals	68

## I. EXECUTIVE SUMMARY

### Context

The New England region currently relies on natural gas to produce 44 percent of its net electricity needs and its total generating capacity, a figure that could exceed 50 percent by 2024.<sup>1</sup> Our region's dependence on natural gas for electricity generation raises concerns about the reliability of electricity supplies during winter peak conditions, when the region's interstate pipeline system is largely committed for heating needs. It also raises concerns about costs. In years when there are frequent constraints with high utilization on interstate pipelines, prices within the region for spot purchases of natural gas often spike, leading to cost increases for electricity consumers. As generation from new, efficient natural gas plants drives down the output from legacy coal, oil, nuclear, and older natural gas generating facilities, the region may in the future become even more reliant on natural gas fired generation to meet peak electric demand. Increased reliance on natural gas and gas-fired generators that operate without firm natural gas transportation capacity has led to concerns about whether, on the coldest winter days, the region will have enough generating resources to maintain system reliability. As a result, some have suggested that additional gas pipeline capacity is needed in the region for power system reliability and price benefits.

At the same time, this transition away from legacy coal, oil and older natural gas units and towards new, efficient natural gas plants has driven down the greenhouse gas (GHG) emission intensity of the system and lowered total GHG emissions, consistent with regional policies. As discussed further in this Report, however, this trend is not sufficient to meet the region's long-run climate objectives.

### Study Purpose

The Massachusetts Attorney General's Office retained Analysis Group, Inc. (AGI) to conduct an independent assessment of the region's power system out to 2030 to determine the following:

- 1. Could the region experience power system "deficiencies" – periods during peak winter demand when the electric system may not be able to meet peak electric demand?*
- 2. If any such deficiencies are identified, what is the full suite of practical options for maintaining power system reliability – particularly during winter months – including but not limited to electric ratepayer funding for natural gas infrastructure?*

Then, considering the practical options identified for maintaining power system reliability:

- 3. What would be the relative costs to electric ratepayers associated with these options – both to implement the options and as a result of how they affect wholesale electric prices?*
- 4. To what extent do various options help achieve or impede New England states' obligations and goals with respect to GHG emission reductions?*
- 5. What other factors not captured in the quantitative analysis are relevant for consideration?*

---

<sup>1</sup> ISO-NE, Resource Mix. Available: <http://isone.org/about/what-we-do/key-stats/resource-mix>.

This Report systematically reviews these questions to gain an understanding of whether the current system can maintain reliability and what the economic costs and benefits (to electric ratepayers) and GHG emission implications would be of either staying the course or pursuing a new path to meet the region's energy needs.

The purpose of this Report is to provide New England's policymakers and stakeholders with an independent and transparent assessment of the potential benefits and drawbacks associated with the various approaches to addressing the region's dependence on natural gas for electricity generation. We recognize that this is but one of many studies related to the region's dependence on natural gas, and that all studies require forecasting and judgment on highly variable and uncertain future market conditions. It is incumbent on policy makers and stakeholders to consider carefully the purpose, analytic method, and outcomes of all such analyses.

### ***Study Method***

Our analysis is focused on the New England region, reviewing system conditions through 2030. We forecast the need for gas-fired generation to meet the region's electrical load requirements in each year and compare that to a forecast of available natural gas supply, after subtracting out firm demand for gas by local gas distribution companies. Combined, we use these forecasts to estimate any potential "deficiencies" – or periods when the electric system may not be able to meet peak electric demand given constraints in natural gas transportation capacity. We model a "base case," which reflects severe winter conditions, the capability of non-gas fired generation, and market incentives that increase the availability of generation to help meet peak electric demands. We also model "stressed system" scenarios that assess the impact of varying increases (over our base case assumptions) in dependence on natural gas for electricity generation that may arise due to changes in the electric generation resource mix.

We then identify several "solution sets" that represent different approaches to meeting any identified reliability needs going forward, including market-driven ("status quo") solutions, natural gas pipeline expansion, and energy efficiency/renewable energy investments. We compare the solution sets from the perspective of electric ratepayers, reviewing both the up-front costs to implement the solutions and the potential benefits of the solutions due to their impact on wholesale energy market prices. We also compare the solutions with respect to their impact on states' abilities to meet GHG reduction obligations and targets.

Additionally, we review two "infrastructure scenarios" that involve the development of natural gas or transmission infrastructure projects that are either larger and/or brought into service earlier than needed to meet power system reliability. These scenarios capture a wider range of impacts above and beyond just electric reliability needs.

We carry out our analysis from a conservative reliability planning perspective – namely, with every judgment and assumption we err on the side of overstating the need for electricity generation, and understating the level of resources available to meet that need.

## **Key Findings**

***Under the base case analysis, power system reliability can and will be maintained over time, with or without additional new interstate natural gas pipeline capacity.***

New England's existing market structure, including recent changes to address reliability during challenging system conditions at the time of winter peak demand, will provide the resources and operational practices needed to maintain power system reliability. The region will continue to rely on natural gas as the dominant fuel of choice, but we find that under existing market conditions there is no electric sector reliability deficiency through 2030. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods.

***Under the stressed system sensitivities we modeled, power system reliability deficiencies emerge by the winter of 2024/2025.***

We also modeled the impact of an increase (over our base case assumptions) in dependence on natural gas for electricity generation. We assume approximately 1,200 megawatts (MW) of additional non-gas fired capacity retirements (beyond our base-case assumptions) are replaced with gas-only resources, and further assume that approximately 20 percent of existing oil-fired resources in the region do not have oil at the time of winter peak demand (this represents approximately 1,800 MW of generation). Under this stressed system scenario, an electric reliability deficiency of approximately 1,675 MW arises in 2024, growing to approximately 2,400 MW in 2029/30. From the perspective of natural gas transportation capacity, this deficiency is the equivalent of approximately 0.42 billion cubic feet per day (Bcf/d). There are 26 hours of deficiency spread out over 9 total days, with only 2 days and 4 hours with a total deficiency greater than 2,000 MW in the 2029/30 winter in any scenario.

To meet this stressed system deficiency need, we considered five “solution sets” that could plausibly emerge given economics and currently-known technological capabilities, and/or that are specifically under consideration by the region's states and stakeholders. The impact of each solution set depends on how it affects price setting in wholesale power markets and also the required costs to implement each solution set. Each solution set also affects the ability of the region to meet its climate goals going forward. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies.

### **Dual-fuel and/or Firm Liquefied Natural Gas (LNG) Solution Sets**

***Absent any action by states, electricity markets would likely meet any deficiency need through the addition of dual-fuel capability at existing facilities, and/or by contracting for LNG.***

New England has significant potential new dual-fuel capability at existing gas-only resources, and underutilized LNG storage and vaporization capacity that could be relied on by gas-fired generators. Absent any action by states to promote alternative solutions, reliability will most likely be maintained through a combination of these resources. This pathway may continue to experience periods of elevated winter prices, but will also require the least cost investment from ratepayers. Specifically, these two “market outcome” solution sets reviewed – involving the conversion of gas-only generation to dual-fuel capability, or the specific contracting on a multi-year basis of storage and delivery as needed of LNG by

or for electricity generators – involve minimal up-front investment by consumers. Instead, these solutions would increase costs to the owners of generating assets to meet capacity and energy market obligations, and associated implementation costs would partly or fully flow through to ratepayers over time through existing wholesale market mechanisms.

***Market-based solutions fail to offer outcomes consistent with the climate change programs and goals of the New England states.***

These market outcome solution sets offer trajectories of GHG emissions that exceed the region’s potential GHG reduction objectives. This level of excess potentially represents a failure to meet the region’s climate goals and could increase GHG emission-reduction compliance costs for electric ratepayers over time.

### ***Additional Natural Gas Pipeline Capacity Solution Set***

***The construction of additional natural gas pipeline capacity could address the identified stressed system deficiency, provided such capacity was fully reserved for delivery to electricity generators under coincident winter peak conditions for heating and electricity generation.***

Long-term investment in firm interstate pipeline capacity would enable sufficient gas-fired electricity generation to meet winter peak needs under the stressed system scenario. Specifically, the reservation of approximately 0.3 Bcf/d or more by 2024, with an incremental 0.12 Bcf/d for a cumulative total of 0.42 Bcf/d or more by 2029 would be sufficient, provided the capacity is guaranteed for delivery to electricity generators at the time of winter peak, and could not be diverted (e.g., to meet unexpectedly high heating needs of natural gas local distribution company (LDC) customers).

***Investment in new interstate pipeline capacity generates significant wholesale electricity price benefits but would require up-front and long-term ratepayer commitments.***

Increasing natural gas transportation capacity in New England would lower wholesale electricity costs by lowering natural gas prices at times when the interstate pipeline system would otherwise face greater constraints, and thus higher natural gas price basis differentials. The annual average price suppression benefit is likely large enough to exceed the annualized cost to implement the solution set. However, this solution set places up-front costs and risk on ratepayers through significant long-term commitments to pay for the associated infrastructure.

***The pipeline solution fails to offer outcomes consistent with the climate change programs and goals of the New England states.***

The pipeline solution set offers a trajectory of GHG emissions that exceeds the region’s potential GHG reduction objectives. This level of excess potentially represents a failure to meet the region’s climate goals and could increase GHG emission-reduction compliance costs for electric ratepayers over time.

## **Energy Efficiency (EE), Demand Response (DR), and Renewable Energy (RE) Solution Sets**

***Increased investment in various combinations of EE, DR, and RE resources could address the identified stressed system deficiency, provided actions were taken to increase such investments beyond existing programs and their current trajectories.***

There are many options to meet any identified deficiency need through expanded investment in EE, DR, and RE (through distant low-GHG resources transmitted across existing or new transmission capacity). We modeled three solution set combinations: 1) EE and DR sufficient to meet the need; 2) EE with imports of distant low-GHG energy using existing transmission lines, and 3) EE with imports of distant low-GHG energy using new transmission lines. The cost of low GHG imports reflects the fact that the capacity and energy must be guaranteed to be available at the time of, and for the duration of, winter peak conditions in order to address the region's reliability needs.

***Investment in EE/DR represents the best solution from the perspective of ratepayer costs.***

Sustained investment over time in EE and DR, above and beyond investment currently committed and expected due to existing state policies, has the greatest potential net consumer benefit. Further, this solution set represents a lower-risk pathway for ratepayers, since it involves flexible annual investments that can be altered over time in response to changing expectations around natural gas supply and demand, EE/DR technology development and resource cost, power system demand growth, and the addition and attrition of electric generating resources. That is, this effort also offers the potential to meet long term climate goals beyond 2030 with lower up-front capital investments. However, increased EE installations would require sustained commitment and action by New England states over the next decade.

***Increased EE combined with new transmission and/or commitments to purchase firm capacity from distant low-carbon resources generates significant potential electricity price benefits but also involves significant ratepayer up-front investment obligations.***

An EE solution set that includes the transmission of low-carbon and/or renewable resources to New England markets instead of DR could generate substantial wholesale electricity price savings, to the extent that imports displace higher-priced marginal generating resources. However, in order to represent a solution to meet reliability deficiency needs, such imports would need to be backed by firm capacity commitments, including delivery at the time of winter peak. The cost of such a capacity commitment, if combined with the cost of transmission investments, could exceed the electricity price suppression benefits associated with this solution. While imports of low-carbon resources that are not backed by firm commitments may be more economic and help the region meet climate goals, they do not represent a solution to any winter reliability need.

***EE combined with firm imports of distant low-carbon resources on new or existing transmission lines provides the greatest benefits from the standpoint of GHG emissions.***

Meeting winter system reliability deficiency needs through EE and firm imports of low carbon resources would achieve significant reductions in the emissions of GHG associated with electricity generation in the New England region relative to the status quo outcome. It would also provide increased flexibility to meet longer-term climate policy targets.

## **Infrastructure Scenarios**

***“Infrastructure scenarios” – involving major pipeline or transmission investments sooner and/or larger than needed to address reliability needs – amplify the impacts of similar solution sets.***

In addition to reviewing solution sets designed to address the reliability need, we reviewed major infrastructure investments in natural gas transportation capacity that is larger and sooner than needed and transmission capacity that comes into operation sooner than needed. These infrastructure scenarios demonstrate cost, risk, electricity price, and GHG emission impacts that are similar in nature but larger in size than the pipeline and transmission solution sets sized and timed to address stressed system deficiencies.

## **Summary of Observations**

Based on our analysis, we find that power system reliability will be maintained with or without electric ratepayer investment in new natural gas pipeline capacity. This outcome is consistent with the current and expected future conditions facing our region. New England has maintained reliability through cold winter conditions over the past few years, and going forward, the regional grid operator forecasts declining peak demand for electricity during winter months.<sup>2</sup> Further, recent changes to wholesale markets provide strong financial signals for resource developers and operators of existing assets to ensure unit reliability during periods of winter scarcity. In short, the combination of declining demand and the success of new market initiatives will likely accomplish intended results: power system reliability will be maintained going forward, including at the time of winter peak demand. However, the region may want to consider pathways that provide additional certainty of meeting identified deficiencies that may exist under a “stressed system” perspective.

Importantly, the different solution sets that meet the stressed system deficiency vary in fundamental ways from both ratepayer cost and climate policy perspectives. Certain options offer long-term price reducing benefits, but require major up-front investments by ratepayers; others require more measured investments, but also provide fewer price reductions for consumers. Thus there may be additional value that should be attributed to the “incremental” approaches to address the stressed system deficiency. This is particularly true given our finding that, under our base case assumptions, we find no deficiency over the forecast horizon.

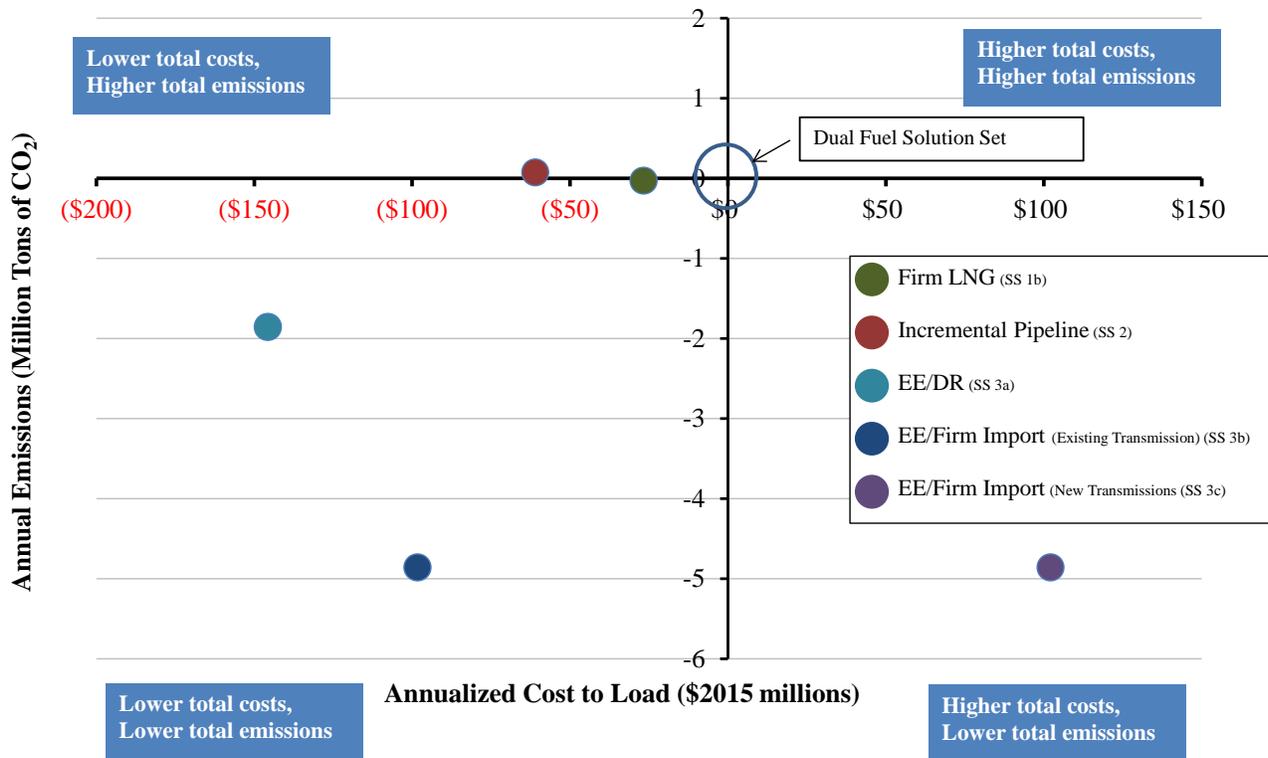
This option value may also be important given the region’s GHG goals and commitments. With little to replace in the way of higher-emitting resources, solution sets that continue our growing dependence on natural gas for electricity generation do not appear sustainable relative to our region’s and our Nation’s evolving GHG emission reduction requirements and goals. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. In contrast, solution sets that fail to do so could require more significant investments at a later date.

---

<sup>2</sup> ISO-NE Capacity, Energy, Load and Transmission (CELT) Report, System Planning, May 1, 2015.

As Figure ES1 (below) shows, only the EE/DR and EE/Firm Import (Existing Transmission) solution sets solve the stressed system reliability deficiency in a way that both reduces ratepayer costs and reduces GHG emissions relative to the current market outlook of relying on dual-fuel capability. Both the pipeline solution set and the firm LNG solution sets can reduce total ratepayer costs but do not reduce total GHG emissions. Finally, a solution set that includes EE and the firm import of distant low-GHG energy over new transmission lines provides substantial GHG emission reduction benefits, but would lead to a net increase in total ratepayer costs after accounting for both the cost of firm energy supply and new transmission capacity. In general, however, imports without a firm capacity commitment may be available at a lower cost, which could help the region meet its climate goals independently of a focus on reliability needs.

**Figure ES1: Annualized Cost and Emission Impacts, By Solution Set (\$2015 mil)**



Infrastructure scenarios that are larger and/or installed sooner than needed to meet the deficiency amplify the impacts of similar solution sets, but do not change the relative ranking of each option. These infrastructure scenarios demonstrate cost, risk, electricity price, and GHG emission impacts that are similar in nature but larger in size than the pipeline and transmission solution sets.

## II. INTRODUCTION AND PURPOSE

### A. Emerging Challenges to Winter Power Supply

New England generating capacity additions and operations are governed by the administration of competitive wholesale markets for capacity, energy, and ancillary services. Recent changes to those markets are expected to provide incentives to ensure that generation capacity is available to meet system needs every hour of the year. Nevertheless, the wholesale market construct has two features that have been the focus of significant analysis and policy deliberation in recent years: (1) resource attrition (i.e., from nuclear, coal, and oil-fired capacity) and addition of gas-fired capacity are increasing the region's reliance on power plants using natural gas as the primary fuel, and (2) to date, most natural gas power plant owners have not found it in their financial interest to purchase much firm natural gas transportation capacity for power plant operations. In light of these two features of wholesale market operations, there is concern that under some scenarios the region could have insufficient generating and demand resource capacity available to meet electric system needs, and/or that system constraints lead to high prices, particularly under cold winter conditions with periods of high natural gas demand from all sectors (especially for home heating demand).

Over the past couple years, a number of states in New England have taken steps to evaluate whether *electric* utilities should be allowed to collect in rates costs associated with the forward procurement of new interstate *natural gas* pipeline capacity on a firm basis.<sup>3</sup> In order to take this step, regulators should be convinced that this type of market intervention is needed to address potential power system reliability risks, and represents a prudent investment for the life of the asset. Beyond reliability, states may also consider whether such an investment would lower overall costs for electricity ratepayers, or otherwise be in the public interest.

Reviewing our dependence on natural gas is warranted for several reasons. Local resources for the supply of electricity are limited in New England, particularly at the time of winter peak demand. The only significant indigenous fuels for electricity generation in the region – biomass, hydro, wind, and sunlight – are restricted by resource availability and/or output variability. The contribution of local and renewable resources to annual energy requirements is significant, has substantial potential for expansion, and continues to grow. However, reliability concerns are tied more to the certainty of resource availability at the time of the winter system peak, or under unpredictable stressed system conditions, than to the magnitude of annual energy production. For example, there are only limited opportunities to increase hydro resources within New England, and at the time of winter peak solar capacity is generally not available and wind resource output is an unpredictable function of weather. As a result, the reliable

---

<sup>3</sup> This includes Massachusetts, Maine, Connecticut, and New Hampshire. Relevant studies include MA (D.P.U. Docket 15-37), ME (Maine Energy Cost Reduction Act, 35-A M.R.S. §1904-(2)), CT (Public Act No 15-107), and NH (NH PUC Docket IR 15-124). In addition, the New England States Committee on Electricity (NESCOE) also reviewed the issue in a series of reports in 2012 and 2013. See B&V (2013).

operation of the electric system in New England under system peak conditions remains heavily dependent on the timely delivery and/or storage of fuels from outside the region for nuclear and fossil-fuel (coal, oil, and natural gas) power plants.

Several of the more “traditional” resource options have their own set of challenges, with implications for the overall level of reliability of fuel supply and electricity generation. The two resource types with the most reliable fuel storage for long-run operations – nuclear and coal-fired generation – face economic and regulatory hurdles to continued operations and have experienced substantial retirements in recent years. Specifically, persistent low energy market prices, and the increased variable costs or need for incremental capital investment associated with emerging safety and emission control requirements, are putting pressure on continued participation by these resources in regional electricity markets.<sup>4</sup> Further, there are major economic and regulatory impediments to the siting new nuclear or coal-fired resources in the region; in fact, no one has filed for review of new nuclear or coal resources under ISO-NE’s interconnection review procedures.<sup>5</sup>

The remaining resources – generating capacity fueled by oil, natural gas, or both (dual-fuel) – require fuel imported from outside New England, and are subject to limitations on the ability to store such fuel for long-run operations. Continuous oil-fired operation at many units is constrained by both limited on-site tank capacity (with the need for potentially frequent replenishment of fuel) and in some cases annual operating limits based on applicable air regulations. Similarly, natural gas-fired capacity is dependent on contemporaneous fuel delivery on an as-needed basis through the region’s interstate pipeline system.<sup>6</sup>

The continuous increase in natural gas capacity and its share of regional generation is creating dependence within New England on natural gas for electricity generation throughout all hours of the year. From 2000 to 2014, the region’s reliance on natural gas for energy generation increased from 15 to 44 percent, largely replacing coal- and oil-fired generation.<sup>7</sup> Over the same time period, the region added approximately 12,000 MW of gas-fired generating capacity, with all other resource types combined adding just over 2,000 MW.<sup>8</sup> Further, there is little reason to believe this trend will diminish anytime soon. Natural gas dominates the ISO-NE interconnection queue for baseload or cycling resources, representing over 7,000 MW and approximately 62 percent of all interconnection queue resources. Most

---

<sup>4</sup> Recent wholesale electricity market rule changes (discussed below) are designed to significantly improve the economics of existing capacity resources. Nevertheless, in October 2015, Pilgrim announced its intent to retire by 2019 (and possibly as early as 2017), due in part to the need for new capital investments in response to NRC regulations.

<sup>5</sup> See, for example, the ISO-NE Interconnection Request Queue, available: <http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue>.

<sup>6</sup> Some of the region’s gas-fired capacity is connected to the distribution networks of the natural gas local distribution companies.

<sup>7</sup> ISO New England, *2015 Regional Energy Outlook*, (hereafter “2015 REO”), page 15.

<sup>8</sup> 2015 REO, page 18.

of the remainder – nearly 3,700 MW (36 percent) – are wind resources whose capacity value is set at a fraction of nameplate capacity.<sup>9</sup>

ISO-NE has conducted significant due diligence over the past five years on the potential impact of our dependence on natural gas on power system reliability. In response, ISO-NE and the region have enacted a comprehensive suite of electricity market reforms to address the issue, affecting virtually every market (energy, capacity, reserves/ancillary services),<sup>10</sup> creating better alignment between the timing of transactions in the natural gas and electricity markets, and establishing clear and frequent lines of communication between power system and pipeline operators, particularly during times of high demand. These changes should fundamentally alter the economics and reliability of power system operations under severe winter conditions, providing the necessary financial signals for enhanced availability and the reliable operation of existing resources, as well as longer-term investment in new resources to enhance the resilience of power system operations during winter peak conditions.

ISO-NE has expressed confidence that the suite of market changes it has promoted will provide the necessary financial incentives for reliable operations at all times of the year on a fuel neutral basis.<sup>11</sup> Yet ISO-NE has also promoted the potential benefits of new natural gas transportation infrastructure to address reliability and energy pricing needs.<sup>12</sup> And while most of the New England states are committed to letting competition in the electricity sector determine the path of infrastructure development and electricity pricing, the states are now actively considering (through legislation and/or regulatory action) options to pursue pipeline infrastructure contracts paid by electricity customers to address winter electric system reliability and cost challenges, and to have electric distribution companies procure large quantities of distant low-carbon resources through long-term contracts in part to help address GHG reduction goals.<sup>13</sup>

---

<sup>9</sup> Due to the variable nature of wind generation and the operational performance incentives inherent to New England’s capacity market (discussed further below), wind resource capacity value is discounted for reliability planning purposes, and many wind resource owners may choose not to take on capacity supply obligations.

<sup>10</sup> Changes include progressively stronger incentives in the capacity market for reliable operations during periods of peak system needs; more flexibility in the timing and structure of energy market offers to allow for a diverse set of approaches to fuel supply and pricing; changes to amounts procured and pricing in reserve markets providing for substantial additional revenues to generators during times of scarcity; enhanced auditing of generating resource operational capability on all fuels; greater coordination between electric and natural gas system operators; and clarification of the responsibilities of generators that have capacity supply obligations. In combination, these changes represent a fundamentally different and more lucrative structure for ensuring the reliable operation of generating units – including the acquisition of necessary fuel on a timely basis – during winter peak conditions and other times of scarcity.

<sup>11</sup> Testimony of Matthew White on behalf of the ISO, submitted ISO New England Inc. and New England Power Pool, Filings of Performance Incentives and Market Rule Changes; Docket No. ER14-1050-000, filed January 17, 2014.

<sup>12</sup> The Recorder: ISO New England calls for increased gas capacity. Richie Davis, Recorder Staff. January 21, 2015. Published in print: Thursday, January 22, 2015.

<sup>13</sup> See FN 1. In addition, see Appendix 4.

To some extent, the states’ efforts reflect the difficult balance between relying on competitive market forces to guide reliable and efficient power system outcomes, but recognizing the paramount importance of preventing power (and natural gas) system reliability failures, and meeting broad-based climate risk mitigation objectives. On one hand, the proper design of the region’s wholesale markets for capacity, energy and ancillary services – particularly with recent changes – should allow the market to identify the most efficient, lowest-cost path to maintaining power system reliability in all hours of the year, resulting from competition among a variety of fuel and resource options including pipeline gas, liquefied natural gas, oil and dual-fuel capability, grid-connected and distributed renewables, and demand-side measures. On the other hand, the consequences of missing the reliability and climate objectives are high, and potentially unacceptable from a public policy perspective: if markets cannot or do not provide proper and timely financial incentives, the potential economic, health and public safety impacts of having insufficient resources and infrastructure to meet peak demand can be severe.<sup>14</sup>

## **B. Purpose of the Study**

The Massachusetts Attorney General’s Office (AGO) hired AGI to conduct an independent region-wide assessment of potential regional power system reliability needs and solutions and to analyze potential future resource outcomes comparing cost and GHG emission impacts. Specifically, we review:

- Could the region experience power system “deficiencies” – periods during peak winter demand when the electric system may not be able to meet peak electric demand?
- If any such deficiencies are identified, what are the full suite of practical options for maintaining power system reliability – particularly during winter months, including but not limited to electric ratepayer funding for natural gas infrastructure?
- What would be the relative costs to electric ratepayers associated with these options – both to implement the options and as a result of how they affect wholesale electric prices?
- To what extent do various options help achieve or impede New England states’ obligations and goals with respect to GHG emission reductions?
- What other factors not captured in the quantitative analysis are relevant for consideration?

The purpose of our review is to provide information and data to help New England’s policymakers and stakeholders consider the potential benefits and drawbacks of various approaches to addressing our region’s dependence on natural gas for electricity generation. We recognize that this is one of many studies related to the region’s dependence on natural gas, and that all studies require forecasting

---

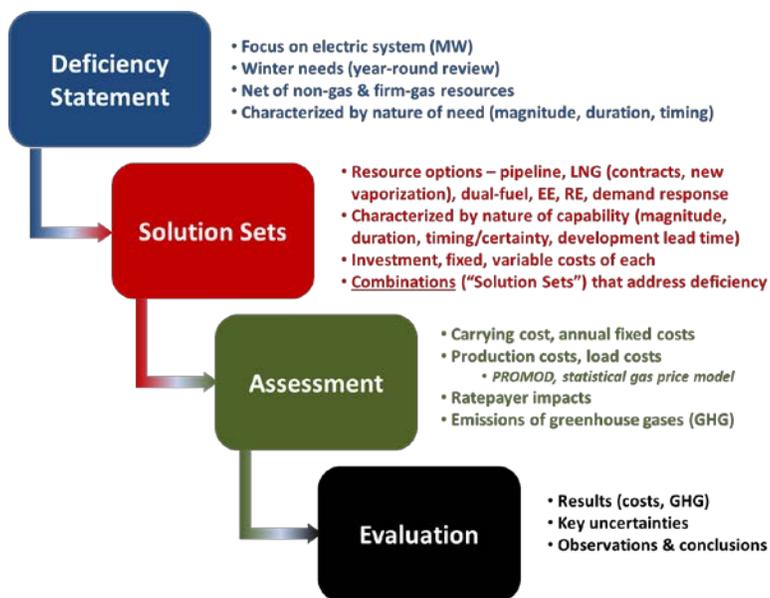
<sup>14</sup> ISO-NE and stakeholders in effect recognize this balance in the implementation of the temporary “Winter Programs.” During the interim period while the financial signals of recent and pending market rule changes begin to take effect and grow, ISO-NE has proposed and the region has implemented significant out-of-market actions to secure fuel for reliable system operations, to ensure power system reliability until the full effect of the new market structures is in place.

and judgment on highly variable and uncertain future market conditions. It is incumbent on policy makers and stakeholders to carefully consider the purpose, analytic method, and outcomes of the various analyses. Our analysis is designed to provide data and analysis to support the region’s consideration of these issues.

### C. Overview of Analytic Method

As noted above, this study’s primary purpose is to provide a consistent cost and emission comparison of feasible options for maintaining reliable electric supply through 2030, in consideration of potential constraints on natural gas delivery for electric generation.<sup>15</sup> We focus on options to maintain system reliability in the face of increasing dependence on natural gas for electricity generation – including but not limited to electric company pipeline capacity contracts – and conduct a comparative evaluation of the options from reliability, ratepayer costs and risks, and GHG emission perspectives.

The analysis comprises four basic components, described further in the sections that follow. First, we identify the timing, magnitude, and nature of deficiencies that would exist on the electric system absent new resource development beyond what will otherwise occur in response to ISO-NE Forward Capacity Auctions to maintain resource adequacy. For the deficiency review we analyze and model electric and natural gas system conditions in New England through the year 2030, taking into consideration electric system load and all available resources, with attention to the amount of natural gas transportation likely to be available for electricity generation (particularly during winter months). Second, we identify a discrete number of solution sets that represents various feasible combinations of infrastructure and/or resource options in amounts that (1) are sufficient to address any identified deficiency, and (2) can result from the operation of market outcomes or otherwise be implemented through legislative or regulatory action.<sup>16</sup> Next, we conduct an assessment of the solutions sets including financial/ratepayer analysis, production cost modeling, and a review of GHG



<sup>15</sup> We assume and expect power supply reliability is maintained, even if it is uncertain at this time which resources will emerge to maintain reliability over the forecast horizon. Thus while we use the term “deficiency,” we do not mean to suggest or indicate an expectation that the electric system will experience a power supply reliability problem over the forecast horizon.

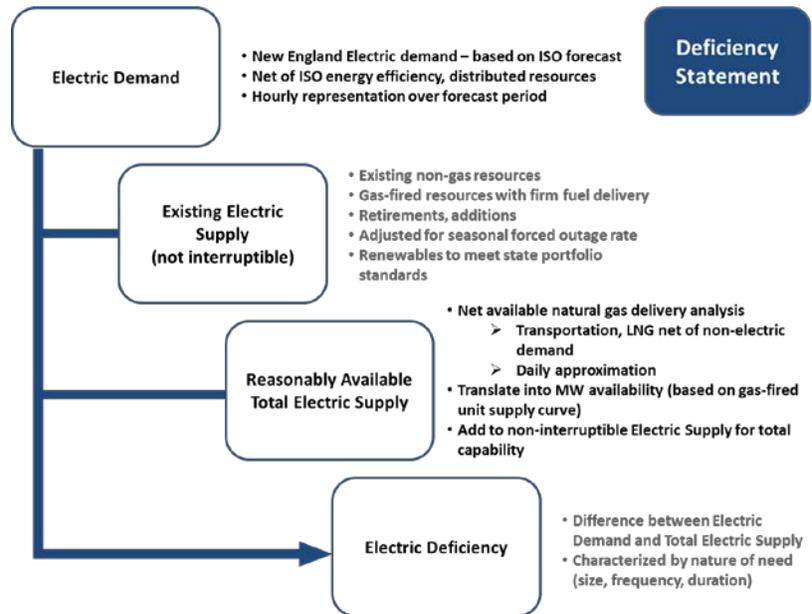
<sup>16</sup> We discuss our screening criteria for “practical” solution sets in Section V.

emission impacts. Finally, we evaluate the results in a comparative analysis of solution sets, identify key uncertainties, and provide observations on the results.

### III. POWER SUPPLY DEFICIENCY ANALYSIS

#### A. Power Supply Deficiency Analysis

To identify the timing and size of solution sets to be evaluated in this report, we first identify a potential deficiency to be met through future resource or infrastructure development. In this context, the term deficiency is not meant to indicate an actual reliability shortfall; instead, it is an estimate for modeling purposes of periods when the electric system may not be able to meet peak electric demand given constraints in natural gas transportation capacity, and thus requiring some combination of additional actions.



In evaluating potential power system deficiencies, we are careful not to construct the analysis in a way that predetermines the conclusion. Specifically, our analysis does not “assume in” a gas supply deficiency by dispatching the electric system *assuming sufficient gas transportation is available in all hours*. This recognizes that whether or not additional interstate pipeline capacity is built (and if so, how much) is not yet known, and that absent additional pipeline capacity there are other ways electric load would be met in constrained hours. Similarly, we do not “assume away” a deficiency by anticipating potential future non-pipeline resource commitments (e.g., firm LNG storage and delivery) or policies (aggressive new renewable, load-shifting, or load-reducing measures or policies). All such potential outcomes are instead configured and evaluated as solution sets to allow for consistent comparison of cost and GHG emission impacts. Thus we adhere in our deficiency analysis to a straight-forward continuation of current market, infrastructure, and regulatory conditions. Under this outlook, the region will continue to rely on natural gas as the dominant fuel of choice, and we include more than 19.5 GW of natural gas fired capacity in 2020 in our base case, representing 52 percent of total system capacity. This total

includes 9.6 GW of dual-fuel capacity, with 2.4 GW of that dual-fuel capacity assumed to come on-line after 2019.<sup>17</sup> This total also assumes the retirement of the Pilgrim Nuclear facility in 2019.<sup>18</sup>

Our development of the deficiency statement involves four basic steps: (1) identifying hourly demand for electricity through the modeling horizon; (2) establishing the contribution of non gas-fired supply resources that may be relied upon during cold winter conditions; (3) estimating the quantity of natural gas pipeline capacity that may be assumed to be available for electricity generation on a daily basis across the year, reflecting forecasted LDC pipeline use, and translating this into MW of available generating capacity; and (4) combining these estimates to develop a daily and hourly representation of the total megawatt deficiency of the electric system over the modeling horizon – that is, the amount of electric load that would need to be met through changed operations on the current system, or development of new infrastructure or resources.

Our deficiency calculation is focused on winter peak conditions from a reliability planning perspective. Consequently, the deficiency statement assumes a demand forecast based on extremely cold weather year conditions (e.g., the temperature profile of 2004, one of the coldest years in the past two decades) and coincident high electric load (e.g., the Capacity, Energy, Loads, and Transmission (CELT) 90/10 load forecast, net of existing energy efficiency and photovoltaic (PV) resources).<sup>19</sup> More detail on the steps in our deficiency calculation are summarized in Appendix 1. Below, we describe in more detail two key elements of the deficiency analysis – our derivation of the quantity of natural gas that will be available for electricity generation (in consideration of natural gas LDC demand forecasts and supply plans), and our estimate of the need for natural gas-fired generation on the electric system once all other electric resource options have been considered.

## 1. Availability of Natural Gas for Electricity Generation

To estimate the total quantity of natural gas available to the electric generation sector, we compare an estimate of forecasted LDC demand for natural gas from interstate pipelines to total available pipeline capacity.<sup>20</sup> First, we assume that the total existing interstate natural gas pipeline capacity is equal

---

<sup>17</sup> This estimate is in-line with other estimates of dual-fuel capability, including the publicly available totals reported in the ISO-NE CELT (2015) and AGI's review of confidential individual generator data provided by ISO-NE as part of its assessment of the ISO-NE Forward Capacity Market Performance Incentives.

<sup>18</sup> In October 2015, the owners of the Pilgrim Nuclear facility filed a non-price retirement request with ISO-NE.

<sup>19</sup> The 90/10 forecast is based on an expectation that system loads will exceed the forecast only 10 percent of the time. In contrast, the 50/50 load, which is used for resource adequacy planning and in the net Installed Capacity Requirement (ICR), would be expected to be exceeded 50 percent of the time.

<sup>20</sup> We recognize that there are other potential sources of natural gas for electricity generation in addition to interstate pipeline gas, such as supplies sourced from regional LNG facilities. Since these would require forward contracts to procure and ensure LNG is available for electricity generation at the time of winter peak, we do not assume LNG as a resource in the deficiency statement but, rather, assess it as potential solution set.

to 3.95 Bcf/day, based on Energy Information Administration (EIA) State to State capacity data.<sup>21</sup> This includes capacity for Algonquin, Iroquois, Tennessee, Portland Natural Gas, and Maritimes & Northeast Pipelines. We include an additional 0.414 Bcf/day of new capacity in the third quarter of 2016 for the Spectra Algonquin Incremental Market (AIM) Project and the Kinder Morgan Connecticut Expansion Project.<sup>22</sup> Therefore, starting in the 2016/2017 winter, the total capacity of interstate natural gas pipelines is 4.36 Bcf/day.

Next, we develop a forecast of LDC demand for natural gas from interstate pipelines based on the historical relationship between interstate pipeline deliveries to both LDCs and other end-users with historical weather conditions. To do so, we use daily scheduled pipeline and LNG deliveries to LDCs and end-users for the period December 1, 2012 to present using data provided by SNL Financial.<sup>23</sup> We also use the weighted average temperature for the ISO-NE Control Area collected by ISO-NE.<sup>24</sup>

Using this historical data, we then develop the statistical relationship between demand and temperature for the three-year winter periods 2012/13, 2013/14, and 2014/15, as shown in Figure 1. We forecast future gas demand assuming a growth rate for LDC and end-user demand from interstate pipelines of 1.4 percent.<sup>25</sup> We recognized that peak day demands of the LDCs are not fully met through pipeline deliveries, and any peak day demand above this growth rate is met through other resources, such as increased LNG vaporization from regional LNG facilities (e.g. Distrigas) and LNG peak shaving supplies. We assume that these supplies are unavailable to the electric generation sector. Therefore, our

---

<sup>21</sup> We note that this assumption is consistent with the 3.7 Bcf/d used in ICF/ISO-NE (2014) and the 3.9 Bcf/d used in B&V/NESCOE (2013). See ICF International. "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II" Prepared for ISO New England, November 20, 2014. Additional detail on our review of LDC supply and demand, and how both may change over the modeling horizon, is presented in Appendix 1.

<sup>22</sup> These projects have received or are pending final FERC authorization. In contrast, we exclude projects that have initiated the FERC pre-filing process or may have precedent agreements with shippers. This includes both the Spectra Atlantic Bridge project, the Spectra Access Northeast project, and the Kinder Morgan Northeast Energy Direct project.

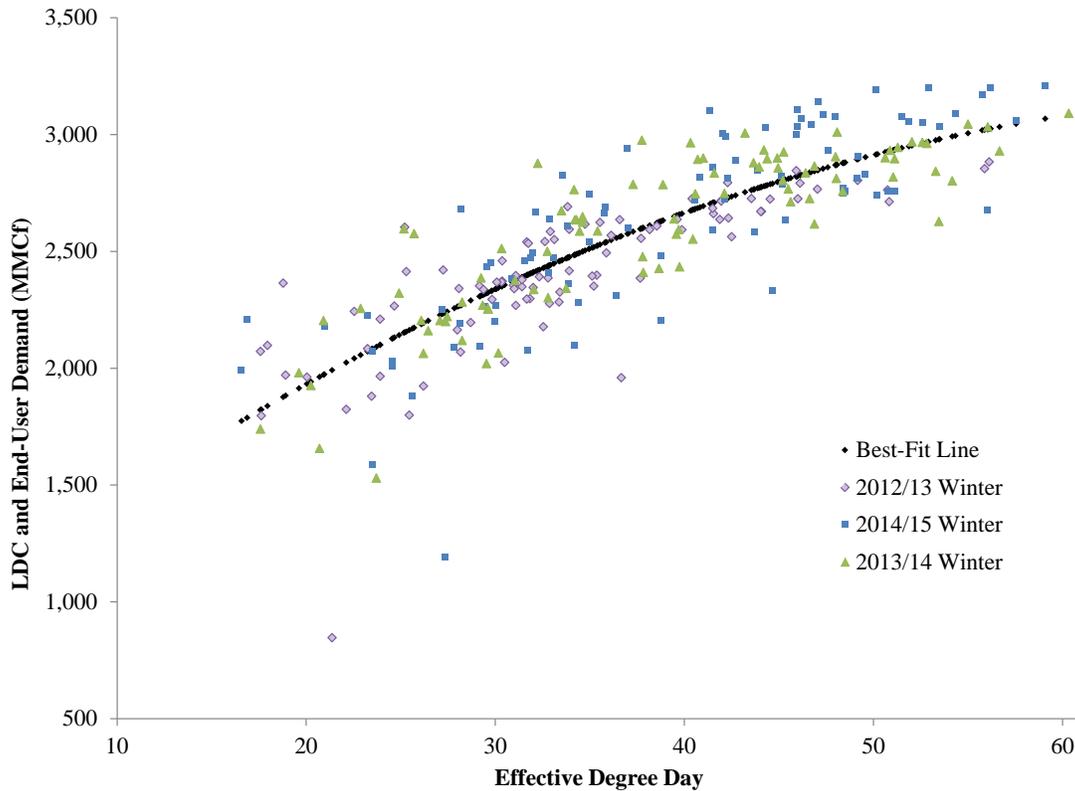
<sup>23</sup> SNL Financial is a data aggregation service that compiles electronic bulletin board data reported by each individual pipeline company. SNL classifies each delivery point based on available contract information.

<sup>24</sup> See ISO-NE, Zonal Information, available: <http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info>.

<sup>25</sup> Our estimate is consistent with the long term growth rate used by other recent studies (ICF (2015); Synapse/DOER (2015)). While certain LDCs currently are forecasting higher growth rates, these forecasts typically include demand from end-use customers (as returning capacity exempt customers), which we already separately account for in our estimates. Using a higher LDC growth rate based on current LDC assumptions could double-count end-user demand. On the supply side we exclude incremental supply resources proposed to meet higher growth rate expectations. We assume that any supply additions approved through an LDC resource planning process would be reserved to meet LDC demand above and beyond the quantity forecasted here and unavailable to the electric generation sector. In Appendix 1 we provide a sensitivity that tests both assumptions.

estimate represents a forecast of LDC firm demand for natural gas only from the existing interstate pipeline system.

**Figure 1: Historical Relationship of Weather and Gas Demand, 2012-2015**



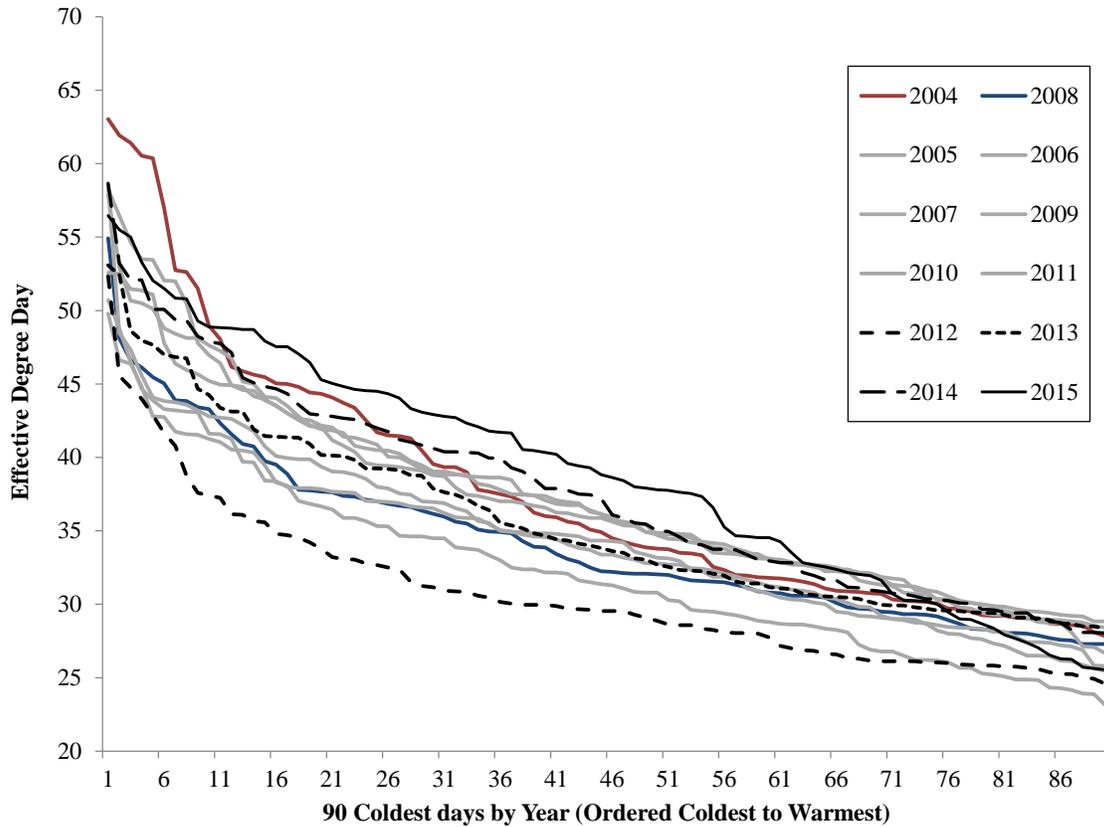
Notes:

- [1] Total deliveries are the sum of LDC and End-User demand.
- [2] Winter includes December, January, and February.
- [3] Effective degree day is defined as 65 degrees Fahrenheit – Temperature.

Using the historical relationship between weather and gas demand Figure 1, we develop natural gas demand forecasts based on both the 2008 weather year (a median winter) and the 2004 weather year (representing a cold weather year, including the coldest day of the past 10 years). As shown in Figure 2, the 2004 year (shown in red) represents far colder winter peak conditions than either of the recent winters in 2012/13 or 2013/14, when New England experienced “Polar Vortex” conditions in late January 2014. This also includes the 2015 year, which experienced a period of sustained cold greater than any previous year.

By combining our estimates for total natural gas pipeline capacity and the daily forecast of natural gas LDC and end-user pipeline demand developed above, we estimate the total hourly pipeline natural gas available to the electric generation sector. Finally, we assume that our daily natural gas availability is fully ratable; that is, the pipeline gas available to electricity generation in each hour is one twenty-fourth of our daily estimate.

**Figure 2: Historical Weather Years, 2004-2015**



Note:

[1] Weighted average temperature for the ISO-NE control area.

[2] Effective degree day is defined as 65 degrees Fahrenheit – Temperature.

## 2. Electric Sector Natural Gas Demand

### *Base Case Deficiency Evaluation*

In the second step, we estimate the total quantity of natural gas fired capacity that is needed to meet electric load in every hour, assuming that non-gas fired resources are operable at the time of winter peak conditions (though quantities available are fully reduced by historical seasonal equivalent forced outage rates). We compare this quantity of capacity to the total capacity of gas-fired generation resources that could be dispatched, given the estimated quantity of pipeline natural gas available to the electric generation sector. As a general rule, we use assumptions and data consistent with the ISO-NE planning process.

This estimate requires forecasts for electric sector load and available electric sector generation resources. In order to focus on demand during colder than average winters, we develop deficiency statements using the CELT 90/10 peak load forecast, net of passive demand response and behind the meter solar PV. This forecast reflects load at a level likely to be exceeded only 10 percent of the time. We translate the CELT seasonal peak loads and annual energy forecasts into an hourly load profile and assume that the system will need to carry 2,000 MW of reserves in every hour.<sup>26,27</sup>

Next, we develop a supply curve of available generation resources in each year, taking into account known additions and retirements. We start with the system as it exists today, including known retirements and additions. This includes the recent retirement announcement of the Pilgrim Nuclear facility. Going forward, we assume that all incremental Renewable Portfolio Standard (RPS) requirements are met through in-region wind resources, derated to 5 percent of nameplate capacity with respect to availability during peak periods, consistent with the ISO-NE Transmission Planning Technical Guide (2014).<sup>28</sup> We include all known retirements, based on a review of the current ISO-NE non-price retirement designations and Ventyx default retirements.<sup>29</sup>

With respect to imports, we follow the ISO-NE CELT convention and only include known imports with a firm capacity supply obligation through Forward Capacity Auction (FCA) # 9. That is, we assume – from a resource adequacy and reliability standpoint – that there are only 95 MW of ‘firm’

---

<sup>26</sup> We developed these hourly load shapes using the Ventyx PROMOD software, a widely used production cost model that simulates the dispatch of the electric generation sector. We describe our use of PROMOD in greater detail in Section V and Appendix 3. Ventyx develops these hourly load shapes based on the historical relationship of hourly data and system annual peak and energy. We reviewed PROMOD’s annual load shapes to ensure consistency with monthly and seasonal peaks specified in the ISO-NE forecast.

<sup>27</sup> We recognize that our assumption of needing to carry 2,000 MW of reserves may to some extent be operationally redundant with our application of equivalent forced outage rates on all available resources. This represents an additional conservative assumption on our part, to ensure electric reliability is maintained in all hours.

<sup>28</sup> We recognize that the contribution of such resources at the time of winter peak could be higher than five percent. However, we assume five percent for the deficiency calculation consistent with our approach to evaluating system deficiencies from a reliability perspective.

<sup>29</sup> A full list of unit retirements is included in Appendix 3.

imports in 2019.<sup>30</sup> Existing imports may continue to participate in future capacity auctions, which could continue to provide an important non-gas resource during winter months. Finally, in estimating resource availability at the time of winter peak, we assume that dual-fuel units are available to operate on oil (and have sufficient oil supply), and we derate the total capacity of each resource by historical fuel specific equivalent forced outage rate demand (EFORd) (for dual-fuel capacity we apply the oil-fired EFORd rate).<sup>31</sup> Finally, we include all new resources that have cleared in recent Forward Capacity Auctions and, over the modeling period, add new generic dual-fuel natural gas capacity as needed to maintain at least a 14.3% reserve margin.<sup>32</sup>

Our assumption that existing oil-fired capacity will be available, and new capacity additions will be dual-fuel capable, reflects the outlook that recent market rule changes in New England will provide strong incentives for asset owners to ensure resource availability during potential scarcity hours. These incentives include (but are not limited to) the performance incentive program in the Forward Capacity Market, more flexible (hourly) pricing in the energy market, improved generator auditing procedures, and increased purchases and pricing levels in the reserve market. These market rule changes were designed, in part, to address periods of scarcity associated with potential constraints on the interstate natural gas pipeline system into the region.

With this complete supply curve and load forecast, we estimate the difference between total load and total non-gas fired resources in each hour of each year. This represents the total MW “need” that could be filled by gas-fired capacity. The total reliability deficiency is the difference between this electric sector need (for gas-fired generation) and the total quantity of natural gas fired generation that can be dispatched, given the hourly pipeline natural gas available to the electric generation sector. The deficiency is defined on an annual basis over the modeling horizon by (a) the maximum total magnitude of the deficiency, in MW and Bcf/day of need; (b) the frequency of deficiency events of any size in terms of number of days and number of hours per year; and (c) the duration of deficiency events in terms of the number of consecutive days over which a deficiency exists.

---

<sup>30</sup> It is unlikely that imports will be as limited in all future years as reflected in this assumption. However, since *in any given year* of the modeling horizon potential import resources could decide to not take on a capacity supply obligation in New England (due, for example, to the exporting region’s supply/demand conditions or relative pricing in other neighboring regions’ capacity markets), we do not assume they will be available at the time of winter peak, consistent with our approach to evaluating system deficiencies from a reliability perspective. As with other assumptions we have made that may overstate demand or understate supply, to the extent this assumption is wrong we are overstating actual future system deficiencies.

<sup>31</sup> This information is provided through the North American Electric Reliability Corporation Generating Availability Data System. See: <http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx>.

<sup>32</sup> We note that this is slightly above the 2018/19 net Installed Capacity Reserve (ICR) requirement of 13.9%, but is consistent with the long-run expected reserve margin forecast in the 2015-2024 ISO-NE Capacity, Energy, Load, and Transmission (CELT) Report.

### *Stressed System Deficiency Evaluation*

In addition to our base-case deficiency evaluation, we also model additional scenarios to explore potential reliability needs in the event that some non-gas fired resources retire or other oil-fired units are otherwise unavailable. These scenarios generally describe conditions in which the electric system experiences an increase in gas demand, greater than that forecast in the base case. This includes limits on the total capacity of oil-fired resources available, and incremental retirements of non-gas fired capacity, as follows:

- Scenario 1: “Oil Unavailable” Scenario: While we expect our reduction of unit capacity for historical seasonal EFORD should to some extent already account for these factors, we make this adjustment in recognition of the fact that units could be unavailable for a number of reasons, including operating limitations under existing air quality permits, available oil supplies during winter events, or generator outages above and beyond historical outage rates. We assume that only existing fuel oil #2 units are available at the time of winter peak, and assume that all other existing resources (fuel oil #6 or unidentified) and other new dual-fuel capacity are available only on gas. This represents approximately 1,800 MW, which is 20 percent of all existing dual-fuel capable units and approximately 40 percent of all dual-fuel units in the future supply stack, including new resources.
- Scenario 2: “Gas-Only” Scenario: We assume the retirement of existing non-gas fired capacity in amounts equal to approximately 1,200 MW, with such capacity replaced by gas-only units (i.e., no dual-fuel capability). This sensitivity reflects, in part, the ability for generators to assume additional risk of non-performance under current pay-for performance rules, which don’t formally require dual-fuel capability. In this sensitivity, from a deficiency analysis perspective, *which* units retire is less important than the fact that the retirements be non-gas units, and that the capacity is entirely replaced by gas-only resources. In effect, this represents an absolute increase in the deficiency amounts.
- Scenario 3: “Stressed System” Scenario: A combination of the previous two scenarios.

## **B. Deficiency Statement Results**

We find that under existing market conditions, there is no electric sector reliability deficiency through 2030, and therefore that no additional pipeline gas capacity is needed to meet electric reliability needs (Table 1). New England’s existing market structure – including recent changes to address reliability during challenging system conditions (such as at the time of winter peak demand) – will likely provide the resources and operational practices needed to maintain power system reliability. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods. And as described in the previous section, we constructed the base case to include several assumptions that reflect worst-case planning scenario conditions, tending to overstate the “deficiency” beyond normal reliability planning practices.

Nevertheless, it is instructive to understand the vulnerability of the current system to increased system stress, above and beyond that already included in our base case. Under the most stressed scenario, we find that an electric reliability deficiency of approximately 1,675 MW arises in 2024, growing to 2,480 MW in 2029/30, occurring in 26 hours across at most nine days. These 26 hours represent a total energy deficiency of approximately 24,000 MWh over the full winter period in the stressed system scenario. There are only two days and four hours with a total deficiency greater than 2,000 MW in the 2029/30 winter in any scenario.

From the perspective of natural gas transportation capacity, this deficiency is the equivalent of approximately 0.42 billion cubic feet per day (Bcf/d), assuming that capacity must be available on a fully ratable basis and that the deficiency must be met entirely with natural gas fired generation.

In the following sections, we identify solution sets that could be used to meet both the peak deficiency and the duration/frequency. Here, the duration and frequency determines in part how often a given solution set will need to be used. The economic assessment compares this frequency of use with the total annual costs required to implement each solution set. This considers the tradeoffs associated with solutions or other market actions that involve fixed costs required throughout the year, and variable costs and actions that may be available on an as-needed basis.

**Table 1: Electric Sector Reliability Deficiency Analysis, 2020-2030**

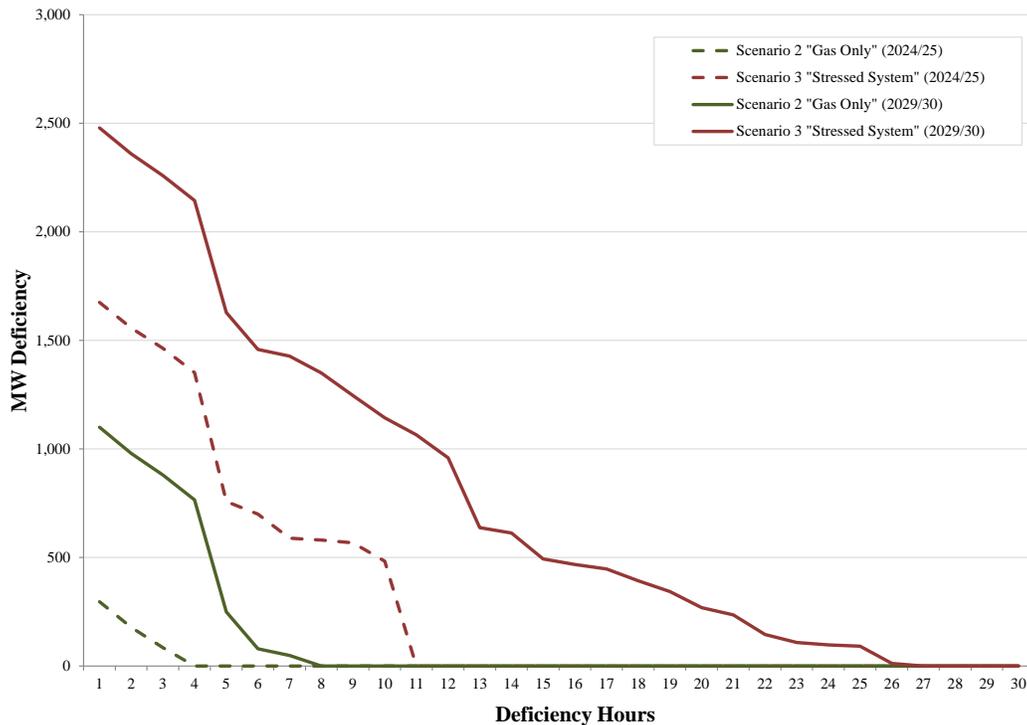
2004 Weather Year, 90-10 Load	Total Hours with a Deficiency									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	3	4	4	4	4	7
Scenario 3 "Stressed System"	0	0	2	3	10	9	13	15	19	26

2004 Weather Year, 90-10 Load	Total Days with a Deficiency									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	2	2	2	2	2	3
Scenario 3 "Stressed System"	0	0	1	2	4	4	5	7	7	9

2004 Weather Year, 90-10 Load	Peak Hour Deficiency (MW)									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	296	576	699	433	743	1,100
Scenario 3 "Stressed System"	0	0	185	435	1,675	1,955	2,078	1,813	2,122	2,479

2004 Weather Year, 90-10 Load	Peak Hour Deficiency (Bcf/hr)									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0.0021	0.0041	0.0050	0.0031	0.0053	0.0078
Scenario 3 "Stressed System"	0	0	0.0013	0.0031	0.0119	0.0139	0.0148	0.0129	0.0151	0.0176

**Figure 3: Deficiency Duration Curve (2024-25 and 2029-30)**

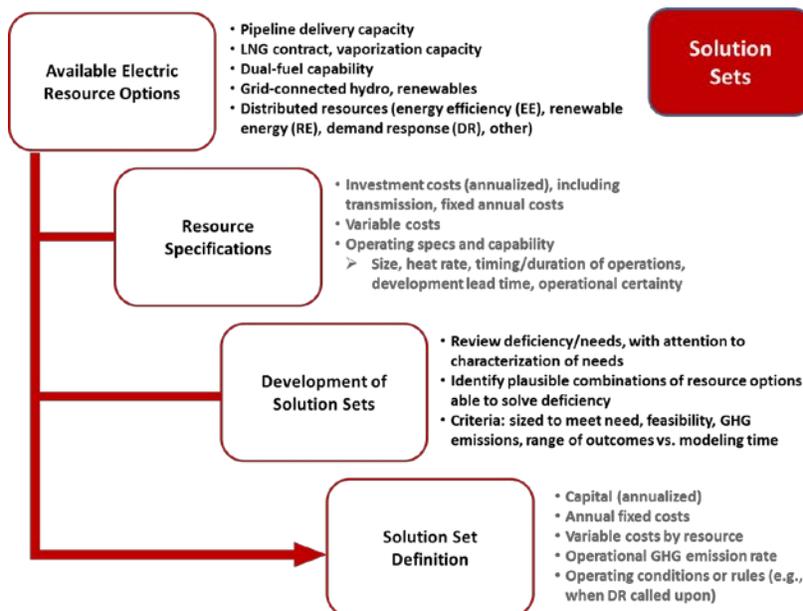


## IV. POTENTIAL ELECTRIC SECTOR PATHWAYS TO ENSURE RELIABILITY UNDER “STRESSED” SYSTEM CONDITIONS

### A. Solution Sets

As noted in Section III, we find no deficiency in our base case analysis. Given this conclusion, there is no need to review solution sets as a response to a base case reliability need. Nevertheless, the continued reliance on oil-fired and dual-fuel generation, and possibly other variable solutions such as LNG, will likely continue to lead periodically to high winter prices due to natural gas constraints, and elevated carbon dioxide emissions from oil-fired generation used during winter peak periods. Consequently, while base case conditions do not require any changes from a reliability perspective, our stressed system scenario does identify potential deficiencies. Policy makers and stakeholders may wish to consider the potential cost and GHG emission implications of various solutions that could address the stressed system needs and may have the potential to lower customer costs, lower total GHG emissions, or both.

The fundamental purpose of identifying solution sets to meet the maximum deficiency is to demonstrate feasible options to meet system needs while providing different benefits for customers, through lower energy prices, lower GHG emissions, or both. Our focus is on resources that could plausibly emerge given economics and currently-known technological capabilities, and/or that are specifically under consideration by the region’s states and stakeholders.



We develop these “solution sets” as various combinations of electric and/or natural gas resources that could reasonably and practically contribute to meeting the maximum deficiency under the stressed system scenario going forward. We focused on the following threshold requirements and criteria:

(1) Solution sets must, at a minimum, be able to provide or support enough power to satisfy the identified deficiency for the magnitude, frequency, and duration of the deficiency. Specifically, the resource(s) of the solution set must be able to produce or enable firm power output at the time of the most severe winter peak conditions, for as long and as often as needed. This not only limits resources available for the solution sets, it also establishes conditions on solution sets to ensure that the solution set can be counted on to meet the reliability deficiency at the time of winter peak.

For example:

- a three-hour demand response resource cannot satisfy a twelve-hour deficiency;
- solar PV cannot contribute to a deficiency that occurs when it is dark (as is generally the case with winter peak period deficiencies);
- pipeline capacity cannot be counted on unless primary firm transportation rights are guaranteed for electricity generation prior to winter operations;
- a transmission solution cannot be counted on unless backed by a “firm” capacity supply obligation that guarantees availability under winter peak conditions (for example, a contract backed by committed resources such as hydro, wind, or a combination of the two); and
- LNG cannot contribute to a deficiency unless the fuel is previously contracted for, with guaranteed storage, vaporization and pipeline delivery reserved and usable at the time of winter peak conditions.

(2) Solution sets must be feasible and practical from technology, market, and regulatory/policy perspectives, based on reasonable knowledge and expectations in place today. Thus, for example, new nuclear or coal capacity is assumed impractical from economic and siting/permitting policy perspectives; advanced grid-connected battery storage is not specifically considered a solution set alternative given current cost and development expectations; and reducing or shifting demand through advanced demand control technologies and new time-of-use rate structures is not considered given the regulatory and rate design issues that need to be settled before this could become a sizable resource.

(3) Solution sets should be sized and timed to address the identified deficiency. As a general rule, solution sets are assumed to be placed into service when and in amounts needed over the modeling horizon. However, in certain solutions sets where the resource in question is not easily scalable, the full size of the solution needed in the *highest* deficiency year may be assumed in place in the *first* deficiency year (e.g., high-voltage transmission to access distant low-carbon resources), or otherwise may be added generally timed to the deficiency, but in just a couple or few increments (e.g., natural gas pipeline capacity increases or new transmission investments).

We include outcomes that would normally flow from existing competitive market incentives, as well as outcomes that would require legislative or regulatory actions by states (and that have been considered in various forms by states). Below, we describe solution sets grouped into the following categories: (1) market driven outcomes that would likely flow directly from existing market incentives, to ensure fuel delivery security during times of scarcity (i.e., incremental dual-fuel capability and/or firm LNG commitments); (2) incremental pipeline transportation capacity sized at a minimum to meet the identified deficiency and dedicated for electricity generation at the time of winter peak through electric ratepayer funding; and (3) aggressive investment (whether from regulatory policy or technological

change) in incremental energy efficiency and other renewable energy.<sup>33</sup>

Each solution set represents an incremental change to the electric generation sector, which will result in an increase in available electric supplies or a decrease in total electric demand. These solution sets include variable options (such as LNG or demand response) which can be called upon only during deficiency hours and also larger fixed options, which would be available both during the winter peak deficiency events and also during all other hours in the year (such as incremental pipeline capacity, new transmission capacity, or increased energy efficiency). Each solution set, therefore, will have a unique impact on total system natural gas utilization, natural gas prices, and the total cost of energy used to serve customers. We discuss these impacts in the next section.

In order to ensure a consistent and comparable analysis focused on electric ratepayers (who would pay for and be the primary beneficiaries of the investments), we conduct the financial analysis with ratepayers responsible for the full cost to implement each solution set, including all fixed and variable costs associated with new investments based on existing cost-of-service principles that also recover return on rate base, depreciation, and taxes. Also, in estimating costs for all solution sets, we assume costs based on current or known information and recent estimates, without presuming increased performance or declining costs for any resource or solution set. We match annualized benefits to annualized costs over the full modeling period and express all values in levelized real 2015 dollars.<sup>34</sup> Additional details on each solution set, including sources and assumptions for costs, are described in Appendix 2.

### *Market-Driven Outcomes*

#### **Solution Set 1(a): “Status Quo” – Dual-Fuel**

The first solution set reflects the market-driven evolution of the region’s resources that would likely occur absent any major steps taken by states to achieve alternative resource outcomes. This market outlook assumes, in effect, the status quo. We compare all other solution sets to this outlook. It assumes neither any specific non-market actions to fund the development of natural gas pipeline capacity for use by electric generators, nor funding for transmission and/or long-term contracts to acquire distant low-carbon resources with firm winter commitments. Finally, it does not assume any technological breakthrough or change in state policies to increase distributed renewable and efficiency resources in the region beyond current expectations.

---

<sup>33</sup> Broadly, this solution set represents increased investment in renewable and other distributed technologies of various types and sizes (grid-connected wind/hydro, energy efficiency, demand response, distributed generation). A solution set focused on energy efficiency represents the likely lowest-cost distributed approach, based on our review of previous studies.

<sup>34</sup> We recognize that solution sets requiring an incremental capital expansion, for either a new transmission line or new incremental gas pipeline, will necessarily have lifetimes beyond 2030 and the end of our modeling period. We do not consider the remainder of ratepayer payments associated with these investments beyond 2030, nor do we consider any potential benefits to the electric generating sector beyond that point. We discuss the implications for these remaining costs further in Section V.

This outlook recognizes that current market incentives are *not* sufficient to cause many power generators to enter into major advanced commitments for firm natural gas pipeline transportation to cover winter peak operations at full output. Instead, and in response to incentives to ensure operation during times of scarcity, market participants would add dual-fuel capability and ensure sufficient alternative fuel is on site to maintain availability at the time of winter peaks. The costs associated with these alternatives are estimated in the assessment phase and compared with other solution set options. This solution option reflects the fact that there is substantial potential capacity for incremental dual-fuel capability within New England, both in the form of reactivating mothballed capability and adding new dual-fuel capability at existing units.

Dual-fuel capability is added at existing units, with annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 (for a total of 2,400 MW). Total annualized incremental dual-fuel capacity costs are assumed to be \$6,856/MW, based on information identified in Schatzki and Hibbard (2013), and include both annualized capital costs and annual operating costs for fuel and operations and maintenance. Importantly, electricity consumers would only realize incremental costs for this solution if and to the extent that the addition of dual fuel capability on an existing resource affects capacity market prices as a marginal capacity resource, which may in fact be unlikely. Nevertheless, for comparison with other solution sets, we provide dual-fuel costs calculated as the full incremental cost on a cost of service basis, potentially overstating the cost impact of this solution on ratepayers. This solution set is referred to a “Dual-fuel (SS 1a)”.

### **Solution Set 1(b) – Firm LNG**

As an alternative to adding dual-fuel capability, gas-fired power plants could enter into seasonal or annual contracts on a single or multi-year basis for the delivery (prior to winter peak, or timed for winter peak), storage and regasification of LNG, along with firm delivery of the associated gas to existing gas-only generating resources, if and as needed for fuel supply during winter peak conditions. Existing incentives in the region’s wholesale markets could lead generating resources to take this approach to ensure availability and operation during times of winter scarcity absent any specific actions taken by states. Thus we include an LNG option as an alternative market-driven solution set with the maximum amount of assumed LNG capability that is available set to an estimate of the region’s LNG vaporization capacity, net of estimated LDC use.

Consequently, we assume that net deliverable natural gas capacity for electricity generation associated with the regional LNG facilities is limited by what is used by LDCs during winter peak conditions – which we assume to be equivalent to the full Maritimes & Northeast (M&N) pipeline capacity (limiting contributions from Canaport, which is included in the total existing pipeline capacity described above) and a portion of the Distrigas storage and vaporization capacity assumed to be used by LDCs.<sup>35</sup>

---

<sup>35</sup> Individual LDCs contract for firm capacity from the Distrigas facility, with the intent that required storage amounts are full as of December 1st in each year. ICF/ISO-NE (2014) reports that 20 percent of the LNG received at

LNG storage and vaporization is contracted for in amounts not more than the full shipment quantities needed to meet the identified deficiency. That is, we do not assume that electric generators or ratepayers pay for firm LNG commitments beyond the quantity required to cover the estimated deficiency. This requires total annual volumes at least equal to the cumulative deficiency need across the winter, which we estimate could be covered by one shipment of LNG, or approximately 3 Bcf. It also requires availability of vaporization capacity up to 0.42 Bcf/d on the maximum deficiency day; we estimate that at least 0.5 Bcf/d vaporization capacity from LNG facilities would be available for electricity generation on peak winter days. Information on potential structures for such contract arrangements, including contract terms and fixed annual and variable costs, were provided to AGI by LNG representatives and Environmental Defense Fund. Our estimate of the cost of this solution set is based on a 90-day term charter arrangement, with a demand charge of \$200,000, escalated annually with inflation, and variable charges based primarily on Henry Hub pricing plus a processing cost of \$3.50 per Dth, shipping costs of \$1.50 per Dth, and delivery charges of \$0.16/Dth, all escalating annually with inflation. This solution set is referred to as “Firm LNG (SS 1b)”.

### ***Incremental Pipeline Transportation***

#### **Solution Set 2 – Incremental Pipeline**

The incremental pipeline transportation outlook assumes the development and construction of new interstate pipeline capacity in amounts needed to address any potential deficiency through 2030. Given the identified size of need, we make no assumption as to whether this new capacity would be added as new development or as an expansion of existing supplies. It is assumed that the costs associated with any incremental pipeline capacity developed to meet electric reliability needs would be fully collected from electricity ratepayers on a cost of service basis.<sup>36</sup> We assume that the minimum incremental pipeline capacity that would be needed to meet a power system need would be sized to meet the peak hourly deficiency identified in the deficiency analysis. We also assume that a pipeline (expressed in Bcf/d) is available on a fully ratable basis (i.e., the minimum size of a pipeline is equal to 24 times the peak hourly need). We model a solution set sized to meet the deficiency need, and placed in service in increments and in time consistent with the emergence of the need. This solution set is directly comparable to other solution sets designed to meet the identified reliability need.

---

Distrigas goes to National Grid’s greater Boston-area distribution system, and another 10 percent is delivered by truck to off-site LNG peak shaving facilities. Thus, for the purposes of our study, we assume that 70 percent of the total Distrigas facility regas capability (0.5 Bcf/d) is available to help meet any identified electric sector reliability need. For solution set development, therefore, we limit the maximum quantity of LNG available from Distrigas and available as a potential solution set to 0.5 Bcf/day.

<sup>36</sup> As discussed above, the focus of the analysis is on pipeline capacity that could be used to meet identified *electric system reliability* needs. We do not assess whether there is a need for incremental pipeline capacity to meet gas LDC needs, or whether power system needs (or lack thereof) should affect considerations related to development and construction of new pipeline capacity for use by gas LDCs.

In this solution set, 0.3 Bcf/d of new pipeline capacity reserved for electricity generation is added in 2024, in-service for the 2024/25 winter, and 0.12 Bcf/d of capacity reserved for electricity generation is added in 2028, in-service for the 2028/29 winter. We assume that total capital costs for the 0.3 Bcf/day installation are approximately \$788 million, with a first year cost of service of \$140 million. Costs for the 0.12 Bcf/day installation are assumed to scale linearly by size. This solution set is referred to as “Incremental Pipeline (SS 2)”.

### ***Energy Efficiency (EE), Demand Response (DR), and Renewable Energy (RE)***

We develop three solution sets that represent an increase in energy efficiency and renewable energy. The first is focused on increases in energy efficiency and demand response in amounts sufficient to eliminate the potential deficiency on the electric system. While there are many renewable and distributed resources available to the electric sector, we limit the first modeled solution set to just EE and DR, since in our judgment this is likely to be the lowest-cost combination of renewable/distributed resources that could address the deficiency.<sup>37</sup> Other solution sets combine EE with the addition of firm imports of low carbon (likely hydropower) resources over existing or new transmission lines.

#### **Solution Set 3(a) – Energy Efficiency and Demand Response**

This solution set combines incremental annual energy efficiency investments plus demand response over time as needed to meet the maximum deficiencies annually. By 2030, this amounts to approximately 1,300 MW of winter peak EE<sup>38</sup> and 1,100 MW of DR. We truncate measure lives for all EE measures and programs at ten years, with complete annual installations starting in 2020 and concluding in 2030. This solution set is focused on the likely lowest-cost distributed approach to address identified deficiencies. We assume that incremental EE is available at a cost of \$0.067/kWh, and to account for the incremental degradation of EE on a \$/kWh basis, we further assume that EE costs increase at a rate of 7.45 percent annually. Our estimate is based on our review of recent filings of actual energy efficiency program data, including the Massachusetts Program Administrators’ draft Program filings for 2016-2018 and the Northeast Energy Efficiency Partnerships’ Regional Energy Efficiency Database (REED). We index the cost of demand response to recent bids offered into the PJM capacity market.<sup>39</sup> This solution set is referred to as “EE/DR (SS 3a)”.

---

<sup>37</sup> This is based on our review of the Synapse/DOER (2015) study, which includes the total, incremental quantities of capacity and energy that could be developed for Massachusetts, including appliance standards, energy efficiency (residential, commercial/industrial, and large industrial), and incremental renewables, including landfill gas, anaerobic digestion, biomass, combined heat and power, solar, and on- and off-shore wind.

<sup>38</sup> Load profiles are developed based on historical program administrator data.

<sup>39</sup> We rely on PJM bid data because similar information is not readily available for ISO-NE. See Monitoring Analytics, Independent Market Monitor for PJM, “Analysis of the 2017/2018 RPM Base Residual Auction.” October 6, 2014, Table 18.

### **Solution Set 3(b) – Energy Efficiency and Firm Imports (Existing Transmission)**

This solution set combines annual energy efficiency investments plus firm winter delivery commitments from low-carbon resources, in amounts sufficient to meet the annual deficiencies over time. By 2030, this amounts to approximately 1,300 MW of winter peak EE, with 1,100 MW of firm winter capability added in 2020. This solution set assumes that imports are delivered using existing transmission capacity. We assume that, in order to meet reliability needs, this interconnection would need to be accompanied by a firm capacity supply obligation equal to the full capability, and a commitment to ensure firm delivery of the capacity at the time of winter peak. We assume that the cost of firm capacity during winter peak is equal to the levelized cost of new hydroelectricity capacity, based on recent levelized cost of electricity EIA data. This solution set is referred to as “EE/Firm Imports (Existing Transmission) (SS 3b)”.

### **Solution Set 3(c) – Energy Efficiency and Firm Imports (New Transmission)**

Solution Set 3(c) is the same solution set as 3(b), except imports are delivered assuming new transmission capacity is required. We assume that new transmission capacity for 1,100 MW costs an additional \$1.4 billion. This solution set is referred to as “EE/Firm Imports (New Transmission) (SS 3c)”.

**Table 2: Summary of Solution Sets**

Solution Set	Description	Key Assumptions
<i>Market Driven Outcomes</i>		
SS 1a: Dual-fuel Capacity	Annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026.	<ul style="list-style-type: none"> <li>Annualized costs of \$6,856/MW</li> </ul>
SS 1b: Firm LNG Capacity	Firm delivery of LNG dedicated for electricity generation with a 5-year contract and rolling renewals; Annual contract quantity available in increments of 3 Bcf.	<ul style="list-style-type: none"> <li>Contract includes daily demand charge and variable costs indexed to Henry Hub, plus relevant adders</li> </ul>
<i>Incremental Pipeline Capacity</i>		
SS 2: Incremental Pipeline	Incremental capacity added incrementally to meet need; 0.3 Bcf/day in 2024 and 0.12 Bcf/d in 2028.	<ul style="list-style-type: none"> <li>Costs indexed to proposed pipelines, maximum reservation charge of \$39/dth-month</li> <li>Total capital costs of \$788 million, first year costs of \$140 million (0.3 Bcf/d)</li> <li>Costs represent full cost of service, including return on equity, taxes, and depreciation</li> </ul>
<i>Energy Efficiency, Demand Response, and Renewable Energy</i>		
SS 3a: Energy Efficiency and Demand Response	<p>Total of 1,300 MW peak winter Energy Efficiency by 2030, with 950,000 MWh installed annually, 2020-2030.</p> <p>Total demand response of 1,100 MW by 2030.</p>	<ul style="list-style-type: none"> <li>Total lifetime costs of \$0.067/kWh, including all incentives and participant costs</li> <li>Demand Response costs indexed to recent capacity market bids</li> </ul>
SS 3b: Energy Efficiency and Firm Imports (Existing Transmission)	Same EE as SS 3a, plus an additional 1,100 MW of firm imports of distant low-carbon energy. We present total ratepayer costs two ways: assuming imports use existing transmission lines (with no incremental cost) and assuming imports require new transmission capacity.	<ul style="list-style-type: none"> <li>Firm imports priced at the levelized cost of new hydropower capacity, using EIA data, \$4.3 billion for 1,100 MW capacity facility</li> </ul>
SS 3c: Energy Efficiency and Firm Imports (New Transmission)		<ul style="list-style-type: none"> <li>Incremental new transmission capacity (SS 3c) available for \$1.4 billion, including all cost of service obligations</li> </ul>

## **B. Infrastructure Scenarios**

In addition to solution sets that meet the above criteria, we separately consider two infrastructure “scenarios” that are larger than needed to meet the deficiency and/or installed as the maximum total need in the first modeling year (e.g., installed before the identified need). This includes both a natural gas pipeline and a transmission scenario. These infrastructure scenarios model extensions of the reliability solution sets, and allow us to consider potential economic and ratepayer impacts beyond the scope of the current study. In order to avoid confusion, we review the results of these scenarios separately, since they are not comparable to the solution sets (i.e., not “fitted” to the identified reliability need). The purpose of analyzing infrastructure investments made earlier and/or larger than necessary is to explore the potential range of cost and emission impacts to ratepayers. Both infrastructure scenarios are assumed to be in-service in 2020, with immediate and comparable reductions in the volatility of natural gas prices at Northeast trading hubs.

### ***Infrastructure Scenario 1 – Larger and Earlier than Necessary Gas Pipeline***

We model the incremental addition of a 0.5 Bcf/day pipeline, where the full amount of capacity is reserved for electricity generation. The pipeline is added in 2020, in-service for the 2020/21 winter. Total capital costs for the 0.5 Bcf/day installation are approximately \$1.3 billion, with a first year cost of service of \$233 million. This scenario is referred to as “Larger Pipeline (IS 1)”.

### ***Infrastructure Scenario 2 – Earlier than Required Transmission Investment***

Similar to the larger/earlier than required pipeline, we also model a transmission infrastructure scenario which considers the full addition of the 2,400 MW of new capacity in 2020. This is more directly comparable to a natural gas infrastructure scenario which is also sized above the reliability need. Both scenarios recognize the lumpy nature of infrastructure investments and consider the potential for more immediate price suppression benefits. This scenario involves the one-time addition of 2,400 MW of firm winter commitments in 2020. We assume that new transmission capacity for 1,100 MW costs \$1.4 billion consistent with the EE/Firm Imports (New Transmission) (SS 3c) solution set, with the remainder (1,300 MW) delivered over existing transmission lines at no incremental cost. The cost of firm energy commitment backed by new hydropower is based on the same costs as the EE/Firm Imports (Existing Transmission) (SS 3b) and the EE/Firm Imports (New Transmission) (SS 3c) solutions, scaled to meet the full 2,400 MW need. This scenario is referred to as “Earlier Transmission (IS 2)”.

## V. ASSESSMENT

### A. Method

Each solution set has a unique impact on total system natural gas utilization, natural gas prices, cost of implementation, the total cost of energy used to serve customers, and GHG emissions.

To compare the impact of solution sets on electric ratepayers in a consistent manner, we take two steps. First, we estimate the total potential up-front cost to ratepayers to “implement” each solution set, with a consistent focus on the annual costs likely to be incurred by ratepayers associated with solution set resources. This includes, for example, an estimate of the cost of service for firm pipeline investments, new transmission, contracts for capacity with distant low-carbon resources, LNG storage/vaporization, or annual costs for incremental EE/DR. We evaluate these costs for each solution set using consistent financial assumptions, and translate them into annualized costs that would be collected from electricity consumers over the forecast horizon.

However, the impact on electricity consumers is not limited to annual costs to implement solution sets. Since each solution set has a unique impact on the marginal price of electricity due to changes in the anticipated dispatch of system resources, each solution set also leads to a unique annual cost to the region’s ratepayers for electricity market purchases. Consequently, in the second step we carry out production cost modeling through 2030 for each solution set, including an integrated gas-electric model to simulate the impacts of each solution set on natural gas prices, in order to establish the total cost to load to meet electric sector needs over the forecast horizon. The production cost modeling is also used to identify annual total system emissions of CO<sub>2</sub> in order to inform our evaluation of each solution set from the perspective of states’ GHG reduction goals and obligations.

The total cost to electric ratepayers combines the results of steps one and two. Specifically, we combine the annual costs to implement each solution set with its impact on total cost to load using production cost modeling results, in order to establish the total annual cost to the region’s electricity consumers associated with each solution set. As described earlier, in our view there is a “status quo” outcome that is likely to occur absent any specific or extraordinary legislative or regulatory action taken by states – namely, a market-driven outcome involving the addition of dual-fuel capability on some portion of the region’s existing gas-only generating resources. To clearly compare the different impacts of each solution set using consistent methods and metrics, and relative to status quo outcomes, we compare each solution set to the Dual-fuel (SS 1a), market-driven dual-fuel capability solution set, on the basis of total annual cost to electric ratepayers and GHG emissions.

In the previous section, and in more detail in Appendix 2, we summarize our estimates of annual ratepayer implementation costs. In the next section, we summarize our approach to the production cost modeling approach. Appendix 3 provides greater detail on modeling inputs, methods, and assumptions.

### *Production Cost Modeling*

We use the PROMOD production cost model to simulate the economic dispatch of generators used to meet system load in every hour of the year over the full ten year period, 2020 to 2030. PROMOD is a widely accepted and commonly used model. The PROMOD simulation engine considers the full mix of available resources and minimizes the total cost to load based on economic and operational criteria, subject to system transmission/operational constraints. To do so, it dynamically solves for the locational marginal price (LMP) in every hour on a zonal basis. LMPs reflect both the system load in each zone and the costs of the marginal (or last) unit required to meet demand in that hour. In ISO-NE, natural gas units were the marginal unit, setting LMPs, approximately 70 percent of the hours in 2014.<sup>40</sup> In our base case market outlook, natural gas continues to be the dominant fuel, and natural gas units provide more than 54 percent of all generation throughout the modeling period. Across all scenarios, natural gas provides at least 48 percent of all generation.

Our PROMOD runs for solutions sets reflect distinct expectations regarding the price of delivered natural gas. Since the New England system relies so heavily on natural gas to provide both baseload and peak generation, the price of delivered natural gas is a key driver in determining the total cost to load for New England ratepayers. In previous winters, high natural gas prices, driven in part by increased demand from the electric generation sector, led to increased electricity costs for electric sector ratepayers during winter periods. Going forward, natural gas prices will continue to reflect changes in the underlying supply and delivery of natural gas to local trading hubs. The “basis differential” – that is, the difference between delivered natural gas prices in New England and the price of natural gas supplies (typically, at Henry Hub) – will continue to reflect the balance of available supply/transportation, and the total demand for delivered gas in Northeast markets. During periods of winter peak demand, delivered natural gas prices will continue to reflect the impact of high utilization of existing natural gas infrastructure in the region.

Each solution set identified in section IV is designed to meet the peak hour deficiency, under the most stressed system scenario. These solution sets are designed to meet the identified need through some combination of increasing total available electric supplies or by decreasing total electric sector demand. Either effect – an increase in available supplies or a decrease in total demand – will potentially lower natural gas prices. To ensure the production cost modeling reflects these changes, we separately model natural gas prices for each solution set.

Our baseline natural gas forecast reflects the current outlook for delivered natural gas prices to the Algonquin and Dracut City Gates, based on futures contracts out to 2022.<sup>41</sup> Beyond 2022, we assume that monthly prices continue to grow at the two year compound average growth rate observed in the futures prices.<sup>42</sup> This allows for growth in the underlying commodity price of gas, as observed at Henry Hub, and for growth in the monthly basis differentials observed at Algonquin and Dracut. Over the modeling period, delivered natural gas prices at the Algonquin City Gates increase from a low of

---

<sup>40</sup> ISO New England’s Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, Figure 2-17.

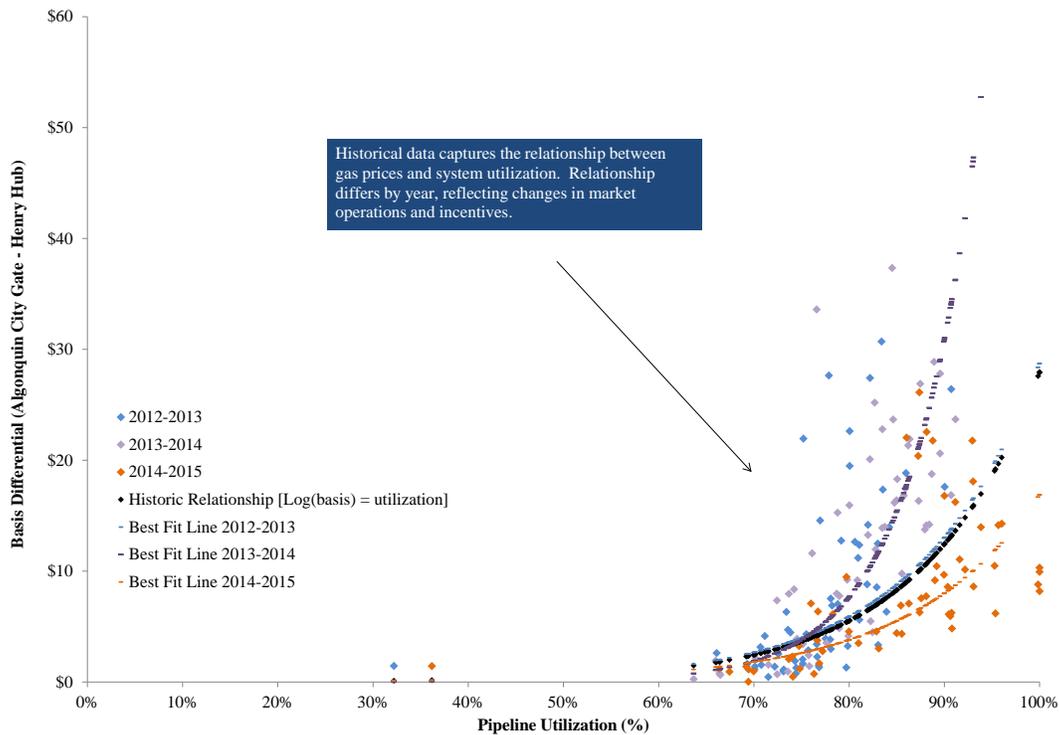
<sup>41</sup> We rely on futures prices as reported by OTC Global Holdings and reported by SNL Financial.

<sup>42</sup> This growth rate is approximately 4 to 5 percent for all months.

approximately \$8.00/MMBtu in winter 2020 to a high of \$11.50/MMBtu in winter 2029/30 and in the base case, continuing to reflect high winter basis differentials relative to the Henry Hub forecast.

To model the impact of each solution set on natural gas prices, we examine the historical relationship between pipeline utilization and the basis differential between the Algonquin City Gate and the Henry Hub price series for the previous three winters. As shown in Figure 4 gas prices in the most recent year (despite being a very cold year) remained lower at similar levels of utilization, as compared to 2012/13 and 2013/14. This relationship may reflect a number of factors that will continue to be in place going forward, including greater use of LNG and increased oil-fired capacity (in part due to the ISO-NE winter reliability program), and greater coordination between the electric and natural gas sectors. We develop our forecast of future gas prices based on the historical relationship between gas prices and pipeline utilization. This method is consistent with several previous studies. First, we estimate the statistical relationship between gas prices and pipeline utilization, based on the relationship in each winter (2012/12, 2013/14, and 2014/15). This relationship captures the non-linear relationship between pipeline utilization and prices – for example, reducing utilization from 95 percent to 90 percent has a greater impact on prices than a similar five percentage point reduction, from 80 percent to 75 percent (see Figure 4). The utilization-price relationship begins to moderate at approximately 80 percent utilization.

**Figure 4: Pipeline Utilization and Natural Gas Prices, Winters 2012-2015**



Notes:

- [1] Daily utilization is based on the sum of LDC, End-User and Power Plant demand divided by system capacity.
- [2] Basis differentials are the difference between Henry Hub and the Algonquin City Gate.

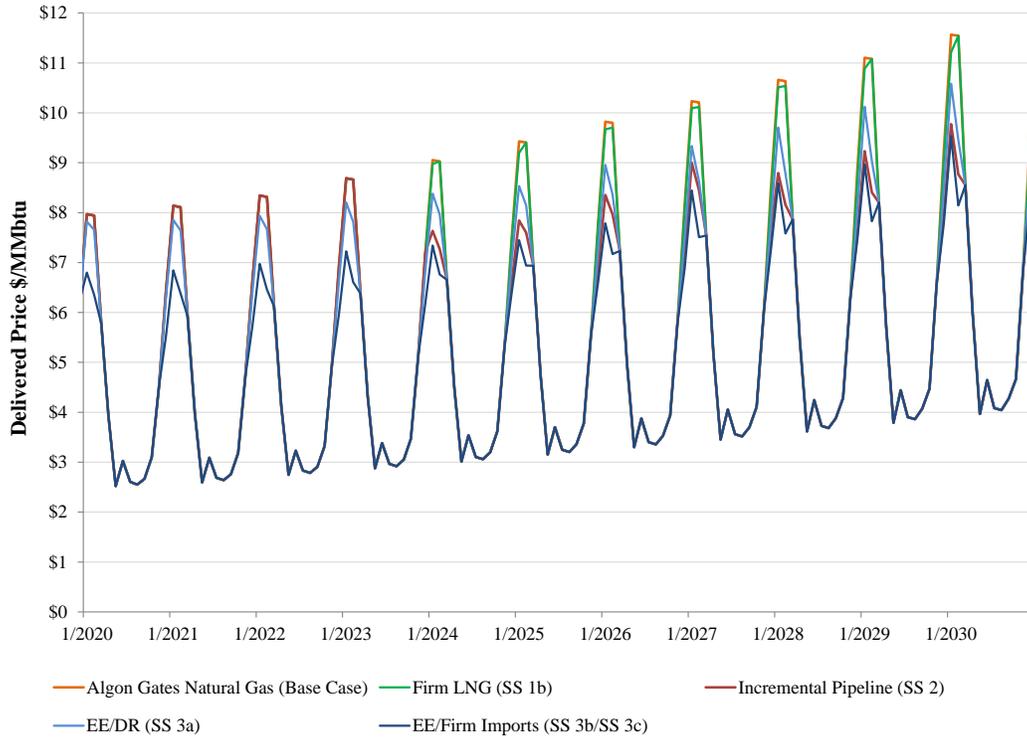
Next, for each solution set, we then estimate the change in daily utilization (relative to the status quo Dual-fuel (SS 1a) market outlook) that would be expected for either an increase in total capacity (both Firm LNG (SS 1b) or Incremental Pipeline (SS 2)) or a decrease in total demand from the electric sector<sup>43</sup> (EE/DR (SS 3a), EE/Firm Imports (Existing Transmission) (SS 3b), EE/Firm Imports (New Transmission) (SS 3c)). Using the relationship illustrated in Figure 4, we translate the estimated change in utilization into a percent change in natural gas prices, relative to the existing market outlook for natural gas prices.<sup>44</sup> The final natural gas price curves for each solution set are illustrated in Figure 5. These gas price curves reflect the fixed and variable nature of the different solution sets. Solution sets that include energy efficiency, which is assumed to be added incrementally in each year, decline in price gradually each year. In contrast, the addition of incremental transmission and natural gas capacity has more immediate and permanent reductions in natural gas prices.

---

<sup>43</sup> For this purpose we assume that energy efficiency or imports displace marginal natural gas fired generation with a 7,600 Btu/kWh heat rate. Further, we assume that variable LNG supplies are available during identified deficiency days, and do not impact prices in every day of the month.

<sup>44</sup> We estimate the change in utilization and corresponding percent change in prices for each day in the winter modeling period. We assume that variable solution sets – like firm LNG or demand response – only impact gas prices during identified deficiency days. Solution sets in operation for every hour are assumed to reduce utilization on all days. As a final step, we estimate the monthly percent change in natural gas prices as the weighted average of the estimated daily changes. This monthly change represents the final input to the production cost model, and captures the expected change in prices relative to the original market outlook.

**Figure 5: Forecasted Natural Gas Prices, By Solution Set**



Finally, to develop our comparison of solution sets, we use PROMOD to model the impacts of each solution set – including the gas price forecast from Figure 5 – on the dispatch of power system operations and outcomes. Here, the difference between each simulation and our market outlook scenario represents the direct incremental impacts of a given solution set on the power system. These simulation runs otherwise maintain the same inputs, in terms of power plants available to be dispatched and their operational characteristics.

Our use of a production cost model also allows us to estimate the locational marginal price, total generation, and GHG emissions. Both measures account for the hourly dispatch of resources to meet system load. Importantly, this dispatch captures these aggregate impacts for every hour in every year of the modeling period. We use these outputs, in combination with the estimated solution set costs identified in Section IV.A, to quantify the total change in ratepayer costs and GHG emissions between solution sets.

## B. Results

In this section we provide the results of our cross-sectional analysis of the impacts of solution sets designed to address the stressed system deficiency. Results are presented as differences relative to the market driven outcome (Dual-fuel (SS 1a), with respect to (1) annualized changes in total costs to electric ratepayers (including both electricity prices and implementation costs) and annualized changes in total emissions, (2) the annual trajectory of GHG emissions and regional climate goals, and (3) additional factors relevant to each scenario. We also provide the results of our infrastructure scenarios: Larger Pipeline (IS 1) and Earlier Transmission (IS 2)).

### 1. Annualized Ratepayer Impacts – Total Costs and GHG Emissions

#### *Solution Sets*

The cost to electric ratepayers in New England associated with the solution sets evaluated here would include either up-front and annual investment and fixed costs or contract obligations in order to make the solutions happen. This could include cost-of-service recovery for long-term investments or contractual obligations for natural gas pipelines, transmission lines, or contracts for firm winter capacity (e.g., from distant low-carbon resources); it could also include annual or market costs for incremental dual-fuel capability, reservation costs for deliverable LNG, or annual investments in EE and DR capability. Absent such commitments up front, one cannot assume that the resource would be available to meet power system needs at the time of winter peak demand, and thus such resources would not represent solutions from the perspective of power system reliability.

The costs to electric ratepayers for each solution set also depends on how operation of that solution set affects price setting in wholesale power markets. As noted earlier, certain solution sets are targeted to and may only operate during the time of deficiency need (e.g., Dual-Fuel (SS 1a), Firm LNG (SS 1b)), and thus only affect power system prices in limited hours throughout the year. Others, such as Incremental Pipeline (SS 2), and EE/Firm Imports (SS 3b/SS 3c), have the potential to affect power system prices in a much larger number of hours throughout the year.

At the same time, costs to electric ratepayers for each solution set also depend on how operation of that solution set affects the ability of the region to meet its climate goals going forward. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. We present the GHG emission trajectory of each solution set immediately following results for ratepayer costs.

**Table 3: Evaluation of Electric Reliability Solution Sets, Annualized Impacts**

*Negative Dollar Values represent lower costs than the Market Outlook Dual-fuel (SS 1a)  
Negative Emissions represent a decrease in GHG emissions relative to Market Outlook Dual-fuel (SS 1a)*

Solution Set	[1] Cost of Energy (Cost to Load)	[2] Cost to Implement Solution Set	[3] = [2] + [1] Total Ratepayer Impact	GHG Emissions (million metric tons)
<b>Market Outlook</b>				
Firm LNG (SS 1b)	-\$45	\$18	-\$27	-0.03
<b>Incremental Natural Gas Capacity</b>				
Incremental Pipeline (SS 2)	-\$127	\$66	-\$61	0.08
<b>Energy Efficiency, Demand Response, and Renewable Energy</b>				
EE/DR (SS 3a)	-\$247	\$101	-\$146	-1.86
EE/Firm Imports (Existing Transmission) (SS 3b)	-\$502	\$404	-\$98	-4.86
EE/Firm Imports (New Transmission) (SS 3c)	-\$502	\$604	\$102	-4.86

Notes: All values for Table 3 and Figure 6 are presented in levelized, real \$2015, millions, unless otherwise noted. Pipeline emissions include an estimate for in-region GHG emissions from fugitive methane leaks.

With this in mind, our analysis of ratepayer costs in the present study is specifically focused on identifying the net impact of both the implementation costs of each solution set and the resulting impact to electricity market costs to load. The results, shown in Table 3 and Figure 6, may be described and summarized as follows:

- All impacts are relative to the status quo Dual-fuel (SS 1a) solution set; thus, in Table 3 and Figure 6 all results represent *differences* from the status quo solution outcome. It is useful to note that in these estimates we assume that the implementation cost of the market outlook dual-fuel solution set – namely the cost of converting gas-only capability to dual-fuel capability – would be completely paid by electric ratepayers.
- Firm contracts for the storage and delivery of LNG-based gas as needed during winter peak conditions (SS 1b) – represents the lowest implementation cost solution set, which would cost ratepayers \$18 million more per year than the dual-fuel solution set. This solution would also reduce electricity market costs to load by roughly \$45 million, leading to net annual ratepayer savings of approximately \$27 million per year. This solution set would lead to a slight decrease in emissions over time (0.03 million metric tons annually) relative to the dual-fuel solution set.
- Incremental Pipeline (SS 2) capacity sized to meet the deficiency would deliver substantial price suppression benefits to the region, amounting to approximately \$127 million in savings per year.

Since the cost to implement this solution would be approximately \$66 million per year, the net impact on ratepayers would be a net savings of approximately \$61 million annually, relative to the status quo outcome. This solution leads to an increase in GHG emissions of 0.08 million metric tons per year relative to the dual-fuel solution set due to an increase in total fossil fired generation.

- The EE/DR (SS 3a) solution set provides the lowest total cost solution accounting for changes in both energy and implementation costs and would save ratepayers approximately \$146 million per year, relative to the dual-fuel option. The \$146 million savings (relative to the dual-fuel solution set) include reductions in electricity market costs of \$247 million per year and annual costs of \$101 million to install EE measures. This solution set lowers total annual emissions by 1.86 million metric tons per year.
- The EE/Firm Imports (Existing Transmission) (SS 3b) solution would provide annual ratepayer benefits of roughly \$98 million per year relative to the dual-fuel solution set. While the EE/firm Imports (existing transmission) solution produces far greater annual energy market savings (\$502 million per year), the estimated cost to procure capacity and energy on a firm basis year-round significantly cuts into electricity market savings.<sup>45,46</sup> This solution set lowers total annual emissions by 4.86 million metric tons per year, the largest reduction among all solution sets.
- And if instead, the same set of incremental firm winter imports required new transmission capacity (SS 3c), total ratepayer costs would be \$102 million per year higher relative to the dual-fuel solution. A solution involving new firm imports would also reduce annual emissions by 4.86 million metric tons per year.

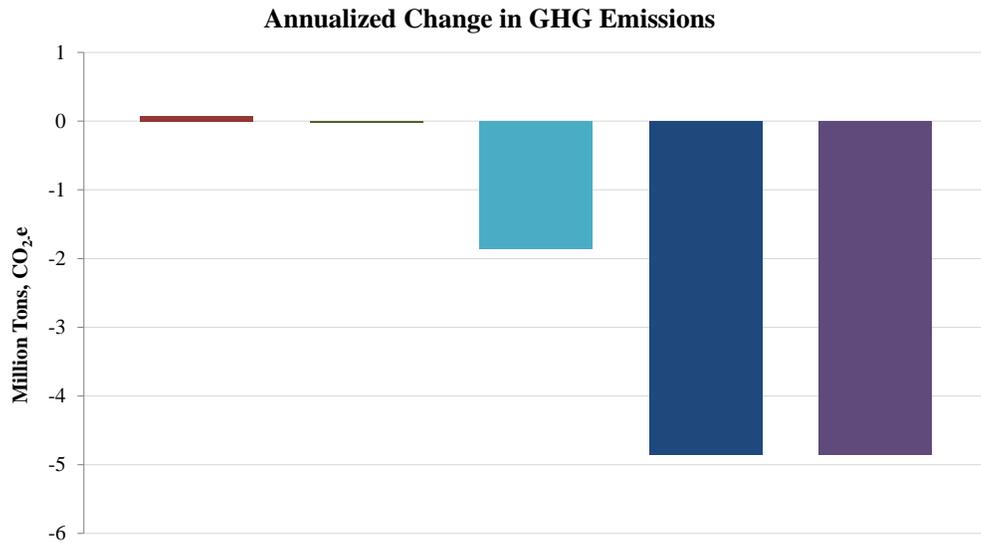
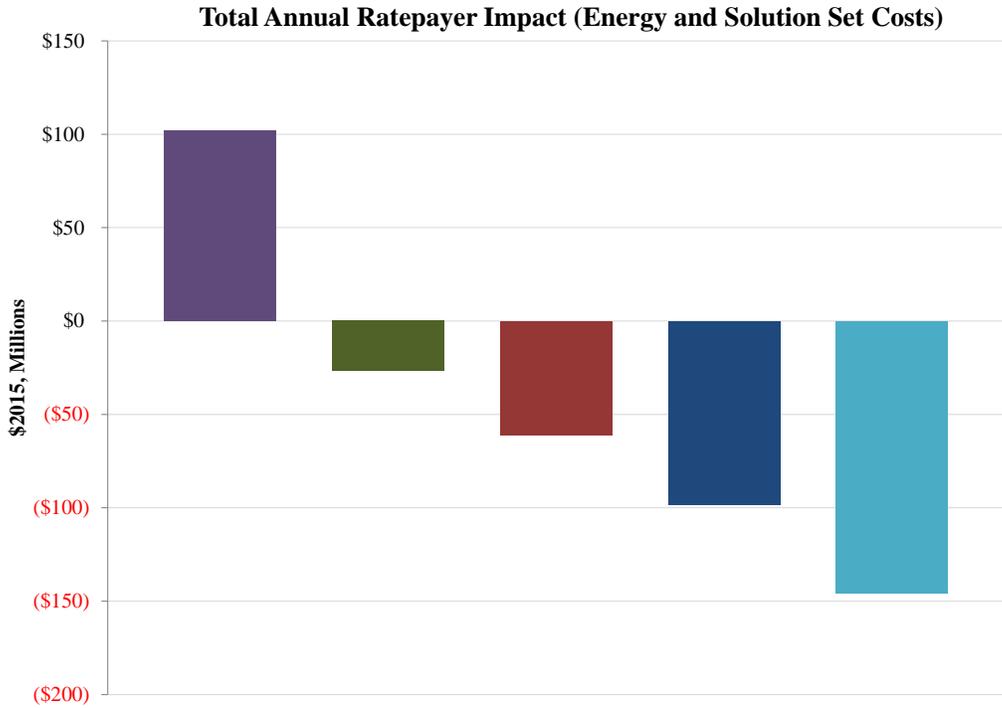
---

<sup>45</sup> As discussed in Section IV, we estimate the costs of such a contract at the estimated levelized cost of new hydroelectric generating capacity, based on Energy Information Administration analysis. That is, we assume that to provide a firm winter delivery contract, the seller would need to construct new capacity to back such a contract, or otherwise compensate the provider (or the provider's ratepayers) at the cost of service value of the capacity now committed to the New England region. The same consideration applies to infrastructure scenario 2.

<sup>46</sup> If the seller of capacity/energy under such a contract either planned to or were contractually obligated to be a price taker in the region's forward capacity market, there could in theory be capacity market price suppression benefits in addition to the estimated energy market price suppression benefits. However, consistent with New England's buyer-side mitigation market rules, it is unlikely that such a contract would qualify as a state-exempt resource, or be allowed to reduce the clearing price for capacity in forward capacity auctions. The same consideration applies to the transmission solution sets and infrastructure scenarios. We discuss the implications for dynamic market interactions in greater detail in Section V.B.3, below.

### Figure 6: Evaluation of Electric Reliability Solution Sets, Annualized Impacts

*Negative Dollar Values represent consumer savings relative to market outlook Dual-fuel (SS 1a)  
 Negative Emissions represent a decrease in GHG emissions relative to market outlook Dual-fuel (SS 1a)*

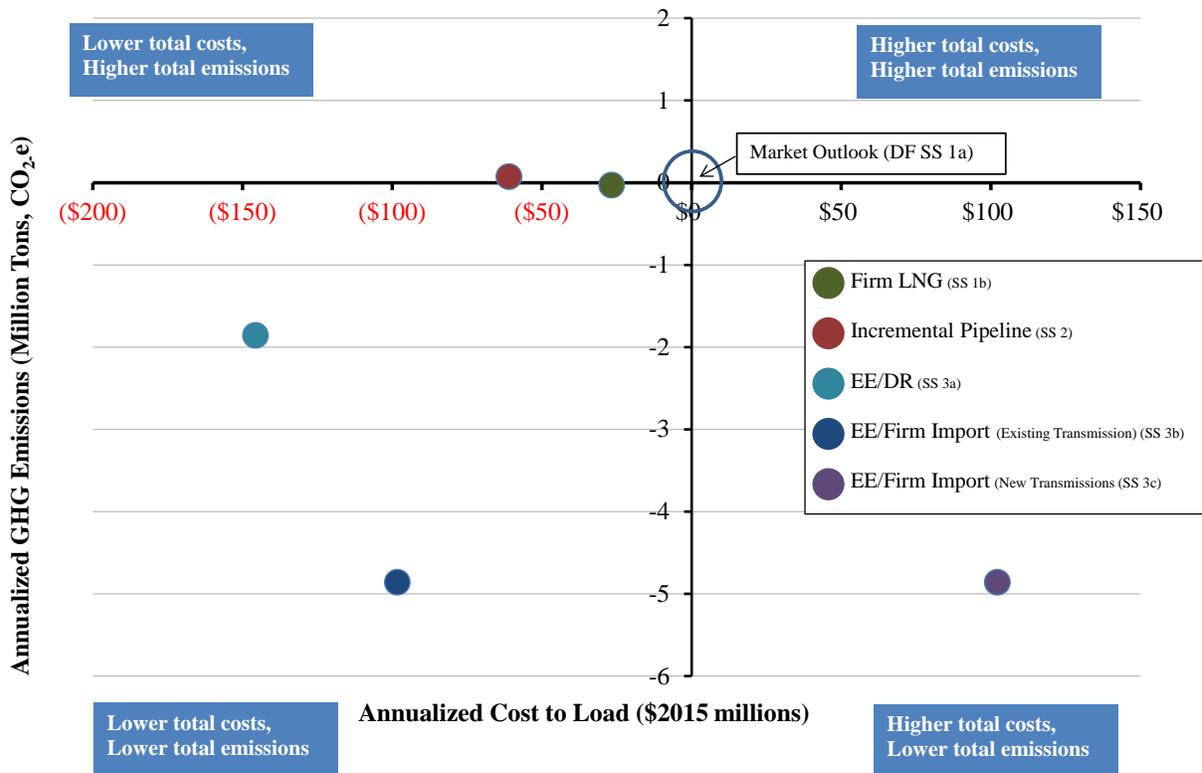


- Incremental Pipeline (SS 2)
- Firm LNG (SS 1b)
- EE/DR (SS 3a)
- EE/Firm Imports (Existing Transmission) (SS 3b)
- EE/Firm Imports (New Transmission) (SS 3c)

These solution sets present a wide range of both ratepayer impacts and GHG emissions impacts. As illustrated in Figure 6, only the EE/Firm Import (Existing Transmission) (SS 3b) solution ranks in the top two of all solution sets from both an annualized cost and annualized GHG emission benefit. Other solution sets present a wider range of performance on these two key metrics. EE/DR (SS 3a) provides the greatest cost savings, and the third greatest GHG reductions. Incremental Pipeline (SS 2) capacity provides the third highest ratepayer cost savings, but represents the worst option in terms of achieving regional GHG requirements.

As Figure 7 shows, only the EE/DR and EE/Firm Import (Existing Transmission) solution sets solve the stressed system reliability deficiency in a way that both reduces ratepayer costs and reduces GHG emissions relative to the current market outlook of relying on dual-fuel capability. In contrast, both the pipeline solution set and the firm LNG solution set can reduce total ratepayer costs but do not reduce total GHG emissions. Finally, a solution set that includes EE and the firm import of distant low-GHG energy over new transmission lines provides substantial GHG emission reduction benefits, but would lead to a net increase in total ratepayer costs after accounting for both the cost of firm energy and new transmission capacity. In general, however, imports without a firm commitment may be available at a lower cost, which could help the region meet its climate goals independently of a focus on reliability needs.

**Figure 7: Annualized Cost and Emission Impacts, By Solution Set**



Note: Pipeline solutions include an estimate for incremental in-region GHG emissions from fugitive methane leaks.

### *Infrastructure Scenarios*

Meeting the reliability need through an earlier and/or larger than necessary infrastructure solution would lead to larger price suppression benefits for the region's electric ratepayers than a pure reliability focused solution. This is true of both the Larger Pipeline (IS 1) and Earlier Transmission (IS 2) infrastructure scenarios. These large investments in new infrastructure also carry immediate and long term cost implications, which must be balanced against these more immediate benefits. The results of these scenarios are presented in Table 4 below.

Meeting the deficiency completely through firm contracts for 2,400 MW of year-round transmission capacity and energy with provider(s) of distant low-carbon resource(s) in 2020 (Earlier Transmission IS 2) represents a scenario that meets the full deficiency in the first year of service.<sup>47</sup> This scenario generates by far the greatest total energy cost savings, of almost \$576 million per year. However, the cost of the scenario, including contract costs plus the cost of new transmission, significantly exceeds this ratepayer benefit, leading to a net annual ratepayer *cost* of \$284 million per year more than the status quo solution set.<sup>48</sup> However, the Earlier Transmission (IS 2) infrastructure scenario yields the largest and most sustained reduction in annual GHG emissions.

Similarly, the Larger Pipeline (IS 1) would generate total annual energy cost impacts of \$309 million per year, against an annual carrying charge of \$176 million, leading to net ratepayer benefits of \$133 million per year. This scenario assumes that new pipeline capacity is added in 2020 and is fully available to the electric generation sector on a firm basis. This scenario assumes the greatest reduction in total basis differentials, which provide net ratepayer benefits each year that the pipeline is in-service. As discussed below, this scenario also creates a long-term obligation on ratepayers, which remains even if the value of the asset diminished or is limited for any reason, including the evolution of GHG reduction goals and obligations. It would also lead to the largest total GHG emissions of all solutions evaluated in the report, including market outlook Dual-fuel (SS 1a) solution. Lower gas prices result in greater fossil fired generation, which displaces both dual-fuel-oil-fired generation and imports of other economic energy resources located outside of ISO-NE. This could include the displacement of resources in neighboring regions, including gas, wind, or hydro imports. To the extent that greater in-region gas fired generation displaces gas fired generation from other Regional Greenhouse Gas Initiative (RGGI) states, it may not increase total RGGI emissions.

---

<sup>47</sup> In contrast, solution sets that include EE/Firm Imports (SS 3b/SS 3c) are still phased in over time to meet the peak need.

<sup>48</sup> It should be noted that the price suppression benefits estimated for solution sets involving distant low-carbon resources (SS 3b/SS 3c/IS 2) may largely exist even if there is no firm contract for capacity, or full capacity costs to acquire this resource. This is because even without a firm capacity commitment, these resources could deliver inframarginal energy in many, if not most, hours of the year. However, absent the firm commitment and firm backing of reliable capacity, such a resource could not be counted on at the time of winter peak conditions, would have zero or near-zero value from the standpoint of winter reliability needs, and could not be considered a solution to a winter reliability deficiency.

**Table 4: Evaluation of Infrastructure Scenarios, Annualized (\$2015 million)**

*Negative Dollar Values represent consumer savings relative to market outlook Dual-fuel (SS 1a)  
Negative Emissions represent a decrease in GHG emissions relative to market outlook Dual-fuel (SS 1a)*

Scenario	[1] Cost of Energy (Cost to Load)	[2] Cost to Implement Solution Set	[3] = [2] + [1] Total Ratepayer Impact	GHG Emissions (million metric tons)
<b><i>Incremental Natural Gas Capacity</i></b>				
<b>SCENARIO</b> (IS 1) - Larger Pipeline (Sized Above Reliability Need)	-\$309	\$176	-\$133	0.20
<b><i>Incremental Transmission Capacity</i></b>				
<b>SCENARIO</b> (IS 2) - Early Transmission (New and Existing Transmission Capacity, Firm Imports, 2,400 MW cumulative)	-\$576	\$860	\$284	-6.65

## 2. Emissions of GHG Relative to States' Electric Sector Emissions Obligations and Objectives

Every New England state has made commitments to address the social, economic and environmental risks of climate change through binding CO<sub>2</sub> emission limits on the electric sector, state GHG reduction targets, and/or long-term multilateral commitments to achieve substantial reductions in GHGs over time.<sup>49</sup> Most recently, the New England Governors' (NEG) and Eastern Canadian Premiers (ECP) adopted a non-binding goal to reduce regional GHG emissions by at least 35-45 percent below 1990 levels by 2030.<sup>50</sup> In addition, EPA's Clean Power Plan (CPP) will result in binding obligations to reduce emissions of CO<sub>2</sub> from the power sector in all states nationwide.<sup>51</sup> Consequently, the GHG

<sup>49</sup> In Massachusetts, for example, the Global Warming Solutions Act (GWSA) established targets and requires the State to reduce total GHG emissions by 25 percent below 1990 levels by 2020 and 80 percent below 1990 levels by 2050. The GWSA includes GHG emissions from buildings, electric power generation, transportation and land use, and non-energy emissions, which considers plastics, solid waste, and other refrigerants. Reductions in the electric generation sector are estimated to provide approximately one third of all reductions anticipated in the 2020 plan; these include increased renewables and long-term contracts, including hydropower, retirements of older coal fired generation, and increased energy efficiency. See Commonwealth of Massachusetts "Global Warming Solutions Act 5-year Progress Report", December 30, 2013, Table 1. The plan estimates that 7.7 percent of all reductions will come from the electric power sector. This represents 28 percent of all reductions estimated in Table 1.

<sup>50</sup> Resolution 39-1 Concerning Climate Change, available: <http://www.coneg.org/negecp>.

<sup>51</sup> Vermont is currently not subject to control requirements under the CPP. The CPP establishes declining and final state GHG emissions goals beginning in 2022 and allows for multi-state compliance plans (including the use of regional programs like RGGI).

emission impacts of different solutions sets evaluated in this Report represent real and meaningful long-term impacts on consumers.

We evaluate GHG emission impacts of different solution sets using the metric of total emissions of CO<sub>2</sub> in New England as a proxy for considering the potential impact of each solution set's GHG trajectory on the difficulty and cost of meeting binding commitments and/or achieving states' long-term GHG goals.<sup>52</sup> In addition, we identify and discuss ways in which different solution sets may lead to GHG emissions outside the New England region or otherwise affect New England states' abilities to meet GHG reduction targets over time.

Each solution set represents a unique path forward with respect to GHG emissions. Figure 8 presents solution set emissions trajectories, where total annual GHG emissions in each scenario represent all in-region fossil fuel (and other carbon resources, such as biomass) generation based on the relevant PROMOD electric sector simulation. These emissions are compared to a projection of RGGI electric sector requirements, assuming that the current allowance cap continues to decline by 2.5 percent in each year after 2020.<sup>53</sup> The results may be described and summarized as follows:

- Each solution set includes declining emissions over the full study period, but by 2030 no single reliability solution would meet this projected RGGI target, even assuming all incremental RPS goals are met.<sup>54</sup>
- Under the market outlook Dual-fuel (SS 1a), natural gas continues to provide almost 50 percent of total generation, with continued reliance on oil-fired generation during winter months (amounting to more than 1,500,000 MWh by 2030).<sup>55</sup> This solution set fails to meet projected regional climate goals.

---

<sup>52</sup> Under existing RGGI and potential future RGGI or CPP binding obligations, the New England states participate in an electric sector mass-based control program, with geographically broad trading of emission allowances among affected sources. In this context, the metric of actual CO<sub>2</sub> emissions may be viewed as indicative of the ultimate cost of allowances, and thus ratepayer cost of compliance. That is, while we do not attempt in this Report to forecast the impact of emission levels on marginal allowance prices, solution sets that lead to regional electric sector emissions exceeding the states' collective RGGI or CPP allocation or emission standards are likely to place upward pressure on allowance prices, marginal unit wholesale price offers, and ultimately costs to electric ratepayers.

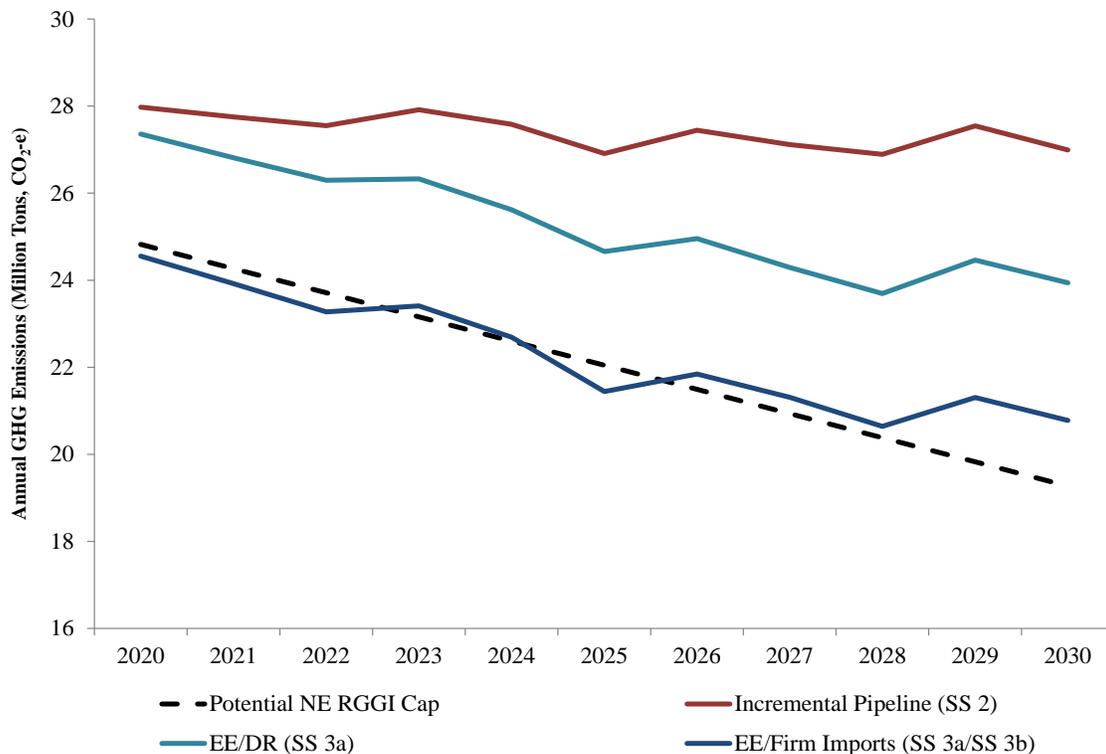
<sup>53</sup> In 2020, the total RGGI cap is 78 million short tons of CO<sub>2</sub>. This cap includes the 6 New England States, plus New York, Maryland, and Delaware. Historically, New England's share of the regional cap has been approximately 35 percent. As described in Appendix 4, we found that RGGI emission targets are more stringent than assumed reductions from the electric sector as specified in GHG action plans and are also below the state targets set forth in the CPP.

<sup>54</sup> As discussed in Appendix 2, we assume a static CO<sub>2</sub> price that increases in real terms by 2.5 percent each year. That is, we do not model the potential dynamics of increasing CO<sub>2</sub> prices in response to any potentially binding constraints.

<sup>55</sup> For comparison, New England used oil for approximately 1,540,000 MWh in the 2013/14 winter. See Brandien, P. "ISO-NE Cold Weather Operations, Federal Regulatory Commission." April 1, 2014.

- The Firm LNG (SS 1b) solution set offsets a portion of the status-quo oil-fired generation, leading to a marginal reduction in oil-fired generation. Nevertheless, this solution set fails to set a carbon emission path consistent with long-term obligations and goals.
- The Incremental Pipeline (SS 2) solution set displaces the need for higher emitting oil-fired generation, but it also increases total fossil fired generation: gas fired generation meets 55 percent of total system load by 2030, an increase of almost 3 GWh (4 percent) in total generation relative to the market outlook (DF SS1a) solution set. Similar to the Firm LNG and dual-fuel solution sets, the incremental pipeline fails to meet projected regional climate goals.
- The EE/DR (SS 3a) solution set leads to meaningful reductions in natural gas-fired generation and would allow for gradual reductions in overall carbon emissions associated with the electric power generation sector. However, this solution set is still insufficient to meet climate goals throughout the full forecast horizon.
- Adding firm contracts for distant low/zero-carbon resources (instead of DR, which has a de minimis impact on CO<sub>2</sub> emissions) to EE solution sets significantly improves GHG trajectory outcomes. The EE/Firm Import (SS 3b/SS 3c) solution sets produce an immediate and long-term reduction in total CO<sub>2</sub> emissions in every year of the study period, and lead to the largest total reduction in in-region carbon emissions. While these solution sets still do not fully achieve the projected RGGI target for 2030, they lead to emissions that are more consistent with projected climate goals.

**Figure 8: Annual GHG Emissions and Potential ISO-NE Climate Goals**



Notes:

Pipeline emissions include an estimate for in-region GHG emissions from fugitive methane leaks. Emissions for Dual-fuel (SS 1a) and Firm LNG (SS 1b) are excluded for clarity; both solution sets report annual emissions that are within 0.15 million metric tons of the Incremental Pipeline (SS 2) solution set.

The estimates in Figure 8 include an estimate for the potential in-region GHG emissions associated with fugitive emissions of methane on the pipeline transportation system for the incremental portion of natural gas use in the Incremental Pipeline (SS 2) (and also included in the Larger Pipeline (IS 1) infrastructure scenario). Using assumptions based on industry standards for pipeline, compressor and meter/regulation station losses, we find that these fugitive emissions could contribute an additional 0.47 million metric tons of CO<sub>2</sub>-equivalent GHG.<sup>56</sup> Our estimate also does not include any GHG impacts associated with an increase in in-region natural gas consumption for residential needs. Specifically, in addition to gas-fired generation emissions and fugitive emissions from interstate pipelines, increases in natural gas consumption in the New England region could increase overall GHG emissions associated with CH<sub>4</sub> releases due to natural gas production, processing, and transport outside the New England region, as well as GHG emissions due to increased operation of compressor stations. This assumes that New England demand does not displace demand from other regions, which may be unlikely given the policy objectives of the CPP.

Finally, it should be noted that solution sets involving incremental firm capacity from distant low-carbon resources (SS 3b/SS 3c) could involve the development of new large hydro generation facilities, which also have potential GHG implications not accounted for in our analysis. Specifically, new dams inundate reservoir basins, which induces further decomposition of biomass and can lead to an increase in total GHG emissions, attributable to the facility's development. Recent research by Hydro Quebec found that these emissions are highest during the two to four years immediately following reservoir construction, and, on a CO<sub>2</sub>-equivalent basis, can exceed the emissions of new gas fired generation before moderating and reaching levels consistent with existing lakes in later years.<sup>57</sup> To date, existing climate policies and renewable portfolio standards (which mostly exclude large hydropower facilities from eligibility) do not consider net emissions of large scale hydro imports, and any estimated net emissions

---

<sup>56</sup> These estimates assume a 21x global warming potential of CH<sub>4</sub> over a 100 year time frame, consistent with Massachusetts facility reporting guidelines. Recent estimates from the IPCC updated this value to 28x that of CO<sub>2</sub> for a 100 year timeframe and 84x the GWP for CO<sub>2</sub> for a 20-year timeframe. (Intergovernmental Panel on Climate Change AR5, Chapter 8, 2013).

<sup>57</sup> Teodoru et al. (2012) estimated the net CO<sub>2</sub> emissions associated with the construction of the 485 MW Eastmain-1 reservoir in the James Bay region of Northern Quebec, Canada, accounting for the pre-construction carbon footprint of the landscape and the actual measurements from the reservoir surface after inundation. They found that the net CO<sub>2</sub> equivalent emission rate for a new hydro dam in a boreal forest landscape could exceed the emissions of a new natural gas combined cycle unit over the first few years of the asset's life, and projected they would then decline to less than half of the assumed emissions of a NGCC over the remaining 100-year life of the hydro facility. Hydro Quebec supported and participated in the development of this study as part of a net greenhouse gas emission study. See <http://www.eastmain1.org/en/index.html>.

would depend on the unique site conditions of each reservoir site.<sup>58</sup> Over the long term, however, these net impacts may be considered under the joint climate plans formed by the New England Governors/Eastern Canadian Premiers (NEG/ECP), or to the extent they are considered by other regions, the price of long term import contracts may reflect the higher cost of meeting in-region climate risk reduction goals.

In contrast, imports that do not require a firm commitment could be based on other resources, including wind (on and off-shore) or existing hydro facilities. These resources could be used to meet regional climate goals, potentially at a lower cost than the firm commitment included here. However, this would not address a potential winter reliability need from a firm planning perspective and are not included here.

### 3. Market Interactions and Other Risk Factors

The sections above focus on quantifiable ratepayer cost and regional GHG emission impacts associated with different solution sets designed to address the identified reliability deficiency. In this section, we review and summarize qualitatively key factors to consider when evaluating the consumer and policy impacts of potential future outcomes. These factors are related to the competitiveness of wholesale markets and impacts on producers and social welfare; the impacts on the customers of natural gas LDCs; and the risks associated with different solution sets from the electric ratepayer perspective. Table 5 contains a high-level summary of a number of important additional qualitative considerations.

***Interaction with competitive wholesale markets*** – In our assessment we specifically model the interaction of solution sets with wholesale market economic commitment and dispatch and the associated changes to energy market pricing and emissions. However, wholesale markets involve a more complicated and dynamic interplay between factors that cannot be fully captured in a production cost modeling of the electric system. This includes the potential impact of differences in energy market net revenues for producers and how producers may respond in turn, through their development of offers to provide capacity and ancillary services. It also includes the potential long-run impact on wholesale market competition that could arise from different approaches to addressing potential reliability deficiencies. An assessment of specific legislative or regulatory actions must carefully consider the balance between market competition, resource outcomes, and ratepayer risks.

The fundamental purpose of states moving to a competitive market structure was to remove the investment risk previously incurred by regulated utilities and borne by ratepayers, and to put that risk in the hands of those best able to manage it – namely, the competitive market participants that operate in both the electric and natural gas markets. While electricity markets remain relatively new, they have evolved rapidly, with the evolution of market design focused on achieving a structure that provides the

---

<sup>58</sup> In contrast, MA does require an analysis of the net lifecycle emissions that account for the “temporal changes in forest carbon sequestration and emissions resulting from biomass harvests, regrowth, and avoided decomposition” associated with Class II biomass facilities. See Renewable Energy Portfolio, MA 225 CMR 14.02.

right signals for market participants to pursue outcomes that represent, in the long run, the most efficient use of society's resources and the lowest possible costs for consumers.

Major long-term investments borne by captive ratepayers may look like a good proposition from the standpoint of short-term ratepayer savings. Indeed, as noted above we find modest ratepayer net benefits across a number of solution sets involving various forms of state-sponsored investment in resource outcomes (e.g., subsidization of natural gas pipelines, transmission, contract capacity, and energy efficiency/renewable resources). But intervention in markets should be carefully weighed against the risk that such actions can seriously interfere with competitive market dynamics by changing the relative prices of competing resources, artificially suppressing prices and producer revenues, and impeding the free entry and exit of current and future market participants. While in a limited short-run analysis such actions may look necessary and/or beneficial, in the long run they are also likely to interfere with competition, reduce market efficiency, and increase all-in consumer prices for energy, capacity and ancillary services.

Another consideration relates to our focus on *ratepayer impacts*. Since the context for our analysis is states' current consideration of having electricity consumers pay for natural gas infrastructure, we quantify in the Report differences in solution set impacts on electric ratepayers, or changes in "consumer surplus." When considering long-term ratepayer investments, this is generally the standard by which public utility commissions evaluate competing alternatives – namely, the total costs, risks, and benefits borne by the *ratepayers* who will be responsible for the cost burden of the investment or commitment in question. However, evaluating the broader efficiency of market outcomes should also consider the potential impact on *producer surplus* – that is, the impact on producer profits over time – with the ultimate goal of maximizing the combination of producer and consumer surplus, or total social welfare.

The solution sets evaluated in this Report would change the underlying economics of participation in wholesale markets by producers and affect the revenue flows to many market participants in both electric and natural gas industries. For example, investments in energy efficiency or natural gas pipelines would reduce energy market costs for consumers, but would also reduce revenues and profits for producers, and change revenue streams (positive and negative) for other participants in electricity and natural gas markets (e.g., energy efficiency providers and natural gas shippers/marketers/pipeline owners). Similarly, contracted capacity for an interconnection to a neighboring region could significantly suppress wholesale market prices, increasing revenues and profits to some producers (e.g., the owners of hydro assets backing power sales), and decreasing revenues and profits to other producers (e.g., owners of in-region generating assets).

The ultimate impact on total social welfare of all consumer and producer impacts is difficult to establish (and is beyond the scope of this Report), since over time the cost reductions and producer revenues lost in the energy market would be at least partially offset by increases in other markets, such as the forward capacity, reserve, and ancillary services markets, as generating asset owners increase offers to ensure economic viability, or otherwise retire and force new entry earlier than otherwise would occur. In

short, reductions in total social welfare that arise from projects supported by non-market actions may discourage or otherwise displace projects that would have been more cost effective in the long run.<sup>59</sup>

***Interaction between electric and natural gas ratepayers*** – Many natural gas LDCs contract with third parties for management of their natural gas supply and transportation assets, with the goal of maximizing the value of those assets. These arrangements often include a sharing of revenues among the portfolio managers, natural gas LDC shareholders, and LDC ratepayers. The addition of natural gas capacity that would in effect be owned by electric ratepayers and dedicated for use by electricity generators would increase available transportation capacity, and thereby decrease or eliminate the value of natural gas LDC assets that are often sold off for use by electricity generators; this would lower rebates to LDC ratepayers, and lower revenues to LDC shareholders and portfolio managers. That is, if electric companies hold firm capacity for use by electric generators, then it is unclear who will remain in the market to purchase large quantities of capacity release from other firm shippers. In fact, by securing firm capacity for electric generators, the resale capacity of LDC firm transportation rights will likely be lower, representing a net cost to natural gas ratepayers. Conversely, the electric ratepayer firm transportation assets may also have resale value, and allow through such resale a reduction in the cost obligation borne by electric ratepayers for the firm pipeline commitments. We expect, however, that this value may be minimal since the addition of electric ratepayer-funded transportation capacity would dramatically reduce the value of such capacity in many or most hours of the year. However, estimating the impact of such capacity resale by transportation asset owners (LDCs and electric ratepayers) is beyond the scope of this Report.

***Ratepayer risk*** – Our financial analysis of different solution sets applies the same financial assumptions and approaches to ensure comparability and uses consistent decision rules related to the timing of the investments. The goal of structuring our analysis in this way was to present the ultimate impact on electric ratepayers using a consistent cost metric – namely, the expected total annual costs to electricity consumers, considering both the expenditures needed to implement the solutions and the annual impact on total energy market costs to load. All of our analyses evaluate impacts over the full forecast period (i.e., through 2030) on a net present value basis and then use these results to identify an annualized ratepayer impact.

While we believe this is the most fair and consistent approach to compare ratepayer impacts across solution sets, it does mask some important differences in the risk profiles of different approaches, and/or in the potential value (or lack thereof) associated with solution sets throughout and beyond the forecast horizon. As noted in Table 5, there are some significantly different risk profiles across solution sets; differences that are a function of the “lumpiness” of implementation costs, and the ability to adjust spending/implementation as new information becomes available over the forecast horizon.

Specifically, solution sets can be loosely grouped into “one time” and “incremental” approaches to addressing potential winter peak deficiencies. On the one hand, pipeline and transmission/capacity

---

<sup>59</sup> See Initial Comments of the Office of the Attorney General, in Re: D.P.U. 15-37, filed June 15, 2015, Section III.B.2.

additions (in both solution sets and infrastructure scenarios) require major one-time<sup>60</sup> investments and associated long-term ratepayer commitments that cannot be reversed if events do not proceed as expected, or if a change in winter demand or in supply technology options suggests an alternative path going forward.<sup>61</sup> In contrast, the other solution sets either have a minimal up-front cost impact on ratepayers (e.g., the Dual-fuel (SS 1a) and Firm LNG (SS 1b) solution sets), or in the EE/DR (SS 3a) solution set require ratepayer commitments that can vary (increase or decrease) each year as new information becomes available related to the magnitude of need and/or cost of various solution set options (i.e., changes in the cost of efficiency measures and programs, or renewable/distributed alternatives). While we have not attempted to quantify it in this Report, there may be a meaningful option value that should be attributed to the “incremental” approaches to address the stressed system deficiency. This is particularly true given our finding that, under our base case assumptions, we find no deficiency over the forecast horizon.

This option value may also be particularly important given the suite of GHG goals and commitments. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. In contrast, solution sets that fail to do so will require more significant investments at a later date. It is also important to note that these climate commitments were made, in part, with a consideration for the wide range of public health, economic, and environmental benefits associated with reduced GHG emissions and a recognition of the many other externalities associated with fossil fuel generation, though a full review of such externalities is beyond the scope of this Report.

---

<sup>60</sup> The EE/Firm Imports (SS 3b/S 3c) solutions require up-front commitments to contract for firm winter capability backed by resources that can deliver at the time of winter peak, and potentially one-time commitments to construct and pay for any transmission needed to deliver such capacity to load. The Incremental Pipeline (SS 2/IS 1) solutions also require major up-front commitments, either on a one-time basis (in the infrastructure scenario) or in two separate pieces (in the solution sized to the stressed system deficiency).

<sup>61</sup> We realize that in theory regulatory commissions could disallow recovery of a portion or all investments made for new interstate pipeline capacity, transmission infrastructure, and/or capacity contracts. However, in practice we expect and assume that the costs associated with any of these solutions would be deemed prudent at the time of investment, and cost recovery would be pre-approved or largely assured through up-front regulatory findings.

**Table 5: Risk Factors and Other Considerations Associated with Solution Sets**

Solution Set	Other Considerations
<i>Market Driven Outcomes</i>	
SS 1a: Dual-fuel Capacity (“Status Quo”)	<ul style="list-style-type: none"> <li>• No up-front investment and requires no action on the part of legislatures or regulators</li> <li>• Dual-fuel upgrade costs may not be passed on to consumers (unless upgrade cost affects marginal capacity market prices), costs borne by producers represent a reduction in profits</li> <li>• Relying on oil during winter peak periods has only limited impact on winter gas prices; when oil prices are low, economic oil-fired generation can reduce on-site inventories leading into stressed winter conditions</li> <li>• Air quality permits often restrict total hours of oil-fired operation, though restrictions generally allow more hours of operation than needed to address winter peak reliability needs</li> <li>• Operation time at units will be limited by the quantity and size of oil storage tanks, ability to switch from gas to oil, and ability to replenish supplies, which can be challenging during extreme cold periods</li> </ul>
SS 1b: Firm LNG Capacity	<ul style="list-style-type: none"> <li>• No up-front costs to consumers; implementation costs reflected in energy market prices on as-needed basis</li> <li>• LNG use targeted to deficiency may have only limited impact on winter delivered gas prices</li> <li>• Creates flexibility with respect to intra-annual operations and allows for 5 year lead time for renegotiation or pursuit of alternative solution sets if needed</li> <li>• Contract prices and terms are untested at this point; firm commitments remain dependent on contract language and financial penalties; imports constrained by global price risk, global supply production risk</li> <li>• Prices would ultimately be set by few suppliers with limited competition</li> </ul>
<i>Incremental Pipeline Capacity</i>	
SS 2: Incremental Pipeline:	<ul style="list-style-type: none"> <li>• Major up-front investment creates long-term ratepayer cost obligation; obligation remains even if use or value of assets diminish or is limited for any reason (e.g., evolution of GHG reduction goals/obligations)</li> <li>• Increased certainty of solution set once approved; known in-service date allows for accountability and tracking of progress made by a single entity</li> <li>• Mechanism to guarantee firm transportation for electricity generation at winter peak is unknown</li> <li>• Increased capacity reduces or eliminates the value of existing capacity release benefits, which may lead to a net loss for gas ratepayers, LDC shareholders, and portfolio managers</li> <li>• Increased in-region flows may be used to serve other markets or LNG exports, potentially increasing pipeline utilization and reducing or eliminating price suppression benefits</li> <li>• Faces significant siting and regulatory challenges, potential local property value impacts and non-GHG environmental impacts</li> <li>• May increase GHG outside New England, and an associated increase in natural gas production and consumption would also increase non-GHG environmental impacts</li> </ul>
<i>Energy Efficiency, Demand Response, and Renewable Energy</i>	
SS 3a: Energy Efficiency and Demand Response	<ul style="list-style-type: none"> <li>• Up-front investment is annual, and can be adapted on an annual basis in consideration of actual need and changes in technology, policy and cost factors; actual technologies/programs relied on could adjust in response to technology and cost breakthroughs</li> <li>• Requires a sustained commitment by states for investment, likely over many years; absent a commitment the EE/DR solution cannot be counted on to meet deficiency in later years</li> <li>• Realization could be limited by ability to ramp up resources and providers; full suite of benefits are not immediately available</li> <li>• Requires robust monitoring and verification to ensure expected winter peak impacts are being realized</li> <li>• Annual costs are not certain – could either grow or decline in later years</li> </ul>
SS 3b/c: Energy Efficiency and Firm Imports (existing and new transmission)	<ul style="list-style-type: none"> <li>• (See above in SS 3a regarding EE)</li> <li>• Major up-front investment creates long-term ratepayer cost obligations; ratepayer obligation remains even if use or value of assets diminish or is limited for any reason</li> <li>• Must guarantee and price firm winter/year-round capacity; otherwise, cannot be counted on to address deficiency; availability and cost of a firm winter deliverable product is unknown</li> </ul>

## VI. REFERENCES

Black & Veatch. “Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England.” Prepared for the New England States Committee on Electricity, August 26, 2013. B&V Project No. 178511.

Beacon Hill Institute at Suffolk University. “The Economic Impact on Massachusetts of the Proposed Northeast Energy Direct Pipeline.” June 2015.

Competitive Energy Services. “Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices.” Prepared for the Industrial Energy Consumer Group, February 7, 2014.

Concentric Energy Advisors. “New England Cost Savings Associated with New Natural Gas Supply and Infrastructure.” May 2012.

Eastern Interconnection Planning Collaborative. “Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study.” DOE Award Project DE-OE0000343, July 2015.

Energzyt Advisors, LLC. “Analysis of Alternative Winter Reliability Solutions for New England Energy Markets.” Prepared for GD Suez Energy North America, August 2015.

ICF International. “New England Energy Market Outlook: Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Project.” Prepared for Kinder Morgan, 2015.

ICF International. “Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England.” Prepared for Eversource Energy and Spectra Energy, February 2015.

ICF International. “Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II.” Prepared for ISO New England, November 2014.

LaCapra Associates. “The Economic Impacts of Failing to Build Energy Infrastructure in New England.” Prepared for New England Coalition for Affordable Energy, August 2015.

Levitan & Associates, Inc. "Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces." DOE Award Project DE-OE0000343, Prepared for the Eastern Interconnection Planning Collaborative, 2014.

London Economics, Inc. “Maine Energy Cost Reduction Act: Cost benefit analysis of ECRC proposals.” Prepared for Maine Public Utilities Commission Staff, June 2015.

Massachusetts Department of Public Utilities, “Investigation by the Department of Public Utilities on its own Motion into the means by which new natural gas delivery capacity may be added to the New England Market, including actions to be taken by the electric distribution companies.” Docket 15-37, Order Issued October 2, 2015.

Monitoring Analytics, Independent Market Monitor for PJM, “Analysis of the 2017/2018 RPM Base Residual Auction.” October 6, 2014.

Peterson, P. and Fields, S. “Challenges for Electric System Planning: Reasonable Alternatives to ISO-NE’s Discounts for Uncertainty.” Prepared for E4 Group, July 24, 2015.

Skipping Stone. “Solving New England’s Gas Deliverability Problem Using LNG Storage and Market Incentives.” Prepared for the Conservation Law Foundation, August 2015.

Spectra Energy Partners. AIM Project, Algonquin Gas Transmission, LLC. FERC Section 7(b) and 7(c) Application and Public Exhibits, Except F-1. FERC Docket No. CP14-96, February 2014.

Synapse Energy Economics. “Massachusetts Low Gas Demand Analysis: Final Report.” Prepared for the Massachusetts Department of Energy Resources, January 7, 2015. RFR-ENE-2015-012.

Schatzki, T. and Hibbard, P. “Assessment of the Impact of ISO-NE’s Proposed Forward Capacity Market Performance Incentives.” September 2013.

Teodoru, C., et al. “The net carbon footprint of a newly created boreal hydroelectric reservoir.” *Global Biogeochemical Cycles*, 2012, Vol. 26, pp. 1-14.

U.S. Energy Information. “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015.” June 2015.

## VII. GLOSSARY

ACO	Annual Contract Quantity
AGI	Analysis Group, Inc.
AGO	Massachusetts Office of the Attorney General
AIM	Spectra's Algonquin Incremental Market pipeline project
Basis differential	The difference between delivered natural gas at trading hubs and the Henry Hub
Bcf	Billion cubic feet: a unit of natural gas
CELT	Capacity, Energy, Loads, and Transmission: ISO-NE annual planning document
CH <sub>4</sub>	Methane
CO <sub>2</sub>	Carbon dioxide
CPP	Environmental Protection Agency Clean Power Plan
Deficiencies	Periods when the electric system may not be able to meet peak electric demand
DOER	Massachusetts Department of Energy Resources
DR	Demand Response
Dth	Dekatherm: a unit of natural gas
ECP	Eastern Canadian Premiers
EE	Energy Efficiency
EFORd	Equivalent Forced Outage Rate on Demand
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
FCA	Forward Capacity Auction
FSRU	Floating Storage and Regasification Unit
GHG	Greenhouse gas emissions
GWSA	Global Warming Solutions Act
ICF	ICF International
ISO-NE	Independent System Operator of New England
LDC	Local distribution company, used for natural gas
LMP	Locational marginal price
LNG	Liquefied natural gas
M&N	Maritimes & Northeast Pipeline
MMTCO <sub>2e</sub>	One million metric tons CO <sub>2</sub> equivalent
MW	Megawatts: a unit of power
NBP	United Kingdom's National Boundary Point
NED	Kinder Morgan's Northeast Energy Direct pipeline project

NEEP	Northeast Energy Efficiency Partnership
NEG	New England Governors
NYISO	New York Independent System Operator
PFP	ISO-NE Pay-for-Performance Program
PJM	Pennsylvania, Jersey, Maryland Interconnection
PROMOD	An industry-standard electric market simulation model marketed by Ventyx
RE	Renewable Energy
REED	Northeast Energy Efficiency Partnerships Regional Energy Efficiency Database
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization

## VIII. APPENDICES

### 1. *Deficiency analysis*

In this appendix, we provide additional detail on the deficiency analysis, specifically with respect to the methodology used to forecast natural gas demand and additional sensitivities of the key results presented in Table 1.

#### *Availability of Natural Gas for Electricity Generation*

As described in Section III, we relied on daily scheduled pipeline and LNG deliveries to LDCs and end-users for the period December 1, 2012 to present using SNL Financial,<sup>62</sup> and the weighted average temperature for the ISO-NE Control Area collected by ISO-NE.<sup>63</sup> Figure A1 below shows the total demand and capacity for the period January to March 2015, and highlights that during peak periods, the system is fully constrained, with total scheduled deliveries net of LNG sendout (shown here as negative demand) approaching total pipeline capacity. Here, we rely on scheduled deliveries during the timely nomination cycle. Under the timely nomination cycle, natural gas is scheduled for delivery by 12:30 pm the day before. That is, the timely nomination gives the greatest assurance to shippers (including both LDCs and generators) that they will receive their nominated capacity. This assurance is necessary under a strict reliability perspective, since it is only the capacity not nominated by firm shippers during the timely cycle that is available to electric generators on an interruptible basis the following day. Other nomination schedules include the evening cycle (by 7 pm the day before, for delivery by 10 am the following day) and the intraday nomination cycles (which allow for nomination and delivery during the same day). Not considered here is the challenge of electric-gas coordination, and the simple fact that the natural gas day and electric generation day operate on different time schedules. We note that greater coordination by the gas and electric sectors has alleviated and can continue to alleviate potential constraints. For example, in recent winters, ISO-NE has advanced the day-ahead market timeline to allow for more time to procure gas and has maintained regular communications with gas pipeline operators.<sup>64</sup>

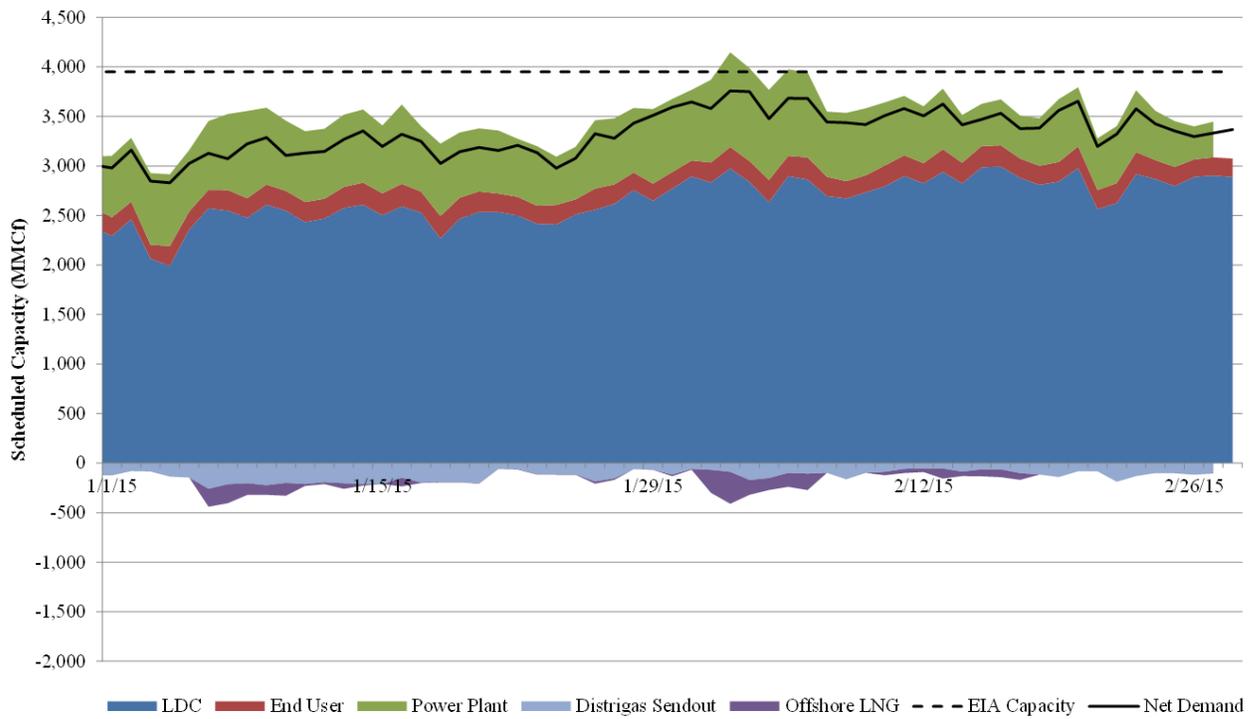
---

<sup>62</sup> SNL Financial is a data aggregation service that compiles electronic bulletin board data reported by each individual pipeline company. SNL classifies each delivery point based on available contract information.

<sup>63</sup> See ISO-NE, Zonal Information, available: <http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info>.

<sup>64</sup> See Callan, W. ISO-NE Winter 2014/15 Review. Electric/Gas Operations Committee (EGOC) Teleconference, June 29, 2015. Available: <http://www.iso-ne.com/committees/industry-collaborations/electric-gas-operations>.

**Figure A1: Scheduled Natural Gas Demand and Total Capacity, ISO-NE System  
January – March 2015**



Notes:

Total deliveries are the sum of LDC’s, end-user, and power plant deliveries. LNG deliveries to the natural gas system are reflected as a reduction in total deliveries, instead of an increase in total capacity. Total capacity is based on EIA state to state data for existing interstate pipeline gas capacity.

Consistent with ISO-NE/ICF (2014), we developed a daily forecast of natural gas demand from LDCs and end-users based on the historical relationship between demand and weather. We developed two separate forecasts – one for winter conditions (defined as any day from December through February of each year, with total temperature less than 65 degrees Fahrenheit) and one for non-winter conditions (defined broadly as all days with temperature greater than 65 degrees Fahrenheit). The statistical relationship in Figure 1 of Section III is defined by Equation 1. Equation 2 provides the non-winter relationship.

**Equation 1: Projected LDC Interstate Pipeline Demand in MMcf (when temp < 65° F)**  

$$= (878 + 60.6 * EDD - 0.4 * EDD^2) * (Year - 2015)^{(1.4\%)}$$

**Equation 2: Projected LDC Interstate Pipeline Demand in MMcf (when temp > 65° F)**  

$$= (905 - 0.53 * EDD) * (Year - 2015)^{(1.4\%)}$$

Our use of the 1.4 percent growth rate, while consistent with recent studies, does not necessarily align with recent estimates for peak design day demand growth as filed in certain LDC long term supply plans. However, there are several important differences between our assumed growth rate of demand from existing pipelines and the *overall* growth rate of LDC demand. These differences include demand from capacity exempt customers, demand met by incremental supplies not available to the electric generation sector, and demand from power plants served by LDCs. We described these key differences in Section III, but provide additional detail here.

First, we apply the 1.4 percent growth rate to both LDC and end-user demand. We obtain historical data for these two sectors separately; end-users are defined as large (typically commercial/industrial) customers that connect directly to the interstate pipeline, typically before the city gate. Recent LDC filings have included plans that account for the return of some capacity exempt customers.<sup>65</sup> While this represents an increase in LDC forecasted demand, it is not a net increase in total demand for the system. These growth rates reflect, in part, growth for the LDC portfolio which includes new LDC customers and are not necessarily limited to new growth for all natural gas users. Because these capacity exempt customers are already captured in our end-user definition, a higher LDC-specific growth rate would double-count their forecasted take from the interstate natural gas pipeline system. Put another way, we assume that both LDC demand and end-user demand grows by 1.4 percent.

Second, our use of a lower growth rate reflects a more narrow view of incremental demand from the existing and approved interstate pipelines used in our base case deficiency statement. That is, this growth rate does not reflect incremental demand that could or will be met from new facilities or from LNG resources that are unavailable to meet electric sector demand.

We have made no assumption for how LDCs will meet incremental new demand, above this 1.4 percent growth rate. To do so would require, in part, an assessment of the cost and benefits of all possible supply strategies. Therefore, for the purpose of estimating incremental gas available to the electric generation sector, we assume that neither the incremental demand nor the associated incremental supplies to meet that demand are available to, or otherwise affect, the electric generation sector.<sup>66</sup>

---

<sup>65</sup> For example, National Grid included returned capacity-exempt load of 41,080 MMBtu/day in 2015/16 and beyond. Subtracting this demand from total firm design peak day would lower the estimated compound annual growth rate during this period from 2 percent to 1.6 percent. See National Grid, Long-range Resource and Requirements Plan, DPU Docket 15-36, Revised Forecast as filed July 10, Response to Information Request DPU-1-5, at page 18 and Table G23-D (Revised).

<sup>66</sup> This includes the recent precedent agreements for new pipeline capacity with the Kinder Morgan Northeast Energy Direct (NED) pipeline. It also includes National Grid's most recent petition of approval for five new LNG contracts. These include a nine year contract with GDF Suez at the Distrigas facility, and agreements for new incremental liquefaction facilities. Because we are primarily concerned with LNG supplies to help meet a peak reliability deficiency in 2025 or later, we assume that contracted capacity at the Distrigas terminal becomes available to the electric generation sector. We do not include new LNG capacity from the proposed liquefaction facilities, which would be used to meet LDC peak design day demand. These new facilities would access the Algonquin pipeline at the current site in Providence, Rhode Island and the Tennessee pipeline at an undisclosed

Third, our estimates of historical demand at LDC city gates will necessarily include demand from the electric power sector served by those LDCs. This fact suggests that we will understate the total quantity of gas available to the electric generation sector and over-state the potential reliability deficiency.

However, as a sensitivity to the results presented in Table 1 of Section III, we also evaluated potential system deficiencies assuming that total natural gas demand from LDCs and end-users grows at compound annual growth rate of 2.2 percent over the life of the study and that the system adds 0.5 Bcf/day of incremental pipeline capacity – to meet LDC needs – in 2020. This capacity is not reserved for the electric generation sector and is only available on an interruptible basis throughout the winter months. We find that the peak deficiency in the stressed system case, considering both a higher growth rate and new capacity to serve that demand, is actually lower than the peak deficiency presented in Section III (see Table A1). This means that our definition of solution sets to meet a potential deficiency are robust to potential assumptions of higher LDC growth rate that could be met by new LDC supplies.

**Table A1: Electric Sector Reliability Deficiency Analysis Sensitivity, 2020-2030**

*Assuming 2.2% growth in LDC/End User Demand and Incremental 0.5 Bcf/d LDC capacity in 2020*

2004 Weather Year, 90-10 Load	Total Hours with a Deficiency									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	2	4
Scenario 3 "Stressed System"	0	0	0	0	4	5	5	5	12	17

2004 Weather Year, 90-10 Load	Total Days with a Deficiency									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	1	2
Scenario 3 "Stressed System"	0	0	0	0	2	2	2	2	5	6

2004 Weather Year, 90-10 Load	Peak Hour Deficiency (MW)									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	173	764
Scenario 3 "Stressed System"	0	0	0	0	450	940	1,266	1,017	1,552	2,143

2004 Weather Year, 90-10 Load	Peak Hour Deficiency (Bcf/hr)									
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	0.0012	0.0054
Scenario 3 "Stressed System"	0	0	0	0	0.0032	0.0067	0.0090	0.0072	0.0110	0.0152

Notes:

Includes the same assumptions described in Section III.

location in Massachusetts. See Joint Testimony of Elizabeth D. Arangio and John E. Allocca, Exhibit NGRID-EDA/JEA-1, D.P.U. 15-129, page 6, filed August 20, 2015.

## 2. **Solution Set Costs**

Each solution set described in Section IV represents an incremental change to the electric generation sector, which will either increase the total availability of fuel for natural gas and/or dual-fuel fired generation or decrease total electric demand during winter peak hours. These solution sets include variable options (such as Firm LNG (SS 1b) or demand response (as part of EE/DR SS 3a)) which can be called upon only during deficiency hours and also larger fixed options, which would be available both during the winter peak deficiency event and during all other hours in the year (such as Incremental Pipeline (SS 2) capacity, or EE/Firm Import (SS 3b/SS 3c) capacity). Each solution set, therefore, will have a unique impact on total system natural gas utilization, natural gas prices, and the total cost to load. We describe the impact of each solution set on natural gas prices in this Appendix.

We assume that ratepayers are responsible for the full cost to implement each solution set, including all fixed and variable costs associated with new investments based on existing cost-of-service principles that also recover return on rate base, depreciation, and taxes. Costs for each solution set are expressed in annualized terms, and in the assessment phase, we match annualized benefits to annualized costs over the full modeling period.<sup>67</sup> When appropriate, nominal costs are converted to real costs assuming a 2.5 percent inflation rate. All values are annualized over the period 2020 to 2030 in level-real terms assuming a 7 percent private discount rate.

Additional details on sources and specifications for solution set costs are described below.

### **Market-Driven Outcomes**

#### **Solution Set 1(a): “Status Quo” – Dual-fuel**

Under the ISO-NE Pay-for-Performance (PFP) program, resources that clear in the forward capacity auction (starting with FCA #9 for deliverability in 2018/2019) will receive base capacity payments, and during periods of scarcity, resources that perform well will receive additional payments while those that fail to perform or perform poorly will receive a significant penalty charge. This places the financial risk (or benefit) of scarcity performance on individual generators and provides for an additional incentive to resources to increase unit reliability during periods of potential fuel shortage. This could include incremental dual-fuel capability or non-interruptible gas supply arrangements. The PFP program will be phased in over seven years and will not be fully available until 2025.

As described below, first, we develop our base case outlook for natural gas and dual-fuel capacity using the Ventyx simulation-ready data for the ISO-NE and Eastern Interconnection region, with adjustments to potential retirement dates and new additions based on our review of relevant planning documents published by ISO-NE. Second, we use a generic resource adequacy capacity market model and add new dual-fuel capable resources over time, in quantities sufficient to meet reliability requirements. We include more than 19.5 GW of natural gas fired capacity in 2020, representing 52 percent of total

---

<sup>67</sup> We recognize that solution sets requiring an incremental capital expansion, for either a new transmission line or a new incremental gas pipeline will necessarily have a lifetime beyond 2030 and the end of our modeling period. We do not consider the remainder of ratepayer payments associated with these investments, nor do we consider any potential benefits to the electric generating sector in years after 2030.

system capacity. This capacity includes 9.6 GW of dual-fuel capacity, with 2.4 GW of that dual-fuel capacity assumed to come on-line after 2019.<sup>68</sup>

Under the existing market outlook, generators have incentives to perform during periods of peak winter demand, and to do so during periods of natural gas shortage or price spikes. However, individual units may be unavailable during winter peak for several reasons, such as generator outages beyond the assumed average EFORd, operating limits for total emissions, or limits on fuel availability and deliverability in generator storage tanks. They may also be unavailable as the full effectiveness of PFP is phased in over the seven year period. To account for this uncertainty, and as part of our stressed system deficiency statement scenario, we assume that all new dual-fuel capacity and all fuel oil #6 capacity is unavailable at the time of winter peak. This represents 20 percent of all existing dual-fuel capable units and approximately 40 percent of all dual-fuel capacity in our assumed future supply stack.

In the dual-fuel solution set, we add sufficient quantities of dual-fuel capability at existing resources to meet the deficiency. This includes 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 (for a total of 2,400 MW). The 2013 AGI review of the ISO-NE FCM PFP found that increased investment in dual-fuel represented the most cost effective investment, and that more than 11,000 MW – including 4,000 MW of mothballed capacity at existing dual-fuel units – was available.<sup>69</sup>

Based on that finding, we estimate that the total cost for the dual-fuel solution set can be met by existing resources with under- or unutilized capability, and total annualized incremental dual-fuel capacity costs are assumed to be \$6,856/MW, consistent with that study, adjusted for inflation. These costs include both annualized capital costs and annual operating costs for fuel and operations and maintenance. Importantly, electricity consumers would only realize incremental costs for this solution if and to the extent that the addition of dual fuel capability on an existing resource affects capacity market prices as a marginal capacity resource, which may in fact be unlikely. Nevertheless, for comparison with other solution sets, we provide dual-fuel costs calculated as the full incremental cost on a cost of service basis.

---

<sup>68</sup> This estimate is in-line with other estimates of dual-fuel capability, including the publicly available totals reported in the ISO-NE CELT (2015) and the AGI's review of confidential individual generator data provided by ISO-NE as part of its assessment of the ISO-NE Forward Capacity Market Performance Incentives.

<sup>69</sup> Schatzki, T. and Hibbard, P. "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives." September 2013, pages. 4 and 21, also Figure 3.

## **Solution Set 1(b) – Firm LNG**

LNG plays an important role in the natural resource portfolio for ISO-NE customers, including local gas distribution companies (LDCs). It provides a flexible natural gas resource that can be used to meet peak demands, and at the same time, provides a hedge against daily volatility in delivered natural gas prices at New England city gates. In New England, there are two primary sources of LNG available to LDCs: facilities with direct import capability connected into the interstate pipeline system and off-system LNG resources that rely on trucked capacity and are available for peak shaving.

Table A2 summarizes LNG facilities and their known capacities. From an electric reliability perspective, we are primarily concerned with LNG supplies that can be used to provide incremental gas service to the electric generation sector during peak demand periods. Therefore, we assume that all LNG peak-shaving facilities owned and operated by LDCs (45 facilities representing a combined 1.4 Bcf/d capacity) are used to meet residential peak day needs and are not available to meet electric reliability demand.

In contrast, both the Canaport and Distringas facilities are connected to the interstate natural gas pipeline system. Canaport is located in New Brunswick and interconnected to the Maritimes & Northeast (M&N) pipeline and supports North to South flows into New England. Canaport is one of several sources of natural gas to the M&N pipeline. As described below, we assume that the full capacity of the M&N pipeline (0.833 BCF/D) is available to New England customers in our deficiency statement. Therefore, we do not include any incremental LNG supplies from Canaport in our analysis.

The Distringas facility, located in Middlesex, Massachusetts and interconnected to the Tennessee Gas Pipeline and Algonquin Pipelines, allows for the back-fill of natural gas into the interstate pipeline system with East to West flows. The Distringas facility also provides LNG to the Mystic Generating Station, a 575 MW natural gas steam turbine. The Distringas facility can store up to 3.4 BCF of LNG and can re-gas up to 0.715 BCF on a continuous basis. This represents 4.75 days of total sendout at maximum capacities.

**Table A2: Existing Liquefied Natural Gas Capability**

Resource	Capacity	Assumption	Solution Set
<b>Canaport</b>	1.3 BCF/Day	Included in the Deficiency Statement, as a supply to the 0.833 BCF/D M&N Pipeline	Not Included in Solution Sets
<b>Distrigas</b>	0.715 BCF/Day	Historical Flows and Back-fill included in Demand Forecast	Non-LDC Capacity available for solution sets
<b>Neptune<sup>70</sup></b>	0.635 BCF/Day	Out-of-Service; Potentially available at a higher cost, including fees to return to service	Not Available for solution sets
<b>Northeast Gateway</b>			
<b>LNG Peak Shaving</b>	1.4 BCF/Day	Used to meet LDC peak Demand in excess of forecast interstate pipeline demand	Not Available for solution sets

There is little publicly available information on the number or terms of LNG contracts with electric generators. Because LNG typically serves as a swing resource used to meet peak demand, economic theory suggests that LNG prices will typically be bounded by the opportunity cost of either selling LNG into alternative markets or purchasing the next available landed fuel resource, such as natural gas from pipelines or delivered oil for electricity generation. That is, variable costs for LNG supplies can be expected to be the higher of the price of oil or natural gas during constrained periods and high prices. Equally important, the current practice of using LNG as a swing resource includes additional risk that supplies may not be available or otherwise accessible during peak periods for a reliability deficiency challenge. LNG may be unavailable for physical reasons of force majeure, if for example, shipments can't land at an off-shore terminal due to winter storms, or may be unavailable for supply resources, if for example, world prices are higher in other markets which limit production or total U.S. sales.

To develop a comparable solution set for reliability purposes, we include both fixed and variable charges for a quantity of LNG that is fully reserved and guaranteed for delivery to the electric power sector. Information on potential structures for such contract arrangements was provided to AGI by LNG representatives and the Environmental Defense Fund through the Study Advisory Group process and presented to all Study Advisory Group members. They provided two potential contracts, described below.

---

<sup>70</sup> The Neptune facility received a five year suspension of its operating license from the U.S. Maritime Administration in summer 2013. See LNG World News, "Neptune Suspends LNG Deepwater Port Operations", July 29, 2013.

The first contracting model, (for the Base-Load LNG Solution) is for a land based terminal where the expected maximum deficiency quantity per hour (MHDQ) is converted to an Annual Contract Quantity (ACQ) for the subject year by multiplying such year's MHDQ by 24 (hours in a day) and then by 90 (days in the December 15 through March 15 deficiency period). This methodology substantially overstates the needed quantity (i.e., the Deficiency Quantity compared with ACQ), but the contributing Study Advisory Group members represented that this simplified approach is consistent with other contracts, which sizes the re-gasification need to the peak hour need, analogous to pipeline scheduling practices.

The second Contracting Model assumes a dedicated Floating Storage and Regasification Unit ship (FSRU) and a term charter arrangement for the same 90 day period. Under this second contracting model, the commensurate ACQ is the greater of the Total Deficiency Quantity (determined by the deficiency model) or 3 Bcf (3,000,000 Dth). The 3 Bcf quantity is the approximate capacity of an FSRU ship. To achieve this latter dedication, the FSRU would be chartered for the full period that it was docked at one of the two off-shore receiving facilities. This service could also be provided using the on shore Distrigas terminal with a similar commercial (i.e., demand charge) arrangement. Both options require a per day chartering fee, comparable to a pipeline demand charge (discussed below).

While not considered here, the relevant Study Advisory Group members indicated that potential hybrid entailing a base-load LNG component (i.e., using a land-based terminal) along with an FSRU component are also commercially and physically feasible: for example, a land-based quantity of LNG for the full 10-year period approximately equal to that in the first year of the Base-Load LNG Solution construct followed by FSRU supply as described above across the same period in the same fashion. Such a hybrid solution could achieve both reliability supply needs and more general price moderation or suppression owing to the addition to the New England market.

In recognition of the global dynamics surrounding the supply and demand of LNG, the variable cost component of fuel supplies for each contract is indexed to the highest of three trading hubs. In this model, proposed structure takes the highest of the: a) Henry Hub plus adders (discussed below); b) the United Kingdom's National Boundary Point (NBP) plus shipping to New England; and, c) 14.5 percent of Brent Crude Oil Index (used as the oil benchmark for LNG). At the current outlook of low oil prices, the "higher-of" price is likely to be set by Henry Hub, and oil prices can serve as a "cap" on future LNG prices. The "adders" for the Henry Hub pricing are: a) a 15% pricing adder for natural gas used to power liquefaction (the recognized sales price adder used at the Cheniere LNG export facility on the Gulf Coast); b) the processing cost; and, c) a shipping cost. Processing costs are based on fixed processing charges for subscribers to Cheniere, which are in the neighborhood of \$3.50 to \$3.60 per Dth of LNG output.<sup>71</sup> The shipping cost is estimated to be \$1.50 per MMBtu bringing the processing cost (\$3.50) plus shipping (\$1.50) to a total estimated adder of \$5.00 per MMBtu.

We base our estimate of an LNG solution set using the FSRU contract model described above. This includes a 90-day term charter arrangement, with a daily demand charge of \$200,000, escalated

---

<sup>71</sup> Cheniere Energy, Inc. SEC Filing 8-K, August 2015, pages 24 -26.

annually with inflation, and variable charges using our forecast of Henry Hub pricing plus the indicated processing cost of \$3.50 per Dth, shipping costs of \$1.50 per Dth, and delivery charges of \$0.16/Dth. All variable costs are assumed to escalate annually with inflation.

### *Incremental Pipeline Transportation*

#### **Solution Set 2 – Incremental Pipeline**

Pipeline development costs can vary significantly based on a number of important factors, including whether the project is an expansion or a new development; the location and distance of the chosen route, including right of way easements and other land requirements; the total pipeline diameter, capacity and number of compressor stations used to deliver natural gas; and other factors, such as the financing structure used in the development. Here, we do not forecast a specific pipeline solution, but rather, include a generic estimate of pipeline capacity based on our review of recently completed and proposed pipeline developments, with costs expressed both in terms of development costs (on a \$/inch-mile basis) and as total ratepayer costs (on a \$/Dth-month maximum reservation charge basis). We index total costs to the two most recent announcements for both the Spectra AIM project<sup>72</sup> and the Kinder Morgan Northeast Energy Direct (NED) project and estimate total ratepayer costs using a maximum reservation charge of \$39/Dth-month.<sup>73</sup>

Based on this review, we assume that total capital costs for the 0.3 Bcf/day installation are approximately \$787.5 million, with a first year cost of service of \$140 million. Costs for the 0.12 Bcf/day installation and the 0.5 Bcf/day installation are assumed to scale linearly by size. In practice, actual costs will depend on the specific project chosen, and costs may not scale linearly between capacities.

### *Energy Efficiency, Demand Response, and Renewable Energy*

#### **Solution Set 3(a) – Energy Efficiency and Demand Response**

To develop the energy efficiency and demand response solution set, we draw from the energy efficiency capability estimates presented in the Synapse/DOER (2015) study. They estimate that the total incremental potential for appliance standards and residential, commercial, and industrial energy efficiency

---

<sup>72</sup> The Spectra AIM project is a 0.342 Bcf/day expansion in New York, Massachusetts, and Connecticut, with a total estimated capital cost of \$876 million, a capital recovery factor of 20 percent and a first year cost of service of \$175 million, with a maximum monthly reservation charge of \$42.58. See Spectra AIM Project, FERC Section 7(b) and 7(c) Application and Public Exhibits, FERC Docket No. CP14-96, February 2014, Exhibit P Tariff and Rates. We note that Synapse/DOER (2015) used the Spectra AIM costs in its analysis, with a linear adjustment to monthly reservation rates assuming 80 percent utilization over a five month period. In contrast, we do not forecast pipeline utilization and prices ahead of time; instead, ratepayers are responsible for the full cost of service, with the total pipeline utilization determined through the electric sector dispatch and modeling results.

<sup>73</sup> This assumes a 30 year depreciation schedule, a 10.4 percent nominal weighted average cost of capital, and recovery of federal and state income taxes.

at the time of winter peak is 590 MW of capacity. We make a simplifying assumption that the total feasible capability of such resources for the ISO-NE region is equal to 2.2 times that of the Massachusetts capability identified by Synapse, based on the portion of end-user load served in Massachusetts relative to the New England region as a whole, for a total of 1,300 MW of winter peak capacity. In contrast to Synapse, we consider this energy efficiency to be incremental to the current ISO-NE CELT forecast, which includes its own estimate of energy efficiency. Conversely, the Synapse estimate presented above is assumed to be incremental to Synapse's own adjustment of the CELT forecast. Their adjustment, which includes additional contributions from EE, is designed to account for uncertainty in ISO-NE's planning approach that may discount total EE contributions to load.<sup>74</sup> Therefore, our analysis does not include or consider any existing energy efficiency which is not already captured in the ISO-NE forecast.

We developed our cost estimate of incremental energy efficiency using the average of the lifetime cost of all planned programs, including incentives and participant costs, as identified in the 2016-2018 Massachusetts Program Administrator draft Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan.<sup>75</sup> Our use of the total lifetime cost allows for an apples-to-apples comparison with other solution sets that also assign the full cost of each solution set to ratepayers. We use these Massachusetts' costs as an approximation for the average cost of incremental EE in the ISO-NE region. The Northeast Energy Efficiency Partnership (NEEP) reports energy efficiency program costs, excluding participant costs, for each state in its Regional Energy Efficiency Database (REED). The load-weighted average cost for all New England states in 2013 is equal to the Massachusetts program cost, which suggests that Massachusetts is a useful proxy for the region as a whole.

In the EE/DR (SS 3a) solution set, the remaining deficiency is met through the use of demand response, which can be called upon by ISO-NE during peak periods to reduce total load. To meet a peak deficiency in 2029/30, we include the cost for an incremental 1,100 MW of demand response at \$31.06/MW-day, based on recent PJM capacity auction results.<sup>76</sup> We estimate that this demand response would be called upon in up to 26 hours during the 2029/30 winter.<sup>77</sup>

---

<sup>74</sup> ISO-NE assumes an annual increase in program costs of 5 percent, with an additional 2.5 percent inflation, and applies a 10 percent uncertainty adjustment or de-rate to estimated savings reductions in MA, RI, and ME. See Peterson, P. and Fields, S. "Challenges for Electric System Planning: Reasonable Alternatives to ISO-NE's Discounts for Uncertainty." Prepared for E4 Group, July 24, 2015.

<sup>75</sup> This corresponds to the total resource cost in the Program Administrator filings, and it is used by program administrators to determine the cost effectiveness of individual efficiency programs. See Massachusetts Energy Efficiency Guidelines, §3.4, Department of Public Utilities Order 08-50-B, October 26, 2009.

<sup>76</sup> We rely on PJM bid data because similar information is not readily available for ISO-NE. See Monitoring Analytics, Independent Market Monitor for PJM, "Analysis of the 2017/2018 RPM Base Residual Auction." October 6, 2014, Table 18.

<sup>77</sup> Our use of 1,100 MW of DR is not a forecast of the total incremental DR that may be available over the full modeling period. For example, in the 2016-2018 draft resource plan, National Grid indicated a soft commitment to procuring up to 3,637 MW of commercial/industrial demand response over the three year period at a total program administrator cost of \$23 million (Massachusetts Joint Statewide Three-Year Electric and Gas Energy

### **Solution Set 3(b) – Energy Efficiency and Firm Imports (Existing Transmission)**

In addition to the EE/DR (SS 3a) solution set outlined above, we also consider a blended solution comprised of both energy efficiency and new incremental imports from hydropower and other new Class 1 renewables which could be used in support of regional climate goals EE/Firm Imports (SS 3b/SS 3c). The imports component of these solution sets is about half of that of amount proposed for procurement under Massachusetts Senate Bill 1965, submitted by Governor Baker in July 2015. Under this bill, utilities could procure up to 18,900,000 MWh of clean energy annually, or approximately 2,400 MW of capacity. If the bill is enacted as proposed, initial solicitations would occur no later than April 1, 2016.

To date, there exists little evidence for the potential cost of a long-term energy contract backed by significant quantities of hydropower or wind energy.<sup>78</sup> The purpose of the current solution set is not to model the potential costs or benefits of SB 1965, but rather, to estimate the potential costs and benefits of using imports to meet a peak winter deficiency need, as defined through our deficiency analysis. To meet this criterion, any imports must be available at the time of winter peak on a firm or guaranteed basis. Our solution set costs reflect that perspective.

The most likely source of firm winter imports will be provided by new hydropower supplied from Hydro Quebec. As a government owned public utility, Hydro Quebec is obligated to earn a return on any investments not used to serve its own customers. Accordingly, it sells power into external markets (IESO, ISO-NE, NYISO, PJM) whenever it is economic to do so, or when the cost of energy is higher abroad than the price it could receive in its own service territory. Going forward, Hydro Quebec will be expected to continue to provide energy when it is economic to do so based on market fundamentals. Because Hydro Quebec is itself a winter peaking system (meaning that it requires the majority of its capacity to meet its own demand), the opportunity cost of selling power during those winter months is higher than during a summer peak. The current analysis does not consider new resources from either New York or other Canadian provinces, although both could be used to provide new incremental import capacity.

As a conservative assumption, we estimate that the contract cost for a firm, long-term commitment of imports at the time of winter peak is equal to the capital cost of a new hydropower facility. This perspective suggests that either a) Hydro Quebec would need to build new hydro resources to back this firm commitment, or b) the opportunity cost of selling that power into the ISO-NE market would at least be equal to the cost it could receive at home. In developing our estimate, we rely on the levelized cost of electricity (LCOE) for new hydroelectric resources as reported by the EIA (2015). This estimate is exclusive of transmission costs and fixed or variable operations and maintenance expenses. Based on the assumed EIA capacity factor (54 percent), cost of capital (6.1 percent real after-tax weighted average cost of capital) and a 30 year asset life, we estimate that the total cost of an additional 1,100 MW of firm capacity would be \$4.3 billion with an annualized cost of \$387 million per year. A 2,400 MW firm commitment of capacity would cost \$9.4 billion, or \$843 million per year. Our use of domestic

---

Efficiency Plan, 2016-2018, filed April 30, 2015, page 444). Instead, our inclusion of 1,100 MW represents our judgment for the mix of resources that offers the lowest cost distributed resource solution set.

<sup>78</sup> In 2011, Vermont public utilities signed a long-term contract for up to 225 MW of peak electric energy supply from Hydro Quebec at a price of \$58/MWh plus the cost of transmission.

hydroelectric costs represents a conservative estimate of potential costs developed in Hydro Quebec. For example, in its 2013 Annual Report, Hydro Quebec reported total capital costs of \$6.5 billion for four generating stations at the 1,550 MW Romaine River facility now under construction, without consideration of the cost of the transmission links required to connect these stations to the Hydro Quebec system. We assume that any new facility is able to provide power throughout the year, consistent with the firm contract, and produce energy at a rate greater than the assumed EIA capacity factor.

We develop two EE/Firm Imports solution sets recognizing that the region has the potential to procure some firm capacity over existing transmission lines. For 2018, approximately 1,500 MW of import capacity cleared in the forward capacity auction and has a capacity supply obligation for 1,017 MW during the winter peak period.<sup>79</sup> Since we do not consider these existing imports in the deficiency analysis (because without a long-term commitment they are not obligated to provide power in any winter over the study period), in the EE/Firm Imports (Existing Transmission) (SS 3b) solution set, we include the potential for existing imports, priced at a long-term firm commitment. In actuality, these resources will likely continue to provide capacity and energy to the New England markets, on a year by year basis depending on economic conditions in other regions. If these resources bid into and clear the FCA, then the true incremental cost to consumers of this resource in any given year may be zero.

#### **Solution Set 3(c) – Energy Efficiency and Firm Imports (New Transmission)**

Finally, we model a second EE/Firm Imports (New Transmission) (SS 3c) solution set that includes both the cost of new firm energy and the incremental cost for new transmission to deliver that energy. We assume a total cost for new transmission capacity of \$1.4 billion,<sup>80</sup> with a first year cost of service charge of \$250 million. This cost is representative of a new 1,100 MW transmission line.

When considering the larger transmission infrastructure scenario, we assume that firm contracts totaling 2,400 MW make use of both existing and new firm transmission capacity. To the extent that a 2,400 MW of firm imports would require two transmission lines over the same distance, our estimate potentially underestimates this cost.

---

<sup>79</sup> In addition, the HQ-NE Phase II line has an energy import capability of 2,000 MW and a capacity import limit of 1,400 MW. See ISO-NE Regional System Plan, 2015, Table 4-9.

<sup>80</sup> In nominal dollars, this is approximately \$1.6 billion for a 2020 in-service date.

**Example LNG Term Sheet**  
**(provided by Study Advisory Group members)**

**FSRU LNG Peak Supply Commercial Format – High Level Term Sheet**

Prepared by Skipping Stone (9/30/15)

**Purpose:**

Core contract terms for ensuring a reliable supply of LNG during peak hours of winter at quantities sufficient to eliminate all projected/modeled hours of deficiency.

**Term:**

A rolling five years with the sixth year pricing and quantity to be agreed upon before the end of a set Contract Year.

[To give provide supply certainty to Buyer and demand certainty for Seller, parties would delineate a Contract Year to negotiate and seek agreement on pricing and quantity of service for purchases and sales in the year(s) following the end of the then current 5 year term. Example: Assume initial contract year 1 is the winter of 2016/17 and initial contract year 5 is the winter of 2020/21. By a date certain (prior to the commencement of initial Year 2 (i.e., the winter of 2017/18) the parties agree on pricing and quantity for the 2021/22 contract year. In this way, should the parties be unable to agree on such terms, both parties have 5 years to make other plans and arrangements. Such a structure neither locks both parties into longer than a five year contract at any one time (absent mutual agreement to the contrary) nor (more importantly) forecloses the parties from pursuing other future supply arrangements for more than five years into the future.]

**Annual Contract Period:**

The Annual Contract Period is from December through March of the succeeding year (absent mutual agreement to the contrary).

**Annual Contract Quantity (ACQ):**

Parties agree to a minimum quantity of LNG for each subject Annual Contract Period. This is a take-or-pay quantity.

**Monthly Contract Quantity (MCQ):**

The parties agree that the Annual Contract Quantity is allocated as a percentage across each of the months of December through March of the Annual Contract Period; each an MCQ. Each MCQ is a take-or-pay quantity.

[Example: 16.66% of the ACQ could be the December MCQ, 33.33% of the ACQ could be the January MCQ; 33.33% of the ACQ could be the February MCQ and 16.67% of the ACQ could be the March MCQ, or such other mutually agreeable, individual, MCQ Amounts such that the total of the individual MCQ's equals 100% of the ACQ.]

**Vaporization Schedule:**

Parties agree to minimum (if any) and maximum daily vaporization quantities (MinDVQ and MaxDVQ) such that each MCQ is vaporized. In addition, the parties agree on a maximum hourly quantity (MHQ) and hours of MHQ in any given day (subject to MaxDVQ and MCQ limits).

[Example: The MinDVQ (if any) and the MaxDVQ can be stated as percentages of MCQ. Likewise the MHQ can be set as a percentage of the MaxDVQ.]

**Pricing:**

For the Initial Five Year Annual Contract Periods the pricing shall be agreed upon at contract signing and shall be based upon the formulae on Exhibit A – Pricing attached hereto and made a part of the Agreement.

**Allocation of Price:**

The Price per MMBtu for each MCQ of each Annual Contract Period shall be allocated between a Fixed Amount and a Variable Amount by Buyer provided the sum of Fixed Amounts and Variable Amounts equals the ACQ times the Price for each ACQ as set forth in Exhibit A – Pricing. Such Fixed and Variable Amount per MMBtu shall be set by Buyer no later than 3 hours before the close of the NYMEX futures contract for the prompt month.

[Example: Fixed and variable amounts are set no later than 12:00 noon on the last day of trading for the prompt month futures contract in order that the variable component of the Buyer's MCQ is price responsive for Buyer's dispatch purposes.]

**Other Terms and Conditions (as appropriate)**

### **3. Electric System Model Overview: PROMOD**

#### ***The PROMOD Model***

PROMOD is an electric market simulation model marketed by Ventyx. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices (“LMPs”) at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generation output. Ventyx simulation-ready data includes data on Eastern Interconnection network structure, resources, fuel prices, basis differentials, and demand.

We use PROMOD to model the impacts of each solution set on the dispatch of power system operations and outcomes, with the difference between each simulation and our market outlook scenario being the direct incremental impacts of a given solution set on the power system. These two simulation runs otherwise maintain the same inputs, in terms of power plants available to be dispatched, power plant operational characteristics, NO<sub>x</sub> and SO<sub>2</sub> allowance costs, baseline load levels, and so forth. The market outlook Dual-fuel (SS 1a) case is benchmarked to actual power system operations in the historical months of the 2012-2014 time period (in New England, New York, PJM). With this as a starting point, several core assumptions (e.g., load levels that change as a result of energy efficiency investments, timing of generic capacity additions, natural gas prices that depend on each solution set) were changed, and the model re-run to simulate the solution set case. As described above, the simulation period covers the ten year period between 2020 to 2030. PROMOD outputs include changes in power plant operations, emissions, prices, customer payments, and producer revenues.

#### ***Fuel Prices in the Power Sector***

As a starting point, we develop our base case outlook for natural gas prices using futures prices at the Algonquin Hub. These future prices reflect the current outlook for constrained winter months with high basis differentials relative to the Henry Hub price. Second, we assume that all distillate oil, residual oil, and coal prices are based on Ventyx fuel price forecasts.

We assume that these monthly prices represent the average expectation of fuel prices within each month, while recognizing that delivered natural gas fuel prices will be both higher and lower on individual days. These average prices also reflect the ability of dual-fuel capable units to switch from natural gas and burn fuel oil, when it is economic to do so. For example, in the 2013/14 winter, gas prices exceeded oil prices on 57 percent of winter days, with oil units dispatched in economic merit order.<sup>81</sup> At the same time, oil units may also be dispatched out-of-merit if needed to meet electric reliability.

Therefore, we estimate the total quantity of oil-fired and dual-fuel fired generation that would have been dispatched, based on the estimated total natural gas availability, as defined in the deficiency

---

<sup>81</sup> Brandien, P. “Cold Weather Operations.” ISO New England. Presentation to Federal Energy Regulatory Commission, April 1, 2014, page 14.

statement. This is a necessary step in order to capture the impact of daily variation in fuel prices and the potential for increased costs of oil-fired generation that may be dispatched out of merit for reliability purposes. We do this in three steps. First, we compare the total natural gas fired generation and total natural gas consumption, as dispatched by PROMOD based on the average monthly fuel prices, to the total quantity of available natural gas. Then, using the supply curve for each hour, we estimate the marginal generating unit based on the total cumulative natural gas consumption at the limit of available supplies. All incremental generation (the difference between dispatched natural gas generation and available natural gas generation) is assumed to be met in a cumulative fashion by the most efficient dual-fuel and oil-fired generators remaining in the supply curve. This estimates the total oil-fired generation and the total oil consumption on an hourly and daily basis. Finally, as a third step, we estimate the total “uplift” cost to dispatch this oil-fired generation, as the difference between the monthly natural gas price and the monthly oil price. This cost is added to the total cost to load from the production cost dispatch.

### ***Power Plants: Existing Units, Unit Retirements and Additions***

The set of power plants is based on actual plants operating within eastern PJM, NYISO, ISO-NE, Ontario, and MISO. We made changes to this dataset (to reflect unit retirements and power plant additions (e.g., to meet the states’ RPS). Unit retirement decisions are based on assumed retirements in the PROMOD generator dataset, which rely on information from Ventyx as of September 2014. Some of these retirements have been adjusted as the result of a review of planning documents published by PJM, NYISO, and ISO-NE, along with press releases. Unit additions listed in PROMOD’s generator dataset beyond FCA #9 have not been adjusted. Random generator outages for existing and new units were calculated once using PROMOD’s algorithm, and fixed for each case. Similarly, scheduled generator maintenance is held constant between solution set modeling runs. Table A3 and A4 below provide generator retirements and additions reflecting these changes.

**Table A3: Unit Retirements**

Unit Name	Area	Fuel Type	Capacity (MW)	In-service Date	Retirement Date
Berlin GT 1	ISNE - Vermont	Oil	46	6/1/1972	6/1/2022
Brayton Point 1	ISNE - Rhode Island	Coal	247	8/1/1963	6/1/2017
Brayton Point 2	ISNE - Rhode Island	Coal	249	7/1/1964	6/1/2017
Brayton Point 3	ISNE - Rhode Island	Coal	638	8/1/1958	6/1/2017
Brayton Point 4	ISNE - Rhode Island	Oil	446	12/1/1974	6/1/2017
Cleary 8	ISNE - Massachusetts - Southeast	Oil	26	6/1/1966	6/1/2026
M Street Jet 1	ISNE - Boston	Oil	68	5/1/1979	6/1/2029
Middletown 3	ISNE - Connecticut - Central-Northeast	Dual Fuel	245	1/1/1964	6/1/2024
Montville 5	ISNE - Connecticut - Central-Northeast	Oil	42	1/1/1954	6/1/2020
Pilgrim	ISNE - Massachusetts - Southeast	Nuclear	680	12/1/1972	6/1/2019
Schiller 4	ISNE - New Hampshire	Coal	48	10/1/1952	6/1/2020
Schiller 6	ISNE - New Hampshire	Coal	49	7/1/1957	6/1/2020
South Meadow 11	ISNE - Connecticut - Central-Northeast	Oil	47	8/1/1970	6/1/2020
South Meadow 12	ISNE - Connecticut - Central-Northeast	Oil	48	8/1/1970	6/1/2020
South Meadow 13	ISNE - Connecticut - Central-Northeast	Oil	48	8/1/1970	6/1/2020
South Meadow 14	ISNE - Connecticut - Central-Northeast	Oil	46	8/1/1970	6/1/2020
Vermont Yankee 1	ISNE - Vermont	Nuclear	619	11/1/1972	1/1/2015
West Medway 1	ISNE - Boston	Oil	55	7/1/1970	6/1/2020
West Medway 2	ISNE - Boston	Oil	53	3/1/1971	6/1/2021
West Medway 3	ISNE - Rhode Island	Oil	56	7/1/1970	6/1/2020

Sources:

Ventyx power plants database. ISO-NE non-price retirement requests and determinations.

**Table A4: Unit Additions**

Unit Name	Area	Fuel Type	Capacity (MW)	In-service Date
Bridgeport Harbor 6	ISNE - Connecticut	Natural Gas	475	6/1/2018
Medway Peaker - NEMA	ISNE - Massachusetts	Natural Gas	200	6/1/2018
Medway Peaker - SEMARI	ISNE - Massachusetts	Natural Gas	200	4/1/2018
Salem Harbor CC1	ISNE - Massachusetts	Natural Gas	692	6/30/2017
Towantic	ISNE - Connecticut	Natural Gas	785	12/1/2018
Wallingford 6/7	ISNE - Connecticut	Natural Gas	90	6/1/2018

Sources:

ISO-NE Forward Capacity Auction Results.

### *Renewables*

RPS MWh targets by state are sourced from Lawrence Berkeley National Labs for PJM and NYISO and from the updated ISO-NE RPS Workbook for ISO-NE. Beginning in 2016, we assume that the region meets 100 percent of its incremental renewable target through in-region wind capacity. We add wind resources assuming a 25 percent capacity factor, based on historical generation identified in the SNL power plant database. Over the full modeling period, this adds approximately 4,000 MW of additional wind capacity. Within the resource adequacy model, we de-rate this capacity to 5 percent of nameplate, consistent with ISO-NE planning standards.

### *Generic Capacity Additions to Meet Resource Adequacy*

After the incremental addition of renewable capacity and retirement of units as discussed above, we analyzed the extent to which each region's capacity satisfied forecasted resource adequacy requirements in each year, based on each region's capacity planning process. In ISO-NE, we assume a long-term reserve margin of 14.3 percent and add new generation in the first year of need in sufficient capacity to meet several years of need. We add new generic natural gas/dual-fuel capable combined cycle and gas turbine plants in each region as necessary to maintain resource adequacy. . The operating characteristics of these new plants are assumed to be the same as recently built natural gas generating units. The units were placed on the high-voltage transmission network in each region to maximize deliverability.

### *Emissions costs*

We developed our base case CO<sub>2</sub> price forecast using the most recent RGGI auction results of \$6.02/ton, and assume that prices increase by 2.5 percent in real terms each year, proportional to the decline in the RGGI allowance cap. NO<sub>x</sub> and SO<sub>2</sub> allowance prices are based on Ventyx price forecasts.

### *Load Forecasts*

Regional Transmission Operator (RTO) level load forecasts are provided by Ventyx, and based on RTO planning documents. ISO-NE data is based on EE-adjusted load from the 2015 CELT Report. PROMOD hourly load shapes were reviewed and calibrated to ensure consistency with seasonal peak demands identified by ISO-NE. NYISO data is based on EE- and PV- adjusted load from the 2014 Gold Book. PJM data is based on EE-unadjusted load from the 2014 PJM Load Forecast Report.

For the energy efficiency solution sets, total energy savings from each program type were divided among summer and winter on-peak and off-peak hours. This distribution of total savings was based on historical data from the final 2013-2015 Massachusetts Program Administrators report. From these load groupings, hourly state savings for each year were determined and modeled in each zone. Total state load savings were proportionally assigned to constituent service areas based on native load in each area.

#### 4. Greenhouse Gases and Regional Climate Goals

Greenhouse gas emissions levels across all sectors for 1990 are based on state-reported historical emissions estimates. “Current” GHG emissions levels are based on state-reported historical emissions estimates, where available, and on business as usual projections otherwise. These “current” emissions levels reflect 2011 emissions levels, the most recent year of estimates available across the largest number of states, and emissions levels for adjacent years otherwise. Specifically, 2010 emissions levels are used for Rhode Island and 2012 business as usual estimates are used for New Hampshire.

Sector-specific emissions levels are based on explicitly labeled emissions categories, except for building emissions, which when not explicitly labeled are calculated as the difference between total emissions and the sum of non-energy, transportation, and electric-sector emissions.

Greenhouse gas emissions targets reflect state-reported emissions goals, illustrated in Table A5. We converted those goals, which are typically reported as a percentage reduction in emissions from baseline levels, to million metric tons of CO<sub>2</sub>-equivalent (MMTCO<sub>2</sub>e) limits using baseline emissions levels and given percentage reductions. Emissions goals are not available for each New England state in every year of interest, so emissions targets used in this report are based on actual values in available years and linearly interpolated values otherwise.

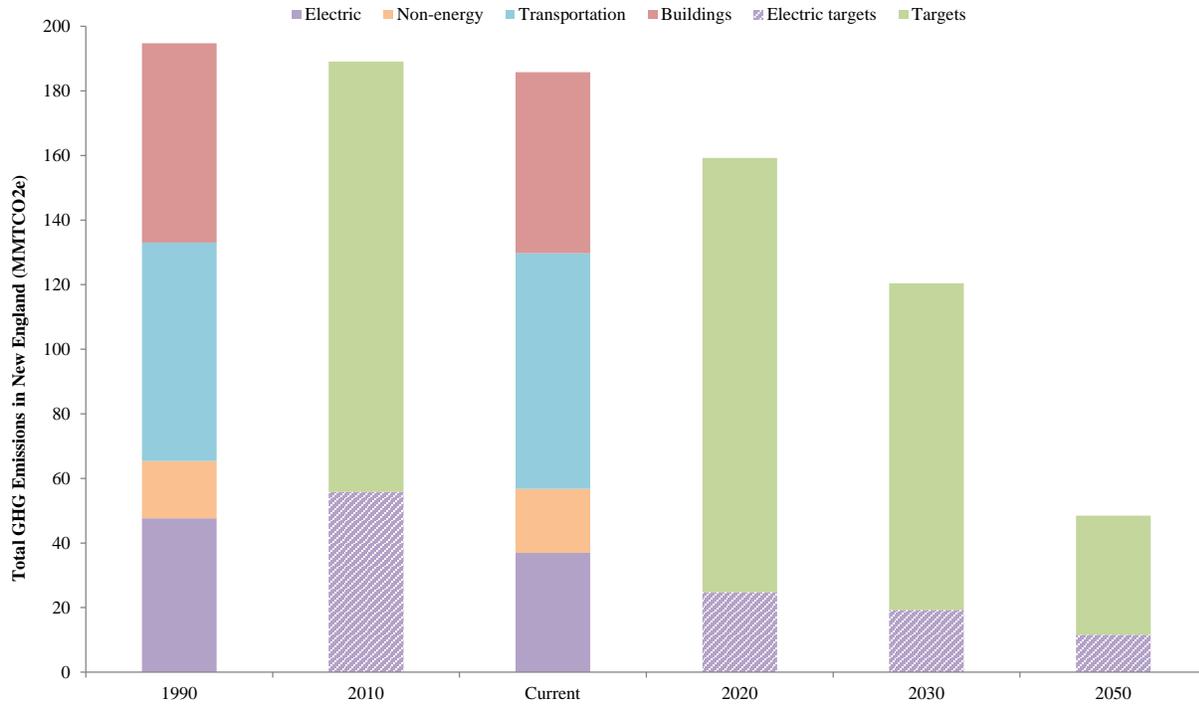
**Table A5: Summary of State GHG Goals**

State	Title of GHG Emissions Reduction	Type of GHG Emissions Reduction	Date of Adoption	GHG Emissions Milestone
Connecticut	Public Act No. 08-98	Action Plan followed by Legislation	Action Plan: 02/15/2005 Legislation: 10/01/2008	2010: Reduce to 1990 Levels 2020: 10% Below 1990 Levels 2050: 80% Below 2001 Levels
Maine	PL 237	Legislation (Includes Request for an Action Plan)	Legislation: 09/13/2003 Action Plan: 12/01/2004	2010: Reduce to 1990 Levels 2020: 10% Below 1990 Levels
Massachusetts	Global Warming Solutions Act	Climate Protection Plan followed by Legislation	Protection Plan: 05/01/2004 Legislation: 08/01/2008	2020: 25% Below 1990 Levels 2050: 80% Below 1990 Levels
New Hampshire	New Hampshire Climate Action Plan	Action Plan	03/01/2009	2025: 20% Below 1990 Levels 2050: 80% Below 1990 Levels
Rhode Island	RI Executive Climate Change Coordinating Council	Legislation (Includes Request for an Action Plan)	05/01/14	2020: 10% Below 1990 Levels 2035: 45% Below 1990 Levels 2050: 80% Below 1990 Levels
Vermont	Executive Order #07-05	Legislation (Includes Request for an Action Plan)	Legislation: 12/05/2005 Action Plan: 10/26/2007	2012: 25% Below 1990 Levels 2028: 50% Below 1990 Levels 2050: 75% Below 1990 Levels

Source: Individual State Planning Documents

As part of our review, we compared estimated electric sector reductions to an assumed continuation of the RGGI CO<sub>2</sub> emissions caps and the mass based standard for new and existing generation under the Federal EPA Clean Power Plan. We found that assumed RGGI limits are consistent with assumed 2030 electric sector targets imputed from state-level greenhouse gas emissions targets and state-reported GHG action plans and also allow for a trajectory of emissions out to 2050 consistent with full state climate goals. Figure A2 illustrates the total greenhouse gas emissions and targets in New England, with the electric sector represented by the potential RGGI allowance targets.

**Figure A2: Total Greenhouse Gas Emissions and Potential Targets, New England**



**Notes:**

1. Emissions goals based on actual values in available years and linearly interpolated values otherwise.
2. Current levels of greenhouse gas emissions are based on 2011 where available and adjacent years where 2011 is unavailable.
3. Building emissions, when not explicitly specified on the state level, are calculated as the difference between total emissions and the sum of non-energy, transportation and electric emissions.

#### Sources used in Appendix 4:

1. "Public Act No. 08-98: An Act Concerning Global Warming Solutions (Global Warming Solutions Act)," State of Connecticut, available at <https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm>, retrieved on August 19, 2015.
2. "Connecticut Greenhouse Gas Emissions Inventory 2012: Executive Summary," Connecticut Department of Energy and Environmental Protection, available at [http://www.ct.gov/deep/lib/deep/climatechange/2012\\_ghg\\_inventory\\_2015/2012\\_ct\\_ghg\\_inventory\\_final.pdf](http://www.ct.gov/deep/lib/deep/climatechange/2012_ghg_inventory_2015/2012_ct_ghg_inventory_final.pdf) retrieved on August 27, 2015.
3. "A Climate Action Plan for Maine," Department of Environmental Protection, December 1, 2004, available at <http://www.eesi.org/files/MaineClimateActionPlan2004Volume%201.pdf>, retrieved on August 19, 2015.
4. "Fifth Biennial Report on Progress Toward Greenhouse Gas Reduction Goals," Maine Department of Environmental Protection, January 2014, available at <http://www.maine.gov/tools/whatsnew/attach.php?id=611577&an=1>, retrieved on August 19, 2015.
5. "Commonwealth of Massachusetts Global Warming Solutions Act 5 Year Progress Report," Commonwealth of Massachusetts, December 30, 2013, available at <http://www.mass.gov/eea/docs/eea/gwsa/ma-gwsa-5yr-progress-report-1-6-14.pdf>, retrieved on August 27, 2015.
6. "Annual & Three-Year Greenhouse Gas Emissions Inventories," Massachusetts Energy and Environmental Affairs, available at <http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/greenhouse-gas-ghg-emissions-in-massachusetts.html>, retrieved on August 12, 2015.
7. "The New Hampshire Climate Action Plan," NH Department of Environmental Services, March 2009, available at [http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action\\_plan/nh\\_climate\\_action\\_plan.htm](http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/nh_climate_action_plan.htm), retrieved on August 13, 2015.
8. "S 2952 Substitute A: An Act Relating to State Affairs and Government – Climate Change," State of Rhode Island, May 1, 2014, available at <http://www.planning.ri.gov/documents/climate/S2952A.pdf>, retrieved on August 14, 2015.
9. "2010 RI Greenhouse Gas Emissions Inventory," Rhode Island Department of Environmental Management, available at <http://www.dem.ri.gov/climate/pdf/gginv2010.pdf>, retrieved on August 14, 2015.
10. "Vermont Executive Order #07-05," Vermont Governor's Commission on Climate Change, December 5, 2005, available at <http://www.anr.state.vt.us/anr/climatechange/Pubs/GCCC%20Appendix%201.pdf>, retrieved on February 27, 2014.
11. "Vermont Greenhouse Gas Emissions Inventory Update 1990 - 2012," Vermont Department of Environmental Conservation, June 2015, available at [http://www.anr.state.vt.us/anr/climatechange/Pubs/Vermont%20GHG%20Emissions%20Inventory%20Update%201990-2012\\_June%20-2015.pdf](http://www.anr.state.vt.us/anr/climatechange/Pubs/Vermont%20GHG%20Emissions%20Inventory%20Update%201990-2012_June%20-2015.pdf), retrieved on August 14, 2015.
12. "First Control Period CO2 Allowance Allocation ", RGGI, Inc., July 2015, available at <http://www.rggi.org/design/overview/allowance-allocation/2009-2011-allocation>, retrieved on September 4, 2015.
13. "Summary Level Emissions Report," RGGI, Inc., August 31, 2015, available at [https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi\\_summary\\_report\\_input&clearfuseattribs=true](https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi_summary_report_input&clearfuseattribs=true), retrieved on September 3, 2015.

[ This Page Intentionally Left Blank ]

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 5**, Press Release,  
Mass Attorney General's office, AG Study: Increased Gas  
Capacity Not Needed to Meet State's Electric Reliability  
Needs, November 18, 2015.



## Attorney General Maura Healey

[Home](#) > [News and Updates](#) > [Press Releases](#) > [2015](#) > [AG Study: Increased Gas Capacity Not Needed](#)

MAURA HEALEY  
ATTORNEY GENERAL

For Immediate Release - November 18, 2015

### Media Contact

Chloe Gotsis  
(617) 727-2543

## AG Study: Increased Gas Capacity Not Needed to Meet State's Electric Reliability Needs

### Study Finds No Regional Electric Reliability Issues Through 2030; Cheaper, Cleaner Alternatives to New Gas Pipeline to Meet Worst Case Power Scenarios

**BOSTON**— Attorney General Maura Healey today announced that a [study](#) commissioned by her office has determined that the region is unlikely to face electric reliability issues in the next 15 years and additional energy needs can be met more cheaply and cleanly through energy efficiency and demand response.

The [study](#)  1MB was designed to, first, determine whether the region is facing electric reliability challenges through 2030 and, second, identify the most cost-effective and clean solutions for addressing any of those challenges.

“As we make long-term decisions about our energy future, it’s imperative we have the facts,” said AG Healey. “This study demonstrates that we do not need increased gas capacity to meet electric reliability needs, and that electric ratepayers shouldn’t foot the bill for additional pipelines. This study demonstrates that a much more cost-effective solution is to embrace energy efficiency and demand response programs that protect ratepayers and significantly reduce greenhouse gas emissions.”

The [study](#)  conducted by the Analysis Group over the last three months and guided by a [Study Advisory Group](#), found that through 2030 the region’s power system reliability will be maintained during our coldest winter months. The study used extremely conservative assumptions, including applying winter conditions from 2004 (one of the coldest years in two decades).

Analysts also modeled a worst case scenario under which New England becomes even more reliant on natural gas power than expected, *and* experiences a short-term disruption in other fuels, causing the electric system to be more stressed than expected on very cold days. Under those conditions, the study determined that the region could need roughly 2,400 MW for a few hours across nine very cold days by 2029/2030. That is the energy-equivalent of an additional 0.42 billion cubic feet per day of new gas capacity.

To solve that deficiency, the study evaluated several options including 1) reliance on incremental dual fuel-power plants (the status quo), 2) a higher reliance on firm liquefied natural gas (LNG), 3) incremental natural gas capacity, 4) energy efficiency and demand response, 5) energy efficiency and low-carbon imports on existing transmission, and 6) energy efficiency and low-carbon imports with new transmission. Solutions were compared to the status quo and evaluated for both their costs/savings for ratepayers and their impacts on New England’s greenhouse gas (GHG) emissions.

The study concluded that all of the solutions would ensure the reliability of the electric system in a worst case scenario. However, investment in energy efficiency and demand response would result in the greatest customer savings and would reduce GHG emissions. New gas pipelines infrastructure would result in less customer savings and would actually drive up GHG emissions. Energy efficiency combined with firm low carbon imports on existing transmission lines would also save customers money and would produce the greatest reduction in GHG emissions.

The study also reviewed two “infrastructure scenarios” – first, an oversized pipeline (new 0.5 Bcf/day natural gas pipeline in service in 2020), which would bring customer savings, but significantly increase GHG emissions; second, low carbon imports (2400 MW in-service in 2020 over existing and new transmission lines) which was the only alternative studied that would meet the region’s climate goals by 2030, but was the most expensive studied alternative.

The study accounted for recent news that Pilgrim Nuclear Power Plant is scheduled to shut down no later than June 2019, resulting in the loss of 680 MW of non-GHG emitting power.

Also today, Attorney General Healey provided a copy of the study to the Federal Energy Regulatory Commission for its consideration as part of the federal review of the Kinder Morgan Northeast Energy Direct pipeline project.

The study was made possible by grants from the Barr Foundation and the John Merck Fund.

#####



**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 6, Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? Synapse Energy, September 12, 2016.**

---

# Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary?

An examination of the need for additional  
pipeline capacity into Virginia and Carolinas

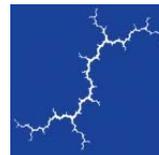
---

**Prepared for Southern Environmental Law Center and  
Appalachian Mountain Advocates**

September 12, 2016

## AUTHORS

Rachel Wilson  
Spencer Fields  
Patrick Knight  
Ed McGee  
Wendy Ong  
Nidhi R. Santen, PhD  
Thomas Vitolo, PhD  
Elizabeth A. Stanton, PhD



**Synapse**  
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2  
Cambridge, Massachusetts 02139

617.661.3248 | [www.synapse-energy.com](http://www.synapse-energy.com)

---



# CONTENTS

- EXECUTIVE SUMMARY ..... 1**
  - Future demand for natural gas..... 1
  - Future natural gas supply ..... 2
  - Result: Natural gas supply exceeds peak demand ..... 3
  - Assessing the need for pipeline investment ..... 4
  
- 1. INTRODUCTION ..... 5**
  
- 2. FUTURE DEMAND FOR NATURAL GAS ..... 6**
  - 2.1. Pipeline Developer Assessment of Need ..... 6
  - 2.2. Estimates of Peak Demand for Natural Gas..... 10
  
- 3. ANTICIPATED NATURAL GAS SUPPLY ON EXISTING AND UPGRADED INFRASTRUCTURE ..... 11**
  - 3.1. Existing Pipelines..... 13
  - 3.2. Natural Gas Storage..... 15
  - 3.3. Planned Reversals and Expansions of Existing Pipelines..... 16
  
- 4. NATURAL GAS SUPPLY EXCEEDS DEMAND..... 17**
  
- APPENDIX A: NON-ELECTRIC DEMAND METHODOLOGY AND DATA SOURCES..... 19**
  
- APPENDIX B: ELECTRIC DEMAND METHODOLOGY AND DATA SOURCES ..... 23**
  
- APPENDIX C: WINTER PEAK MODELING ..... 26**

## EXECUTIVE SUMMARY

The Southern Environmental Law Center and Appalachian Mountain Advocates retained Synapse Energy Economics, Inc. (Synapse) to determine whether proposed new interstate pipelines that would deliver natural gas from West Virginia to Virginia and the Carolinas are necessary to maintain adequate gas supply to the region. Two new interstate pipelines have been proposed to transport natural gas from the Marcellus Shale into Virginia and the Carolinas:

- 1) Atlantic Coast Pipeline (proposed by Dominion Pipeline, Duke Energy, Piedmont Natural Gas, and AGL Resources); and
- 2) Mountain Valley Pipeline (proposed by EQT Midstream Partners, NextEra US Gas Assets, WGL Midstream, and Vega Midstream MVP).

In their proposals, the developers of these projects assert that subscription rates for pipeline capacity demonstrate the need for additional natural gas in the target region, but they fail to compare the region's existing natural gas supply capacity to its expected future peak demand for natural gas. We undertake that comparison in this report. In the analysis presented here Synapse finds that, in fact, given existing pipeline capacity, existing natural gas storage, the expected reversal of the direction of flow on the existing Transco pipeline, and the expected upgrade of an existing Columbia pipeline, the supply capacity of the Virginia-Carolinas region's existing natural gas infrastructure is more than sufficient to meet expected future peak demand. This result raises significant questions about the need for additional investment in new interstate natural gas pipelines in the region and, more generally, the utility of pipeline subscription rates as justification for these projects.

### Future demand for natural gas

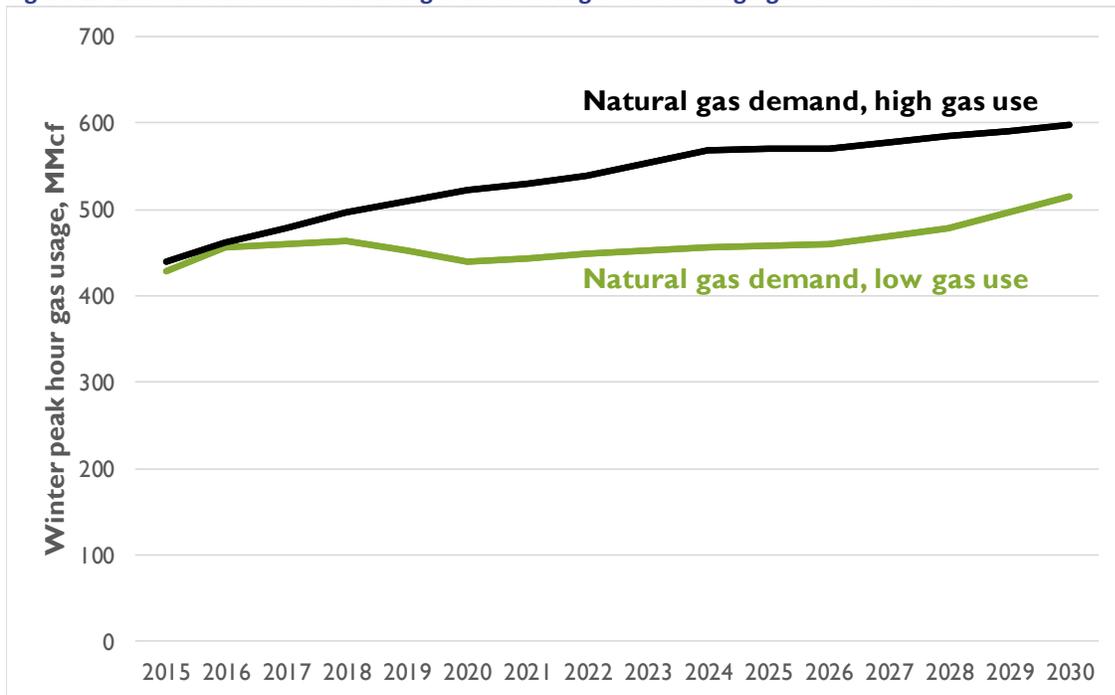
Synapse developed low and high scenarios of future natural gas use for the study region, defined as Virginia, North Carolina, and South Carolina, to identify the expected range of likely demand for natural gas. Both low and high scenarios comply with the U.S. Environmental Protection Agency's limits for carbon dioxide emissions under the Clean Air Act. These limits consist of two separate regulations under Section 111(b) (Carbon Pollution Standards), which establishes federal standards for new, modified, and reconstructed power plants, and Section 111(d) (Clean Power Plan), which establishes state-based standards for existing power plants. While the demand for energy services is the same in each scenario, the low gas use scenario assumes greater energy efficiency savings and a more rapid build out of renewable generating facilities while the high gas use scenario assumes a greater number of retirements of coal-fired generating units and the use of new and existing natural gas-fired generators to meet emission goals.

In the high gas use scenario, renewable capacity and savings from energy efficiency in each state are determined by individual Renewable Portfolio Standards and Energy Efficiency Resource Standards. North Carolina is the only state in our study region with a Renewable Portfolio Standard, so its renewable capacity increases to meet its targets. Otherwise, renewable capacity and energy efficiency



savings remain relatively constant in the high gas use scenario throughout the study period. Natural gas is used to meet Clean Power Plan targets, thus representing the outer bound of likely future natural gas demand. For both scenarios, Synapse estimated the highest combined electric and non-electric natural gas demand in any hour of the year in order to compare this “peak hour” value to the region’s anticipated supply capacity of natural gas. If the region’s natural gas infrastructure can supply sufficient gas during the peak hour of greatest demand, then there should be no obstacle to supplying gas during the rest of the year. Figure ES-1 shows the peak demand for natural gas in each year during the study period for the low gas use and high gas use scenarios.

**Figure ES-1. Peak demand for natural gas in the low gas use and high gas use scenarios**



## Future natural gas supply capacity

In Virginia and the Carolinas, peak demand for natural gas is satisfied by the combination of several different types of supply capacity, notably:

- Existing pipelines:** The existing pipelines belonging to Transco, Cove Point, Columbia Gas Transmission, Dominion Transmission, Southern Natural Gas, South Carolina PL Corporation, East Tennessee Natural Gas, Nora Transmission, and Bluefield Gas have the capacity to supply just over 300 MMcf per hour into the study region.
- Reported natural gas storage:** Storage is an essential part of every natural gas supply system and plays a critical role in meeting peak demand. Reported liquefied natural gas (LNG) and underground natural gas storage in the region has the capacity to supply 71 MMcf per hour. Not all owners of natural gas infrastructure are required to report storage capacity, so the region’s maximum or actual natural gas storage is not known.

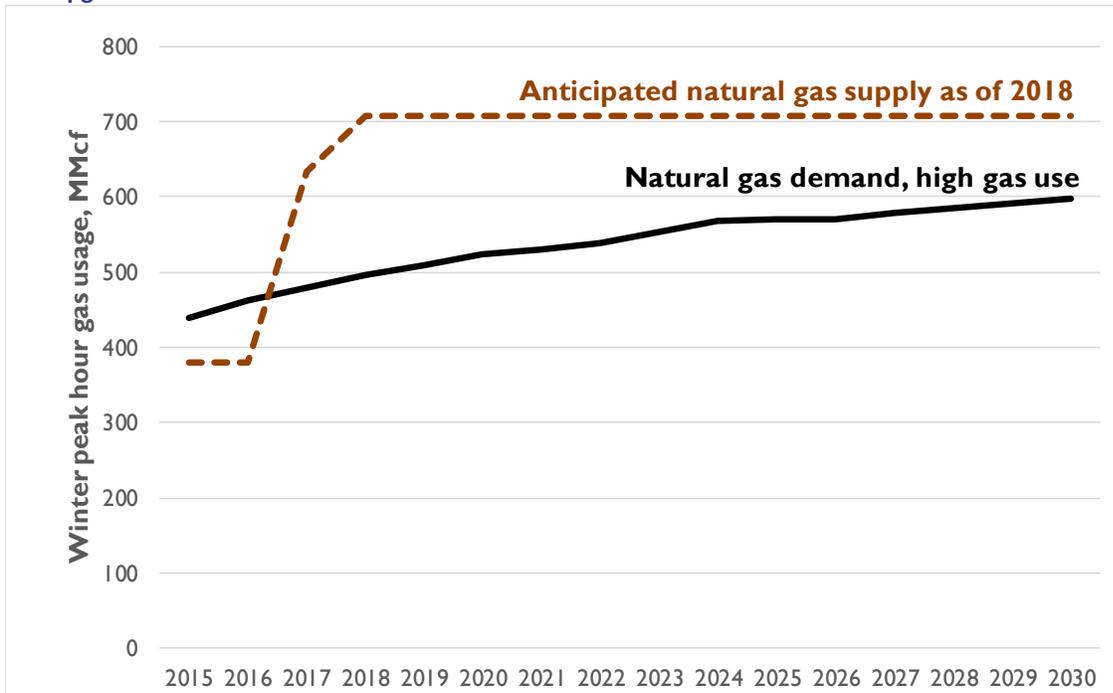
The “reported” storage value used in this analysis is, therefore, a conservative assumption and, indeed, is lower than the minimum amount of regional storage that existed in 2015 (that is, the difference between pipeline capacity and peak hour demand).

- Expected reversals and upgrades of existing pipelines:** The reversal of the Transco Mainline pipeline as part of the Atlantic Sunrise project has been proposed before the Federal Energy Regulatory Commission (FERC) and is expected to add the capacity to supply 254 MMcf per hour to the study region in 2017 (changing the export of 127 MMcf to an import of 127 MMcf, for a net change of 254 MMcf). The WB Xpress project, an upgrade to an existing pipeline proposed by Columbia Gas, would add an additional 73 MMcf per hour to the region beginning in 2018.

### Result: Natural gas supply capacity exceeds peak demand

Figure ES-2 compares maximum expected natural gas demand (peak-hour demand in our high gas scenario) in years 2015 through 2030 to anticipated natural gas supply capacity on existing and upgraded infrastructure, including existing pipelines, reported storage, the 2017 reversal of the Transco Mainline pipeline, and the 2018 WB Xpress project. (Note that reported supply capacity is lower than actual peak hour demand in 2015 and 2016: In all likelihood, the gap in capacity to serve actual peak was supplied by natural gas storage facilities that are not reported in publicly available data sources.)

**Figure ES-2. Maximum peak hour natural gas demand compared to anticipated natural gas supply on existing and upgraded infrastructure**



For Virginia and the Carolinas, the anticipated natural gas supply capacity on existing and upgraded infrastructure is sufficient to meet maximum natural gas demand from 2017 through 2030: Additional interstate natural gas pipelines, like the Atlantic Coast and Mountain Valley projects, are not needed to keep the lights on, homes and businesses heated, and existing and new industrial facilities in production. This assessment of sufficient supply capacity includes only reported storage capacity, ignoring the existence of additional unreported storage capacity demonstrated by recent years' peak hour demand.

## **Assessing the need for pipeline investment**

Interstate transmission pipeline infrastructure serving Virginia and the Carolinas is part of an interconnected system that includes pipeline and storage capacity both inside and outside of the region. Considering each new pipeline proposal as an isolated project ignores important alternatives that would increase regional natural gas supply capacity and avoid the adverse impacts on communities or the environment that can result from new construction. Alternatives to new pipeline construction include:

- Projects that reverse the flow of the Transco pipeline will lead to a significant increase in natural gas capacity in the Virginia and Carolinas region, and make new interstate transmission infrastructure (e.g., the proposed Atlantic Coast Pipeline and the Mountain Valley Pipeline) unnecessary to serve the market in Virginia and the Carolinas. Reversal of the Transco pipeline is one component of the proposed Atlantic Sunrise project.
- Investment in additional storage facilities may be a more cost-effective solution to boosting natural gas supply capacity in those few hours of the year where concerns exist regarding supply constraints.
- New or accelerated measures for gas energy efficiency, electricity energy efficiency, demand response (programs that pay large electric consumers to shift demand off of peak hours), and investment in renewable generating resources are critical tools to lower both annual and peak demand for natural gas.

To safeguard public interests, a determination of need for new pipeline infrastructure requires a detailed, integrated analysis of natural gas supply capacity and demand for the region as a whole.



# 1. INTRODUCTION

Two new interstate pipelines have been proposed to transport natural gas from West Virginia into Virginia and the Carolinas: 1) Atlantic Coast Pipeline (proposed by Dominion Pipeline, Duke Energy, Piedmont Natural Gas, and AGL Resources); and 2) Mountain Valley Pipeline (proposed by EQT Midstream Partners, NextEra US Gas Assets, WGL Midstream, and Vega Midstream MVP).<sup>1</sup> The developers of both projects assert that these pipelines are necessary to meet regional energy demand now and in the future.

Interstate transmission pipeline infrastructure serving Virginia and the Carolinas is part of an interconnected system that includes natural gas pipeline and storage capacity both inside and outside of the region. For a pipeline developer to establish that a new interstate pipeline is necessary, it would need to demonstrate that existing natural gas capacity in Virginia and the Carolinas region is not sufficient to provide enough gas to meet the demand over the course of a year or—more importantly—in the peak winter hour. For such a demonstration to be defensible, it would be necessary to base estimates of future capacity and demand of natural gas on detailed modeling of both the non-electric and electric sectors. If there were evidence of a capacity shortage in the model, it would likely present itself through higher natural gas prices and resulting higher electricity prices and/or through modeled results showing curtailment of natural gas-fired generators.

The developers of the Atlantic Coast and Mountain Valley proposal development projects assert that these pipelines are necessary to meet regional energy demand. Synapse conducted an independent examination of the validity of these statements by analyzing public documents relating to the proposed and existing natural gas infrastructure, and performing a modeling analysis of projected natural gas demand. We conducted our analysis in four steps:

- Estimation of winter peak non-electric demand in our study region
- Development of two scenarios of demand for natural gas in the electric sector and low, reference, and high sensitivity assumptions regarding the price of natural gas
- Assessment of future natural gas supply in our study region
- Analysis of balance between natural gas capacity and demand during the winter peak hour

Section 2 of this report provides an overview of the ways in which pipeline developers have assessed the need for their projects in the filings submitted to the Federal Energy Regulatory Commission. It then describes our own estimates of future peak demand for natural gas.

---

<sup>1</sup> Note that a third pipeline, the Appalachian Connector Pipeline, has also been proposed by the Williams Company but the necessary application and supporting materials have not yet been filed with the Federal Energy Regulatory Commission.

Section 3 describes existing natural gas capacity infrastructure and anticipated future supply.

Section 4 compares existing and projected natural gas supply with natural gas demand during the winter peak for each modeled year.

Finally, three appendices present detailed modeling assumptions and results:

- Appendix A presents the methodology used to estimate non-electric demand.
- Appendix B presents the methodology used to estimate demand from the electric sector.
- Appendix C presents the methodology used to develop the estimates of winter peak natural gas use in the ReEDS model.

## **2. FUTURE DEMAND FOR NATURAL GAS**

A determination of need for incremental pipeline capacity in the Virginia-Carolinas region requires a projection of future demand for natural gas from non-electric (residential, commercial, and industrial) and electric end uses. Residential and commercial use of natural gas is primarily for space and water heating and thus peaks annually in the winter when temperatures are lower. Industrial use often stays consistent from month to month. Regional use of natural gas for electric generation has historically been summer peaking; however, a slight decline in summer gas use in the past year, combined with an increase in winter gas demand, has resulted in similar gas consumption levels in the electric sector for both summer and winter peaks. As a result, when we combine the non-electric and electric uses for natural gas, we find that the “ultimate system peak,” or hour of maximum natural gas demand, occurs in the winter. In order to ensure adequate supply to consumers, local distribution companies must be able to procure enough natural gas to reliably meet this ultimate system peak.

In their filings with the Federal Energy Regulatory Commission (FERC), pipeline developers must demonstrate that a market need exists for each of the proposed new pipelines, which should include detailed forecasts of expected end-use demand in the region. However, as described below, the developers’ assessments of need rely primarily on Energy Information Administration (EIA), the statistical and analytical agency within the United States Department of Energy, projections of growth in natural gas used for electric generation.

### **2.1. Pipeline Developer Assessment of Need**

The developers of the new natural gas pipelines proposed to run through Virginia and the Carolinas assert that their projects are necessary to meet future energy needs. Under Section 7(c) of the Natural Gas Act of 1938, FERC has jurisdiction over pipeline infrastructure and is authorized to issue certificates of “public convenience and necessity” for “the construction or extension of any facilities...for the



transportation in interstate commerce of natural gas.” FERC’s decision to grant or deny a pipeline certificate is based upon a determination of whether the pipeline project would be in the public interest. The agency accounts for several factors, including a project’s potential impact on pipeline competition, the possibility of overbuilding, subsidization by existing customers, potential environmental impacts, avoidance of the unnecessary use of eminent domain, and other considerations. This determination relies heavily on a demonstrated market need for the proposed new pipeline. FERC requires assessments of the need for new natural gas supply in the study region. Those assessments, which reside in the *Resource Report 1* documents filed by the developers, are summarized below.

## Atlantic Coast Pipeline

The developers of the Atlantic Coast Pipeline attribute the need for the pipeline largely to their expectation of growth in future electric demand from natural gas generation. The developers cite data from EIA and the U.S. Census Bureau, stating that natural gas demand for all uses in Virginia and North Carolina has grown by 37 and 50 percent, respectively, between 2008 and 2012.<sup>2</sup> The pipeline’s developers claim that “demand for natural gas in Virginia and North Carolina is expected to increase in coming decades due to a combination of population growth and displacement of coal-fired electric power generation.”<sup>3</sup> They use the U.S. Census Bureau prediction that between 2000 and 2030, Virginia’s population will grow by 2.7 million residents and North Carolina’s by 4.2 million residents.<sup>4</sup> They also state that coal plant retirements and low natural gas prices will cause natural gas to surpass coal as the most common fuel for electric power generation in the region by 2035.<sup>5</sup>

The Atlantic Coast Pipeline developers commissioned a study from ICF International showing a scenario in which between 2019 and 2038 approximately 9,900 megawatts (MW) of coal and nuclear generating capacity in Virginia and North Carolina will retire, while the region builds 20,200 MW of new natural gas capacity. As a result, ICF predicts that demand for natural gas for electric power generation in the two states will “grow 6.3 percent annually between 2014 and 2035, increasing from 1 Bcf/d (billion cubic feet per day) to 3.7 Bcf/d.”<sup>6</sup>

In April 2014, Duke Energy and Piedmont issued a request for proposals in North Carolina for incremental pipeline transportation service, citing their “existing and future natural gas generation requirements, core load growth, and system reliability and diversity goals.”<sup>7</sup> Virginia Power Services Energy Corp, Inc. issued a similar request to serve Virginia. These companies contracted for

---

<sup>2</sup> Natural Resource Group. 2015. *Draft Resource Report 1: General Project Description*. Prepared for Atlantic Coast Pipeline, LLC Docket No. PF15-6-000 and Dominion Transmission, Inc. Docket No PF15-5-000. Available online at: <https://www.dom.com/library/domcom/pdfs/gas-transmission/atlantic-coast-pipeline/acp-shp-rr1-1.pdf>.

<sup>3</sup> Ibid.

<sup>4</sup> Ibid.

<sup>5</sup> Ibid.

<sup>6</sup> Ibid, page 1-5.

<sup>7</sup> Ibid, page 1-5.

transportation service on the Atlantic Coast Pipeline, along with other companies in the region. According to the pipeline’s developers, “over 90 percent of the new pipeline system’s capacity has been contracted for in binding precedent agreements with major utilities and local distribution companies...(and) (t)he ACP [Atlantic Coast Pipeline] is not designed to export natural gas overseas; this is not a component of the purpose and need of the ACP.”<sup>8</sup>

## Mountain Valley Pipeline

The assessment of need from the developers of the Mountain Valley Pipeline has fewer details, though they also base their needs assessment on their expectation of growth in electric power generation from natural gas. Developers state that the EIA predicts total U.S. natural gas consumption will increase from 25.6 trillion cubic feet in 2012 to 31.6 trillion cubic feet in 2040, with much of this increase in demand coming from the electric sector.<sup>9</sup> Developers also state that “the increased demand for natural gas is expected to be especially high in the southeastern United States, as coal-fired generation plants convert to or are replaced by natural gas fired generation plants. The infrastructure design of the Project is expected to benefit these regions by connecting the production supply to the market demand.”<sup>10</sup> Finally, according to the developers, “MVP [Mountain Valley Pipeline] may also support additional uses of natural gas in south central West Virginia and southwest Virginia by providing an open access pipeline that can facilitate interconnects and subsequent economic development associated with having access to affordable gas supplies, as these areas currently have limited interstate pipeline capacity.”<sup>11</sup> The Mountain Valley Pipeline reports that it has secured 20-year commitments for firm transportation capacity for its full capacity, though the amount of gas that will be contracted for has not been reported at this time.<sup>12</sup>

## Summary

The assessment of need from the developers of these proposed pipelines rely entirely on the expectation that there will be significant growth in regional natural gas use for electric power generation over the next 20 years. Developers expect that the Atlantic Coast Pipeline and Mountain Valley Pipeline will primarily (1) serve new natural gas-fired electric generating units constructed to replace retiring coal units or (2) meet growing electric demand in Virginia and North Carolina. Both pipeline developers rely on projections of electric demand and infrastructure additions from the EIA; however, the EIA has

---

<sup>8</sup> Ibid, page 1-7.

<sup>9</sup> Mountain Valley Pipeline Project. 2015. *Resource Report 1 – General Project Description*. Prepared for Docket No. PF-15-3. Available online at: <http://www.mountainvalleypipeline.info/current-news>.

<sup>10</sup> Ibid.

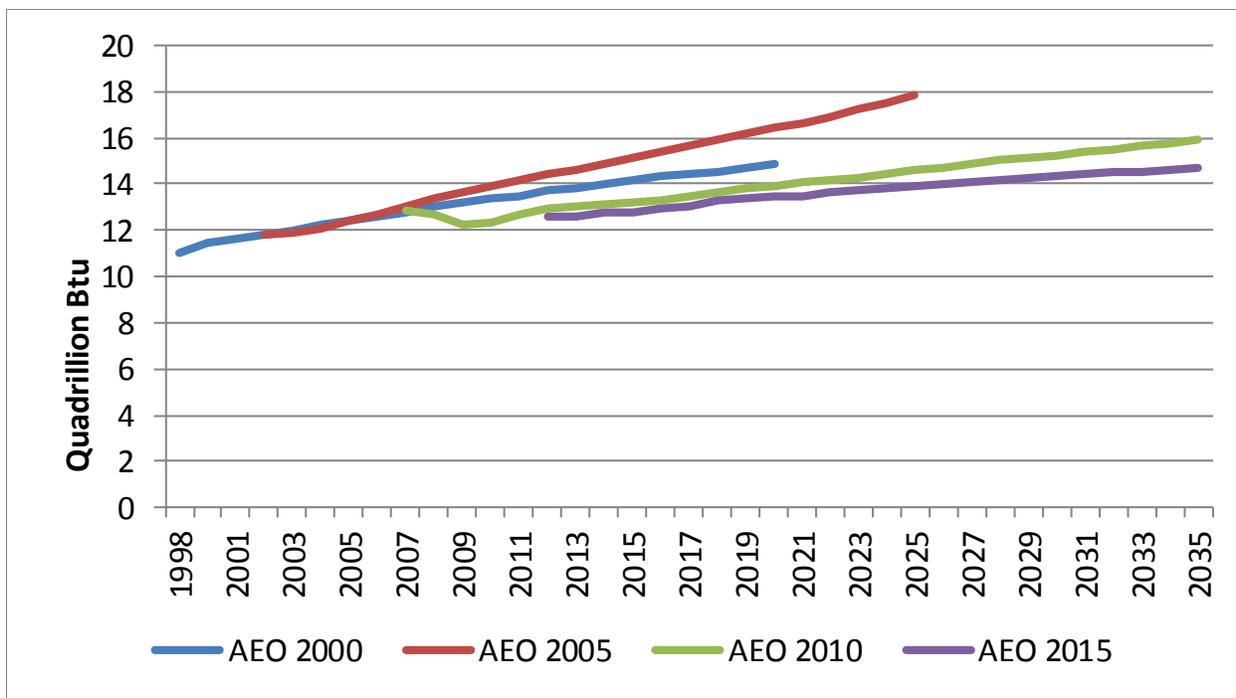
<sup>11</sup> Ibid.

<sup>12</sup> Business Wire. 2016. *Mountain Valley Pipeline Secures New Shipper Commitment with Con Edison*. Available online at: <http://www.businesswire.com/news/home/20160122005701/en/Mountain-Valley-Pipeline-Secures-Shipper-Commitment-Con>



revised its forecasts of electricity consumption steadily downward over the last 15 years, as shown in Figure 1.

**Figure 1. Historic EIA forecasts of electricity consumption, as published in the Annual Energy Outlook (AEO)**



Pipeline developers also rely on subscription rates as a demonstration of need for new pipeline capacity. However, many of the customers that have contracted for capacity on these proposed pipelines are affiliates or subsidiaries of the pipeline owners, and are regulated utilities that pass pipeline costs to consumers through rates.

Of the two proposed pipeline developers that have filed an assessment of need, only the Atlantic Coast Pipeline developer did a modeling study to quantify the projected increase in natural gas demand. Neither developer assessed current and projected pipeline and storage capacity in the region to determine whether it is adequate to meet a projected increase in natural gas demand.

### Pipeline Economics

Insufficient capacity to meet expected future natural gas demand is not the only reason that may explain proposals to develop new natural gas pipelines. Reasons for private investors to advance proposals for new natural gas supply infrastructure also include:

- A secure return on investment:** Guaranteed—or otherwise very secure—avenues for returns on investments in natural gas pipelines are possible if utilities receive legislative, utility commission, or FERC approval to recover pipeline expenditures from gas or electric customers. These returns are, at time, higher than those for other investment opportunities.

- **Market benefits from lower or higher natural gas prices:** Large corporations with diverse holdings may take actions that depress or inflate the price of natural gas. These actions may have complex benefits in other related markets such as providing a stimulus for additional fuel switching to natural gas.
- **Commitment to the future of natural gas:** For corporations with both deep and wide-spread investments in the future of natural gas, actions to further entrench public energy infrastructure in this fuel may have long-run benefits unrelated to meeting current or near-future demand.
- **Interplay between market competitors:** Companies that have the development of natural gas pipelines as a core business area may propose pipelines early—before their competitors—as part of a long-run strategy to protect their market share.
- **Overseas exports:** The expected rapid expansion of U.S. exports of liquefied natural gas (LNG) over the next five to ten years will require sufficient infrastructure to deliver natural gas to existing and proposed LNG terminals. Pipeline developers that are confident that demand for U.S. LNG exports is on the rise have an additional motivation to expand their ownership interests in natural gas supply infrastructure.

## 2.2. Estimates of Peak Demand for Natural Gas

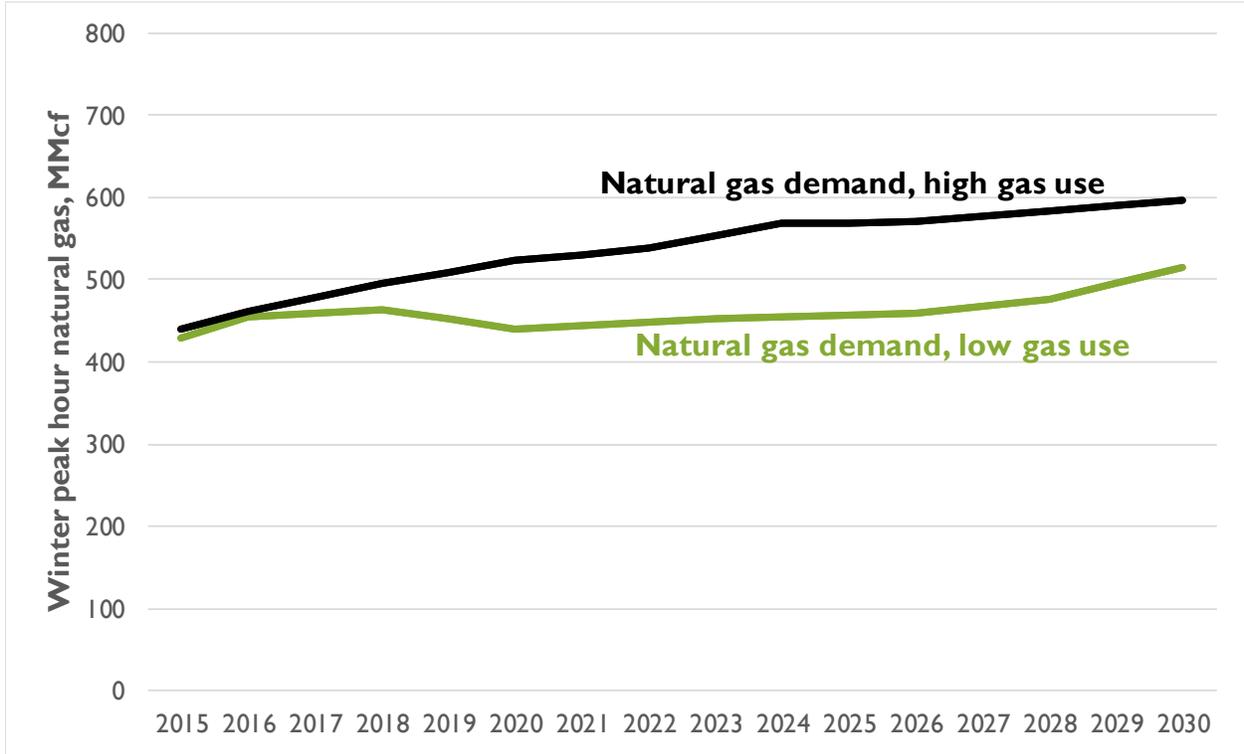
Synapse projected peak demand for natural gas in Virginia and the Carolinas from 2015 to 2030. This projection had two components: non-electric natural gas demand and demand for natural gas from the electric sector. Forecasts of non-electric demand for natural gas reflect demand projections from natural gas suppliers in the Virginia-Carolinas region under a single scenario, commonly referred to as the “design-day” forecast. However, demand for natural gas from the electric sector is highly dependent upon the compliance pathway that each state decides to pursue to meet its individual reduction targets for emissions of carbon dioxide (CO<sub>2</sub>) as established under the Clean Air Act’s regulation of new and existing power plants.

We estimated peak natural gas demand under two scenarios: (1) a low gas use scenario that assumes compliance with the Clean Air Act through greater energy efficiency savings and a more rapid build out of renewable generating facilities; and (2) a high gas use scenario that assumes increased use of natural gas for electric power generation (thus representing the maximum expected gas use in the region). As described in more detail in Appendix A, we relied primarily on filings from natural gas distribution companies with the public utility commissions in their respective states as the basis for our forecast of non-electric natural gas use. For the electric sector, we used the National Renewable Laboratory’s Regional Energy Deployment System (ReEDS model) to simulate electric system dispatch in the Eastern Interconnection and provide the forecasted volume of peak natural gas use under our high gas use and low gas use scenarios.

We then combined the forecast of peak non-electric demand with the forecasts of electric sector natural gas demand under both the high gas use and low gas use scenarios, as shown in Figure 2.



Figure 2. Combined peak demand for natural gas (non-electric and electric) in the low gas use and high gas use scenarios



As shown in Figure 2, total demand for natural gas is higher in the high gas use scenario when companies rely on gas-fired generators to meet Clean Air Act goals. Demand in the peak hour reaches 597 MMcf in 2030 in this scenario, which reflects the maximum possible gas use in the region during the study period, compared to a peak-hour demand of 515 MMcf in the scenario that relies upon increased additions of renewable energy and energy efficiency in order to meet emissions reduction targets for CO<sub>2</sub>.

### 3. ANTICIPATED NATURAL GAS SUPPLY ON EXISTING AND UPGRADED INFRASTRUCTURE

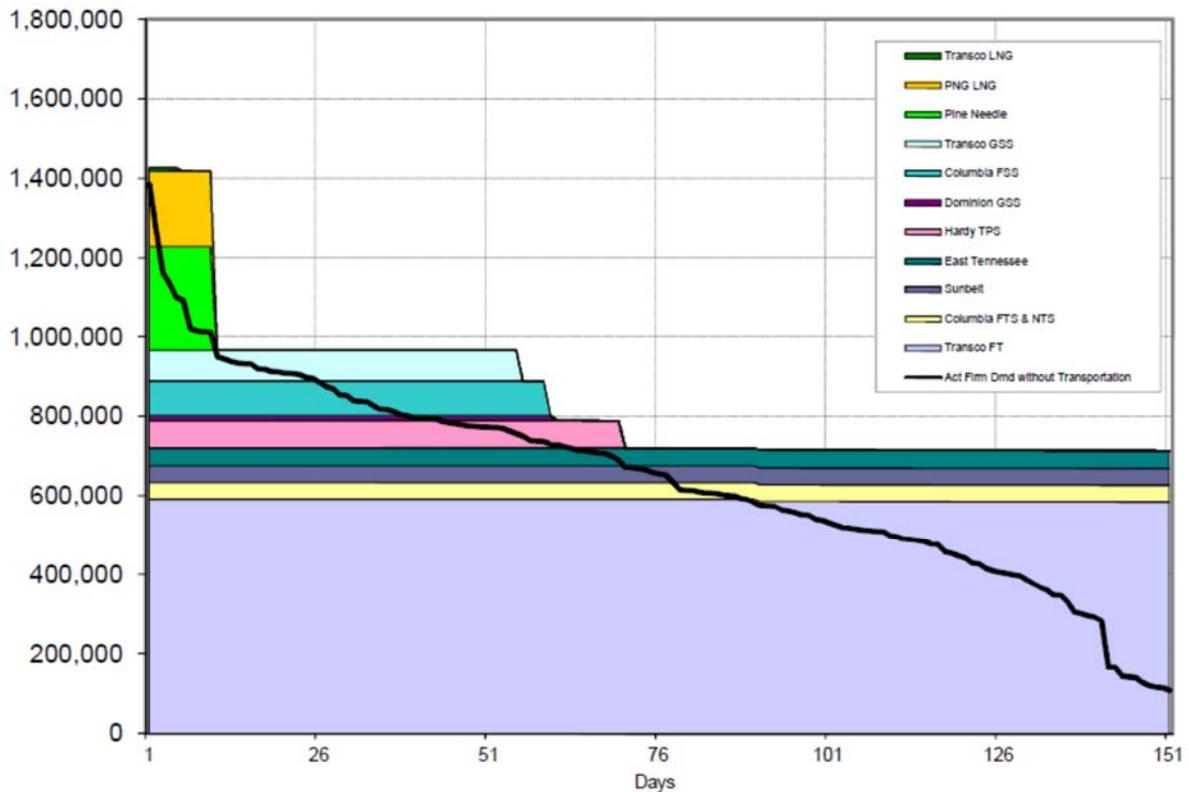
A determination of need for additional incremental pipeline capacity in the Virginia-Carolinas region also requires an inventory of existing natural gas infrastructure and planned upgrades and modifications to that infrastructure and an assessment of whether or not that supply flow is adequate to meet projected demand. The forms of natural gas capacity infrastructure considered in this analysis include existing pipeline capacity, existing storage, and future reversals and expansions of existing pipelines that would bring additional natural gas into the Virginia-Carolinas region. Inter- and intrastate natural gas pipelines transport gas from producing areas to both local distribution companies and directly to large consumers

like electric power plants. These natural gas supplies typically help regions meet baseload (that is, average or everyday) natural gas demand, while storage resources contribute to meeting peak demand. Natural gas can be stored underground in aquifers, salt caverns, and depleted oil and gas fields, as well as aboveground in tanks that allow storage in liquid form.

Figure 3 gives an example graphical representation of the relationship between natural gas demand and natural gas supply infrastructure. The graph shows the forecasted winter demand for natural gas in 2015 and the supply available in the region from Piedmont Natural Gas, a distributor of natural gas in North and South Carolina, to meet that demand. The black line represents natural gas demand, and the colored rectangles represent the various types of capacity infrastructure used to meet demand on a given day. The graph shows pipeline capacity at the bottom of the stack, with the Transco, Columbia, Sunbelt, and East Tennessee pipelines providing natural gas in each of the 151 days shown on the graph. Base storage capacity is shown in the middle of the graph, and is represented by the Hardy storage facility as well as the storage services available on the Dominion, Columbia and Transco systems. Finally, the top tier of the graph shows available LNG storage, which is used to meet demand on a small number of peak winter days, and includes the Pine Needle, PNG LNG, and Transco LNG facilities. Note that in 2015 the Piedmont Natural Gas territory—as is common throughout the Virginia-Carolinas region—requires natural gas storage facilities in order to adequately supply natural gas on approximately 50 percent of winter days.



Figure 3. Piedmont Natural Gas 2015 design winter supply and demand – total Carolinas



Source: Piedmont Natural Gas. Testimony and Exhibits of Michelle R. Mendoza before the Public Service Commission of South Carolina. Docket No. 2015-4-G. June 3, 2015.

Synapse reviewed available information on existing pipelines in Virginia and the Carolinas in order to determine the capacity of the region’s current natural gas infrastructure. Existing natural gas capacity comprises:

- existing pipeline capacity in the three-state region of Virginia, North Carolina, and South Carolina; and
- existing storage capacity within the region.

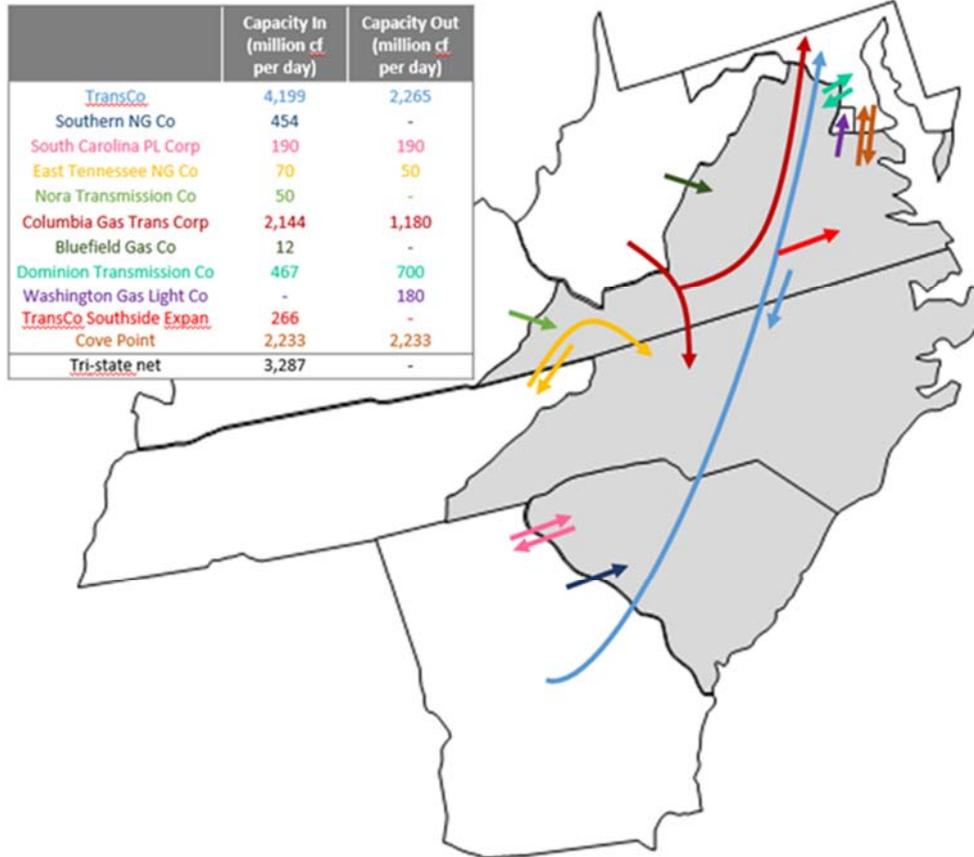
The following sections describe the region’s existing and projected natural gas infrastructure in more detail.

### 3.1. Existing Pipelines

To estimate existing capacity in this analysis, we considered “historical in-flow,” which limits the capacity to the pipeline inflow that existed in 2014, less any contracts out of the region. It is important to note that not all natural gas that originates in or passes through the region is meant for local use. We exclude

gas under contract for capacity outside of the region from our estimation of the volume of gas available to contribute to in-region capacity. Figure 4 shows the existing pipelines currently in place in the region, along with a table detailing the current in-flow and out-flow capacity of these pipelines according to EIA data from 2014.

**Figure 4. Currently existing natural gas supply capacity into and out of the Virginia-Carolinas three-state region**



Source: Synapse analysis based on data from EIA. U.S. state-to-state capacity. December 2014. Available at: <http://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xls>.

Note: Locations of pipelines are approximate and are not meant to portray the exact pipeline locations.

Note that the Williams Company placed the Transco Virginia Southside Expansion project into service in September 2015.<sup>13</sup> The 2014 EIA data shown in Figure 4 does not include that project, and Synapse added it to our estimate of the existing total pipeline capacity.

Figure 4 above shows the net capacity from existing pipelines in MMcf per day. In order to calculate the capacity from existing pipelines in the peak hour, we employ the industry standard assumption that 5.6

<sup>13</sup> Williams Company. 2015. "Williams' Transco Completes Virginia Southside Expansion." September 1. Available online at: <http://investor.williams.com/press-release/williams/williams-transco-completes-virginia-southside-expansion>

percent of daily gas demand occurs in the peak hour.<sup>14</sup> Estimated natural gas capacity available from existing pipelines during the peak hour is approximately 309 MMcf for the duration of the analysis period.

### 3.2. Natural Gas Storage

While natural gas pipeline capacity is used to meet baseload (average day-to-day) demand for natural gas, gas storage facilities play an essential role in meeting peak demand. As a standard, continual practice, natural gas is injected into these storage facilities during periods of low gas demand and withdrawn during peak periods. Peak send-out capacity in the Virginia-Carolinas region must provide sufficient volumes of natural gas to meet demand on even the coldest winter day. To do so requires a combination of pipeline and storage capacity resources.

Natural gas can be stored in several ways:

- **Underground reservoirs** are the primary form of natural gas storage, and consist of depleted oil and gas reservoirs, aquifers, and salt caverns. Suppliers can draw from these underground facilities to meet base demand or demand during peak periods.
- **Aboveground facilities**, such as LNG storage tanks, serve primarily during periods of peak demand and offer several advantages over underground facilities. LNG storage occupies less space than underground facilities, as they store natural gas in liquid form. For this reason, they tend to be in closer proximity to end-use markets and can often provide higher levels of deliverability on short notice.
- **“Line packing,”** in which natural gas is stored temporarily in existing pipelines by packing additional gas volumes into pipelines, provides additional natural gas during peak demand periods.

Owners and operators of natural gas storage facilities tend to be: 1) interstate and intrastate pipeline companies, which use storage to meet the demand of end-use customers; 2) local gas distribution companies, which use gas from storage to serve customers directly; and 3) independent storage service providers. Government authorities do not require all owners and operators of natural gas infrastructure to report their storage capacity, so we do not know the region’s maximum or actual natural gas storage. We collected the Pipeline and Hazardous Materials Safety Administration’s partial data on LNG facilities in the Virginia-Carolinas region, as well as EIA’s data on the region’s underground storage facilities. Together, these values make up the “reported” storage value used in this analysis. The hourly capacity contribution of reported storage is estimated to be 71 MMcf per hour and is shown in Table 1, below.

---

<sup>14</sup> Levitan & Associates, Inc. 2015. Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems. Prepared for the Eastern Interconnection Planning Collaborative. p.82. Available online at: <http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1>

**Table 1. Storage capacity of LNG and underground facilities with deliverability to the Virginia-Carolinas region**

Company Name	Facility Type	Facility Name	State	Total Daily Capacity (MMcf)	Hourly capacity (MMcf)
Columbia Gas of Virginia Inc	LNG	Lynchburg LNG	VA	6	0.3
Columbia Gas Transmission, LLC	LNG	Chesapeake LNG	VA	120	5.0
Greenville Utilities Commission	LNG	LNG Plant	NC	24	1.0
Piedmont Natural Gas Co Inc	LNG	Bentonville LNG	NC	180	7.5
Piedmont Natural Gas Co Inc	LNG	Huntersville LNG	NC	200	8.3
Public Service Co of North Carolina	LNG	PSNC Energy LNG	NC	110	4.6
Roanoke Gas Co	LNG	LNG Facility	VA	30	1.3
South Carolina Electric & Gas Co	LNG	Salley LNG	SC	90	3.8
South Carolina Electric & Gas Co	LNG	Bushy Park LNG	SC	60	2.5
Pine Needle Operating Company, LLC	LNG	Pine Needle LNG	NC	400	16.7
Columbia Gas/Piedmont Natural Gas	Underground	Hardy	WV	170.9	7.1
Spectra Energy	Underground	Early Grove	VA	20	0.8
Spectra Energy	Underground	Saltville	VA	300	12.5
Total				1,710.9	71.3

Sources: (a) Pipeline and Hazardous Materials Safety Administration. *Distribution, Transmission & Gathering, LNG, and Liquid Annual Data. Liquefied Natural Gas (LNG) Annual Data – 2010 to present.* Available at <http://phmsa.dot.gov/pipeline/library/data-stats/distribution-transmission-and-gathering-lng-and-liquid-annual-data>; (b) US EIA. *Natural Gas Annual Respondent Query System (EIA-191 Data through 2015).* Available at [http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f\\_report=RP7](http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7)

The estimate of 71 MMcf per hour from storage is a conservative assumption. The Hardy storage facility in West Virginia is included in this estimate because publicly available documentation demonstrates that distribution companies in the Virginia-Carolinas region contract for storage with this facility. In addition, EIA data show the existence of an additional 149 MMcf/hour of active natural gas storage in West Virginia that we did not include in our estimate due to lack of evidence that this storage was contractually available to local distributors in our study area.

### 3.3. Planned Reversals and Expansions of Existing Pipelines

The major interstate pipelines continue to announce new expansion projects aimed at delivering gas from the Marcellus area to reach anticipated markets. Of the many proposals submitted to FERC that would affect markets across the United States, several propose large-scale expansion projects intended to deliver natural gas to the Virginia-Carolinas region.

The largest of these is Transco’s Atlantic Sunrise project, which would reverse the flow of the Transco pipeline and allow the company to provide 1,675 MMcf per day of incremental firm transportation capacity for natural gas from northern Pennsylvania through our study region, terminating in Alabama. The expected in-service date for the project is July 1, 2017.<sup>15</sup> Transco in-flows and out-flows were

<sup>15</sup> Transcontinental Gas Pipe Line Company, LLC. 2015. *Resource Report No. 1: General Project Description.* Prepared for Atlantic Sunrise Project Docket No. CP15-138. Available online at: [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20150331-5153](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20150331-5153)

included in our calculations of existing pipeline capacity. We assume that with the reversal of the Transco pipeline, the out-flows would be eliminated, and there would be a corresponding increase of in-flows, resulting in a net gain of 254 MMcf per hour of peak capacity from the Atlantic Sunrise project.

NiSource's Columbia Gas Transmission Company (TCO) has announced a number of new pipeline expansion projects including its WB Xpress project, designed to send additional shale gas supplies (about 1.3 Bcf per day) east from the Marcellus to West Virginia, Virginia, and the Cove Point LNG facility in Maryland. The WB Xpress project would replace about 26 miles of existing TCO pipeline with a new line of the same diameter. Increased flows would result from the use of higher pressures that the new line would carry. The project, which the company anticipates being in-service in 2018, would add approximately 73 MMcf per hour of peak capacity.

## 4. NATURAL GAS SUPPLY EXCEEDS DEMAND

Figure 5 compares our modeled maximum expected natural gas demand (peak-hour demand in our scenario of high gas use) in years 2015 through 2030 to future natural gas infrastructure, including existing pipeline capacity, reported storage, the expected 2017 reversal of the Transco Mainline pipeline, and the expected 2018 WB Xpress project. (Note that reported capacity is lower than actual peak hour demand in 2015 and 2016. In all likelihood, the gap in capacity to serve actual peak was supplied by natural gas storage facilities that are not reported in publicly available data sources and/or by some portion of the 149 MMcf/hour of active storage located in West Virginia.)

The region's anticipated natural gas supply on existing and upgraded infrastructure is sufficient to meet maximum natural gas demand from 2017 through 2030. Additional interstate natural gas pipelines, like the Atlantic Coast Pipeline and the Mountain Valley Pipeline, are not needed to keep the lights on, homes and businesses heated, and industrial facilities in production. This assessment of sufficient capacity includes only reported storage capacity, ignoring the existence of additional unreported storage capacity demonstrated by recent years' peak hour demand.

**Figure 5. Peak hour natural gas demand under scenarios of low and high natural gas use compared to anticipated natural gas supply on existing and upgraded infrastructure**

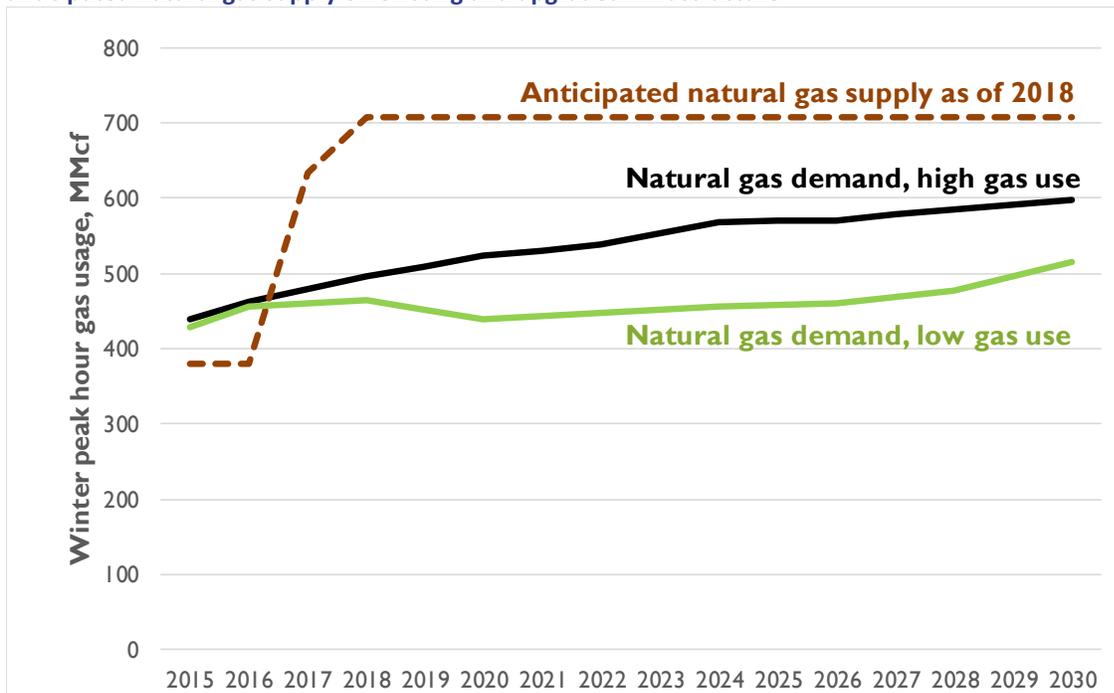


Figure 5 shows an excess of natural gas supply under a scenario of maximum natural gas demand. The policy pathway chosen by states for compliance with Clean Power Plan emissions reduction targets has a significant impact on the magnitude of this excess supply capacity, as shown in Figure 7. Under the high natural gas use scenario, where Clean Power Plan compliance is achieved primarily through the addition of new natural gas combined-cycle power plants, peak demand for natural gas climbs steadily throughout the study period and results in excess natural gas supply of approximately 100 MMcf per hour in 2030. In contrast, the low gas use scenario, which minimizes the addition of new NGCC generators and instead relies on new installations of renewable energy capacity and savings through efficiency measures, results in surplus supply of almost 200 MMcf per hour.

Projected future natural gas demand depends greatly on the policies pursued by each of the states in this analysis. While non-electric natural gas demand remains fairly constant during our analysis period, natural gas demand from the electric sector rises significantly over time in a scenario of high natural gas use, where the states pursue Clean Power Plan compliance through the use of new natural gas generating capacity. If states choose to pursue additional energy efficiency and renewable energy capacity under a scenario of low gas use, combined natural gas demand rises much more slowly over time and results in an even greater capacity surplus in 2030.

## APPENDIX A: NON-ELECTRIC DEMAND METHODOLOGY AND DATA SOURCES

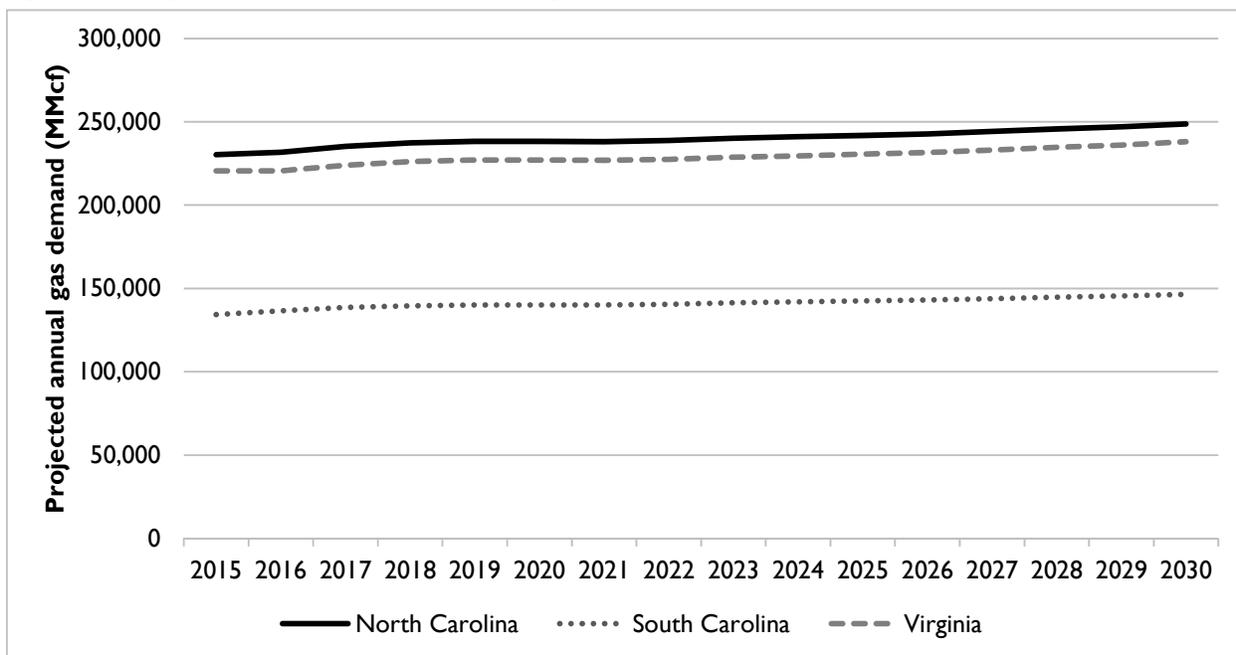
As an input to our modeling, we calculated projected demand for natural gas in Virginia and the Carolinas from 2015 to 2030.<sup>16</sup> This projection had two components: non-electric natural gas demand and demand for natural gas from the electric sector. As described below, we relied primarily on EIA data for the former and we used the Regional Energy Deployment System (ReEDS model) to calculate the latter. We projected natural gas demand for two different time periods, first calculating annual natural gas demand, and next making a projection of winter peak demand—the amount of natural gas consumed in both sectors at the hour of maximum demand. This section describes the methodology and data sources used to forecast non-electric natural gas demand, while Appendix B provides further detail on the methodology and data sources used to estimate natural gas demand from the electric sector.

Synapse based its forecast of non-electric natural gas demand for the states included in the analysis—North Carolina, South Carolina, and Virginia—on data from EIA’s 2015 Annual Energy Outlook (AEO). EIA publishes data on forecasted natural gas demand in the residential, commercial, industrial, and transportation sectors for the South Atlantic Region of the United States through 2040. We took the historical natural gas consumption rates by state and by sector and applied them to the forecasted regional natural gas demand in order to arrive at a forecast of annual non-electric demand for each of the three states in our analysis. These results are shown in Figure A-1.

---

<sup>16</sup> U.S. Energy Information Administration. 2015. *Annual Energy Outlook*.

Figure A-1. Projected annual non-electric natural gas demand

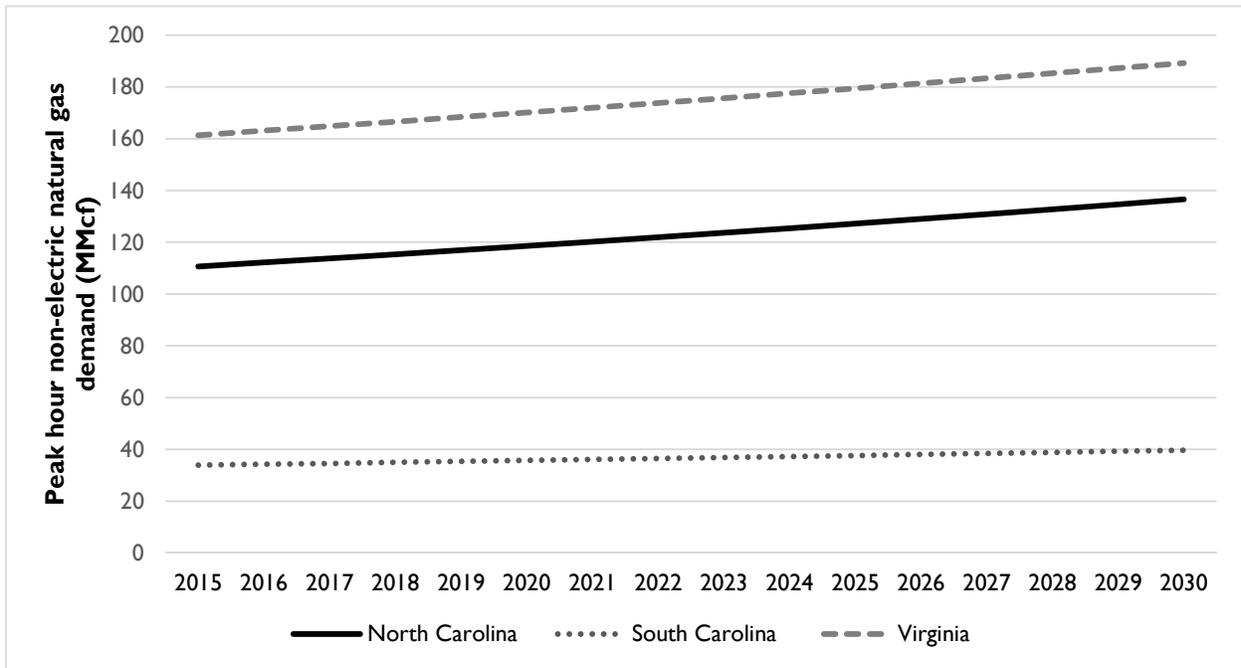


Source: EIA 2015 Annual Energy Outlook.

Second, projected non-electric winter peak demand was calculated using filings with state public utilities commissions from the 13 gas distribution companies located within the three states in this analysis. We reviewed filings from each local distribution company for the most recent year to determine the companies’ “design day” natural gas requirements—the volume of gas needed to meet customer demand on the coldest winter day—and then summed the results across the distribution companies to arrive at design day totals for each of the three states. Companies typically presented results for the next one to five years in the future. Based on these results, we calculated compound annual growth rates for each company and applied them to future years to generate a forecast through 2030. In order to arrive at peak hour requirements from the design day, we assumed that the volume used in the peak hour of the design day represents 5.6 percent of the total design day volume.<sup>17</sup> Those projections of non-electric winter peak demand are shown in Figure A-2. Projected peak hour non-electric natural gas demand in the peak hour, non-electric natural gas requirements rise gradually throughout the modeled period, beginning at 306 MMcf in 2015 and rising to 366 MMcf in 2030.

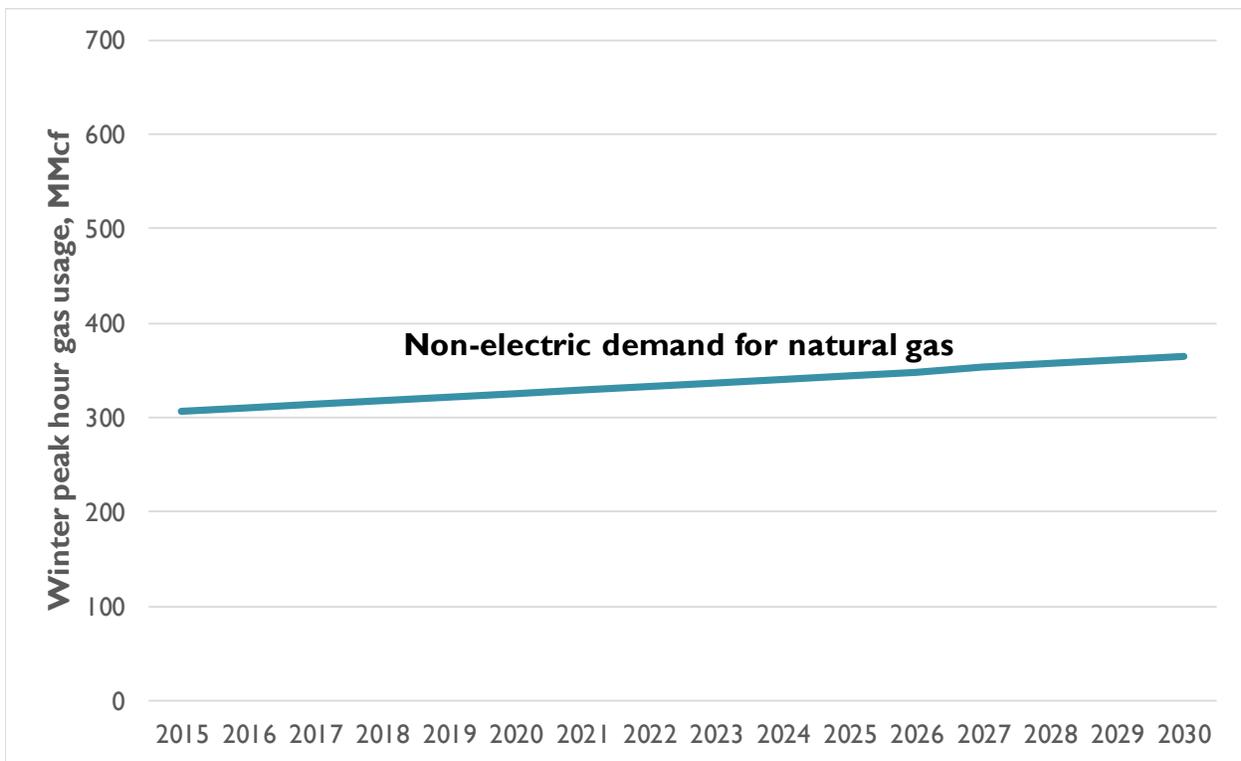
<sup>17</sup> Levitan & Associates, Inc. 2015. Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems. Prepared for the Eastern Interconnection Planning Collaborative. p.82. Available online at: <http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1>

Figure A-2. Projected peak hour non-electric natural gas demand



Source: Data were taken from filings made with state public utilities commissions by gas distribution companies

Figure A-3. Peak-hour non-electric demand for natural gas in Virginia and the Carolinas



These methodologies resulted in forecasts for both annual and peak non-electric natural gas demand. Demand from the electric sector was derived from electric sector modeling, and is described in the next section.



## APPENDIX B: ELECTRIC DEMAND METHODOLOGY AND DATA SOURCES

Electric sector modeling scenarios of low and high natural gas use were designed to comply with the U.S. Environmental Protection Agency's limits for carbon dioxide emissions under Sections 111(b) and 111(d) of the Clean Air Act, released on August 3, 2015. Section 111(b) (the Carbon Pollution Standards) sets emissions limits for new fossil-fueled power plants that commenced construction after January 8, 2014, or units that were modified or reconstructed as of June 18, 2014. Separate standards exist for coal- and natural gas-fired units, but each reflects the degree of emission limitation that EPA believes represents the best system of emission reduction (BSER) for each type of unit. The standard for new and reconstructed natural gas that is operating under baseload conditions is 1,000 pounds of CO<sub>2</sub> per MWh on a gross-output basis, while non-baseload units must meet a clean fuels input-based standard. Standards for coal-fired plants depend on whether the unit is new, reconstructed, or modified. New coal-fired power plants must meet a standard of 1,400 pounds of CO<sub>2</sub> per MWh-gross; reconstructed units must meet a standard of either 1,800 or 2,000 pounds of CO<sub>2</sub> per MWh-gross, depending on their heat input; and the standards for modified facilities are plant specific and are consistent with best annual historical performance.

Section 111(d) (the Clean Power Plan) aims to reduce emissions of carbon dioxide (CO<sub>2</sub>) from existing fossil fuel-fired power plants by approximately 30 percent below 2005 levels by 2030. Each state's approach to compliance with the proposed Clean Power Plan—its choice of what new resources to build and how much to run existing fossil-fuel generators—will have a critical role in determining how much electric-sector natural gas is needed in future years. In order to meet the emission reduction goals set by EPA, states must develop plans that will reduce their average CO<sub>2</sub> emission rate at affected generating units from a 2012 baseline rate to a lower state-specific target rate by 2030. In its proposed Clean Power Plan, EPA offers each state the flexibility to choose either mass- or rate-based targets for compliance.

We conducted modeling of electric sector demand in two steps. First, we developed two scenarios of Clean Power Plan compliance: (1) a scenario of high natural gas use that complies with emissions reduction targets through the use of new natural gas generators, and (2) a scenario of low natural gas use that relies on energy efficiency and installations of new renewable energy capacity to meet targets. We then screened them using Synapse's own Clean Power Plan Planning Tool (CP3T), which allows users to design future energy scenarios for Clean Power Plan compliance, to examine the various compliance pathways available to a state, and quantify the costs associated with those pathways.

The second step was to input these scenarios into the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model, which dispatches the electric generators in the Eastern Interconnect in order to meet electric demand and provides annual values of natural gas use from the electric sector over our study period. ReEDS is a deterministic optimization model that provides a detailed representation of the electricity generation and transmission systems in the contiguous United States. It draws many of its assumptions from EIA's 2014 AEO. There are 356 resource supply regions in ReEDS, which are grouped into four tiers of larger regional groupings: balancing areas, reserve sharing



groups, North American Electric Reliability Council (NERC) regions, and interconnects. States are also represented in such a way that state policies can be depicted accurately. ReEDS contains 17 annual “time-slices,” representing the various ways that electricity loads are met throughout each day and year using all major generator types. One of these 17 time slices is representative of a summer peak—a collection of the highest 40 non-consecutive hours in the summer season, represented by a single “superpeak” time slice. The purpose of this analysis, however, was to evaluate the natural gas requirements for the winter peak hour, which is not represented by any of ReEDS 17 time slices. Synapse performed custom modifications to the underlying ReEDS code to add a winter superpeak time slice, which represents the single hour between the winter months of November and February in which electricity demand is at its highest. For more information on the winter peak modifications made to ReEDS, see Appendix C.

We began our modeling under a set of input assumptions for forecasting future retail sales of electricity, distributed solar PV adoption, natural gas prices, non-coal unit retirements, and announced unit additions through 2020. Future retail sales are based on EIA AEO data. Distributed solar PV adoption rates come from the SunShot 50 trajectory, which is the NREL trajectory that assumes that the cost of solar is reduced by 50 percent by 2020 and then remains constant—a conservative assumption. Natural gas prices used by the model are the regional forecasts from EIA’s AEO. Announced unit retirements and additions were included in the modeling based on announcements from electric utilities in the study region.

We then had to develop two different scenarios of natural gas use in the Virginia-Carolinas region that met mass-based Clean Power Plan emission targets without significant over compliance. Mass-based targets were selected for modeling accuracy, and we assumed the new source complement in order to avoid emissions leakage to new power plants. This required the use of the CP3T and ReEDS models in combination. Electric sector capacity build-outs under the two different scenarios—one of which added significant amounts of new NGCC capacity to yield the highest likely estimate of natural gas demand, and one of which relied on new renewable capacity and energy efficiency—were first tested in CP3T for compliance. If those build-outs were found to achieve compliance within CP3T, which does not account for the electricity market interactions between states in the Eastern Interconnect, those values were then input into the ReEDS model, which does capture those market interactions. This ensures that interactions between states are adequately captured in terms of electricity imports and exports from one state to another. The outputs from the resulting ReEDS runs were then input back into CP3T in order to check for CPP compliance. Several iterations of CP3T/ReEDS modeling were required before we arrived at the capacity build-outs for the high gas use scenario (the addition of new NGCC generators) and for the low gas use scenario (the addition of renewable energy and energy efficiency) that would allow compliance with the emission targets established by the Clean Power Plan.

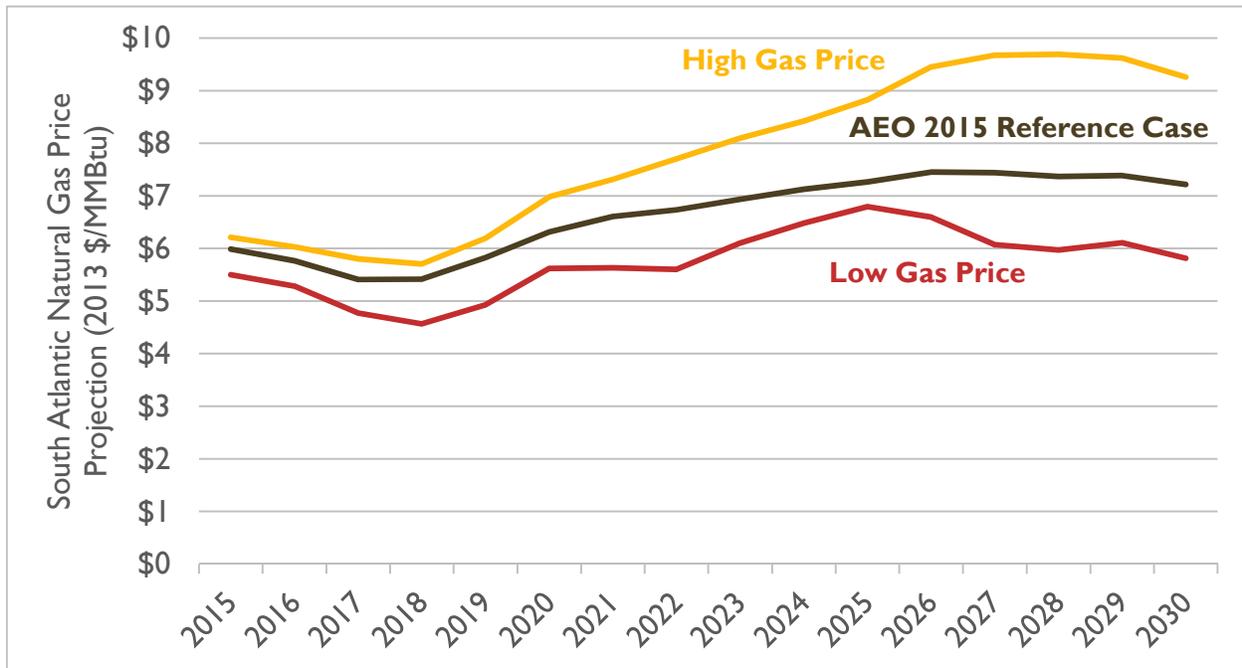
### **Natural gas price sensitivities**

Synapse modeled each of the three scenarios described above with a mid-level, Reference Case natural gas price forecast and evaluated sensitivity cases that examined the effects of natural gas use in the electricity sector under high and low natural gas price forecasts. The mid-level natural gas price forecast



was taken from the EIA’s AEO 2015 South Atlantic Reference Case. Because the sensitivity case forecasts are only published biannually, the low natural gas price sensitivity forecast was determined by multiplying the Reference Case forecast by the ratio of the High Oil and Gas Resource Case<sup>18</sup> to the regional Reference Case found in AEO 2014. Similarly, the high natural gas price sensitivity forecast was determined by multiplying the Reference Case forecast by the ratio of the Low Oil and Gas Resource Case to the regional Reference Case found in AEO 2014. Those natural gas prices are shown in Figure C-1, below.

**Figure C-1. Projection of natural gas prices in South Atlantic region**



Synapse input the combinations of scenarios/sensitivities into the ReEDS model, which dispatched the future electric system to meet forecasted electricity demand throughout the analysis period. After running the various scenarios through the ReEDS model, Synapse exported the volume of natural gas, in million cubic feet (MMcf), used for electricity generation in each of the states in the analysis. These data were exported into an Excel spreadsheet both on an annual basis and at the hour of peak demand in each year, from 2015 to 2030, for each modeling scenario. Synapse combined this information with the non-electric demand for natural gas to analyze the need for additional pipeline capacity.

<sup>18</sup> The High Oil and Gas Resource Case assumes large volumes of available oil and natural gas resources, leading to lower prices for oil and gas. Conversely, the Low Oil and Gas Resource Case assumes limited available oil and natural gas resources, leading to higher prices.

## APPENDIX C: WINTER PEAK MODELING

NREL's ReEDS model is a national-scale long-range generation capacity expansion planning model with the process of economic dispatch represented through seventeen "time slices" that make up the entire year. NREL chose time slices to appropriately represent times of the year (season) and times of the day when electricity power system operations are expected to be (approximately) similar. For reliability planning purposes, peak demand must be represented; ReEDS does this by collecting the highest 40 non-consecutive hours in the summer season, and representing them with a single "superpeak" time slice, H17. The other sixteen time slices original to ReEDS are shown in Table C-1.

While the summer superpeak is well represented in ReEDS, the winter peak is not. In the original version of the model, each time slice for winter (H9 – H12) is represented as the average load (GW) across all hours encompassed in the time slice. Although this is a very common methodology to keep long-range capacity planning models tractable, the equivalent of a winter season "superpeak" is missed, which in some areas can be significantly different than the average loads represented by the current wintertime slices.

The purpose of the changes Synapse made to the ReEDS model is to represent this winter superpeak for modeling gas-demand in the West Virginia, Virginia, North Carolina, and South Carolina (WV-VA-NC-SC) region. Synapse decided to implement the new winter superpeak using a single peak hour from November – February in the four-state WV-VA-NC-SC region. Below are the steps taken to develop the new one-hour winter superpeak version of the NREL ReEDS model, as well as a snapshot of results from a validation of the model.



**Table C-1. Original ReEDS time slice definitions**

<b>Time Slice</b>	<b>Hours</b>	<b>season</b>	<b>time of day</b>
H1	736	summer	10PM-6AM
H2	644	summer	6AM-1PM
H3	328	summer	1PM-5PM
H4	460	summer	5PM-10PM
H5	488	fall	10PM-6AM
H6	427	fall	6AM-1PM
H7	244	fall	1PM-5PM
H8	305	fall	5PM-10PM
H9	960	winter	10PM-6AM
H10	840	winter	6AM-1PM
H11	480	winter	1PM-5PM
H12	600	winter	5PM-10PM
H13	736	spring	10PM-6AM
H14	644	spring	6AM-1PM
H15	368	spring	1PM-5PM
H16	460	spring	5PM-10PM
H17	40	summer	superpeak
8,760 (total)			

Source: NREL ReEDS Model.

## Methodology

### Step 1. Review ReEDS code, input tables, and time slice dependent equations

The first step in developing the capability of ReEDS to model a single-hour winter peak was to understand the structure of the underlying GAMS code, how the inputs interact with the code, and—most importantly—where the electricity demand and time period definitions are represented within the equations of the model. Synapse reviewed each GAMS file and all worksheets in the Excel workbook used to modify inputs to understand how “hard-coded” the time slice definitions were in the model and whether they would adapt to changes in the input Excel file. The programming code was also reviewed to ensure that optimizing dispatch over a single hour, where multiple hours used to be aggregated, would not cause instability in the mathematical algorithm itself. Synapse determined that as long as we left the “H17” summer superpeak intact (which was hard-coded in many places in the model), we could make all but one modification<sup>19</sup> to represent the single hour in the ReEDS Excel input file. The NREL

<sup>19</sup>The single modification made in the actual GAMS code involved adding the new winter superpeak to a set of time slices ReEDS represents as “not peak.” GAMS reserve margin calculations exclude these extraordinary peaks, so per NREL’s

ReEDS model development team<sup>20</sup> confirmed that no stability issues or other model infractions would result from representing a single-hour dispatch in the ReEDS dispatch algorithm.

## **Step 2. Determine new time slice designations**

Synapse repurposed an existing time slice to represent the single highest one-hour period during the winter (November, December, January, and February in ReEDS), and used another time slice to “absorb” the remaining hours. Using an existing time slice to represent the single hour (rather than adding an 18<sup>th</sup> time slice) prevented the need for any major modifications to the underlying GAMS code or run the off-line GIS-based meteorological models that NREL runs to inform several different inputs for each of the time slices.

We used the two time slices in the winter months that had the most similar levels of demand (on balance, across all power control areas [PCA], in our region of interest). Figure C-1 below shows the levels of demand by time slice and PCA for WV-VA-NC-SC in the model. Table C-2 provides the percentage differences between the possible pairs of time slices, showing the high level of similarity between the H10 and H12 slice for most of the PCAs, and the average difference across PCAs by time slice weighted by the level of demand in each PCA. As the table shows, the H10 and H12 slices are by far the most similar with respect to level of demand.

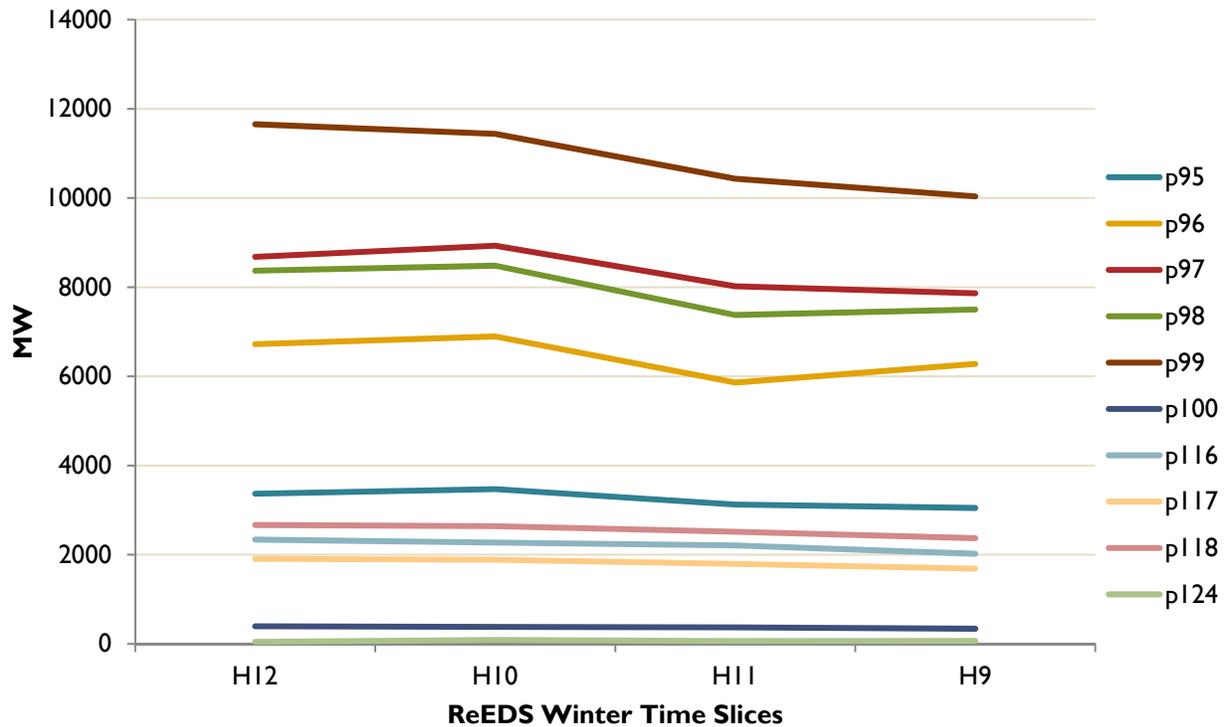
---

suggestion, the new winter peak time slice (described in more detail in the following steps) was also excluded from the reserve planning margin calculation.

<sup>20</sup> NREL, 2015. Personal communication with Stuart Cohen, June 4, 2015.



Figure C-1. Average winter loads by time slice for WV-VA-NC-SC PCAs in ReEDS



Source: NREL ReEDS Model.

Table C-2. Percent difference in demand levels for pairs of winter season time slices

Time Slice Pair	p95	p96	p97	p98	p99	p100	p116	p117	p118	p124 <sup>21</sup>	Weighted Average % Difference
H12-H10	3%	3%	3%	1%	2%	3%	3%	1%	1%	91%	2%
H12-H11	7%	13%	8%	12%	10%	6%	6%	6%	6%	35%	10%
H12-H9	10%	7%	9%	10%	14%	14%	14%	12%	11%	43%	11%
H10-H11	10%	15%	10%	13%	9%	3%	3%	5%	5%	30%	10%
H10-H9	14%	10%	14%	13%	14%	13%	13%	12%	11%	33%	13%
H11-H9	2%	7%	2%	2%	4%	8%	9%	6%	6%	6%	22%

Source: NREL ReEDS Model.

For the slice with the lesser number of hours (H12—winter evening, 600 hours), the duration was decreased to 1 hour, and for the slice with the greater number of hours (H10—winter morning, 840 hours), the duration was increased to 1439 hours = 840 + 600 – 1. The determination of the actual new

<sup>21</sup> Note that p124 is a very low demand PCA, with an average load of 68 MW compared to 346 and 1705 MW as the next lowest PCA average loads.

(peak) demand level to use for the new H12 one-hour slice is described below. The demand for the new H10 slice is now represented as the average load for all hours it includes.<sup>22</sup> The new time slice designations are shown in Table C-3.

**Table C-3. New ReEDS time slice definitions to represent a one-hour winter peak demand**

Time Slice	Hours	Season	Time of Day
H1	736	summer	10PM-6AM
H2	644	summer	6AM-1PM
H3	328	summer	1PM-5PM
H4	460	summer	5PM-10PM
H5	488	fall	10PM-6AM
H6	427	fall	6AM-1PM
H7	244	fall	1PM-5PM
H8	305	fall	5PM-10PM
H9	960	winter	10PM-6AM
H10	1439	winter	6AM-1PM & 5PM-10PM
H11	480	winter	1PM-5PM
H12	1	winter	1 hour peak
H13	736	spring	10PM-6AM
H14	644	spring	6AM-1PM
H15	368	spring	1PM-5PM
H16	460	spring	5PM-10PM
H17	40	summer	superpeak
	8,760 (total)		

### Step 3. Determine demand levels for winter peak time slice

Once we developed the new time slice designations, Synapse assigned actual demand levels to the single highest demand hour in the ReEDS winter season.

Focusing on the WV-VA-NC-SC region, we performed an analysis on the original ReEDS 2010 hourly demand dataset to determine the single hour across the four-state region that had the highest level of demand November 1 through February 28 (ReEDS winter designation).<sup>23</sup> Each state contains multiple

<sup>22</sup> The NREL ReEDS model developers supplied us with the underlying 8,760 hours data it used to develop the original 17 time slices, along with the scripts they used to summarize average loads. This enabled us to make a good estimate of the new average load for the H10 elongated time slice. Note: ReEDS runs on 8760 ABB (Ventyx) data; NREL was able to provide this data due to our existing license with ABB. Synapse received prior approval from ABB to receive this data.

<sup>23</sup> ReEDS uses 2010 demand data as its reference year.

transmission zones,<sup>24</sup> so finding a coincident peak hour across each individually was not possible.<sup>25</sup> However, when aggregated to the state level, a single hour could be determined. The hour we used to represent the winter peak demand was December 15 at 8:00AM. Table C-4 shows the new winter peak demand levels at this hour for each PCA in the four-state area of interest, and the original H12 average time slice demand level for comparison.

**Table C-4. New winter peak demand level in the WV-VA-NC-SC area represented in ReEDS**

State	PCA	I-HR Winter Peak (MW)	Original H12 Slice (MW)
SC	p95	4,988	3,369
SC	p96	10,488	6,723
NC	p97	12,769	8,681
NC	p98	12,696	8,371
VA	p99	16,069	11,654
VA	p100	483	394
WV	p116	2,842	2,339
WV	p117	2,393	1,908
VA	p118	3,342	2,667
VA	p124	46	46

We found the 8:00 AM hour on December 15 to be:

- The maximum winter demand hour for each individual state (VA, SC, NC), when demand for a state is defined as the sum of demands across all transmission zones in that state.
- The maximum winter demand hour for the four-state region as a whole (inclusive of WV), when demand for the four-state region as a whole is defined as the sum of demands across all transmission zones encompassed across all four states.
- Consistent with a “sensible” winter peak—a morning hour later in the winter.
- The maximum winter demand hour, when demand is defined as the sum of demands across all transmission zones in the four-state region, from the set of hours that contain at least one absolute winter peak for a single transmission zone in the four-state region. This hour is the *actual* single hour winter peak transmission zone 304 in VA.
- The same hour determined from a simple optimization that minimizes the sum of errors between the hour chosen and the other transmission regions’ absolute winter peak loads. This essentially means that while the hour we chose to model as the winter peak demand does not

<sup>24</sup> Each PCA is made up of multiple transmission zones; the original ReEDS hourly demand data is organized by the underlying transmission zones.

<sup>25</sup> While many transmission zones within the four-state area had the *exact* same hour timestamp for their winter peak, some did not. This result is not unexpected given the system-level detail represented in the ReEDS model, and the reality of operations of the electric power system. While the system is highly interconnected, the highest demand in one location will not necessarily occur when demand is highest in another location.

represent the absolute winter peak across all transmission zones, it minimizes the disruption to the original dataset.

Note that while Synapse used the WV-VA-NC-SC region to identify the single hour to represent the peak demand, the ReEDS model ran on the broader Eastern Interconnect region for this WV-VA pipeline analysis. To ensure that a coincident winter peak was represented throughout the Eastern Interconnect, Synapse represented the winter peak demand using this same December 15 8:00AM hour for all PCAs represented in the ReEDS model.

Finally, other demand-related planning parameters were also adjusted as a result of shifting the duration of the time slices from the original model. Lk1, which defines the ratio between average annual load and peak load, and Lk2, which defines the level of variation in demand within a time slice (for the new H12 slice this value is 0 as there is no variation in the single-hour value), were re-calculated using the NREL-provided demand-by-PCA data and R script (ReEDS\_load.R).

#### **Step 4. Adjust renewables time slice-dependent capacity and other adjustment factors**

ReEDS represents renewable Concentrated Solar Power, PV (central and distributed), and wind using capacity factors and capacity factor adjustments by time slice for each PCA. These factors are developed offline in other models, and pulled into ReEDS hardcoded in the input spreadsheet.

Because these values are time slice dependent, we needed to adjust the H10 winter morning time slice to account for the respective capacity factor for the hours of the H12 winter evening time slice it was “absorbing.” The approach used to account for this was to take a weighted average of these factors based on the hours the new time slice H10 represents from each of the original time slices: 840 hours of the original H10 time slice and 599 hours of the original H12 time slice.

For example, the original H10 and H12 capacity factors (CF) for central station PV for p95, a PCA in South Carolina, were 0.25463 and 0.01908, respectively. The new H10 capacity factor is:

$$0.15658 = 0.25463 * (840/1439) + 0.01908 * (599/1439), \text{ or}$$

$$\text{New H10 CF} = \text{Original H12 CF} * (\# \text{ Hours in Original H12 Slice} / \# \text{ Hours in New H12 Slice}) + \text{Original H10 CF} * (\# \text{ Hours in Original H10 Slice} / \# \text{ Hours in New H10 Slice})$$

The original H12 capacity factor was left intact; using the average capacity factor was the best assumption without re-running the offline meteorological models to calculate the new one-hour capacity factor. Note that while the example above is pulled from a PCA in the four-state region of interest for the current project, for consistency this method was applied to all PCAs represented in ReEDS.



## Step 5. Adjust Canadian import factors

ReEDS represents imports from Canada using annual imports, allocating them across the 17 time slices via a seasonal and diurnal assignment factor. Appropriately representing imports for the new set of time slices, where one slice consists of a single hour, required adjusting the fraction of imports that occur in the new winter peak H12 time slice. Imports for H12 were scaled from the original 600 hours to a single hour (1/600<sup>th</sup>), and the remaining fraction of imports was reassigned to the new elongated H10 slice. This original and new import factors are shown below (Table C-5).

**Table C-5. Canadian import factors by time slice in ReEDS**

Time Slice	Adjusted CA Import Factor	Original CA Import Factor
H1	0.0516	0.0516
H2	0.0954	0.0954
H3	0.0448	0.0448
H4	0.0612	0.0612
H5	0.0398	0.0398
H6	0.0299	0.0299
H7	0.0490	0.0490
H8	0.0522	0.0522
H9	0.0498	0.0498
H10	0.1835	0.1050
H11	0.0629	0.0629
H12	0.0001	0.0786
H13	0.0521	0.0521
H14	0.1000	0.1000
H15	0.0634	0.0634
H16	0.0589	0.0589
H17	0.0055	0.0055
Sum	1.0000	1.0000

## Model Validation: Comparison of Results

A comparison of results between ReEDS with the single-hour winter peak represented and the original time slice formulation shows excellent consistency in total generation, capacity, coal and gas usage, and emissions (all differences are well below 1 percent, see Table C-6).<sup>26</sup> Figure C-2 and Figure C-3 show generation (MW) by time slice for the original and reformulated models, and Figure C-2 highlights the dramatically increased production from combined-cycle and combustion-turbine units in the new H12 time slice. The combination of the consistency in total generation, fuel usage, and emissions, with the

<sup>26</sup> Results shown are based on “Eastern Interconnect-only” ReEDS runs. This is the setting this WV-VA pipeline analysis project uses for its ReEDS modeling.

higher production from natural gas units in the new H12 one-hour time slice shows that the peak winter demand is properly captured.

**Table C-6. Comparison of results for key variables between the original ReEDS model and the version with a single-hour winter peak represented**

	2010	2012	2014	2016	2018	2020
<b>Capacity (GW)</b>						
Original ReEDS	737.33	755.14	740.61	728.29	738.67	739.52
1HR Winter Peak ReEDS	737.78	755.59	741.06	730.62	741.11	741.63
<i>% Difference</i>	0.061%	0.060%	0.061%	0.320%	0.330%	0.285%
<b>Generation (TWh)</b>						
Original ReEDS	2,937	2,838	2,849	2,941	3,010	3,041
1HR Winter Peak ReEDS	2,937	2,838	2,849	2,941	3,010	3,042
<i>% Difference</i>	-0.001%	-0.001%	-0.007%	-0.003%	0.000%	0.027%
<b>Coal Usage</b>						
Original ReEDS	15.62	12.54	13.33	12.98	13.56	13.42
1HR Winter Peak ReEDS	15.62	12.54	13.32	12.95	13.51	13.43
<i>% Difference</i>	0.000%	0.000%	-0.075%	-0.231%	-0.369%	0.075%
<b>Gas Usage</b>						
Original ReEDS	4.24	5.11	4.49	5.01	4.84	5.05
1HR Winter Peak ReEDS	4.25	5.11	4.49	4.98	4.87	5.02
<i>% Difference</i>	0.236%	0.000%	0.000%	-0.599%	0.620%	-0.594%
<b>CO2 Emissions</b>						
Original ReEDS	1.68	1.44	1.48	1.48	1.52	1.52
1HR Winter Peak ReEDS	1.68	1.44	1.48	1.47	1.52	1.52
<i>% Difference</i>	0.000%	0.000%	0.000%	-0.676%	0.000%	0.000%

Figure C-2. Generation by technology by time slice—Original ReEDS formulation

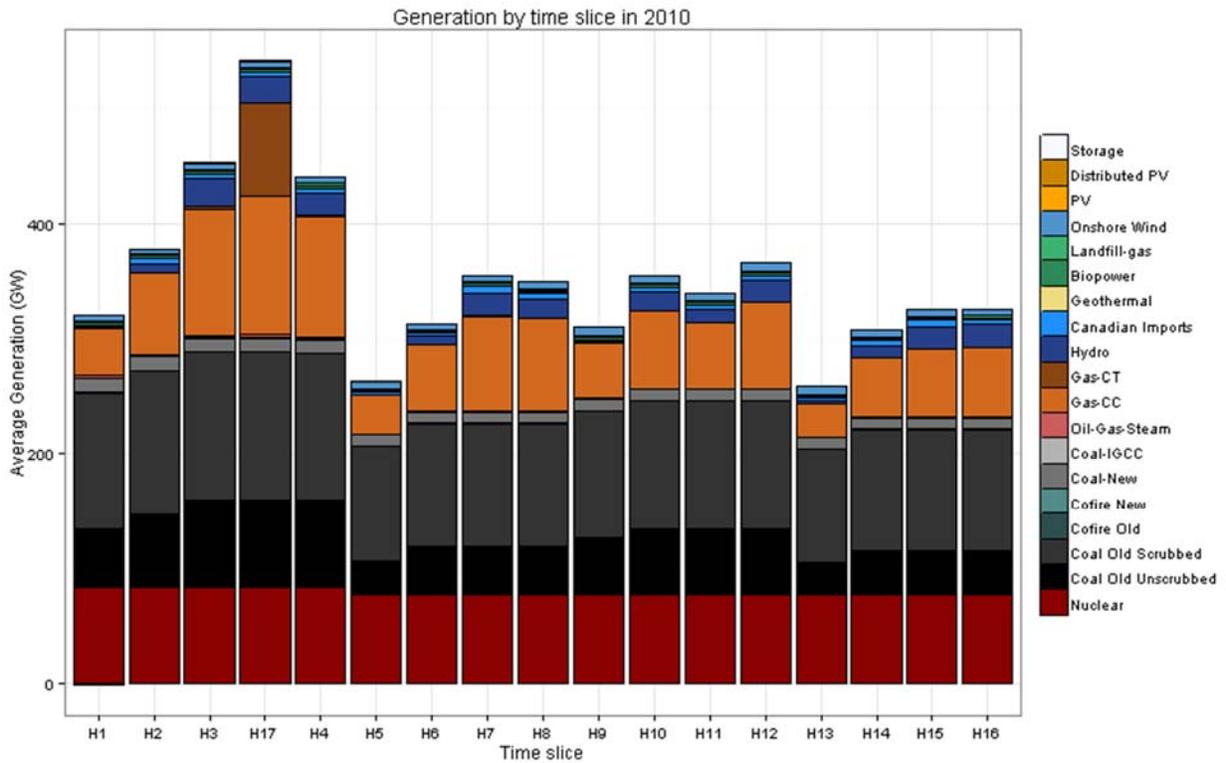
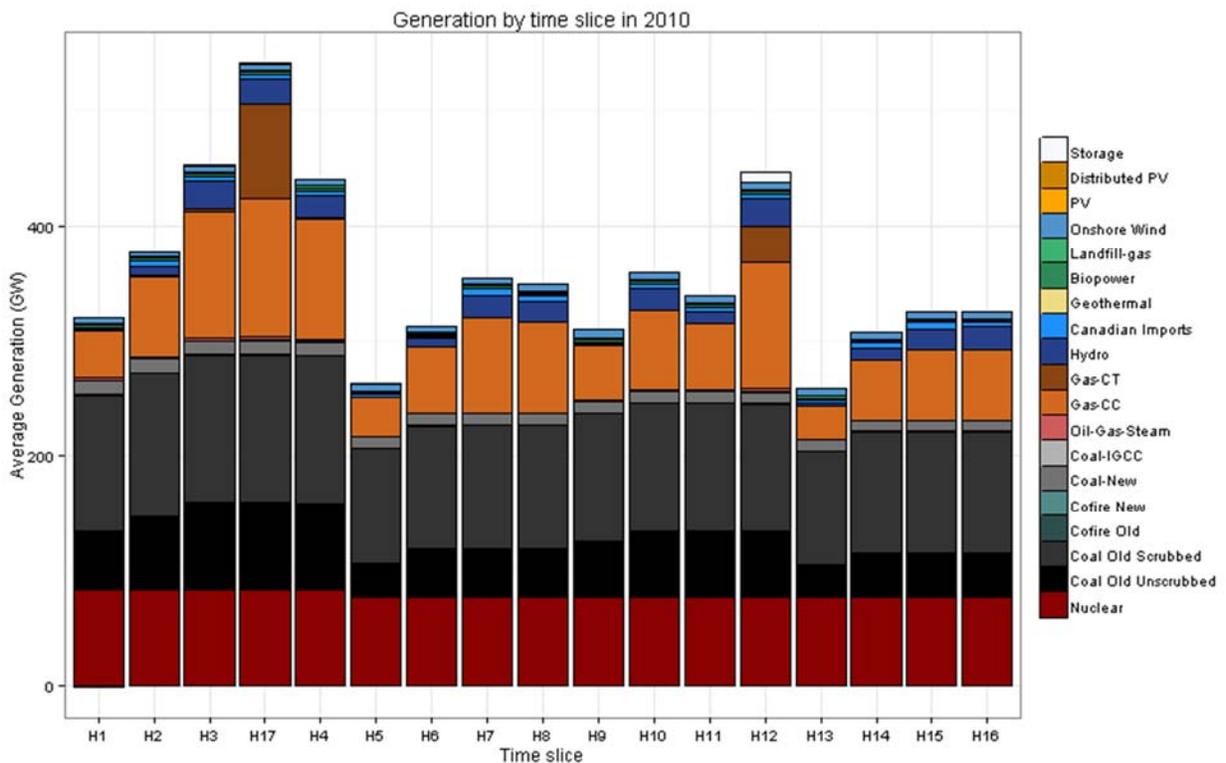


Figure C-3. Generation by technology by time slice—ReEDS with a one-hour Winter Peak (H12)





**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 7, Report on Need  
for the Constitution Pipeline, April 7, 2014.**

Anne Marie Garti  
814 Frisbee Road  
East Meredith, NY 13757

April 7, 2014

**VIA eFiling to FERC in Docket No. CP13-499**  
**VIA email to US Army Corps of Engineers**

Kimberly D. Bose, Secretary  
The FERC  
888 First Street NE, Room 1A  
Washington, D.C. 20426

Jodi M. McDonald  
Chief, Regulatory Branch  
US Army Corps of Engineers  
New York District, CENAN-OP-R  
Upstate Regulatory Field Office  
1 Buffington Street, Bldg. 10, 3rd Floor  
Watervliet, New York 12189-4000

**Re: Report on the Need for the Proposed Constitution Pipeline  
Comments on the Draft Environmental Impact Statement  
Docket Nos. CP13-499 and CP13-502; NAN-2012-00449-UBR**

Dear Secretary Bose and Ms. McDonald:

Attached please find a Report on the Need for the Proposed Constitution Pipeline, which is being submitted as a comment on the Draft Environmental Impact Statement for the proposed Constitution Pipeline Project. Once FERC assigns an accession number for this report, I will upload supporting documentation to the docket, in case it is needed in future hearings.

Thank you for this opportunity to comment.

Sincerely,



Anne Marie Garti

**Report on the  
Need for the Proposed Constitution Pipeline  
  
Analysis of the  
Draft Environmental Impact Statement  
Federal Energy Regulatory Commission (FERC)  
  
FERC EIS 0249D - - February 2014  
  
Docket Nos.: CP13-499; CP13-502; PF12-9**

Prepared by Anne Marie Garti, Esq.  
Information Analyst  
April 7, 2014

## Table of Contents

I.	Introduction	3
II.	Credentials	3
III.	FERC states the market for the gas is in New York City and New England	3
IV.	FERC's analysis is contingent upon a starting and end point for the proposed pipeline that appears unrelated to the use of gas in New York City and New England	4
V.	Gas cannot reach NYC and New England from Wright, NY because the interconnecting pipelines do not have room to accept 650,000 Dth/day of gas	6
VI.	The gas will be exported to Canada, and from there can be transported overseas	10
VII.	The proposed project is driven by excess supply, not market demand	19
VIII.	Recently completed and planned projects satisfy market demand	20
IX.	Potential local use is overstated, speculative, and unfair to landowners	23
X.	Conclusion	26

## **I. Introduction**

This report is an analysis of the need for the proposed Constitution Pipeline. The Federal Energy Regulatory Commission (“FERC”) repeatedly declares in its Draft Environmental Impact Statement (“DEIS”) that the market for this gas would be in New York City and New England. This statement, as well as others made in the DEIS, are compared with information found in other documents, such as studies performed by government agencies, information provided by the industry, and reports of industry consultants. The picture that emerges from this analysis is that the gas that would be shipped through the proposed pipeline would not be consumed in New York City and New England. Instead, most of it would be exported.

## **II. Credentials**

Anne Marie Garti was an information analyst and an interface and software designer for over two decades. Her clients ranged from start-ups to established corporations and institutions, including Citibank, IBM, Lucent Technologies, RCA Labs, National Gallery of Art, and Metropolitan Museum of Art.

## **III. FERC states the market for the gas is in New York City and New England.**

The statements made in FERC’s DEIS are consistent and repetitive: the gas in the proposed pipeline would be consumed in New York City and New England:

“According to Constitution, the proposed pipeline project was developed in response to natural gas market demands in the New York and the New England areas...”<sup>1</sup>

“Any system alternative for the projects would need to be able to transport similar volumes of natural gas to the vicinity of the existing Wright compressor station or to the ultimate market destinations of New York and New England.”<sup>2</sup>

“According to Constitution, the proposed pipeline project was developed in response to market demands in New York and the New England area. . . .”<sup>3</sup>

“this new natural gas supply for New York and New England markets”<sup>4</sup>

FERC’s statements reflect what was included in the application and draft resource reports of the Constitution Pipeline Company, LLC (“Company”). It should be noted that the application was submitted under oath by Scott Turkington, Director, Rates and Regulatory,

---

<sup>1</sup> FERC, *Draft Environmental Impact Statement*, ES-1 (Feb. 2014), available at [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20140212-4002](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20140212-4002) [hereinafter DEIS].

<sup>2</sup> *Id.* at ES-11.

<sup>3</sup> *Id.* at 1-1.

<sup>4</sup> *Id.* at 3-2.

Williams Gas Pipeline Company, LLC.<sup>5</sup> Submission under oath is a requirement of Rule 2011(c)(5) of the Commissions Rules of Practice and Procedure, 18 C.F.R. 385.2011(c)(5).

#### **IV. FERC's analysis is contingent upon a starting and end point for the proposed pipeline that appears unrelated to the use of gas in New York City and New England.**

In the DEIS, FERC states “The proposed projects would deliver up to 650,000 dekatherms per day (Dth/d) of natural gas supply from Susquehanna County, Pennsylvania to the interconnect with the TGP and Iroquois systems at the existing Wright Compressor Station (to markets in New York and New England).”<sup>6</sup> With that sentence, FERC appears to adopt the Company's assumption that the project is contingent upon a starting point in Susquehanna County, Pennsylvania, near Williams' new Central Compressor Station, which was authorized under state law, and ending in Wright, NY, near Iroquois' Compressor Station, which would be expanded under a current, and simultaneous, environmental review by FERC, under docket no. CP13-502.

FERC reasserts its commitment to these starting and end points in Section **3.2 System Alternatives**. There FERC states that system alternatives would only be practical, and economical, if they start in Susquehanna County, Pennsylvania, and end in Wright, NY.

Two of the Applicants' objectives that are **crucial** to the evaluation of system alternatives would be their ability to:

- deliver up to 650,000 Dth/d of natural gas supply from Susquehanna County, Pennsylvania to the interconnects with the Iroquois and TGP systems at the existing Wright Compressor Station (or otherwise delivery of the same amount of natural gas to the destination markets through other means); and
- expand access to new sources of natural gas supply, thereby increasing supply diversity and improving operational performance, system flexibility, and reliability in the New York and New England market areas.<sup>7</sup>

FERC does not justify why the proposed route must terminate approximately a hundred and fifty miles north of New York City, when the stated market for the gas is in New York City, except to say that it conforms to the Company's stated objectives.

FERC then engages in an analysis of potential system enhancements and co-location options within and along a series of existing pipeline routes, depicted in **Figure 3.2.1-1, Constitution Pipeline Project, Relative Location to Other Projects Overview Map**:<sup>8</sup>

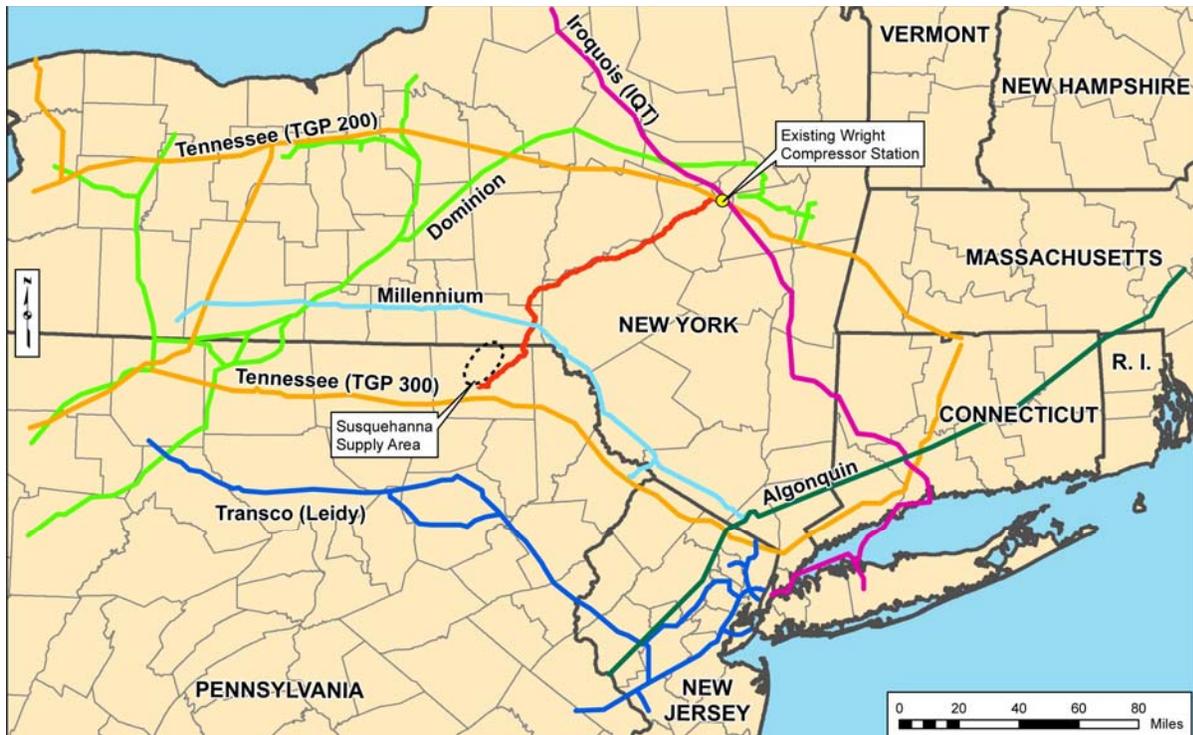
---

<sup>5</sup> Constitution Pipeline Company, LLC, *Application for Certificate of Public Convenience and Necessity*, pdf p. 25 (June 13, 2013), available at [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20130613-5078](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20130613-5078) [hereinafter Application].

<sup>6</sup> DEIS at ES-1. (TGP refers to the Tennessee Gas Pipeline.).

<sup>7</sup> *Id.* at 3-13. (Emphasis added.)

<sup>8</sup> DEIS, Figure 3.2.1-1.



FERC deems all of the options for system enhancements and alternatives infeasible, or not preferable to the proposed route. No detailed, side-by-side comparisons are made of environmental impacts of these alternate routes to the preferred route, and no explanation is made as to why all of the alternatives must end in Wright, NY.<sup>9</sup>

There is a clause contained within the Company’s objectives that states “(or otherwise delivery of the same amount of natural gas to the destination markets through other means)”.<sup>10</sup> By including this clause, FERC implies that the goal of the proposed project is to deliver gas to New York City and New England. However, FERC dismisses the possibility of routing the pipe to the east, and only analyzes alternatives that would deliver gas from Susquehanna County, Pennsylvania to Wright, NY. This makes all of the alternative routes that FERC considers in the System Alternatives section longer and more expensive.

Many system alternatives are missing from the analysis. For example, if a 124-mile long pipeline were to run from Susquehanna County, Pennsylvania to the southeast, instead of to the northeast, it would almost reach its market destination in New York City. FERC’s dismissal of the possibility of moving the gas east to New York City, and then north to New England, along the existing Millennium, TGP 200, or Transco pipeline easements, is based on the opinion that those options “would be constrained by the high level of development within New York City and the surrounding area.”<sup>11</sup> However, recent events call that judgment into question. Williams, which owns Transco, and is a partner in the Company, recently announced its plans to construct a new pipeline, collocated with the Transco line

<sup>9</sup> DEIS at 3-15 – 3-23.

<sup>10</sup> *Id.* at 3-13.

<sup>11</sup> *Id.* at 3-19.

part of the distance towards New York City.<sup>12</sup> In addition, other pipelines were recently constructed through high-density areas into Manhattan, and surrounding areas.<sup>13</sup> In June 2013 Spectra prefiled an application to increase its capacity on the Algonquin pipeline, which runs just north of New York City to New England.<sup>14</sup> If these pipeline companies can move gas east and north, through areas with a “high level of development”, then FERC needs to explain why the Company whose application is under review in this DEIS cannot do the same.

## **V. Gas cannot reach NYC and New England from Wright, NY because the interconnecting pipelines do not have room to accept 650,000 Dth/day of gas.**

FERC states in the DEIS that there is a need for additional pipelines to New York City and New England, but the supporting documentation provided in the DEIS is out-of-date and misleading. According to the project description, the “Iroquois’ project would provide additional compression allowing delivery of up to 650,000 Dth/d of natural gas from the terminus of the proposed Constitution pipeline into the existing Iroquois and the TGP systems.”<sup>15</sup> However, both the Iroquois and Tennessee Gas Pipelines (“TGP”) are congested into New York City and New England, and are therefore incapable of moving the gas that would be transported in this new pipeline to those markets.

New pipeline capacity has been added in Pennsylvania, New Jersey, along the east coast of New York State, and in Western New York State, but no new projects have been built in Central New York State. Thus there are still constraints where the Company’s proposed pipeline would terminate. In other words, while FERC states that the proposed pipeline must terminate in Wright, NY, there is no way to move 650,000 Dth/day of gas from that point to New York City and New England because the two pipelines that would transport it are already full, particularly at the times of the year when gas is most critically needed.

In the fall of 2013, Levitan and Associates, Inc (“Levitan”) issued a study of pipeline capacity in the New York Control Area (“NYCA”).<sup>16</sup> The Levitan assessment has three objectives, the first of which is “to analyze historical pipeline congestion patterns across NYCA.”<sup>17</sup> The overall conclusion of the report is that “New York State’s natural gas infrastructure is large, dynamic and more than adequate to serve the requirements of entitlement holders.”<sup>18</sup>

---

<sup>12</sup> *Williams Partners Transco Receives Binding Commitments for 1.7 Million Dekatherms per Day of Firm Natural Gas Pipeline Capacity on Its Proposed Atlantic Sunrise Expansion*, MARKET WATCH (Feb. 20, 2014), available at [http://www.marketwatch.com/story/skycross-reveals-new-products-and-technology-platform-as-well-as-partnership-program-to-advance-development-of-next-generation-wireless-broadband-front-end-solutions-2013-02-20?reflink=MW\\_news\\_stmp](http://www.marketwatch.com/story/skycross-reveals-new-products-and-technology-platform-as-well-as-partnership-program-to-advance-development-of-next-generation-wireless-broadband-front-end-solutions-2013-02-20?reflink=MW_news_stmp).

<sup>13</sup> See Section VIII of this report.

<sup>14</sup> *Algonquin Gas Transmission, LLC, Draft Resource Report 1 and Summary of Alternatives under PF13-16* (July 29, 2013), available at [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20130729-5146](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20130729-5146).

<sup>15</sup> DEIS at 2-6.

<sup>16</sup> *Levitan and Associates, Inc., NYCA Pipeline Congestion and Infrastructure Adequacy Assessment, New York Independent System Operator*, 3 (September 2013) [hereinafter Levitan]. (The Levitan assessment is attached.)

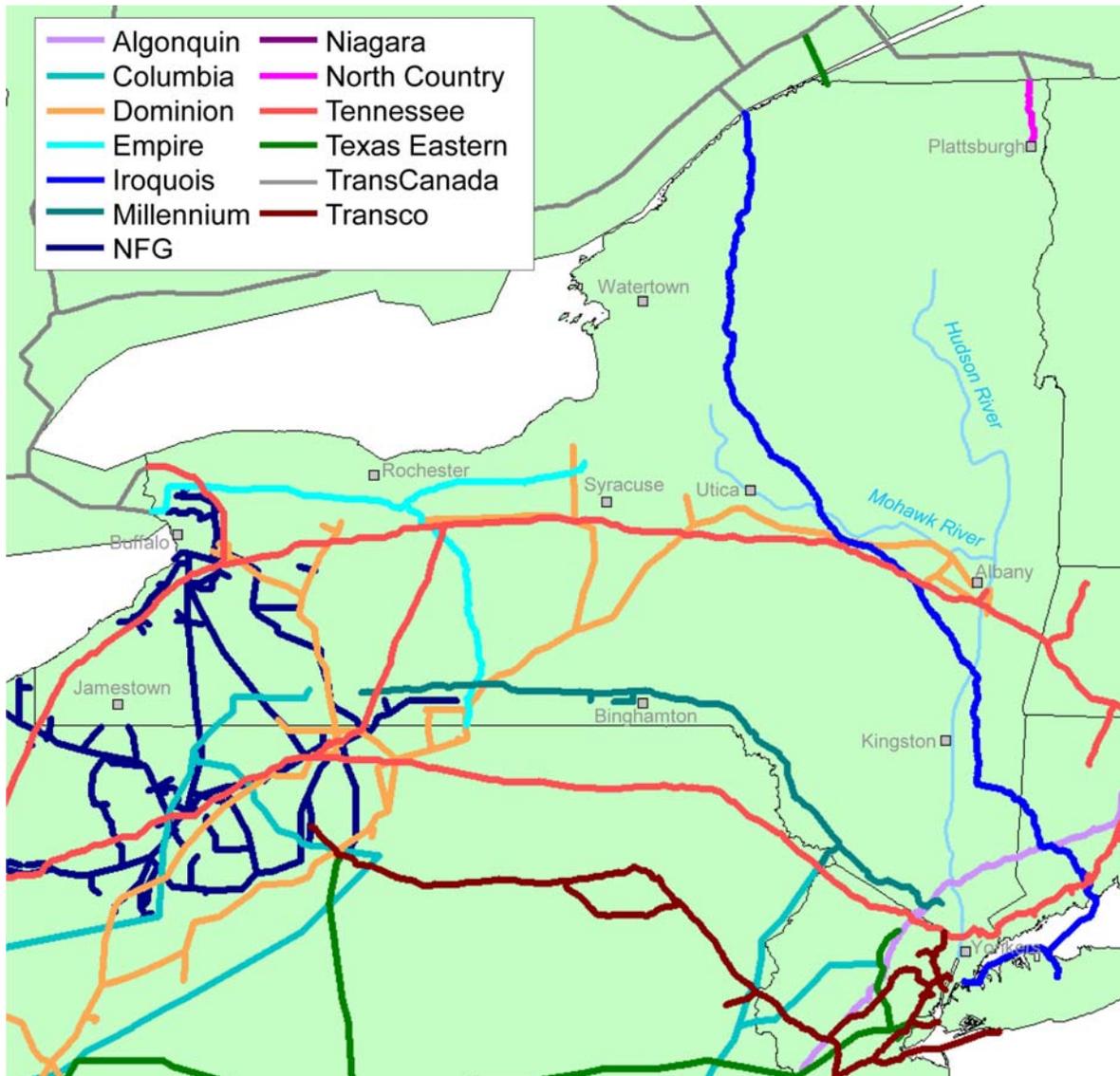
<sup>17</sup> Levitan at 1.

<sup>18</sup> *Id.* at 20.

Although NYCA has experienced increasing congestion levels on key transport paths in recent years, upcoming infrastructure expansions bringing Marcellus gas to market will materially increase infrastructure capability in the heart of the market, thereby lessening concerns over grid security related to fuel assurance.<sup>19</sup>

However, Wright, NY is not “in the heart of the market” and the Iroquois and Tennessee Gas Pipelines, which would interconnect with the “Constitution” pipeline, do not have room to accept the gas that would be transported by the proposed project to their stated destinations.

**Figure 1. Natural Gas Pipeline Network in NYCA<sup>20</sup>**



<sup>19</sup> Levitan at 1.

<sup>20</sup> *Id.* at 3.

For those unfamiliar with how the gas transmission business operates, pipeline companies generally have long-term firm contracts with Shippers, and short-term non-firm contracts with other purchasers, such as electric utility companies, who can buy gas on the spot market when there is sufficient room in the pipe above that day's demand by the firm Shippers. Once pipelines begin to reach full capacity, which normally occurs in the cold winter months in the north, prices can spike. During those periods, utility companies either use an alternative fuel, or pay a premium price for gas.

As part of its assessment, Levitan analyzed the congestion patterns of both the Iroquois and Tennessee Gas Pipeline 200 Line ("TGP"). Congestion doesn't have a precise definition, so Levitan applied utilization rates of 90% and 95% of available capacity as an indication of congestion.<sup>21</sup> Rates higher than that "are most likely to constrain the flow of natural gas to non-firm shippers in the relevant zones."<sup>22</sup>

The Iroquois Pipeline is owned by five corporations, including TransCanada Corp. ("TransCanada"), Dominion, and National Grid.<sup>23</sup> It runs from Waddington, at the New York and Canadian border, down to Long Island, and traditionally the gas flowed from Canada, at the north end, down to the New York metropolitan area at the south end. The Iroquois Pipeline has interconnections with TransCanada at Waddington, NY, with Dominion at Canajoharie, NY, with Tennessee at Wright, NY, and with the Algonquin at Brookfield, CT.<sup>24</sup> However, because it operates at higher pressures than some of these pipelines, Iroquois can only deliver gas at Waddington to TransCanada and at Brookfield to Algonquin, at its northern and southern ends.<sup>25</sup> It's capable of transporting 1,200,000 Dth/day of gas, almost twice the capacity of the proposed "Constitution" pipeline.

Both Brookfield and Waddington have high utilization rates during the winter months, with Brookfield also experiencing some congestion during the summer because of its proximity to the New York metropolitan area.<sup>26</sup> Therefore Iroquois could accept gas from the proposed "Constitution" pipeline from April through October, but gas is not needed during those seasons. During cold winter months, when there is a potential need for gas, there is not enough room on the Iroquois to accept the gas that would be transmitted on the proposed "Constitution" pipeline.

Congestion also exists on the Tennessee Gas Pipeline 200 Line, and at Station 245, near Wright, NY. **The congestion exists year round.**<sup>27</sup>

---

<sup>21</sup> Levitan at 38.

<sup>22</sup> *Id.*

<sup>23</sup> *Partners in Natural Gas Transportation*, IROQUOIS, available at <http://www.iroquois.com/natural-gas-transporters.asp>.

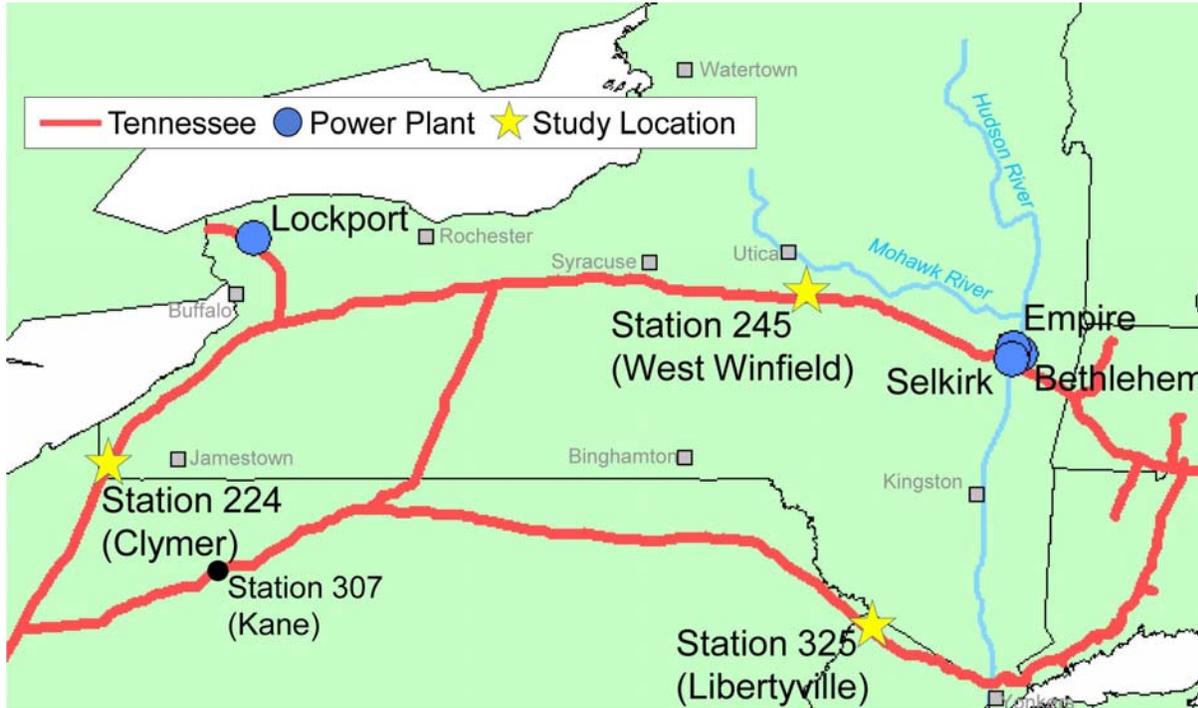
<sup>24</sup> Iroquois, *Natural Gas: Frequently Asked Questions*, available at <http://www.iroquois.com/natural-gas-questions.asp>.

<sup>25</sup> Levitan at 61-62.

<sup>26</sup> *Id.* at 60, 62, 66.

<sup>27</sup> *Id.* at 77. (Emphasis added.)

Figure 54. Tennessee Pipeline<sup>28</sup>



According to Levitan’s assessment,

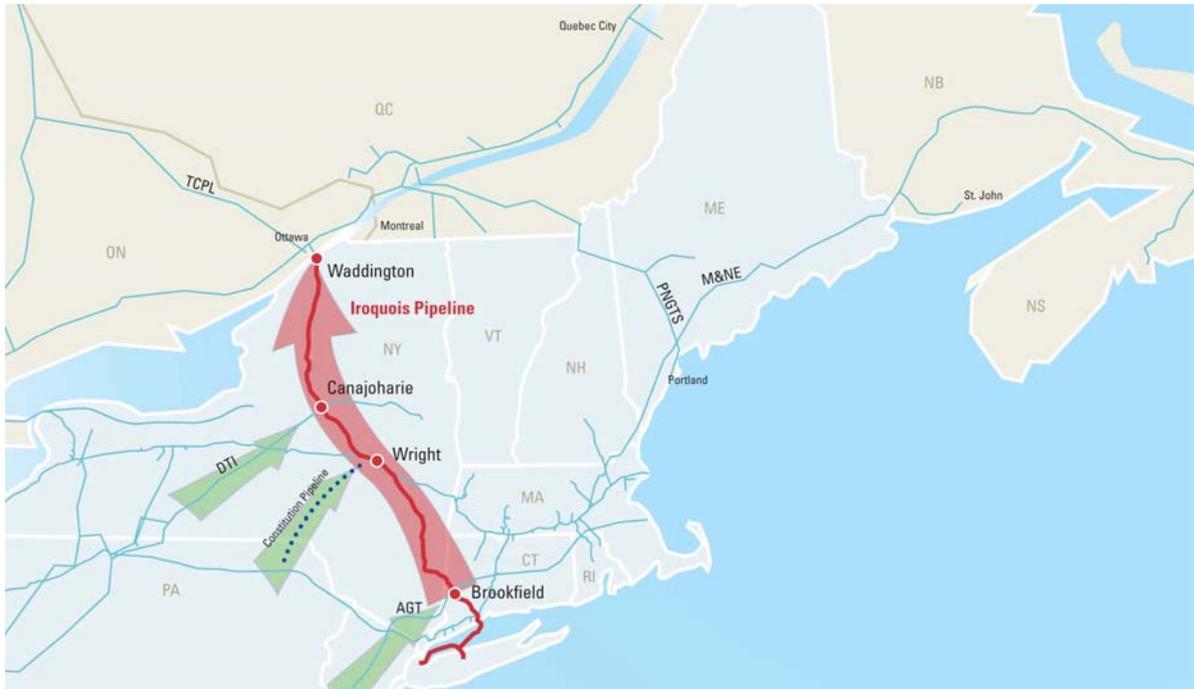
Station 245 is the principal bottleneck on Line 200, which causes deliveries on Tennessee downstream of Station 245 to be valued at the Tennessee Zone 6 pricing point, an index that is highly correlated with the Algonquin Citygates pricing point. Station 245 experienced pipeline utilization rates of 90% or greater on 588 days during the truncated time series, distributed roughly equally between the heating and cooling seasons.<sup>29</sup>

Since there are no pipelines capable of transporting gas from the proposed “Constitution” pipeline to New York City and New England, those markets should be removed from further consideration in the DEIS. The question that needs to be answered is, if there is no room on the Iroquois and Tennessee Gas Pipelines, then where would the gas from the proposed “Constitution” pipeline go? The answer is on the corporate website of Iroquois. Instead of going to New York City, the gas in the Iroquois pipeline would be exported to Canada.<sup>30</sup>

<sup>28</sup> Levitan at 73.

<sup>29</sup> *Id.* at 77.

<sup>30</sup> *South-to-North Open Season Brochure*, IROQUOIS, 1 (Dec. 2013), available at <http://www.iroquois.com/documents/SoNoOSBrochureFinal.pdf>.



## VI. The gas will be exported to Canada, and from there can be transported overseas

The network of gas pipelines enables a smooth movement of gas from one pipe to another via established points of interconnection. Much like blood in our vascular system, gas within the network is mixed and mingled, and acts like an integrated and unified whole. This pipeline network is not limited to the United States, but crosses the border into Canada. Until recently gas flowed from Western Canada into the United States. In New York State gas moved from west to east on the TGP 200 Line, and from north to south on the Iroquois. However, over the past three years, these patterns started to change, as the production and distribution of shale gas developed in Pennsylvania and Ohio, and as natural gas supplies in Western Canada diminished and were shifted to extract tar sands oil.<sup>31</sup> These developments were extensively covered in the oil, gas, and pipeline industry journals, and were therefore well known by the pipeline companies, and presumably by FERC. However, this dramatic change in the use of our resources is not in the public consciousness.

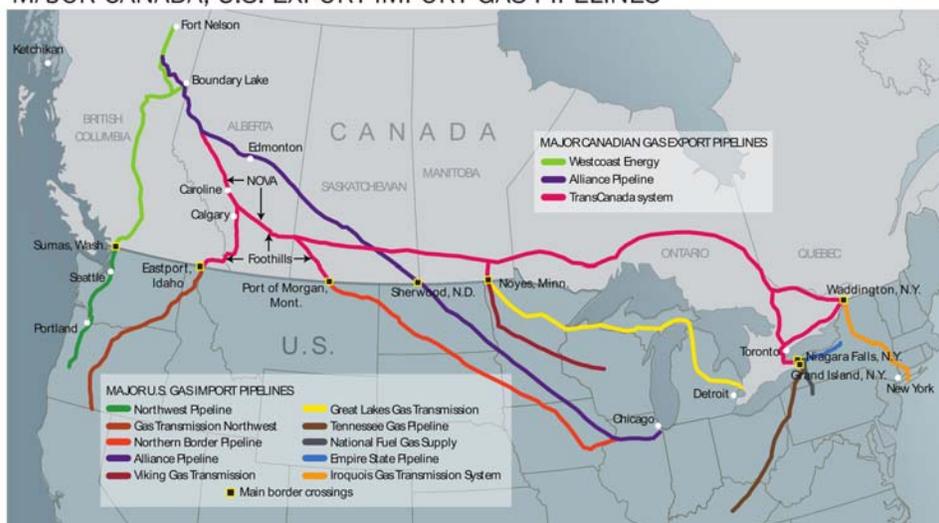
Iroquois began transporting gas from Canada into New York State in January 1992.<sup>32</sup> TransCanada, which has a network of 42,500 miles of gas pipelines, owns almost 45% of Iroquois.<sup>33</sup>

<sup>31</sup> Sandy Fielden, *Return to Sender No Such Demand Canadian Gas Flows Reverse at Niagara*, RBN ENERGY, LLC (Jan. 24, 2013), available at <https://rbnenergy.com/return-to-sender-no-such-demand-canadian-gas-flows-reverse-at-niagara> [hereinafter *Return to Sender*].

<sup>32</sup> *Iroquois Pipeline Operating Company*, INGAA FOUNDATION, available at <http://www.ingaa.org/Members/789.aspx>.

<sup>33</sup> *Natural Gas*, TransCanada, available at <http://www.transcanada.com/natural-gas-pipelines.html>.

## MAJOR CANADA, U.S. EXPORT-IMPORT GAS PIPELINES



34

On September 11, 2011, TransCanada announced its plans to begin reversing the flow of gas at Niagara Falls.<sup>35</sup> “U.S. shale gas is projected to cross the border via Canada's Niagara and Chippawa delivery points northwest of Buffalo, NY, reversing the flow at the TransCanada Mainline interconnects with the National Fuel Gas, Empire and Tennessee Gas Pipeline systems.”<sup>36</sup> Seven months later, the “Constitution” Pipeline Company, then owned by Williams and Cabot, requested permission from FERC to prefile an application for its “Constitution” pipeline.<sup>37</sup> The proposed pipeline would interconnect with the Tennessee and Iroquois, both of which have interconnections with TransCanada. Iroquois can also accept gas from the Algonquin and Dominion, and that gas could also be transported north to Canada. It therefore appears that the Company’s project was calculated to be part of a larger trend to move Appalachian shale gas north to Canada, which explains why it must terminate in Wright, NY.

Canada wants gas from the United States for a variety of reasons. The amount of gas being produced in Western Canada is diminishing, being diverted from Eastern Canadian markets to extract tar sands oil, and slated for export, where it can fetch higher prices.<sup>38</sup> In turn, Canada is planning to convert its Mainline from the transport of natural gas, to the transport

<sup>34</sup> *Alaska natural gas pipeline projects guide, maps*, ALASKA NATURAL GAS TRANSPORTATION PROJECTS (Oct. 7, 2013) available at <http://www.arcticgas.gov/sites/default/files/images/map-gas-pipeline-distribution-lower-48.png>.

<sup>35</sup> *Tide Turns at Niagara from U.S. Imports to Marcellus Shale Exports*, NGI Reports, BUSINESS WIRE, (September 11, 2011), available at <http://www.businesswire.com/news/home/20110913006702/en/Tide-Turns-Niagara-U.S.-Imports-Marcellus-Shale>.

<sup>36</sup> *Id.*

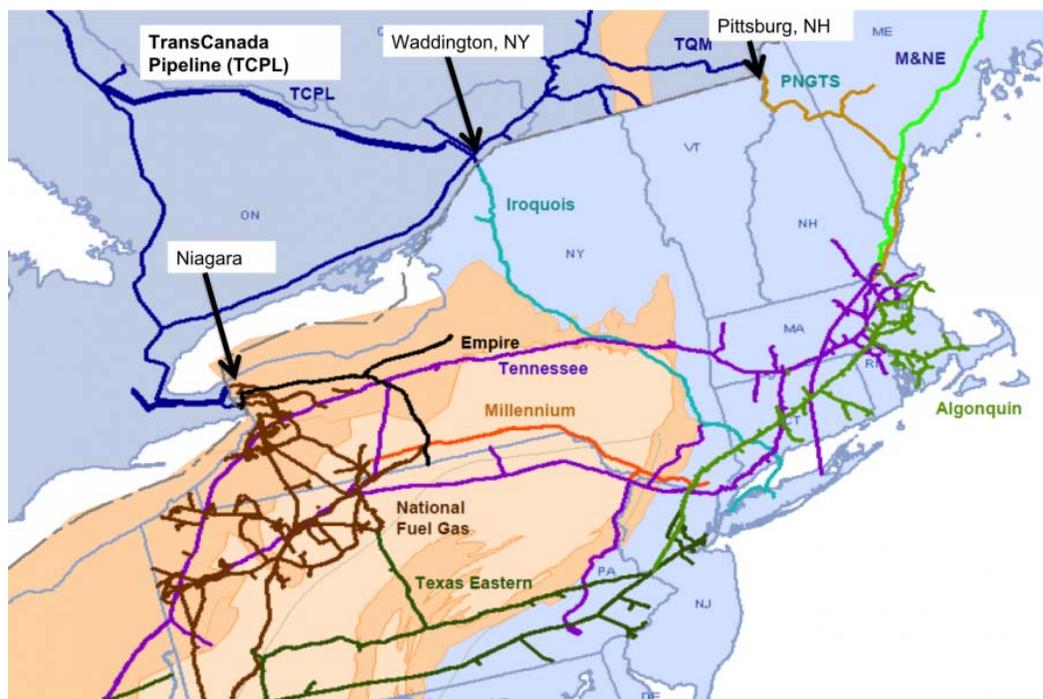
<sup>37</sup> Constitution Pipeline Company, LLC, *Request to Initiate Pre-Filing* (April 5, 2012), available at [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20120405-5066](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20120405-5066).

<sup>38</sup> Bob Bookstaber, ; *Deja vu all over again - Northeast Natural Gas, Pipelines and Big Decisions*, RBN ENERGY, LLC (Oct. 2, 2012), available at <https://rbnenergy.com/deja-vu-all-over-again%E2%80%9393northeast-natural-gas-pipelines-and-big-decisions>; Return to Sender; *NEB Approves Jordan Cove LNG Natural Gas Export License*, NATIONAL ENERGY BOARD (Feb. 20, 2014), available at <http://www.neb-one.gc.ca/clf-nsi/rthnb/nws/nwsrls/2014/nwsrls08-eng.html>.

of tar sands oil, so it can be exported from the Maritimes, in Northeast Canada.<sup>39</sup> This means that shale gas from the United States is needed to replace the gas from Western Canada that used to supply major cities in Eastern Canada, such as Toronto, Montreal, and Quebec. Finally, shale gas from the United States is cheaper than what can be produced in Canada.<sup>40</sup>

The convergence of these trends lead to an unusual coordination of Open Seasons over the past six months involving pipeline projects in and around Canada and the Northeast.<sup>41</sup> When looked at in totality, there appears to be a master plan that includes overseas exports via existing and planned import and export facilities along the coasts of New England and Maritimes Canada. There are dozens of export applications pending in both countries, and two of the potential LNG facilities are in Nova Scotia.<sup>42</sup> Therefore, an integrated look at the pipeline projects proposed for the Northeast shows that exports to Canada are assured, and LNG exports overseas are reasonably foreseeable.

Major pipelines in the northeast:<sup>43</sup>



<sup>39</sup> *TransCanada To Transport Oil From Western To Eastern Canada*, PIPELINE & GAS JOURNAL (Sept. 2013), available at <http://pipelineandgasjournal.com/transcanada-transport-oil-western-eastern-canada>.

<sup>40</sup> *Tide Turns at Niagara from U.S. Imports to Marcellus Shale Exports*, NGI Reports, BUSINESS WIRE, (September 11, 2011), available at <http://www.businesswire.com/news/home/20110913006702/en/Tide-Turns-Niagara-U.S.-Imports-Marcellus-Shale>; ICF Consulting Canada, Inc., *The Future of Natural Gas Supply for Nova Scotia*, ICF, 4 (March 28, 2013).

<sup>41</sup> An open season is used by pipeline companies to gauge the amount of market interest in existing pipelines, or in potential pipeline expansions. *Natural Gas Pipeline Development and Expansion*, EIA, available at [http://www.eia.gov/pub/oil\\_gas/natural\\_gas/analysis\\_publications/ngpipeline/develop.html](http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/develop.html).

<sup>42</sup> *LNG Export Licence Application Schedule*, NATIONAL ENERGY BOARD, available at <http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/lngxprtlnccpplctns/lngxprtlnccpplctns-eng.html#s2>; *North American LNG Import/Export Terminals, Proposed/Potential*, FERC (Sept. 12, 2013), available at <http://www.ferc.gov/industries/gas/indus-act/lng/lng-proposed-potential.pdf>.

<sup>43</sup> Return to Sender.

There are a number of existing LNG facilities in New England and the Maritimes.<sup>44</sup>



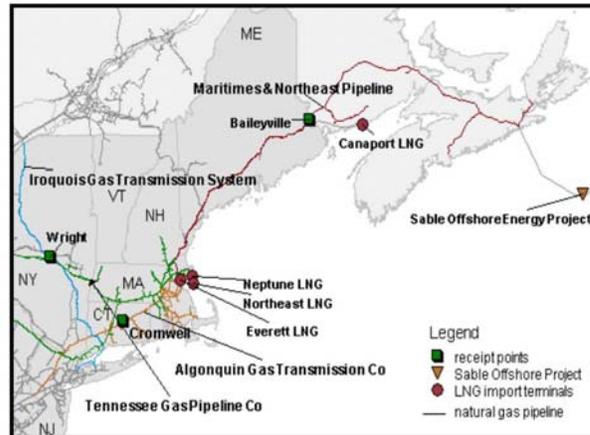
## New England Gas Supply Paths

### Canadian Supply

- East - declining production long term
- East - declining LNG imports
- West - supply constrained, transport cost very volatile

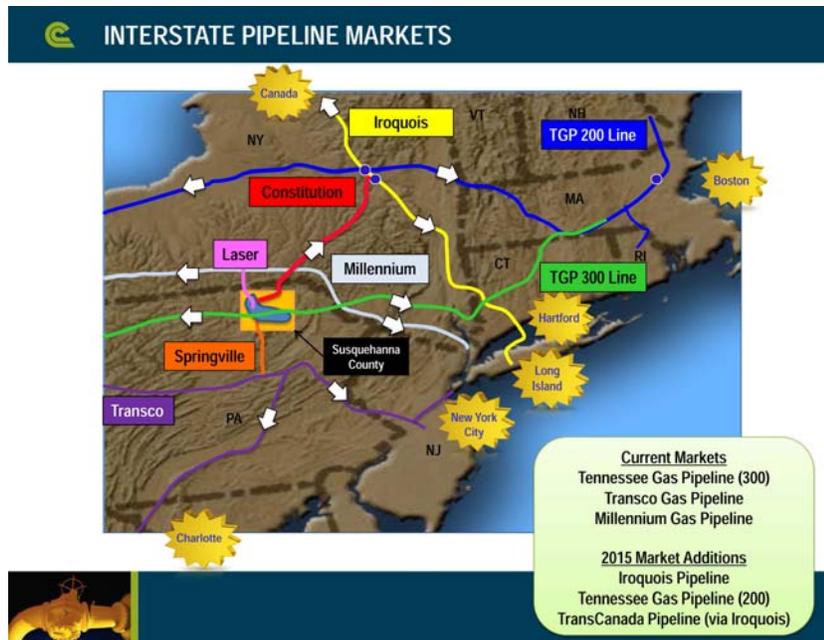
### U.S. Supply

- Marcellus / Utica shale “game changer” prolific supplies
- Tennessee Gas Pipeline – one of two major suppliers to region
- Expanded infrastructure needed



56

According to Cabot, Tennessee Gas Pipeline also plans to reverse the flow of its 200 Line at, or near, Wright, NY.<sup>45</sup> TGP has an interconnection with TransCanada near Niagara Falls.



<sup>44</sup> Tennessee Gas Pipeline, 2013 Shipper Meeting, 56, KINDER MORGAN (Aug. 14-16, 2013), available at <http://tebb.elpaso.com/TgpLookup/Presentations/08191312-111713-081913112518-2013%20Shipper%20Meeting%20Presentation.pdf>.

<sup>45</sup> Cabot Oil & Gas Corporation, Investor Presentation, 18 (Aug. 12, 2013), available at <http://www.enercominc.com/the-oil-and-gas-conference/presentation-pdf-downloads/>.

**Following is a list of projects in New York and Pennsylvania that were recently announced, which would increase the flow of gas into Canada, near Niagara Falls, and connect with TransCanada. The first, which set the stage, was completed in 2012.**

1. Tennessee Gas Pipeline Company (TGP)  
Name: Northeast Supply Diversification Project<sup>46</sup>  
Amount: 250,000 Dth/day increase on 300 line.  
Date: Placed in service on November 1, 2012.  
Shippers: Cabot, Anadarko, and Seneca
2. Tennessee Gas Pipeline Company (TGP)  
Name: Niagara Expansion Project<sup>47</sup>  
Amount: 153,000 Dth/day.  
Date: Announced 12/19/13. Expected in-service date of 11/1/15.  
Shipper: Seneca
3. National Fuel Gas Supply Corporation (NFGS)  
Name: Northern Access 2015<sup>48</sup>  
Amount: 158,000 Dth/day  
Date: Announced 12/17/13. Expected in-service date of 11/1/15.  
Shipper: Seneca
4. National Fuel Gas Supply Corporation (NFGS)  
Name: Westside Expansion and Modernization (West Side)<sup>49</sup>  
Amount: 175,000 Dth/day  
Date: Announced 12/17/13. Expected in-service date of 11/1/15.  
Shippers: Range and Seneca

**Following is a list of coordinated Open Seasons that would expand and integrate gas pipelines in Eastern Canada and New England.**

5. TransCanada Pipeline Limited (TCPL)<sup>50</sup>  
Owns: 44.5% of Iroquois  
61.7% of Portland Natural Gas Transmission System (PNGTS)  
Name: Eastern Triangle Natural Gas Pipeline Expansion Projects<sup>51</sup>  
Location: Between North Bay, Toronto and Montreal.

---

<sup>46</sup> *Northeast Supply Diversification*, KINDER MORGAN, available at [http://www.kindermorgan.com/business/gas\\_pipelines/east/TGP/NSD/](http://www.kindermorgan.com/business/gas_pipelines/east/TGP/NSD/).

<sup>47</sup> *Agreement reached to support Niagara Expansion Project*, PIPELINES INTERNATIONAL (Dec. 19, 2013), available at [http://pipelinesinternational.com/news/agreement\\_reached\\_to\\_support\\_niagara\\_expansion\\_project/084875/](http://pipelinesinternational.com/news/agreement_reached_to_support_niagara_expansion_project/084875/).

<sup>48</sup> *National Fuel Executes Contracts on Major Pipeline Expansions And Long-Term Firm Transportation Capacity*, NATIONAL FUEL (Dec. 17, 2013), available at <http://investor.nationalfuelgas.com/mobile.view?c=90873&v=203&d=1&id=1885288>.

<sup>49</sup> *Id.*

<sup>50</sup> *Natural Gas*, TRANSCANADA, available at <http://www.transcanada.com/natural-gas-pipelines.html>.

<sup>51</sup> *Eastern Triangle Natural Gas Pipeline Expansion Projects*, TRANSCANADA (Nov. 29, 2013), available at <http://www.transcanada.com/news-releases-article.html?id=1786765>.

Amount: Size would match interest and legal obligations  
Dates: Open Season from 11/29/13 to 1/15/14

6. Iroquois

Owners: TransCanada owns 44.48% of Iroquois  
Dominion owns 24.72% of Iroquois  
National Grid owns 20.40% of Iroquois<sup>52</sup>  
Name: South-to-North Project<sup>53</sup>  
Location: Brookfield, CT to Waddington, NY  
Interconnects with Algonquin at Brookfield, CT  
Would interconnect with the “Constitution” at Wright, NY  
Interconnects with Dominion at Canajoharie, NY  
Interconnects with TransCanada at Waddington, NY  
Serving: Eastern Canadian and Northern New England Markets  
Amount: 300,000 Dth/day (available on this Open Season)  
Dates: Open Season from 12/3/13 to 1/24/14.  
Expected in-service date of November 2016.

7. Dominion Transmission

Owns: 24.72% of Iroquois  
Name: Iroquois Access<sup>54</sup>  
Amount: 250,000 Dth/day  
Location: Leidy, PA to Canajoharie, NY  
Interconnects with Iroquois at Canajoharie, NY  
Date: Completed Open Season. Expected in-service date of November 2016.

8. Spectra Energy

Owns: 77.6% of Maritimes and Northeast Pipeline<sup>55</sup>  
Name: Algonquin Incremental Market (AIM) Project<sup>56</sup>  
Amount: 342,000 Dth/day  
Location: Ramapo, NY to Boston, MA  
Interconnects with Iroquois at Brookfield, CT  
Interconnects with Maritimes and Northeast Pipeline near Beverly, MA  
Date: Pre-Filed 7/29/13 (PF13-16). Expected in-service date of November 2016.

---

<sup>52</sup> *Partners in Natural Gas Transportation*, IROQUOIS, available at <http://www.iroquois.com/natural-gas-transporters.asp>.

<sup>53</sup> *South-to-North Open Season Brochure*, IROQUOIS, 1 (Dec. 2013), available at <http://www.iroquois.com/documents/SoNoOSBrochureFinal.pdf>.

<sup>54</sup> Josh Eakle, *Dominion - Expanding to Meet the Needs of the Marcellus and Utica Shales*, INGAA FOUNDATION, 12 (April 11-13, 2012); *South-to-North Open Season Brochure*, IROQUOIS, 2 (Dec. 2013), available at <http://www.iroquois.com/documents/SoNoOSBrochureFinal.pdf>.

<sup>55</sup> Canadian Natural Gas Pipelines, SPECTRA ENERGY, available at <http://www.spectraenergy.com/Operations/Canadian-Natural-Gas-Pipelines/MaritimeNortheast-Pipeline/>. (“The Maritimes & Northeast Pipeline brings offshore, onshore and LNG-sourced natural gas from Atlantic Canada to North American markets.”)

<sup>56</sup> *Algonquin Incremental Market (AIM) Project*, SPECTRA ENERGY (July 29, 2013), available at <http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/Algonquin-Incremental-Market-AIM-Project/>.

9. Spectra Energy

Owns: Algonquin and 77.6% of Maritimes and Northeast Pipeline<sup>57</sup>

Name: Atlantic Bridge<sup>58</sup>

Amount: 100,000 to 600,000 Dth/day expansion, based on interest.  
Reversal of gas flow in the Maritimes and Northeast Pipeline

Location: Boston, MA to Nova Scotia

Interconnects with Maritimes and Northeast Pipeline near Beverly, MA

Date: Open Season from 2/5/14 to 3/31/14.

10. Portland Natural Gas Transmission System (PNGTS)

Owners: TransCanada owns 61.7% of Portland Natural Gas Transmission System

Name: Continent 2 Coast Expansion Project<sup>59</sup>

Location: Pittsburg, NH to Westbrook, ME

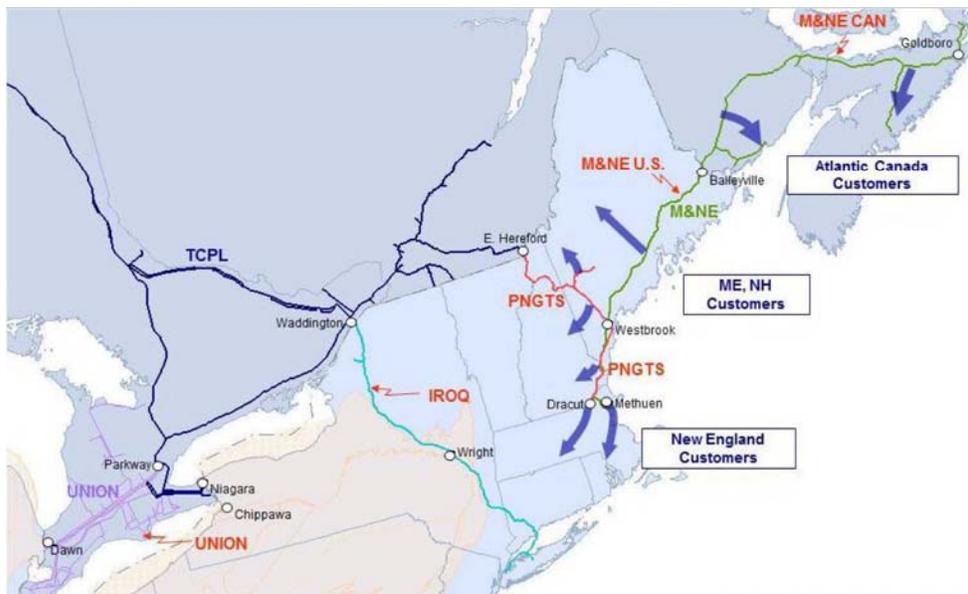
Interconnects with Trans-Quebec at E. Hereford

Interconnects with Maritimes & Northeast at Westbrook, ME

Interconnects with Tennessee Gas Pipeline in Dracut, MA

Amount: 132,000 Dth/day increase

Dates: Open Season from 12/3/13 to 1/24/14



<sup>57</sup> Canadian Natural Gas Pipelines, SPECTRA ENERGY, available at <http://www.spectraenergy.com/Operations/Canadian-Natural-Gas-Pipelines/MaritimeNortheast-Pipeline/>. (“The Maritimes & Northeast Pipeline brings offshore, onshore and LNG-sourced natural gas from Atlantic Canada to North American markets.”)

<sup>58</sup> Spectra Energy to Expand Pipeline Systems in New England, SPECTRA ENERGY (Feb. 5, 2014), available at <http://www.spectraenergy.com/Newsroom/News-Archive/Spectra-Energy-to-Expand-Pipeline-Systems-in-New-England/>.

<sup>59</sup> Open Season Notice, Portland Natural Gas Transmission System, <http://www.gasnom.com/ExternalFiles/SitesIP/pngts/OpenSeasonDocumentAndBindingRequest.pdf>.

## 11. Kinder Morgan – Tennessee Gas Pipeline (TGP)

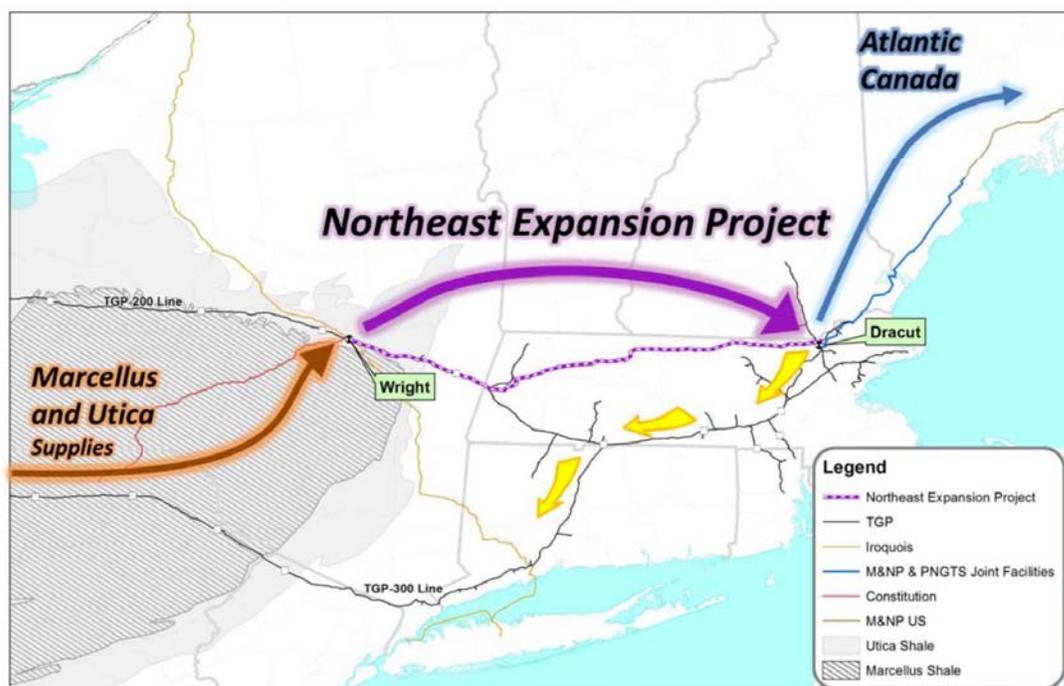
Name: Northeast Expansion Project<sup>60</sup>

Location: Wright, NY to Dracut, MA  
interconnects with PNGTS at Dracut, MA

Serving: Northern New England, Atlantic Canada, with ability to export from there

Amount: 600,000 to 2,200,000 Dth/day

Dates: Open Season from 2/13/14 to 3/28/14.



The dozen pipeline projects (including the “Constitution”) summarized above show the extent of the interest in moving large volumes of gas out of Pennsylvania (and New York) to Canada and overseas. In combination, these projects paint the big picture of where shale gas extracted in the Northeast is going, and that image mocks the industry’s ads that tout energy independence for the United States. Here we see a consortium of companies, many of them interrelated and with partial Canadian ownership, engaged in coordinated planning in order to export a massive amount of fracked shale gas to Canada and around the world.

It must be noted that the Acting Chair of FERC, Cheryl A. LaFleur, “served as executive vice president and acting CEO of National Grid USA.”<sup>61</sup> National Grid owns 20.40% of Iroquois.<sup>62</sup>

<sup>60</sup> Northeast Expansion Project Open Season, KINDER MORGAN, available at [http://www.kindermorgan.com/business/gas\\_pipelines/east/neupopenseason/](http://www.kindermorgan.com/business/gas_pipelines/east/neupopenseason/).

<sup>61</sup> Biography, FERC, available at <https://www.ferc.gov/about/com-mem/Lafleur/bio.asp>.

<sup>62</sup> *Partners in Natural Gas Transportation*, IROQUOIS, available at <http://www.iroquois.com/natural-gas-transporters.asp>.

Figure 2-2 Maritimes and Northeast Pipeline United States<sup>63</sup>

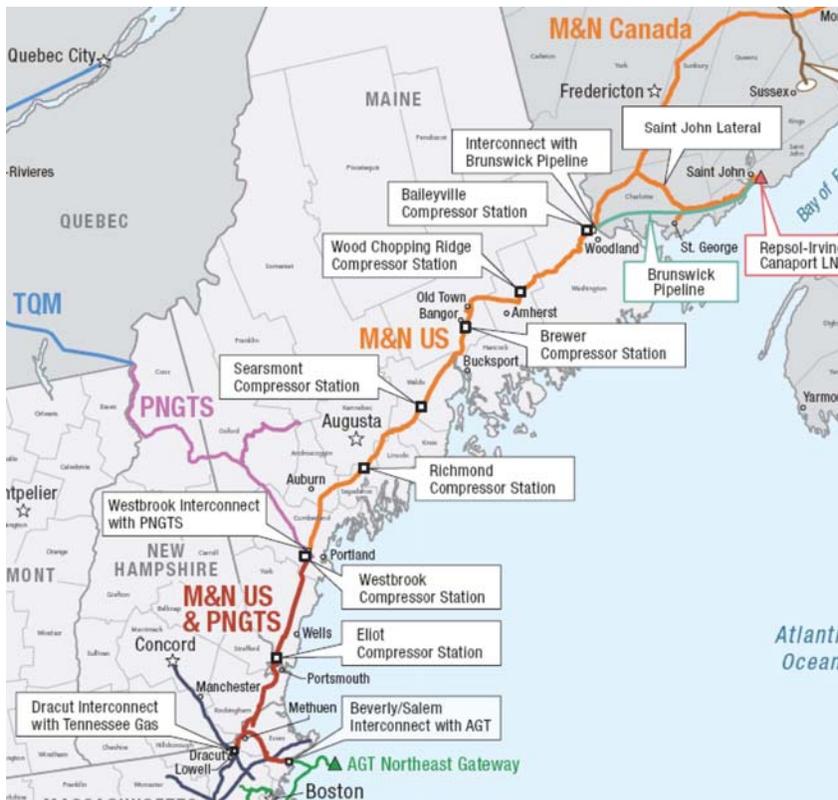
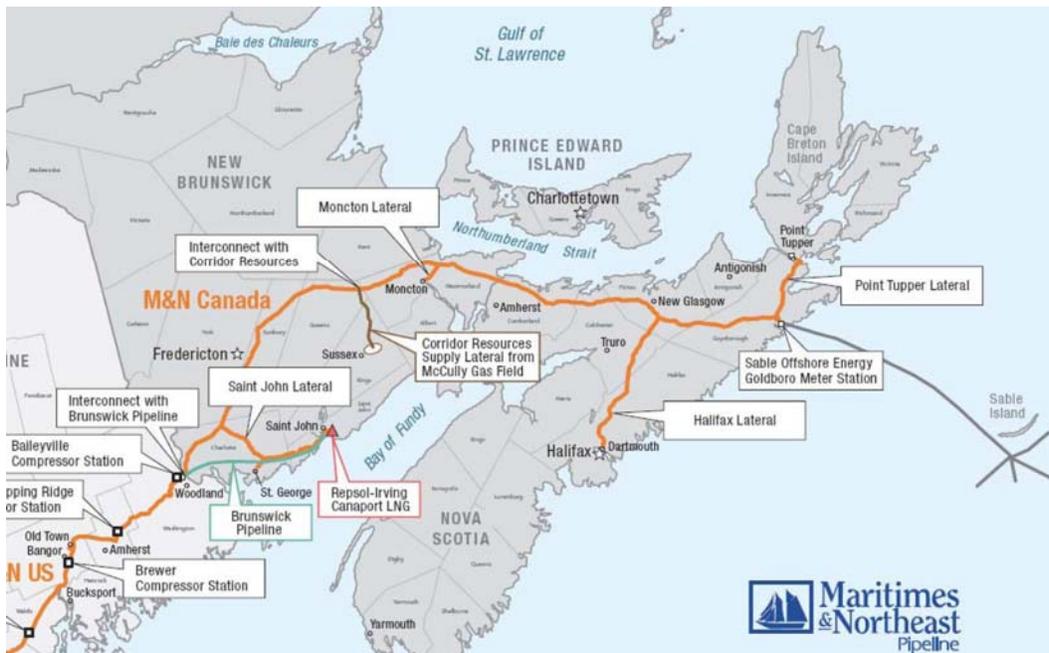


Figure 2-1 Maritimes and Northeast Pipeline Canada<sup>64</sup>



<sup>63</sup> ICF Consulting Canada, Inc., *The Future of Natural Gas Supply for Nova Scotia*, ICF, 12 (March 28, 2013).

<sup>64</sup> *Id.* at 11.

## VII. The proposed project is driven by excess supply, not market demand

The shale gas industry suffers from a glut of gas that comes from overproduction. This has driven down the price of gas, which forces gas companies to drill even more in order to meet their expenses. As a result of this vicious cycle, some companies that are drilling in Pennsylvania are integrating the transport of gas into their businesses. “Producers with large portfolios in Marcellus have been primarily responsible for the financial commitments on the new pipeline and storage facilities to accommodate soaring production from Marcellus, including new pipeline projects into the LHV and NYC.”<sup>65</sup>

This is particularly true with the proposed “Constitution” pipeline because the entities that have partnered to form the Company, and the entity that has contracted to ship most of the gas through the proposed pipeline, have many interrelated shale gas business relationships. For example, Cabot Oil and Gas Corporation, which holds many gas drilling leases in north central Pennsylvania, will be shipping 500,000 of the 650,000 Dth/d in the proposed pipeline.<sup>66</sup> The gas driller’s wholly owned subsidiary, Cabot Pipeline Holdings, LLC, owns 25% of the Company.<sup>67</sup> Similarly, a number of companies owned by Williams are drilling, gathering, compressing, and distributing Pennsylvania gas, and are positioning themselves to play a similar role in New York.<sup>68</sup> Williams Field Services Company, LLC builds gathering lines and compressor stations, Williams Partners Operating, LLC currently owns 41% of the Company (down from 75% when the application was pre-filed), and Williams Pipeline Company, LLC will operate and maintain the pipeline once it is constructed.<sup>69</sup> In other words, these companies are proposing to drill for gas, to gather it, and to build an interstate pipeline through which they can transport the gas they have sold to themselves after they have extracted, gathered, and compressed it. Whether there is any public interest, or actual market need, in these arrangements is yet to be determined.

The Company more or less admits that it is seeking a market for its excess supply of gas in its application to FERC.

The Project will provide firm access to new sources of gas supply being developed in North Central Pennsylvania, which is experiencing a dramatic increase in natural gas production, primarily from the development of shale

---

<sup>65</sup> Levitan, 18-19. (LHV stands for Lower Hudson Valley.)

<sup>66</sup> Constitution Pipeline Company, LLC, Application for Certificate of Public Convenience and Necessity, Exhibit A, Articles of Incorporation and Bylaws, Exhibit C, pdf p. 66 (June 13, 2013), *available at* [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20130613-5078](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20130613-5078) [hereinafter Application].

<sup>67</sup> Application, Exhibit A, Articles of Incorporation and Bylaws, Exhibits A & D, pdf pp. 64, 67; Amendments to LLC Agreements, pdf pp. 68, 77; Application, Exhibit D, Subsidiaries and Affiliations, pdf p. 133.

<sup>68</sup> Application of Williams Field Services Company, LLC and DMP New York, Inc. for a Certificate of Environmental Compatibility and Public Need Pursuant to Construct an Approximately 9.5 Mile Natural Gas Gathering Pipeline in the Town of Windsor, Broome County, (Dec. 2, 2013), *available at* <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=44189>; Williams Field Services, Petition for Approval to NYSPSC, 4 (Feb. 7, 2013), *available at* <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={543877AE-3417-4535-8864-B3EA878498D2}>.

<sup>69</sup> Application, Exhibit A, Articles of Incorporation and Bylaws, Exhibits A & D, (pdf p. 64, 67); Exhibit D, Subsidiaries and Affiliations (pdf p. 133); Amendments to LLC Agreements (pdf pp. 68, 77); Construction, Operation and Maintenance Agreement (pdf p. 91).

deposits. This increased production has the potential to provide economic benefits to the region by increasing competition among fuel sources, and to increase the reliability and diversification of the nations supply of natural gas.<sup>70</sup>

The Company is not alone in seeking a market for its shale gas. In a recent interview, Justin Carlson, an analyst of natural gas markets for Bentek EnergyBentek, was asked:

**Q:** So is there a demand for all this gas?

**A:** Right now, there's not. We've seen a substantial amount of basins that have had to pull back partially because gas prices are not high enough. . . .

**Q:** In your presentation you mentioned all the proposed LNG [liquefied natural gas] exports projects. Do those need to happen in order for the market to balance?

**A:** Right now, to balance the market, those need to happen. If you exclude those, we're going to have to reduce our production profile pretty substantially.<sup>71</sup>

Domestic gas companies have too much gas, with too low prices, to meet their overhead and investor demand for growth. In their search for new markets, they are forcing an unprecedented build out of gas pipelines, and reversing the flow of others, that will enable them to export gas to Canada, and overseas. Therefore statements in FERC's DEIS that the gas transported in the proposed "Constitution" Pipeline would be for the New York and New England markets are misrepresentations of the truth, and must be corrected.

### **VIII. Recently Completed Projects Satisfy Market Demand in New York City**

One of FERC's roles is to ensure there is no overbuilding of pipeline capacity. Such an analysis requires the inclusion of the most current pipeline information. Instead, FERC's DEIS refers to a two-year old assessment and a five-year old report, both of which are extremely out of date because of the extensive amount of recent pipeline construction.

FERC's DEIS states:

The New York State Energy Planning Board (2009) assessment of natural gas markets in New York and in the northeast concluded that most of the interstate transmission pipelines in the region are at or near capacity on peak days, and that by 2018 unmet peak day natural gas demand for New York and New England could range between an estimated 300,000 to 900,000 Dth/d.<sup>72</sup>

---

<sup>70</sup> Application at 8.

<sup>71</sup> Marie Cusick, *With A Glut Of Gas, Industry Looks To Increase Demand*, STATEIMPACT, NPR (Sept. 10, 2013), available at <http://stateimpact.npr.org/pennsylvania/2013/09/10/with-a-glut-of-gas-industry-looks-to-increase-demand/>.

<sup>72</sup> DEIS at 3-2.

This information, from a 2009 assessment, is no longer true, and more recent, and accurate, information is easily available. For example, in the fall of 2013 Levitan reported that “[s]everal noteworthy pipeline expansions have occurred in and around New York since November 2009, many of which are contracted by producers to transport Marcellus gas to the market center in New Jersey and NYC.”<sup>73</sup>

FERC’s DEIS states:

Other reports have also documented increased demand for natural gas in New York and New England and the lack of adequate pipeline capacity to deliver required volumes of natural gas (ISO-New England 2012, ICF International 2012).<sup>74</sup>

ICF updated the report FERC quotes in late 2013, finding New England has sufficient pipeline capacity to meet its firm contracts, but not enough for non-firm contracts of utility companies on hot summer, and cold winter days.<sup>75</sup> It is projected that there will be unmet demand for electric production on 24 to 34 days of the winter season in 2019/20.<sup>76</sup> The DEIS should consider whether new pipelines should be constructed through “greenfields” to meet a few weeks of shortage per year. Also, additional pipeline capacity is not the only way to meet that need, and the ICF analysis did not consider the possibilities of conservation, solar, and offshore wind to supply electricity for 24 to 34 days per year.

A review of recently completed projects in and near New York State show that market demand in New York City has been met. According to Levitan,

Spectra’s 800-MDth/d New Jersey – New York Expansion Project and Transco’s 250-MDth/d Northeast Supply Link Project, of which 200 MDth/d will flow to NYC, will increase deliverability into the New York Facilities System by approximately 30%. Both the New Jersey – New York Expansion Project and the Northeast Supply Link Project are designed to accommodate soaring gas production from Marcellus. These two projects represent 1,000 MDth/d, approximately 1 Bcf/d, of incremental deliverability into NYC.<sup>77</sup>

The following tables list recent pipeline projects that were not included in FERC’s analysis. If they had been discussed, the conclusions about the need for more gas in the target markets would have been different.

---

<sup>73</sup> Levitan and Associates, Inc., *NYCA Pipeline Congestion and Infrastructure Adequacy Assessment, New York Independent System Operator*, 22 (September 2013) [hereinafter Levitan]. (The Levitan assessment is attached.)

<sup>74</sup> DEIS at 3-2, 3-3.

<sup>75</sup> Kevin R. Petak and Frank Brock, *Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs, Phase II*, 7, ICF INTERNATIONAL (December 18, 2013).

<sup>76</sup> *Id.* at 29.

<sup>77</sup> Levitan at 8. (Spectra’s New York Expansion Project and Transco’s Northeast Supply Link Project came online in November 2013.)

**Recently completed pipelines and compressor stations (2010 - 2013)  
Increased availability of gas in Southern and Eastern New York State, and beyond**

<b>Name</b>	<b>Pipeline Co.</b>	<b>Docket</b>	<b>MDth/day</b>	<b>Interconnection, Destination</b>
Laser Northeast	Williams	NYSPSC	400	Millennium, NY
Bluestone Gathering	Bluestone	NYSPSC	600	Millennium, NY Tennessee, PA
Minisink Compressor	Millennium	CP11-515	150	Algonquin, NY
300 Line Project	Tennessee	CP09-444	350	PA, NY, CT, MA 50 MDth White Plains
Bayonne Delivery Lateral Project	Transco	CP09-417	250	Bayonne, NJ, north of Staten Island
TEAM 2012	Texas Eastern	CP11-67	200	Transco and Eastern Shore, PA
MARC I	Inergy	CP10-480	550	Transco, PA to NY
NJ – NY Expansion Project	Spectra	CP11-56	800	Manhattan, NY
Northeast Upgrade Project	Tennessee	CP11-161	636	Algonquin in Mahway, NJ
Northeast Supply Link Project	Transco	CP12-30	250	NJ and NYC

**Recently Completed Pipelines and Compressor Stations (2010 - 2013)  
Increased availability of gas in Western New York State, and Canada**

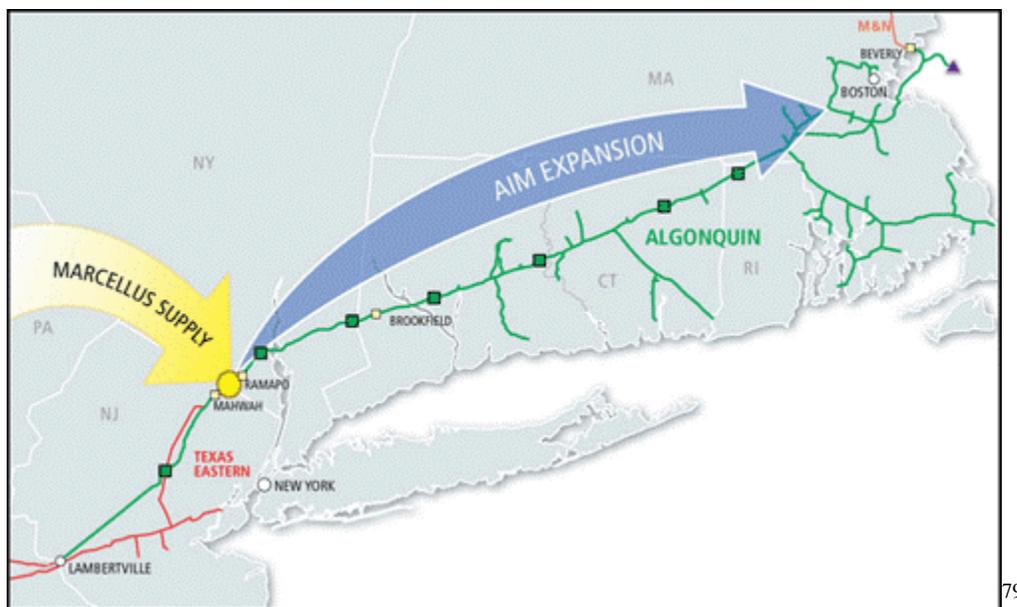
<b>Name</b>	<b>Pipeline Co.</b>	<b>Docket</b>	<b>MDth/day</b>	<b>Interconnection, Destination</b>
Tioga County Extension Project	Empire	CP10-493	350	Empire
Northeast Supply Diversification Proj.	Tennessee Dominion	CP11-30 CP11-41	250	Niagara, TransCanada Exports – Nov. 2012
Northern Access Project	NFG / Tennessee	CP11-128	250	Niagara, TransCanada Exports – Jan. 2013

**Pending projects that may increase capacity in or through New York State.**

<b>Name</b>	<b>Pipeline Co.</b>	<b>Docket</b>	<b>MDth/day</b>	<b>Interconnection, Destination</b>
Hancock Compressor Project	Millennium	CP13-14	107.5	Algonquin, Ramapo, NY
Northeast Connector	Transco	CP13-132	100	Rockaway Lateral, NY
Rockaway Lateral Project	Transco	CP13-36	647	Ngrid, NY
Woodbridge Delivery Lateral	Transco	CP14-18	264	NJ
TEAM 2014	Texas Eastern	CP13-84	600	PA and NY

East Side Expansion Project	Columbia	CP14-17	312	Millennium and Tennessee
Algonquin Incremental Market	Algonquin	PF13-16	433	NY to New England

FERC’s DEIS fails to include current information on pipeline capacity and market need for gas in New York City. In addition, a major expansion of capacity from New York to New England, which is currently under review by FERC, is not mentioned in the DEIS.<sup>78</sup>



These recent projects fulfill the need for gas in the markets the Company’s proposed pipeline is supposed to serve. Therefore the assessments and reports referred to by FERC are out-of-date. Since FERC is authorized to approve all of these pipeline projects, and maintains an extensive library of the material in its dockets, it raises questions about why the data in the DEIS is so dated. FERC should revise the DEIS to include up-to-date information on market need and pipeline capacity.

**IX. Potential local use is overstated, speculative, and unfair to landowners**

In order to take private property through eminent domain under the Natural Gas Act, and to fill wetlands under the Clean Water Act, there must be sufficient public need for the project. In the DEIS, Section 1.1 Project Purpose and Need is approximately one and a half pages long. A full paragraph, amounting to a third of a page, describes the potential use of gas by a local distribution company – a start-up that has never delivered gas in New York State.

<sup>78</sup> Algonquin Gas Transmission, LLC, *Draft Resource Report 1 and Summary of Alternatives under PF13-16* (July 29, 2013), available at [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20130729-5146](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20130729-5146).

<sup>79</sup> Chris Dubay, *New England Natural Gas Pipeline Projects Needed Sooner Than Later*, ENERGY BIZ (Dec. 12, 2013), available at <http://www.energybiz.com/article/13/12/new-england-natural-gas-pipeline-projects-needed-sooner-later>.

As noted in the second bullet above, Constitution has identified that the proposed pipeline could provide natural gas service to nearby municipalities that do not currently have access to natural gas. According to Leatherstocking Gas Company, LLC (Leatherstocking), Leatherstocking has entered into a Memorandum of Understanding with Constitution, which would allow Leatherstocking to interconnect with Constitution's pipeline at several delivery points (Leatherstocking 2013). Leatherstocking would then be able to deliver gas from Constitution's pipeline to homes and businesses within communities in Pennsylvania and New York. In New York, the Town of Bainbridge, the Village of Windsor, the Town of Windsor, the Village of Bainbridge, the Town of Unadilla, the Village of Unadilla, the Town of Sidney, the Village of Sidney, and the Village of Delhi have granted Leatherstocking approvals for the opportunity to serve their communities (Leatherstocking 2013). Leatherstocking would evaluate the need for gas in these communities and construct the necessary infrastructure as part of the New York State Department of Environmental Conservation's (NYSDEC) permitting process for natural gas gathering and local distribution lines and could be subject to other processes including review by the COE for impacts on waters of the United States.<sup>80</sup>

Much has been made of this potential use, even though no firm contract exists between the Company and Leatherstocking. Instead, the Company has engaged in a public relations campaign to sell its high-pressure interstate pipeline project based on claims that gas might be utilized by people and businesses along the route. FERC does not mention the amount of gas that would be delivered, but this information was recently provided by Leatherstocking.

To provide some perspective, Leatherstocking Gas has estimated that throughput for the Village and Town of Sidney would be less than 1,000 Mcf/day even when the distribution system is fully built out. This amount is approximately 0.3% of the total Constitution throughput. . . . Even if the other distribution facilities that could follow the Sidney system are constructed, the total throughput for all Leatherstocking Gas distribution, including Sidney, would be in the range of 2,000 Mcf/day or approximately 0.6% of Constitution's total throughput. . . .<sup>81</sup>

In the DEIS, FERC never states that a mere 0.6% of the entire proposed project might be used to satisfy local need. Nor does FERC state that this is only a possibility, which would occur at some point in the future. Nor does FERC perform an analysis of whether there is, in fact, a local need for gas, and at what price. Such a study should include population densities of nearby villages and towns, potential volumes of gas that could be consumed, costs of delivery, and potential rates based on a range of future gas prices. The potential benefits of local use should then be balanced against the potential impacts of the required build out of

---

<sup>80</sup> DEIS at 1-1. (NYSDEC does not have permitting authority over gathering and distribution lines in NYS.)

<sup>81</sup> Nixon Peabody LLP on behalf of Leatherstocking Gas Company LLC, *Answer in Opposition to the Motion for Extension of Time*, 5, Fn 8 (March 31, 2014), available at [http://elibrary.FERC.gov/idmws/file\\_list.asp?accession\\_num=20140331-5183](http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20140331-5183).

distribution pipelines to serve future customers, along with the potential impacts of induced development. Finally, an analysis of alternatives should be performed to determine whether there are other methods of delivering this energy, and what their impacts would be. While none of these factors are evaluated – or even mentioned in the DEIS – a simple internet search can uncover such a discussion.

On April 11, 2012, Leatherstocking testified at a hearing in Wysox, Pennsylvania about the potential of using locally produced gas in rural areas.<sup>82</sup> Michael German, CEO and president of Corning Natural Gas Corporation and Leatherstocking gave a presentation in which he stated that Leatherstocking would be serving customers by tapping local gas drilling wells and gathering lines.<sup>83</sup> It took over a year and a half for Leatherstocking to connect its first customer.<sup>84</sup> Sonny Popowsky, Consumer Advocate of Pennsylvania, discussed the difficulties and high costs of bringing natural gas infrastructure to sparsely populated areas.<sup>85</sup> While supportive of the effort, he stated the project was controversial, a competing company had applied to serve the same community, and the Pennsylvania Public Utility Commission would “decide which, if either, of these applications is to be granted.”<sup>86</sup> Tony Ventello, Executive Director for the Central Bradford Progress Authority, discussed the need for public subsidies in order for these ventures like these to succeed.<sup>87</sup> He stated there simply aren’t enough customers to pay for the capital costs of building out the infrastructure.

The situation is more complicated in New York than in Pennsylvania because, for now, there are no gas wells or gathering lines to tap. Instead, Mr. German stated during presentations he made in Delaware County, NY, that Leatherstocking has a Memorandum of Understanding with the Company to be able to tap the proposed “Constitution” pipeline. He admitted that the agreement is not binding. However, five villages and five towns in New York State have signed franchise agreements with Leatherstocking. Since these agreements carry no obligation to proceed by either side, these ten municipalities are merely providing social support for this start-up.

There was also a recent flurry of press releases and photo opportunities regarding a \$750,000 grant from New York State to connect Amphenol, which is a manufacturing facility located in Sidney, NY, to the proposed pipeline, via a Leatherstocking distribution line.<sup>88</sup> What was

---

<sup>82</sup> Senator Yaw, *Agenda* (April 11, 2012), available at <http://www.senatorgeneyaw.com/files/2013/06/Hearing-Natural-Gas-Extension-Services.pdf>.

<sup>83</sup> *Blueprint for Success*, 6, LEATHERSTOCKING GAS COMPANY (April 11, 2012), available at <http://www.northerntier.org/upload/11-14-12-3LGC%20WYSOX.pdf>.

<sup>84</sup> *Leatherstocking Gas Company Celebrates 1st Residential Natural Gas Customer*, BINGHAMTON HOMEPAGE (Nov. 14, 2013), available at [http://www.binghamtonhomepage.com/story/leatherstocking-gas-company-celebrates-1st-residential-natural-gas-customer/d/story/ysTykQx\\_PEGLF-D1Xmfepg](http://www.binghamtonhomepage.com/story/leatherstocking-gas-company-celebrates-1st-residential-natural-gas-customer/d/story/ysTykQx_PEGLF-D1Xmfepg).

<sup>85</sup> Sonny Popowsky, *Testimony Regarding the Extension of Natural Gas Service in Rural Pennsylvania*, 4 OFFICE OF CONSUMER ADVOCATE (April 11, 2012), available at [http://www.oca.state.pa.us/Testimony/2012/Testimony%20re%20Extension%20of%20Natural%20Gas%20Service%20\\_00154591\\_.pdf](http://www.oca.state.pa.us/Testimony/2012/Testimony%20re%20Extension%20of%20Natural%20Gas%20Service%20_00154591_.pdf).

<sup>86</sup> *Id.* at 5.

<sup>87</sup> Johnny Williams, *Public hearing addresses issues in local distribution of natural gas*, THE DAILY REVIEW (April 12, 2012), available at <http://thedailyreview.com/news/public-hearing-addresses-issues-in-local-distribution-of-natural-gas-1.1298722>.

<sup>88</sup> Joe Mahoney, *Pipeline would send gas to Amphenol, towns*, THE DAILY STAR (March 19, 2014), available at <http://www.thedailystar.com/localnews/x1387873940/Pipeline-would-send-gas-to-Amphenol-towns>.

not included in the Company's press release, or the related news articles, was that this money was applied for by the Delaware County Industrial Development Agency to aid in the rebuilding of Amphenol after the devastating floods of 2011.<sup>89</sup>

The Delaware County Industrial Development Agency, a public benefit corporation empowered to provide financial assistance to private entities through tax incentives, will use a grant of up to \$750,000 for a portion of the cost to construct a natural gas distribution line from the Constitution Pipeline to Amphenol Corporation's existing facility at 40-60 Delaware Avenue, **as well as the new manufacturing facility to be constructed at 171 Delaware Avenue.**<sup>90</sup>

In other words, it appears the original grant application, which was written to assist in the rebuilding of the Amphenol facility, has simply been amended to include a connection to the proposed "Constitution" pipeline. According to the Governor's press release, the money can be spent entirely on the construction of the new building.

Amphenol has received over thirty-six million dollars in local, state, and federal grants and tax credits to rebuild in Sidney, rather than relocate out of state.<sup>91</sup> Amphenol also received out-of-territory hydroelectric power service from the Delaware County Electric Coop.<sup>92</sup> Now Amphenol, Leatherstocking, and the Company want local landowners to give up a portion of their land for their benefit. Many of the landowners are middle and working class citizens, who have invested their life savings in their property. Is it fair for the government to force these people to give up their assets so that a few private companies can increase their profits?

The question of the need for the project has profound implications – for over seven hundred directly affected landowners, and thousands of others. The analysis provided in the DEIS is insufficient to determine need under both the Natural Gas Act and the Clean Water Act.

## X. Conclusion

The proposed "Constitution" Pipeline would not serve the New York City and New England markets as the two interconnecting pipelines, Iroquois and Tennessee, do not have room to accept the gas. Instead, as Iroquois' recently announced South to North project makes clear, the gas would be transported to Canada, and could be exported overseas from there. If Tennessee's Northeast Expansion is required to bring the gas to New England, then the impacts from that project must be integrated into this environmental review.

---

<sup>89</sup> Erika Eklund, *Efforts Continue To Rebuild Amphenol Plant In Sidney*, THE MOUNTAIN EAGLE (Aug. 30, 2012), available at [http://www.registerstar.com/the\\_mountain\\_eagle/news/article\\_ac21b3c5-9cab-5bfd-bf56-4f1136236d46.html?mode=jqm](http://www.registerstar.com/the_mountain_eagle/news/article_ac21b3c5-9cab-5bfd-bf56-4f1136236d46.html?mode=jqm).

<sup>90</sup> *Governor Cuomo Announces \$5.9 Million to Fund Projects That Will Spur Economic Opportunity in Four Regions* (Feb. 20, 2014), available at <http://www.governor.ny.gov/press/02202014-fund-economic-opportunity>. (Emphasis added.)

<sup>91</sup> *Commissioner Adams, State and Local Officials, Break Ground on Amphenol's New Facility in Delaware County*, EMPIRE STATE DEVELOPMENT (May 13, 2013), available at [http://esd.ny.gov/NewsRoom/Data/2013/05132013\\_AnphenolPR.pdf](http://esd.ny.gov/NewsRoom/Data/2013/05132013_AnphenolPR.pdf). (Emphasis added.)

<sup>92</sup> Derrill Holly, *N.Y. Co-op Helps Preserve Jobs*, ECT (April 24, 2012), available at <http://www.ect.coop/industry/business-finance/n-y-co-op-helps-preserve-jobs/43002>.

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 8**, Arthur Berman,  
Labyrinth Consulting Services, Inc., Professional Opinion  
on the PennEast Pipeline, February 2015.



February 26, 2014

Ms. Kimberly Bose  
Federal Energy Regulatory Commission  
Office of the Secretary  
888 1<sup>st</sup> Street, NE  
Washington, DC 20428

Re: Docket No. PF15-1-000: Comments Regarding PennEast Pipeline Project, Scoping Period

Dear Ms. Bose,

Attached please find an expert analysis of “need” for the PennEast Pipeline Project.

Arthur E. Berman, author of the attached analysis, is a Geological Consultant and Director of Labyrinth Consulting Services. Mr. Berman is a petroleum geologist with 36 years of oil and gas industry experience. Mr. Berman is an expert on U.S. shale plays, and has published more than 100 articles on oil and gas plays and trends.

Please accept this expert analysis for the record from the Delaware Riverkeeper Network.

Sincerely,

A handwritten signature in blue ink that reads "Maya K. van Rossum".

Maya K. van Rossum  
the Delaware Riverkeeper



# Labyrinth Consulting Services, Inc.

623 Lorring Lane • Sugar Land, TX 77479

February 26, 2015

## Professional Opinion on the Proposed PennEast Pipeline Project

The PennEast Pipeline project proposal fails to adequately address need and volume requirements and, therefore, should not be approved unless these issues are adequately addressed. Based on current natural gas supply and demand, there is no apparent need for the gas that would be transported by the pipeline. If future demand is anticipated, this must be stated and explained clearly in the proposal. Assuming that need is shown, the proposal is vague about what portion of the approximately 1 billion cubic feet per day (Bcf/d) would be delivered to consumers in southeastern Pennsylvania versus New Jersey. It is also unclear whether there may be an intention not stated in the proposal to supply gas to markets beyond Pennsylvania and New Jersey.

Existing interstate pipelines provide all of New Jersey's natural gas demand and Pennsylvania is a net exporter of natural gas to other states so has no unfilled demand. Based on these facts about present supply and demand, it is not clear that a need exists for the PennEast Pipeline project.

Natural gas consumption for New Jersey has been relatively flat for the past four years at average rate of 1.8 billion cubic feet of gas per day (Bcf/d), somewhat below the higher levels of the late 1990s (Figure 1). Although consumption increased slightly in 2013 compared to the three previous years, New Jersey cannot be called a growth market as the proposal states. New Jersey gas supply is shown in Table 1. The small difference between supply and consumption is accounted for by processing and transportation loss, and compression needs.

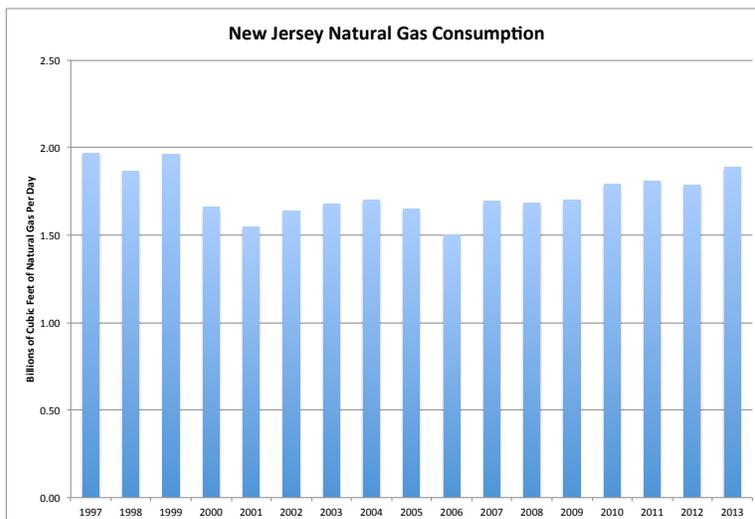


Figure 1. New Jersey annual natural gas consumption. Source: EIA.

Net Natural Gas Pipeline Deliveries

Bcf/d	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
New Jersey	1.8	1.8	1.7	1.7	1.3	1.3	1.2	1.4	1.2	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.1	1.1
Pennsylvania	-2.8	-2.5	-1.6	-1.2	-0.2	0.0	0.0	-0.7	-0.3	0.0	0.0	0.0	0.0	-0.4	0.3	0.3	0.4	0.6

Table 1. New Jersey and Pennsylvania net natural gas deliveries by interstate pipeline. Source: EIA.

Pennsylvania natural gas demand has grown since the recent boom in Marcellus Shale production (Figure 2). At the same time, Pennsylvania has been a net exporter of natural gas since 2003 (Table 1). Pennsylvania exported 2.5 Bcf/d in 2013 and 2.8 Bcf/d in 2014. It must, therefore, be assumed that most if not all of the gas for the proposed PennEast Pipeline would go to New Jersey.

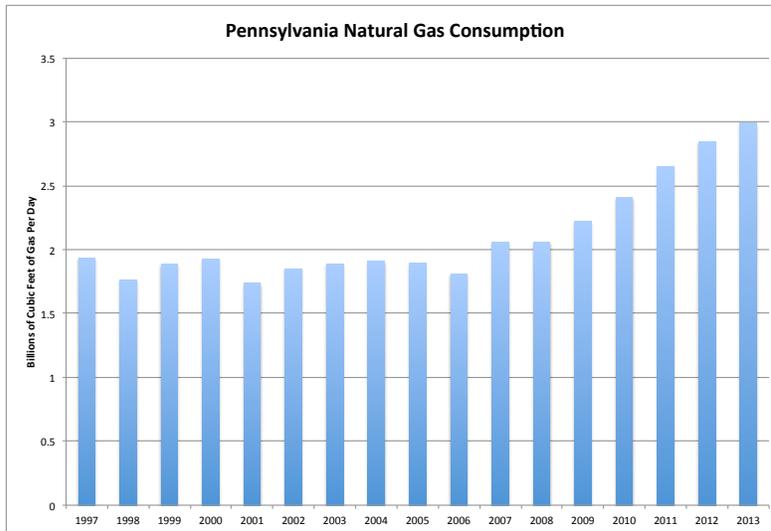


Figure 2. Pennsylvania annual natural gas consumption. Source: EIA.

Although PennEast discusses price competition and diversity of supply as positive potential outcomes for their proposed pipeline, they fail to address need. Additional future need for natural gas may exist as New Jersey moves away from heating oil and coal-fueled sources of electric power but these are not mentioned in the proposal.

The proposed PennEast Pipeline would deliver an additional 1 Bcf/d of natural gas to New Jersey potentially creating a 53% supply surplus above the current level of consumption. Assuming that PennEast can demonstrate some need, it is unclear why 1 Bcf/d of additional supply is warranted or appropriate particularly in light of the considerable property and environmental issues that construction will entail. If PennEast intends to supply additional markets outside of New Jersey, there is no mention of this in the proposal.

Marcellus Shale production today can only be described as an epidemic of over-production. When the play began in earnest in 2005, the northeastern United States relied on pipeline gas deliveries from the Gulf Coast. At that time there was a positive differential relative to Henry Hub pricing. As production has increased, the northeastern gas market is near saturation and spot prices are presently at a negative differential of about -\$1/ million cubic feet compared with the Henry Hub.

The over-supply from the Marcellus Shale is expected to increase as more wells are drilled. The only relief for producers is to export gas outside of Pennsylvania via new pipelines and by reversing flow in existing pipelines. The plan to export gas to New Jersey benefits producers who have consciously destroyed value in Pennsylvania by providing them with additional markets for their gas. It is unclear if there is any benefit to the public. Although it is certainly the right of mineral owners to over-produce natural gas at a loss if

they choose to and can justify it to shareholders, it is unclear why FERC should grant them the means to remedy the unfavorable price environment that they have deliberately brought upon themselves.

Because of the lack of demand for Marcellus gas in Pennsylvania and adjacent New Jersey, it is possible that PennEast and its committed suppliers have an unstated intent to send gas to other markets not specified in their proposal including the Cove Point LNG export facility in Maryland. Although much has been made of the supposed profitability of LNG export based on the price arbitrage between North America and Europe and East Asia, these claims fail to address the cost of liquefaction and trans-ocean transport.

The best case for LNG export from a brown field export terminal like Cove Point yielded marginally economic outcomes before the recent drop in oil prices. Since most LNG contracts in Europe and Asia are based on crude oil-price linkage, lower oil prices now make LNG export sub-commercial.

In summary, the proposed PennEast Pipeline project should not be approved because need has not been demonstrated. If need can be shown, the proposed 1 Bcf/d volume must be justified.

A handwritten signature in black ink, appearing to read 'AEB', with a long horizontal flourish extending to the right.

Arthur E. Berman  
Petroleum Geologist

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 9**, Arthur Berman,  
Labyrinth Consulting Services, Inc., PennEast Updated  
Opinion, September 11, 2016.



## Labyrinth Consulting Services, Inc.

---

623 Lorfing Lane • Sugar Land, TX 77479

September 11, 2016

### PennEast Opinion Updated September 11, 2016

In June 2015, I reviewed all relevant documents pertaining to the proposed PennEast Pipeline project including “Request for Approval of Pre-Filing Review” dated October 17, 2014 (“*Request for Approval*”<sup>1</sup>). Based on that review I concluded<sup>2</sup> that there was inadequate justification for approval of PennEast’s *Request for Approval*.

Following were my main conclusions:

- New Jersey’s natural gas market is not growing as stated in *The Request For Approval*, and
- New Jersey already uses far more natural gas for heating than the U.S. national average and more than in adjacent states, and
- New Jersey’s natural gas and electricity costs are already well below the national average, and
- New Jersey does not need to reduce reliance on fuel oil beyond present low and decreasing levels.

The chief reason for my earlier conclusions was that there was no need for the increased gas supply in the New Jersey and southeastern Pennsylvania markets specified by PennEast. In fact, those markets were and remain adequately supplied with natural gas.

I concluded that Pennsylvania was already grossly over-supplied and that the proposed additional 1 Bcf/d supply would result in an over-supply for New Jersey of approximately 53%.<sup>3</sup>

Another key reason for my previous conclusions was cost and competition. New Jersey’s current natural gas and electricity costs are comparable to those in major gas-producing states like Texas and Louisiana. There is no evidence based on cost data from Texas and Louisiana that more gas supply resulted in lower costs to consumers.

A final reason for my conclusions last June was that New Jersey did not have meaningful heating oil substitution needs. Approximately 74% of New Jersey’s space heating needs are already met

---

<sup>1</sup> Request for Approval of Pre-Filing Review, PennEast Pipeline Company, LLC, p.2, October 7, 2014.

<sup>2</sup> Professional Opinion on the Proposed PennEast Pipeline Project Updated June 18, 2015.

<sup>3</sup> Professional Opinion on the Proposed PennEast Pipeline Project Updated June 18, 2015, p. 3.

by natural gas, far above the national average of 48% and more than the 54% usage in neighboring mid-Atlantic states.<sup>4</sup>

Beyond my conclusions from 2015, northeastern U.S. natural gas market conditions have changed appreciably and gas supply is now declining. That is hardly a favorable environment for adding pipeline capacity.

U.S. gas production is declining and shale gas output is down almost 2.5 Bcf per day (Figure 1).

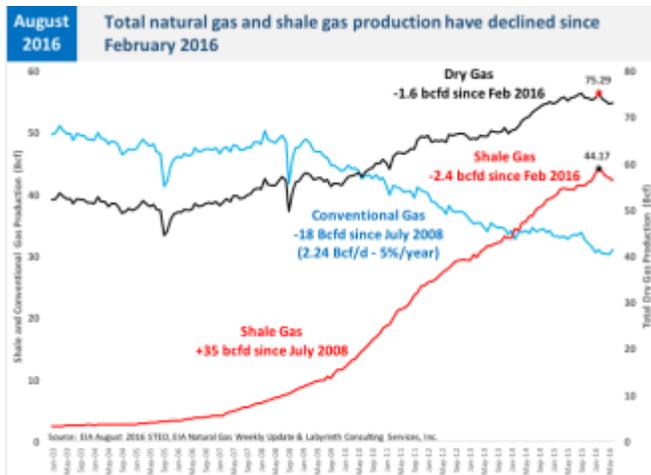


Figure 1. Total U.S. Natural Gas and Shale Gas Production Have Declined Since February 2016. Source: EIA August 2016 Short Term Energy Outlook and Labyrinth Consulting Services, Inc.

Conventional gas has been in terminal decline since 2008, and shale gas production growth has maintained and increased U.S. supply. Now, that shale gas production is also in decline. It is unlikely that production will increase much without much higher prices. It is, furthermore, unlikely that even higher prices will offset production declines based on energy company reductions in capital budgets and the generally weak state of the U.S. economy and business investment.

All shale gas plays have declined including the Marcellus which is down -0.64 Bcf/d (Figure 2). Even the relatively new Utica play has declined -0.12 Bcf/d. The legacy plays have declined the most: Haynesville, -3.77 Bcf/d; Barnett, -1.91 Bcf/d; and Fayetteville, -0.92 Bcf/d. No new horizontal wells have been drilled in either the Barnett or Fayetteville since early 2016.

PLAY	Haynesville	Barnett	Fayetteville	Eagle Ford	Marcellus	Antrim	Utica	Other	Bakken	Woodford
CHANGE FROM MAX (BCF/D)	-3.77	-1.91	-0.92	-0.79	-0.64	-0.26	-0.18	-0.12	-0.08	-0.07

Figure 2. Shale gas play declines from maximum production. Source: EIA Natural Gas Weekly Update and Labyrinth Consulting Services, Inc.

<sup>4</sup> Professional Opinion on the Proposed PennEast Pipeline Project Updated June 18, 2015, p. 5.

Moreover, the financial condition of the leading producing companies in the Appalachian region is weak and their commitments to pipeline volumes must be questioned. All leading companies in the Marcellus and Utica plays reported net losses for the second quarter of 2016, summarized in Figure 3.

	Q2 Net Gain/Loss (\$mm)	Q2 Gain/Loss Per Share	Q2 AVG Share Price	1H Share Offering (\$mm)
Antero	-\$596	-\$0.52	\$27.24	\$762
Cabot	-\$63	-\$0.14	\$23.98	\$888
Consol	-\$223	-\$1.02	\$14.02	-
EQT	-\$259	-\$1.55	\$71.42	-
Gulfport	-\$340	-\$2.71	\$30.26	\$371
Range	-\$225	-\$1.35	\$40.91	-
Rice	-\$139	-\$0.02	\$18.66	\$312

Figure 3. Marcellus-Utica key operator second quarter (Q2) 2016 gains and losses and first half (1H) 2016 equity offerings. Source: Company documents and Labyrinth Consulting Services, Inc.

In summary, the compelling fact-based reasons for denying the PennEast *Request for Approval* stated in my 2015 opinion remain, and are made even stronger based on changes in U.S. and northeastern natural gas market.

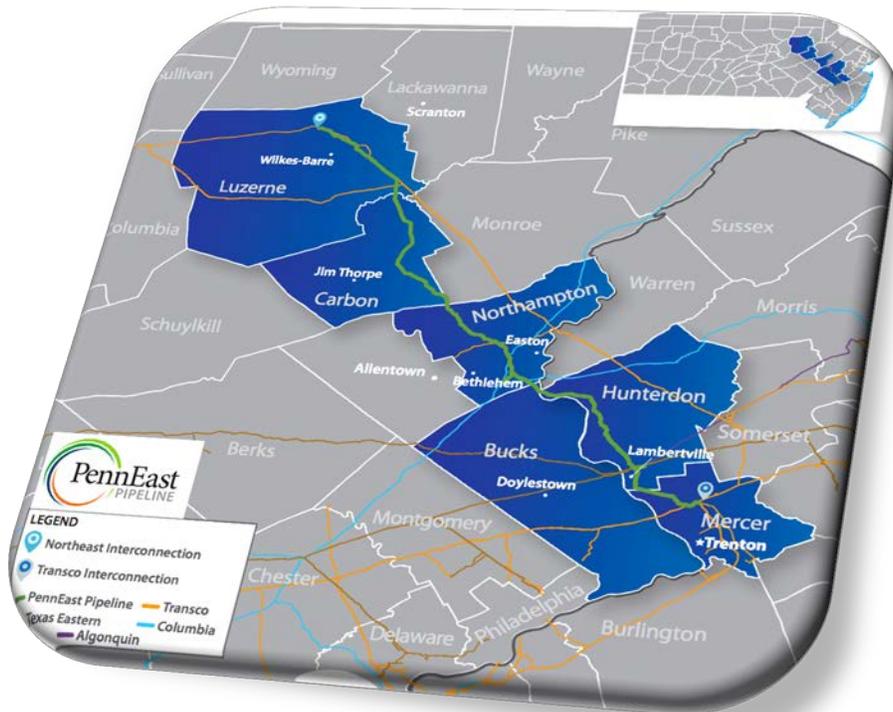


Arthur E. Berman  
Petroleum Geologist

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 10**, Analysis of  
Public Benefit Regarding PennEast, Skipping Stone,  
March 9, 2016.

## Analysis of Public Benefit Regarding PennEast Pipeline



Author: Greg Lander

For

The New Jersey Conservation Foundation



[www.skippingstone.com](http://www.skippingstone.com)

March 9, 2016

### **About Skipping Stone**

Skipping Stone is an energy markets consulting firm that helps clients navigate market changes, capitalize on opportunities and manage business risks. Our services include market assessment, strategy development, strategy implementation, managed business services and talent management. Market sector focus areas are natural gas and power markets, renewable energy, demand response, energy technology and energy management. Skipping Stone's model of deploying only energy industry veterans has delivered measurable bottom-line results for over 270 clients globally.

Skipping Stone operates Capacity Center which is a proprietary technology platform and data center that is the only all-in-one Capacity Release and Operational Notice information source synced with the Interstate pipeline system. Our database not only collects the data as it occurs, it is a storehouse of historical Capacity Release transactions since 1994. We also track shipper entity status and the pipeline receipt and/or delivery points, flows and capacity. Our analysts and consultants have years of experience working in natural gas markets. Capacity Center has worked with over a hundred clients on a wide variety of natural gas market and pipeline related reports and projects.

Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles, Tokyo and London. For more information, visit [www.SkippingStone.com](http://www.SkippingStone.com).

###

**Warranties and Representations.** Skipping Stone endeavors to provide information and projections consistent with standard practices in a professional manner. SKIPPING STONE MAKES NO WARRANTIES HOWEVER, EXPRESS OR IMPLIED (INCLUDING WITHOUT LIMITATION ANY WARRANTIES OR MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), AS TO THIS MATERIAL. Specifically but without limitation, Skipping Stone makes no warranty or guarantee regarding the accuracy of any forecasts, estimates or analyses, or that such work products will be accepted by any legal or regulatory body.

**Waivers.** Those viewing this Material hereby waive any claim at any time, whether now or in the future, against Skipping Stone, its officers, directors, employees or agents arising out of or in connection with this Material. In no event whatsoever shall Skipping Stone, its officers, directors, employees, or agents be liable to those viewing this Material.

**Disclaimer.** "This report was prepared as work sponsored by New Jersey Conservation Foundation. Neither the New Jersey Conservation Foundation nor any agency or affiliate thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process or service by trade name, trademark, manufacturer or otherwise does not necessarily constitute or imply its endorsement, recommendation or favoring by the New Jersey Conservation Foundation or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the New Jersey Conservation Foundation or any agency or affiliate thereof."

## Table of Contents

<b>EXECUTIVE SUMMARY</b> .....	<b>4</b>
<b>SECTION I – STUDY OVERVIEW</b> .....	<b>6</b>
<b>SECTION II – UNSERVED DEMAND FOR PIPELINE CAPACITY AND ANALYSIS OF COST-EFFECTIVE ALTERNATIVES</b> .....	<b>7</b>
CAN LDCs MEET NEEDS FOR FIRM PIPELINE CAPACITY? .....	7
IS FIRM PIPELINE CAPACITY COST-EFFECTIVE FOR ELECTRIC GENERATION CUSTOMERS? .....	9
IS DUAL FUEL A COST-EFFECTIVE ALTERNATIVE? .....	9
CALCULATION OF ALL-IN COMPARATIVE COSTS FOR FUEL OIL.....	10
CALCULATION OF ALL-IN COMPARATIVE COSTS FOR LNG .....	11
<b>SECTION III – POTENTIAL FOR INCREASED COSTS TO CAPTIVE CUSTOMERS ON COMPETING PIPELINES</b> .....	<b>12</b>
WHAT IS THE IMPACT OF PENNEAST ON SECONDARY MARKET CAPACITY VALUES? .....	12
WHAT IS THE IMPACT OF NON-RENEWALS OF SUBSCRIBED CAPACITY ON OTHER PIPELINES? .....	14
<b>SECTION IV – FACTORS THAT DIMINISH POSSIBLE FUTURE SAVINGS SUGGESTED BY CONCENTRIC</b> .....	<b>16</b>
ARE POTENTIAL SAVINGS DUE TO A REPEAT OF POLAR VORTEX CIRCUMSTANCES LIKELY? .....	16
ARE POTENTIAL SAVINGS IMPACTED BY RECENT ELECTRIC MARKET REFORMS? .....	17
<b>SECTION V – WEAK PUBLIC BENEFIT BUT STRONG FINANCIAL INCENTIVES</b> .....	<b>18</b>
IS RETURN ON CAPITAL A MOTIVATING FACTOR? .....	18
DO NON-ARM’S-LENGTH COMMITMENTS DEMONSTRATE MARKET NEED? .....	20
<b>SECTION VI – CONCLUSION</b> .....	<b>21</b>

## Executive Summary

In evaluating the PennEast application, FERC Commissioners will seek to determine whether the application to build new pipeline capacity provides evidence of public benefit. This study evaluates a central claim in the application – that PennEast will lower costs to consumers. This analysis also examines unserved demand for firm capacity and evaluates two alternatives for meeting peak demand needs of electric generation customers, thereby ensuring reliability of electric generation.

Our major conclusions are as follows:

1. **Local gas distribution companies in the Eastern Pennsylvania and New Jersey market have more than enough firm capacity to meet the needs of customers during peak winter periods.** Our analysis shows there is currently *49.9% more capacity than needed to meet even the harsh winter experienced in 2013 (the Polar Vortex Winter)*<sup>1</sup>.
2. **Providers of gas-fired electric generation can meet their need for electric reliability more cost-effectively by using either dual fuel or natural gas from LNG facilities.**

Natural gas pipelines are typically fully utilized between 10 and 30 days a year. Building a pipeline that is only fully utilized for a short period of time is not a cost-effective way to provide reliable electricity. Electric generation customers prefer to purchase supplies using interruptible contracts<sup>2</sup>, knowing that they may not be able to obtain gas supplies during peak demand periods. Under pressure to improve electric reliability, such customers now have to choose between contracting for firm supply from new pipeline capacity, such as PennEast, or choose an alternative to natural gas. A common alternative is to switch to oil-fired generation when natural gas is not available; a second is to purchase natural gas from LNG facilities.

Based on our analysis of alternative costs, an electric generator would bear a higher fixed cost burden by choosing to meet peak demand through firm pipeline capacity and would be economically better off choosing oil or LNG for the few days each year of high electric demand.

3. **PennEast will add significant excess capacity to the market in Eastern Pennsylvania and New Jersey.** Shippers representing almost 40% of capacity stated in the application that they intend to shift their gas supplies from existing competitor pipelines to PennEast, leaving excess and unutilized capacity on other pipelines.
4. **The impact of PennEast may well be to increase, rather than decrease, costs to gas customers. Analysis shows that rate-paying consumers of local gas distribution companies (LDCs) bear the greatest risk of increased costs regardless of whether they are on PennEast or competing pipelines.** Customers of the LDC shippers subscribing to PennEast will pay the full cost of annual service for only

---

<sup>1</sup> Concentric Energy Advisors' (Concentric) report for PennEast used peak sendout figures for this period.

<sup>2</sup> Interruptible transportation contracts are contracts under which no fixed charges are incurred, rather charges are only incurred when and to the extent the contract is actually used to deliver gas.

a few days of effective usage per year. Customers served by LDCs on competing pipelines are likely to suffer financial losses in two ways. First, as PennEast adds 1 billion cubic feet per day of capacity to the market, the value of existing capacity in the secondary market will collapse, shrinking by as much as 50 to 90%. Our analysis of transactions on two competitor pipelines shows that the loss of benefit to ratepayers, just on those two pipelines, could be between \$130 to \$230 million each year. Second, as customers shift contracts from existing pipelines to PennEast, FERC rules permit those pipelines to file for rate increases on remaining customers to recover lost revenues. Resulting rate increases could expose ratepayers to additional costs of over \$50 million per year – just on these two pipelines.

5. **PennEast claims of potential savings for gas consumers or electric generation customers are based on faulty assumptions and analysis.** The price spike experienced during the Polar Vortex is unlikely to be repeated and does not alone justify the addition of new pipeline capacity. PennEast claimed benefits that are not based upon future projections of gas prices and do not take into account 8.1 billion cubic feet per day of infrastructure scheduled to ramp up in 2017. PennEast does not address evidence that similar price spikes did not occur in Winter 2014/2015 or the introduction by PJM and NEISO of important Supply Assurance Programs that reduce dependence on constrained natural gas pipelines during peak demand periods.
6. **FERC should not rely on non-arms-length transactions as a foundation for finding market need.** Owners of PennEast contracted for 74.2% of total capacity. FERC Commissioners have a special responsibility to protect rate-paying customers. For PennEast, 38.9% of the capacity is held by local gas distribution companies whose parent firms will benefit from their ownership of PennEast, and whose customers – rate-payers – are at risk of paying for unneeded capacity for 15 years.
7. **In the case of PennEast, the precedent contracts signed by local distribution companies are not arm's length and should not be relied upon for a finding of public convenience and necessity.**
8. **The Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is being met by the proposed pipeline and whether less disruptive and more cost effective alternatives exist to meet such demand.**

## Section I – Study Overview

Skipping Stone was asked to review the proposed PennEast Pipeline and provide its opinion of the potential utilization of the incremental capacity into the geographic region, and what that might mean for electric generation customers. Understanding that the choice faced by electric generation firms would require an analysis of the cost and benefits of purchasing firm capacity on a new pipeline compared to other options, we also provide indicative cost-benefit analyses of two alternatives. Skipping Stone was also asked to examine possible financial motivations of the Sponsor/Shippers of PennEast as an alternative explanation for the purpose of the project.

This review is based on our examination of documents from the PennEast Pipeline LLC FERC Certificate Application CP15-558 and publicly available natural gas industry data and documents.

The application makes a number of assertions about the project purpose as follows:

“to bring lower cost natural gas produced in the Marcellus Shale region in eastern Pennsylvania to homes and businesses in New Jersey, Pennsylvania, New York and surrounding states.”

“...with the additional pipeline capacity, energy consumers throughout eastern Pennsylvania and New Jersey would have realized over \$890 million in reduced energy costs in the winter of 2013-2014.... Further, without additional natural gas infrastructure providing the region increased access to the abundant dry natural gas reserves located in the eastern Pennsylvania production area, similar price spikes and correspondingly, the potential savings offered by the PennEast Project, could be anticipated in the future. Thus, the PennEast Project is expected to bring annual energy cost savings and significant economic benefits to the Pennsylvania and New Jersey economies.”

The assertion that PennEast will produce annual energy cost savings requires looking at a number of salient factors, including:

- 1) What is the demand that PennEast is purporting to serve, is there unmet demand for year-round, firm capacity in the subject region, and related to that, what would be the utilization rate of such incremental capacity into the subject market.<sup>3</sup> And at such utilization rate, what would be the effective per-unit cost of such incremental capacity at indicative utilizations?
- 2) Is firm, year-round capacity a cost-effective solution to meet electric generation customers’ needs during peak winter periods?
- 3) What might be offsetting costs to any potential savings?

---

<sup>3</sup> In this regard, Skipping Stone assumes that the utilization rates of other lines serving the subject market are or remain the same and that utilization of the PennEast line comes from displacement of peak-shaving resources and electric generation. Even if PennEast were to be higher utilized than the estimated utilizations used in this memorandum, such higher utilization of PennEast would come at the expense of utilization of other pipelines serving the market. Thus, for economic analysis of the effective per unit cost of the added capacity, Skipping Stone assumes for these purposes that in the aggregate, PennEast would serve load unmet by existing natural gas pipelines (i.e., load met by LNG, or oil-fired electric generation).

- 4) Are the potential savings predicated on repeats of unusual circumstances?
- 5) Have there been developments in electric and gas markets subsequent to the filing of the PennEast application which undermine the assumptions that must be made in order for there to be future savings associated with the incremental capacity proposed to be provided by PennEast?
- 6) In light of potentially questionable demand, what financial motives might underpin the Sponsor/Shippers' decision to seek permission to construct a new natural gas pipeline.

## **Section II – Unserved Demand for Pipeline Capacity and Analysis of Cost-Effective Alternatives**

### **Can LDCs Meet Needs for Firm Pipeline Capacity?**

To evaluate whether current pipeline capacity is sufficient to meet current and future demand from LDCs and other customers requiring firm capacity in the Eastern PA, NJ region, it is important to identify the Peak Day demand from LDCs in the region and compare it to Total Peak Day Resources available in the region. The Concentric Energy Advisors report, sponsored by PennEast, fails to examine actual pipeline contracts and available resources to meet peak demand in determining whether PennEast is, in fact, needed to meet peak demand.

We utilized information provided by Concentric about LDC demand in the region from Table 2: “Eastern Pennsylvania and New Jersey LDC Summary Operating Statistics.”<sup>4</sup> Information for each LDC is reproduced below in Table 1 as columns (a), (b), (c), and (d) representing Local Distribution Companies (LDCs), Number of Natural Gas Customers, 2013 Retail Sales Volumes (Mcf) and Peak Day Sendout (Mcf), respectively.

To properly calculate current Peak Day Resources it is important to include not only LDC held pipeline capacity and LNG sendout capability, but to also include winter pipeline subscribed capacity levels of retailers<sup>5</sup> serving load in eastern PA and NJ, end-users and electric generators with contracts to locations in the same geographic area<sup>6</sup> and capacity held by producer marketers into this same geographic area<sup>7</sup>. Rows 13 and 14 provide the contracted winter pipeline capacity for these two categories of pipeline capacity holders. For both

---

<sup>4</sup> Sources: EIA Form 176, Annual 1307(f) Filing materials, State LDC Filings, and information provided by LDCs.

<sup>5</sup> Here, retailers are those marketers that explicitly serve residential and commercial load in the geographic area and have pipeline FT contracts with firm primary delivery points in the subject geographic area. Note these entities can be distinguished from wholesale Producer-Marketers because these retailer entities in these markets and others have capacity releases from LDCs that carry the indicator that they are serving retail load under one or another “retail choice programs” of LDCs.

<sup>6</sup> With respect to electric generators' capacity, Skipping Stone excluded subscribed winter pipeline capacity level contracts that were for lateral capacity only as these lateral capacity(ies) only entitle the electric generators to move gas under these agreements from one end of the lateral to another.

<sup>7</sup> This type of capacity contract is often referred to as “producer-push” capacity where the capacity comes into the geographic area often (but not always) to pooling points from which it can be purchased for delivery to actual delivery locations within the geographic area.

categories, note that capacity held by shippers to New York points or to pipelines leaving New Jersey, such as Algonquin, was excluded.

We include additional information in columns (e)<sup>8</sup>, (f) and (g).

- Column (e) shows these same entities' 2015 Contracted Winter Pipeline Capacity levels in their eastern PA and NJ service locations<sup>9</sup>
- Column (f) provides publicly available LNG vaporization capacity in the same geographic area (including proposed) and
- Column (g) shows Total Peak Day Resources (which is the total of columns (e) and (f))<sup>10</sup>

Table 1. Analysis of LDC Demand in Eastern Pennsylvania and New Jersey

(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	No. of Natural Gas Customers	2013 Retail Sales Volumes (Mcf)	Peak Day Sendout (Mcf)	2015 Contracted Winter Pipeline Capacity	2015 LNG Vaporization (Mcf)	2015 Total Peak Day Resources	
<b>Eastern Pennsylvania</b>							
1	UGI Utilities	357,408	116,675,523	654,050	494,607	202,500	697,107
2	UGI Penn	163,796	56,733,872	416,488	218,490	0	218,490
3	PGW	498,694	73,229,988	616,000	304,892	225,000	529,892
4	PECO	498,843	85,834,449	759,594	551,834	161,700	713,534
5	Subtotal	1,518,741	332,473,832	2,446,132	1,569,823	589,200	2,159,023
<b>New Jersey</b>							
6	PSEG	1,790,240	453,524,804	2,973,000	1,894,994	64,000	1,958,994
7	NJNG	501,595	67,616,570	690,415	525,604	170,000	695,604
8	SJG	359,732	58,997,922	495,056	404,871	75,000	479,871
9	SJR Proposed					250,000	250,000
10	Elizabethtown	278,871	52,732,119	440,148	302,435	24,000	326,435
11	Subtotal	2,930,438	632,871,415	4,598,619	3,127,904	583,000	3,710,904
12	Concentric Regional Total	4,449,179	965,345,247	7,044,751			
13	Retailers, End-Users & Power Gen w- Eastern PA & NJ Capacity				940,095	0	940,095
14	Producer/Marketers w-Eastern PA & NJ Capacity				3,748,500	0	3,748,500
15	Regional Totals			7,044,751	9,386,322	1,172,200	10,558,522

<sup>8</sup> Skipping Stone used 2015 Winter Contracted Capacity because this is the level of capacity to which the PennEast capacity is additive. In addition, it represents the level of capacity that exists (and would exist) absent PennEast and that would be utilized to meet repetitive peak send-outs of the magnitude of those experienced in 2013.

<sup>9</sup> Note that Skipping Stone excluded from such subscribed winter pipeline capacity level contracts that were for lateral capacity only as these lateral capacity(ies) do not entitle the entity(ies) to receive more gas but rather are means of moving gas under these agreements from one end of the lateral to another.

<sup>10</sup> Note that Skipping Stone did not include propane-air resources of any of the entities in the Total of Peak Day Resources.

The above analysis shows that currently subscribed pipeline capacity alone exceeds the Concentric identified entities' peak day sendout by over 33% (Line 15 column (e) divided by Line 15 column (d)). Including these entities' LNG resources increases deliverability resources to 10,558,522 (Mcf per day). The purpose of LNG resources is to provide a local distribution company with additional supplies during peak demand periods that are more cost-effective than the purchase of additional firm pipeline capacity. In total, there are 49.9% more resources available to meet peak day demand from local gas distribution companies in the region than is needed, according to Concentric's own demand data (Line 15 column (g) divided by Line 15 column (d)).

If PennEast is not needed to supply the needs of LDCs in the region, then is the additional supply of 1 billion cubic feet per day of pipeline capacity actually necessary, and for what purpose?

### **Is Firm Pipeline Capacity Cost-Effective for Electric Generation Customers?**

The Concentric study analyzes demand for electric generation, which is typically provided either by contracts for interruptible capacity or by means of bundled (transportation capacity and gas) sales at the generators' delivery points out of the gas network<sup>11</sup>, rather than by generator-held contracts with pipelines for firm capacity. That said, the report nevertheless argues that additional capacity is needed for electric generation and to prevent "price spikes."

The period of greatest demand for natural gas is that period of "coincident demand," when gas demand for home heating (provided by LDCs) and for electric generation are both high. In the eastern PA, NJ region coincident demand occurs during winter cold spells. If the demand that PennEast might serve is the coincident demand of natural gas for heating and electric generation in the winter-period, then one has to ask two related questions:

- What is the duration of this coincident demand?
- What is the most economical means of meeting such coincident demand?

Recent studies by EISPC, ICF, ENERGYZT and Skipping Stone<sup>12</sup> have all identified that the period of this coincident demand is from 10 to 30 days, and may increase to 45 days by 2020 and 60 days by 2030. The following analysis calculates the cost of capacity for 10, 20 and 30 days, and includes calculations for 45 and 60 days for completeness.

### **Is Dual Fuel a Cost-Effective Alternative?**

To assess the most economical means of meeting this very short period of peak-period coincident demand, we compare the costs of relying on firm pipeline capacity with a well-known alternative, the use of dual fuel for electric generation. First, we calculate the cost of providing

---

<sup>11</sup> These delivery points out of the gas network are either at direct-to-plant pipeline points or are points on LDC systems where the generator can receive gas from the LDC.

<sup>12</sup> EISPC "Study on Long-Term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection" September 2014

ICF "Options for Serving New England Natural Gas Demand October 22, 2013

ENERGYZT "Analysis of Winter Reliability Solutions for New England Energy Markets August 2015

Skipping Stone "Solving New England's Gas Deliverability Problem using LNG Storage and Market Incentives" September, 2015

pipeline capacity that is fully utilized only between 10 and 60 days per year. We then compare this cost with the equivalent cost of using fuel oil rather than natural gas. This analysis also assumes that because the pipelines in the subject geographic area are fully subscribed from their production locations to their market locations, then electric generation customers, to get such capacity for natural gas during coincident peak demand days, would require incremental firm pipeline capacity that cannot be interrupted during such periods of peak demand.

The all-in cost is the effective cost to a power generator reserving capacity year-round<sup>13</sup> that is only needed from 10 to 60 days per year<sup>14</sup>. To illustrate, Skipping Stone provides the analysis shown in Table 2. This analysis is based on two assumptions that can be adjusted: The 100% Load Factor Pipeline Cost (assumed to be \$.50/Dth/Day); and the Winter Gas Cost (using the estimated 2019/2020 winter gas cost published by NYMEX in Feb-2016).

Table 2. Analysis of All-in Cost of Capacity

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
100% Load Factor Pipeline Cost	Days Per Yr	Annual Cost/Dth /Day of Capacity	Equivalent Days of 100% load Factor Use /Yr	Cost of Pipeline Capacity per Dth used	Winter Gas Cost	All-in Delivered Cost per Dth used	Dth/Gal	Equivalent \$/Gal
\$0.43	365	\$156.95	10	\$15.70	\$2.90	\$18.60	0.139	\$2.58
\$0.43	365	\$156.95	20	\$7.85	\$2.90	\$10.75	0.139	\$1.49
\$0.43	365	\$156.95	30	\$5.23	\$2.90	\$8.13	0.139	\$1.13
\$0.43	365	\$156.95	45	\$3.49	\$2.90	\$6.39	0.139	\$0.89
\$0.43	365	\$156.95	60	\$2.62	\$2.90	\$5.52	0.139	\$0.77

### Calculation of All-in Comparative Costs for Fuel Oil

How does the total cost of using natural gas to meet peak load, available only through year-round firm capacity, compare with the cost of using No.2 fuel oil?

First, we evaluate the cost of contracting for firm pipeline capacity for a given number of peak days. Column (c) shows the annualized cost per Dth per day of capacity<sup>15</sup>. Column (d) varies

<sup>13</sup> This same all-in cost calculation would also apply to an LDC displacing some amount of LNG vaporization capacity with year-round pipeline capacity. This occurs when the LNG vaporization and LNG storage capacity is utilized to an extent such that it makes economic sense to add an increment of pipeline capacity and then “grow into” that pipeline capacity again relying on LNG for needle peaks until overall load growth and winter period demand once again makes another incremental pipeline capacity addition economical..

<sup>14</sup> The reason that such capacity may only be needed by a power generator from 10 to 60 days per year is that there is sufficient otherwise un-used existing capacity all but those days when the coincident demand from electric generation and heating load exceeds existing pipeline capacity. See also Concentric report Page 18 where it discusses price spikes when demand is greater than 8 Bcf/d into the subject market which according to Figure 11 on page 17 occurred some 15 times during the Polar Vortex winter of 2013/2014.

<sup>15</sup> The annual cost per Dth per day presents what the cost for one Dth on one day would be if one Dth per day of capacity was reserved for a year and only used on one day to receive the one Dth.

the number of equivalent days of 100% load factor, or days of peak usage. Ten days of full use is equivalent to 5 days of full use and 10 days of 50% use. The all-in cost of capacity per Dth (assuming a cost of \$0.43 per Dth per day of reservation and 10 days of use during times of peak load) has an effective capacity cost of \$15.70 per Dth used. At 30 days of peak load, the all-in capacity cost drops to \$5.23. To calculate the all-in cost of use, we add the cost of gas during the winter period, \$2.90 per Dth, for a total delivered fuel cost of \$18.60 per Dth used.

Column (i) shows the price per gallon for fuel that results in an equivalent cost per Dth for the natural gas alternative. For peak demand of 10 days, the natural gas alternative would be the lower cost alternative if the cost of No.2 fuel oil is \$2.58 per gallon or higher, equivalent to \$108.56 per barrel of oil. For peak demand of 30 days, the natural gas alternative would be the lower cost alternative if the cost of No.2 fuel oil is \$1.13, equivalent to \$47.47 per barrel of oil.

It should be noted that this 10 to 60 days of peak demand analysis is for illustrative purposes to show that even a pipeline that has a daily transportation rate of as little as 43 cents can result in very high effective costs in use unless it is utilized much more than 60 days – i.e., the existing gas system is constrained on that many or more days.

Based on this basic analysis of alternative costs, one can readily see that it is highly unlikely that a generator will choose to bear the fixed cost burden of the pipeline capacity and would be economically better off choosing oil as fuel during the few days of coincident demand each year.

### **Calculation of All-in Comparative Costs for LNG**

In addition to the oil alternative, securing additional LNG deliveries at locations downstream (i.e., north and east) of the NJ/PA demand centers, as well as from existing LNG facilities within the NJ/PA geographic area cited by the Concentric report, are likely to be even less expensive as a supply alternative. Of note here, any additional LNG that is vaporized at Northeast LNG facilities, such as Eastern MA or New Brunswick, Canada, can make supplies traveling to the Northeast on various pipelines available instead for delivery into the NJ/PA region. This is because the LNG resources would physically serve the New England market thereby enabling supplies otherwise bound for New England to remain in the NJ/PA market and serve demand there. As a result, additional capacity would become available on one or more of the major pipelines connecting the NJ/PA demand centers to New England, such as Texas Eastern, Transco, Tennessee or Columbia to Algonquin (or Maritimes and Northeast).

Because of the current substantial excess of worldwide LNG, future LNG supplies are currently priced at \$6.00 to \$8.00 per Dth vaporized into New England markets. At these prices, LNG supplies are likely to clear the market lower than the above modeled oil prices in Table 2. Customers can arrange LNG supplies in advance of the winter period and ensure that the inventory is either in the LNG tanks or on the floating storage and regasification ships during the winter period. LNG inventory is arranged in advance in much the same way as pipeline capacity is reserved in advance, except subscription terms are typically year to year and for use of existing facilities do not require multi-year commitments.

## Section III – Potential for Increased Costs to Captive Customers on Competing Pipelines

The FERC Commissioners are concerned with protecting consumers from excessive rates. We analyzed the potential impact of additional capacity on captive customers of competing pipelines with particular regard for the likely impact on rate-payers. Shippers who own capacity on competing pipelines are likely to suffer two negative impacts, or offsetting costs, as a direct result of the addition of the substantial 1 Billion cubic feet per day incremental capacity proposed by PennEast.

Shippers will encounter two sources of increased costs:

- 1) As the total supply of capacity increases, the value of secondary market capacity is likely to decline, particularly if demand is largely unchanged over the vast majority of the year (i.e., all but the highest 10 – 60 demand days per year).<sup>16</sup> Thus, shippers who own existing pipeline capacity and seek to resell unused capacity into the secondary capacity market **will suffer a loss of value.**
- 2) Non-renewal or turnback of subscriptions on existing lines could lead to cost-shifting to captive customers of such lines at the next rate case. The risk of non-renewal is significant, as several PennEast Shippers stated in the PennEast application that they plan not to renew portions(s) of their existing legacy capacity portfolios. In addition, other shippers may find that they are able to rely on excess capacity as a consequence of the addition to the market of the PennEast capacity and also choose to not renew. The revenue lost from such turnbacks will ultimately be re-distributed to the pipelines' remaining shippers.

### What is the Impact of PennEast on Secondary Market Capacity Values?

Since there is no evidence of significant increased demand for the 40% of capacity purchased for in-state New Jersey use, the increased supply from PennEast will add to the total supply of pipeline capacity in the region and lead to significant underutilized capacity.

The secondary market enables shippers to find buyers for their unneeded capacity by means of either capacity release transactions and/or Asset Management Agreements<sup>17</sup> (AMAs). As a result of excess capacity, secondary market values related to capacity release and AMAs could drop dramatically.

---

<sup>16</sup> The reductions in secondary market values impact any firm capacity holder with a less than 100% load factor use of their capacity which sells their unused capacity to others during period of low use. These secondary market purchasers pay the capacity holder for their firm rights. To the extent a particular geographic area is flooded with new capacity, the secondary market values drop to near zero because the supply greatly exceeds the demand. Specifically, it is generally LDCs that sell unused capacity and use large percentages (usually 80% or more) of these secondary market revenues to reduce rates paid by their firm sales customers (ex. residential and commercial customers).

<sup>17</sup> Asset Management Agreements are agreements where a purchaser agrees to provide capacity management services (and often gas supply) and pay the holder of firm capacity often large sums of money to gain control of their capacity in return for agreeing to use a limited amount of that capacity to meet the needs of the selling party while using the balance to make other sales to other parties. These AMAs are effectuated through capacity release transactions in the secondary market.

In particular, for the purposes of this memorandum, Skipping Stone studied capacity release transactions<sup>18</sup> on two pipelines in the subject geographic area: Texas Eastern Transmission (TETCO) and Transcontinental Gas Pipe Line (Transco). The period studied was 2015. The transactions analyzed were those where the capacity terminated in the same eastern PA and NJ geographic area as that discussed in the Concentric study for PennEast.

Skipping Stone found for these two pipelines that the value of traded capacity was in excess of \$250 Million in 2015. The aggregated dollars, quantities and average rates for the two lines' 2015 transactions are set forth in the two tables that follow.

Table 3. Texas Eastern (TETCO) Traded Capacity<sup>19</sup>

<b>TETCO 2015 Capacity Release Quantities, Rates and Value</b>			
<b>Eastern PA and NJ locations</b>	<b>Annualized Daily Equivalent Traded (Dth)</b>	<b>Avg Rate per Dth/Day</b>	<b>Dollars Realized 2015</b>
From M2 and into M3	1,398,127	\$0.3415	\$174,292,476

---

<sup>18</sup> The transaction types studied were releases from capacity holders to acquiring shippers that were done outside of those done to enable retail choice. Under retail choice many LDCs release capacity at pipeline maximum rates (regardless of capacity values) to marketers that have contracted to serve firm customers on the LDCs' systems. These transactions do not reflect competitive pipeline capacity market conditions and therefore were eliminated so as not to overstate the value of released capacity in the subject markets. In addition, in those cases where no price was provided under an AMA transaction, the average price for the similar capacity was used.

<sup>19</sup> TETCO presents the values of their trades on a segment and point basis so Skipping Stone provided just the segment values (i.e., the values of capacity to get gas into M3 which is the eastern PA and NJ zone from the adjacent M2 area which is the western PA and OH zone) as those would be the values most impacted by an incremental 1 Billion Cubic feet (1,000,000 Dth/d) of capacity into their M3 zone serving eastern PA and NJ. Transco on the other hand reports the values for their trades on a point-to-point basis so the value of getting to a market area point from supply areas is that which would be impacted.

Table 4. Transcontinental Gas Pipe Line (Transco) Traded Capacity

<b>Transco 2015 Capacity Release Quantities, Rates and Value</b>				
<b>ST</b>	<b>County of Delivery</b>	<b>Annualized Daily Equivalent Traded (Dth)</b>	<b>Avg Rate per Dth/Day</b>	<b>Dollars Realized 2015</b>
NJ	Camden	2,000	\$0.3050	\$222,650
NJ	Essex	215,924	\$0.1761	\$13,879,181
NJ	Gloucester	104,589	\$0.1430	\$5,459,521
NJ	Mercer	208,184	\$0.3453	\$26,238,007
NJ	Middlesex	264,000	\$0.2130	\$20,524,680
NJ	Union	1,274	\$0.0200	\$9,300
PA	Monroe	152,459	\$0.2553	\$14,204,015
PA	Montgomery	167,962	\$0.1135	\$6,958,227
PA	Philadelphia	42,691	\$0.1683	\$2,622,767
<b>Totals and Average</b>		<b>1,159,083</b>	<b>\$0.2130</b>	<b>\$90,118,348</b>

Within the subject market area, the Annualized Daily Equivalent Traded<sup>20</sup> quantity on the two pipelines was approximately 2.55 Billion cubic feet per day. The impact of adding another 1 Billion cubic feet to the same market, an amount roughly equivalent to a 40% increase in regional capacity, would likely crush these values; potentially by as much as 50-90% depending on time of year and other factors. Thus, the PennEast pipeline is likely to put at risk the value of existing capacity, which recently traded for \$260 Million per year in secondary market transactions. The greatest volume of existing capacity is held by local gas distribution companies, and ratepayers receive 80% of the value of such resale transactions. These ratepayers are captive customers of the LDCs served by existing pipelines and would suffer a significant financial loss if excess capacity were to be approved by FERC Commissioners.

Notably, this loss of benefit to ratepayers in the subject market would be experienced every year and we estimate could be between \$130 Million and \$230 Million, or averaging \$180 Million each year until such time as the regional demand increase sufficiently to make use of the incremental capacity.

### **What is the Impact of Non-Renewals of Subscribed Capacity on other Pipelines?**

With the addition of the incremental capacity associated with PennEast into the subject market, shippers with contracts expiring in the near to medium term (3 to 10 years from now) would be able to either forgo renewal and rely on the existence of the capacity or be able to negotiate substantial discounts.

---

<sup>20</sup> Annualized equivalent means if there were two trades, one of 1,000 Dth/d for a year and another for 365,000 Dth/d for a day, the Annualized Daily Equivalent of each would be 1,000 Dth/d and the total of the two would be 2,000 Dth/d.

We evaluate the potential impact of non-renewals on customers of Texas Eastern (TETCO) and Transco pipelines. The rates on TETCO and Transco for capacity to Eastern PA and NJ run on average between \$0.52 and \$0.67 per Dth/day. To illustrate, we calculated the impact if half of PennEast capacity, or 500,000 Dth/d, were to go unsubscribed on existing pipelines. At the average of the two rates above (~\$0.595), the result would be a loss of over \$108 Million per year between the two pipelines.

FERC rules permit affected pipelines to file for rate increases on remaining customers to seek to recover lost revenues. This could mean that the same ratepayers facing a potential loss of secondary market benefits could see a substantial portion of the costs of a rate increase as well. Moreover, like the cost of lost secondary market benefit, the cost of increased rates would be a cost they would bear every year.

Even if Pennsylvania and New Jersey ratepayers were forced to absorb **only half** of the potential lost revenues of \$108 Million, this conservative estimate shows that ratepayers could be asked to pay an additional \$50 Million a year.

## **Section IV – Factors that Diminish Possible Future Savings Suggested by Concentric**

### **Are Potential Savings Due to a Repeat of Polar Vortex Circumstances Likely?**

Concentric cites the 2013/2014 market disruptions coincident with the Polar Vortex as a measure of savings that could have been realized had PennEast been in service at that time.

Concentric appears to be justifying the build of a pipeline purely on the basis of a past price experience, one that notably did not occur in either the 2014/2015<sup>21</sup> nor in prior winters. So, the likelihood of reoccurrence is lower than assumed by Concentric. Concentric should, in any case, reduce their estimate of “potential savings” based on the likelihood of a reoccurrence of the conditions that would create such savings.

Furthermore, any calculation of potential savings should also include potential additional costs that would be borne by ratepayers holding capacity on competing pipelines. The costs, as calculated above, could range from \$180 to \$280 Million a year (averaging possibly \$230 Million a year).

In addition, potential savings are reduced or even wholly eliminated as additional pipeline capacity comes online. Several other projects are slated to come on line before or around the same time as PennEast might come on line. If this occurs, the price depression facing producers with trapped gas supplies will largely be or have been abated. As recently reported by Barclays Bank<sup>22</sup>, “Almost 8.1 Bcf/d of infrastructure in the Northeast region has been fully subscribed and is scheduled to ramp up in 2017.” Barclays goes on to state “[m]ost of the 2017 pipeline projects are in the southwestern portion of the Marcellus and Utica shales<sup>23</sup>, which potentially could strengthen price points,” meaning that once the trapped production has outlet to market, the currently favorable pricing will dissipate, if not fully evaporate.

Pipelines should be planned to address longer-term conditions and trends, rather than as a response to a single event, since planning and construction of pipeline capacity takes several years. In order to have been in service by the winter of 2013 PennEast would have had to have started its development process somewhere around the 2008/2009 period. The gas price situation at that time was wholly different from the price situation today, and five years from now the price situation will be wholly different from today’s, with or without PennEast.

---

<sup>21</sup> Notably the winter of 2014/2015 was colder and had colder days than the Polar Vortex winter of 2013/2014.

<sup>22</sup> See Natural Gas Intelligence March 03, 2016 “Barclays Reduces 2016 NatGas Price Outlook and Sees Breakout in 2017”

<sup>23</sup> These projects largely involve east to west capacity additions and pipeline flow reversals to the south and west. This means that these now trapped supplies will soon have choices of markets and will flow to the most favorably priced market, whereas absent these additions, producers have few choices and compete with one another to gain access to the limited NE market, namely the subject geographic area identified by Concentric.

## **Are Potential Savings Impacted by Recent Electric Market Reforms?**

In the past two years, both PJM and NEISO have instituted market rules which heavily incentivize generators to have fuel during peak critical periods<sup>24</sup>. Skipping Stone will refer to these market rule changes as “Supply Assurance Programs.”

Notably also, in the short-run NEISO has instituted its Winter Reliability Program where it pays generators to have fuel oil and/or LNG in tanks ready to be used to assure such critical winter period fuel supplies are available for generation. In New England this has had the effect in both of the past two winters (2014/15 and 2015/16) of greatly dampening price spikes. In turn, price spikes in the subject geographic area have also been dampened, as the pipelines running through eastern PA and NJ also either continue north and east or supply pipelines running into New England.

Under the Supply Assurance Programs, both PJM and NEISO have auctions that create price signals and payments to generators. While significant dollars are to be paid to generators under these Supply Assurance Programs, they are amounts that are far short of amounts required to cover year-round firm transportation on interstate pipelines. As a result, anecdotally and to Skipping Stone’s knowledge, gas-fired generators have either opted to install dual fuel capability, arrange for peaking LNG supplies, or make firm supply call arrangements with large wholesale players to backstop their commitments.

The likely ongoing impact of these developments is that the scrambling for supply that led to the enormous price spikes experienced during the period covered by the Concentric report are much less likely to occur in the future. Thus, it is increasingly likely that price spike avoidance, a claimed attribute of a proposed PennEast Pipeline, has in large part already, and enduringly, been addressed. To the extent, then, that the potential for future price spikes have been largely avoided by such market rule changes, the supposed benefits from such avoidance have already been realized – without the proposed presence of PennEast to do so.

---

<sup>24</sup> In PJM this market rule change is known as “Capacity Performance” and in NEISO the market rule change is referred to as “Pay for Performance”.

## **Section V – Weak Public Benefit but Strong Financial Incentives**

Given the lack of evidence from the LDC Sponsor/Shippers of their systems' load growth, as well as certain LDC Sponsor/Shippers' statements made regarding replacing some of their currently contracted interstate capacity with proposed new-build PennEast capacity, questions arise as to what could be the driver behind such a project.

Generally pipelines are proposed and built to meet known demand, such as when LDCs sign-up for expansion to serve new territories or replace over-reliance on winter-peaking resources. Pipelines can also be proposed to meet the needs of Producers who seek to move gas from capacity constrained supply areas to liquid market locations. From our review of the documents, the PennEast Pipeline is proposed to serve neither demand from LDCs nor supply from Producers.

What then is a possible motivating genesis for PennEast?

### **Is Return on Capital a Motivating Factor?**

A potential motivator might be a rather simple one: namely, a vehicle for the LDC Sponsor/Shippers to replace dollars collected from ratepayers and sent to third-party unaffiliated interstate pipelines, with dollars collected from ratepayers and paid to themselves – or rather paid to the affiliated, non-regulated, companies owned by the same corporate shareholders as the regulated LDC signing the contracts.

Under an LLC structure such as that of PennEast, the owners (called unit-holders) are generally entitled to distributions of cash net of direct expenses and retained working capital. Direct expenses of new pipelines are both Fixed and Variable. Fixed Expenses can be simplified into the categories of a) interest payments, b) overhead, c) maintenance expenses and d) Non-income taxes (ex. property taxes and franchise taxes). Variable expenses, such as the costs of running compressors and those related to transporting gas, are collected from customers as they transport gas and do not meaningfully figure into the profits of pipeline owners. Thus, for the purposes of this analysis they will be disregarded.

In addition, Pipeline LLCs typically have a 50% Equity and 50% Debt capital structure. Below is a simplified but typical structure for the annual revenue of a pipeline and how it is generally put together.

Assuming an initial capital cost of \$1.2 Billion, at the LLC level, investors would put in \$600 Million and banks would finance the other \$600 Million. For these purposes, Skipping Stone will assume an annual interest rate of 5%. Generally, pipelines then seek to get rates that will generate revenue based upon an annual percentage of total capital that is between 8% and 10% more than their interest rate (i.e., 13% to 15%) and apply that percentage (i.e., revenue level) to total initial capital cost (i.e., the \$1.2 Billion). Assuming the lower level, 13% applied to the \$1.2 Billion would mean that the pipeline would seek rates that recovered \$156 MM per year. Once pipelines have determined their desired revenue level they then design their rates. In our simplified example, applying that revenue level to a pipeline with 1 Bcf per day (1,000,000 Dth/d) of capacity yields daily rates per the below.

Table 5. Simple Economic Structure of Pipeline Revenue Derivation

	Dollars (\$M)	Typical Pctg.	Annual Revenue (\$M)	Capacity (Dth/d)	100% LF Rate (\$/Dth/d)
<b>Assumed Interest Rate</b>		5.0%			
<b>Typical delta to Int Rt%</b>		8.0%			
<b>Upfront Costs</b>					
<b>Total Capital Cost</b>	\$1,200	13.0%	\$156	1,000,000	\$0.4274

Then, there are costs that are deducted from the pipeline's revenues which in the case of LLC structured pipelines result in distributable cash – otherwise considered return to the investors. A typical illustrative revenue, cost and distributable cash<sup>25</sup> structure of a new-build LLC Pipeline is set forth below.

Table 6. Typical LLC Pipeline Revenue, Cost, and Distributable Cash Structure

	Applicable Dollars for Pctg (\$M)	Typical Pctg.	Annual (\$M)	Capacity (Dth/d)	Cost Component in Rate
<b>Annual Revenue</b>			\$156	1,000,000	\$0.4274
<b>Annual Costs</b>					
<b>Total Capital Cost Financed</b>		50.0%			
<b>Interest Cost</b>	\$600	5.0%	\$30	1,000,000	\$0.0822
<b>Typical Annual Costs as Pctg of Total Capital Cost</b>					
<b>Operations &amp; Maintenance</b>	\$1,200	1.0%	\$12	1,000,000	\$0.0329
<b>Non-income taxes</b>	\$1,200	2.5%	\$30	1,000,000	\$0.0822
<b>Overhead</b>	\$1,200	2.0%	\$24	1,000,000	\$0.0658
<b>Total Annual Cost</b>	\$1,200	8.0%	\$96	1,000,000	\$0.2630
			<b>Annual Cash (\$M)</b>		<b>Portion of Rate to Investor Cash</b>
<b>Distributable Cash</b>	\$1,200	5.0%	\$60	1,000,000	\$0.1644

In addition, it is often the case that entities that form LLC Pipelines also double leverage their invested capital. This generally means that while the LLC gets 50% of its total capital cost as equity (in the case above \$600 Million), the LLC Members then finance often as much as 50% of that equity contribution at their respective corporate levels. If this were to be the case with all of the LLC members of the LLC Pipeline, then their total equity cash investment would be just

<sup>25</sup> Note that Distributable Cash is on-going once the pipeline has established what it considers sufficient Working Capital Reserves, usually on the order of 2-4% of Total Capital Cost.

\$300 Million and assuming they financed their other \$300 Million at the same 5% (for an annual cost of \$15 Million) then the return on equity to those partners would be \$45 Million (\$60 Million of cash minus \$15 Million of interest) on a \$300 Million cash investment. This would mean that those entities would possibly be seeing a 15% return on their cash investments.

The potential 15% return on capital is a very healthy one indeed in this overall economic environment. It is quite possible that this level of financial gain is a very strong motivator behind the proposed PennEast Pipeline.

### **Do Non-Arm's-Length Commitments Demonstrate Market Need?**

Since the restructuring of the US Natural Gas Pipeline Industry in the mid 1990's, the Federal Energy Regulatory Commission (FERC) has had a policy of relying on contracts to pay for new pipelines and expansions of existing pipelines as evidence of market need sufficient to find such construction was in the "public convenience and necessity." A finding that a project is in the public convenience and necessity is what is required for the FERC to both grant eminent domain and to justify any construction of interstate facilities. That said, for most of the past 20 years since it established its policy of reliance on contracts as evidence of market need, those contracts were almost always between un-related parties – they were arm's-length contracts.

That previously prevailing fact is not the case with respect to 74.2% of the capacity and ownership of PennEast. In fact most of the Shippers, that is, the contracting parties on whom FERC typically relies as evidence of market need, are owners with a distinct financial interest in the existence of the pipeline and the returns it will provide. Moreover, assuming the LDC shippers are able to have their PennEast Contracts paid for by those LDCs' ratepayers, one has to question whether the FERC can continue its policy of relying on contracts as evidence of market need, the foundational aspect to a finding of public convenience and necessity.

### ***This cannot be overstated or overemphasized.***

If non-arm's-length contracts, possibly motivated by financial gain to affiliates of the shippers, are properly scrutinized then there may be *no market need* for a large proportion of the PennEast capacity upon which a finding of public convenience and necessity can rely. Instead, it may be that rather than a market need, there is purely a shareholder return "need" which should not be sufficient to grant a certificate of public convenience and necessity.

## Section VI – Conclusion

As discussed in this memorandum, given all of the following:

- 1) The potentially evident low percentage utilization;
- 2) The likely existence of lower cost potentially less disruptive alternatives<sup>26</sup>;
- 3) The likely negative impacts on ratepayers who presently benefit from secondary market transactions to reduce their energy costs;
- 4) The possible negative impact on LDC ratepayers due to turnback of capacity and/or non-renewal of capacity due to a potential glut of capacity;
- 5) The likely elimination of favorable pricing for gas in the supply area of the proposed line owing to other known developments;
- 6) The inappropriateness of relying on past events rather than modeling and forecasting future events based upon known changes as a justification for an action as large as adding a Billion cubic feet of incremental pipeline capacity to a limited geographical area;
- 7) Recent changes in Electric market rules which may have already eliminated the conditions that gave rise to the price spikes of the past;
- 8) The likely inappropriateness of reliance on non-arm's-length transactions as a foundation for finding market need; and finally,
- 9) The fact that most of the sponsors of the proposed line are the regulated utility-shippers' unregulated affiliates that are likely committing ratepayer dollars to provide equity returns that will be realized by the unregulated affiliates;

the Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is to be met by the proposed pipeline and whether less disruptive and more cost-effective alternatives exist to meet the demand determined from such evidentiary proceeding.

---

<sup>26</sup> Especially alternatives relying on greater utilization of existing LNG facilities to meet short duration peak demands

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 11**, Florida Power and Light, Ten Year Power Plant Site Plan, 2016-2025, April 2016, p.56-62.

**Ten Year Power Plant Site Plan  
2016 – 2025**



**FPL**

***(This page is intentionally left blank.)***



**FPL**

***Ten Year Power Plant Site Plan***

***2016-2025***

***Submitted To:***

***Florida Public  
Service Commission***

***April 2016***

***(This page is intentionally left blank.)***

## Table of Contents

List of Figures and Tables.....	iii
List of Schedules .....	iv
Overview of the Document .....	1
List of Abbreviations .....	3
Executive Summary .....	5
<b>Chapter I. Description of Existing Resources .....</b>	<b>11</b>
A. FPL-Owned Resources .....	13
B. Capacity and Energy Power Purchases .....	17
C. Demand Side Management (DSM).....	22
<b>Chapter II. Forecast of Electric Power Demand .....</b>	<b>25</b>
A. Overview of the Load Forecasting Process .....	27
B. Comparison of FPL’s Current and Previous Load Forecasts .....	28
C. Long-Term Sales Forecasts .....	29
D. Net Energy for Load (NEL) .....	32
E. System Peak Forecasts .....	33
F. Hourly Load Forecast .....	36
G. Uncertainty .....	36
H. DSM .....	37
<b>Chapter III. Projection of Incremental Resource Additions .....</b>	<b>45</b>
A. FPL’s Resource Planning .....	47
B. Projected Incremental Resource Additions/Changes in the Resource Plan .....	56
C. Discussion of the Projected Resource Plan and Issues Impacting FPL’s Resource Planning Work.....	56
D. Demand Side Management (DSM) .....	62
E. Transmission Plan .....	66
F. Renewable Resources.....	72
G. FPL’s Fuel Mix and Fuel Price Forecasts .....	80
<b>Chapter IV. Environmental and Land Use Information .....</b>	<b>115</b>
A. Protection of the Environment .....	117
B. FPL’s Environmental Policy .....	119
C. Environmental Management .....	120
D. Environmental Assurance Program .....	121
E. Environmental Communication and Facilitation .....	122
F. Preferred and Potential Sites .....	122
Preferred Sites.....	123
1. Preferred Site # 1 - Babcock Ranch Solar Energy Center, Charlotte County .....	123
2. Preferred Site # 2 - Citrus Solar Energy Center, DeSoto County .....	126

3. Preferred Site # 3 - Manatee Solar Energy Center, Manatee County .....	128
4. Preferred Site # 4 - Lauderdale Plant Peaking Facilities, Broward County .....	131
5. Preferred Site # 5 - Ft. Myers Plant Peaking Facilities, Lee County .....	134
6. Preferred Site # 6 - Okeechobee Site, Okeechobee County .....	137
7. Preferred Site # 7 - Turkey Point Plant, Miami-Dade County .....	140
Potential Sites .....	145
8. Potential Site # 1 - Alachua County .....	145
9. Potential Site # 2 - Hendry County .....	146
10. Potential Site # 3 - Martin County .....	147
11. Potential Site # 4 - Miami-Dade County... ..	148
12. Potential Site # 5 - Putnam County.....	149
13. Potential Site # 6 - Volusia County.....	149
 Chapter V. Other Planning Assumptions and Information .....	 217

**List of Figures and Tables**

<b>Table ES-1</b>	<b>Projected Capacity &amp; Firm Purchase Power Changes.....</b>	<b>10</b>
<b>Figure I.A.1</b>	<b>Capacity Resources by Location (as of December 31, 2015).....</b>	<b>14</b>
<b>Table I.A.1</b>	<b>Capacity Resource by Unit Type (as of December 31, 2015) .....</b>	<b>15</b>
<b>Figure I.A.2</b>	<b>FPL Substation &amp; Transmission System Configuration.....</b>	<b>16</b>
<b>Table I.B.1</b>	<b>Purchase Power Resources by Contract (as of December 31, 2015).....</b>	<b>19</b>
<b>Table I.B.2</b>	<b>FPL’s Firm Purchased Power Summer MW .....</b>	<b>20</b>
<b>Table I.B.3</b>	<b>FPL’s Firm Purchased Power Winter MW.....</b>	<b>21</b>
<b>Figure III.A.1</b>	<b>Overview of FPL’s IRP Process.....</b>	<b>48</b>
<b>Table III.E.1</b>	<b>List of Proposed Power Lines .....</b>	<b>67</b>
<b>Table IV.E.1</b>	<b>2015 FPL Environmental Outreach Activities .....</b>	<b>122</b>
	<b>Preferred Site # 1 - Babcock Maps.....</b>	<b>151</b>
	<b>Preferred Site # 2 - Citrus Maps.....</b>	<b>157</b>
	<b>Preferred Site # 3 – Manatee Maps.....</b>	<b>163</b>
	<b>Preferred Site # 4 – Lauderdale Maps.....</b>	<b>169</b>
	<b>Preferred Site # 5 – Ft. Myers Maps .....</b>	<b>175</b>
	<b>Preferred Site # 6 – Okeechobee Maps.....</b>	<b>181</b>
	<b>Preferred Site # 7 – Turkey Point Maps .....</b>	<b>187</b>
	<b>Potential Site # 1 – Alachua County Maps .....</b>	<b>193</b>
	<b>Potential Site # 2 – Hendry County Maps .....</b>	<b>197</b>
	<b>Potential Site # 3 – Martin County Maps.....</b>	<b>201</b>
	<b>Potential Site # 4 – Miami-Dade County Maps .....</b>	<b>205</b>
	<b>Potential Site # 5 – Putnam County Maps .....</b>	<b>209</b>
	<b>Potential Site # 6 – Volusia County Maps.....</b>	<b>213</b>

## List of Schedules

<b>Schedule 1</b>	<b>Existing Generating Facilities As of December 31, 2015</b> .....	<b>23</b>
<b>Schedule 2.1</b>	<b>History and Forecast of Energy Consumption &amp; Number of Customers by Customer Class</b> .....	<b>38</b>
<b>Schedule 2.2</b>	<b>History and Forecast of Energy Consumption &amp; Number of Customers by Customer Class (Continued)</b> .....	<b>39</b>
<b>Schedule 2.3</b>	<b>History and Forecast of Energy Consumption &amp; Number of Customers by Customer Class (Continued)</b> .....	<b>40</b>
<b>Schedule 3.1</b>	<b>History and Forecast of Summer Peak Demand (MW)</b> .....	<b>41</b>
<b>Schedule 3.2</b>	<b>History and Forecast of Winter Peak Demand (MW)</b> .....	<b>42</b>
<b>Schedule 3.3</b>	<b>History and Forecast of Annual Net Energy for Load (GWh)</b> .....	<b>43</b>
<b>Schedule 4</b>	<b>Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month</b> .....	<b>44</b>
<b>Schedule 5</b>	<b>Fuel Requirements (for FPL Only)</b> .....	<b>89</b>
<b>Schedule 6.1</b>	<b>Energy Sources</b> .....	<b>90</b>
<b>Schedule 6.2</b>	<b>Energy Sources % by Fuel Type</b> .....	<b>91</b>
<b>Schedule 7.1</b>	<b>Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak</b> .....	<b>92</b>
<b>Schedule 7.2</b>	<b>Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak</b> .....	<b>93</b>
<b>Schedule 8</b>	<b>Planned and Prospective Generating Facility Additions and Changes</b> .....	<b>94</b>
<b>Schedule 9</b>	<b>Status Report and Specifications of Proposed Generating Facilities</b> .....	<b>96</b>
<b>Schedule 10</b>	<b>Status Report and Specifications of Proposed Transmission Lines</b> .....	<b>104</b>
<b>Schedule 11.1</b>	<b>Existing Firm and Non-Firm Capacity &amp; Energy by Primary Fuel Type Actuals for the Year 2015</b> .....	<b>112</b>
<b>Schedule 11.2</b>	<b>Existing Non- Firm Self-Service Renewable Generation Facilities Actuals for the Year 2015</b> .....	<b>113</b>

## **Overview of the Document**

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change, at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document is based on Florida Power & Light Company's (FPL's) integrated resource planning (IRP) analyses that were carried out in 2015 and that were on-going in the first Quarter of 2016. The forecasted information presented in this plan addresses the years 2016 through 2025.

This document is organized in the following manner:

### **Chapter I – Description of Existing Resources**

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

### **Chapter II – Forecast of Electric Power Demand**

FPL's load forecasting methodology, and the resulting forecast of seasonal peaks and annual energy usage, is presented in Chapter II. Included in this discussion is the projected significant impact of federal and state energy efficiency codes and standards.

### **Chapter III – Projection of Incremental Resource Additions**

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2015 and early 2016. This chapter also discusses a number of factors or issues that either have changed, or may change, the

resource plan presented in this Site Plan. Furthermore, this chapter discusses FPL's previous and planned demand side management (DSM) efforts, the projected significant impact of the combined effects of FPL's DSM plans and state/federal energy efficiency codes and standards, FPL's previous and planned renewable energy efforts, projected transmission planning additions, and FPL's fuel cost forecasting processes.

#### **Chapter IV – Environmental and Land Use Information**

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

#### **Chapter V – Other Planning Assumptions and Information**

This chapter addresses twelve (12) "discussion items" which pertain to additional information that is included in a Site Plan filing.

**FPL  
List of Abbreviations  
Used in FPL Forms**

<b>Reference</b>	<b>Abbreviation</b>	<b>Definition</b>
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	PV	Photovoltaic
	ST	Steam Unit (Fossil or Nuclear)
Fuel Type	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	NUC	Uranium
	Pet	Petroleum Coke
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
ULSD	Ultra - Low Sulfur Distillate	
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	L	Regulatory approval pending. Not under construction
	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

***(This page is left intentionally blank.)***

## Executive Summary

Florida Power & Light Company's (FPL's) 2016 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet FPL's projected incremental resource needs for the 2016 through 2025 time period. By design, the primary focus of this document is on projected supply side additions; *i.e.*, electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed, based on FPL's load forecast, after accounting for FPL's DSM resource additions. DSM Goals for FPL for the time period 2015 through 2024 were set in November 2014 by the Florida Public Service Commission (FPSC). Consequently, the level of DSM additions reflected in the 2016 Site Plan is consistent with these DSM Goals including an extension of that level of DSM in the year 2025. DSM is discussed in Chapters I, II, and III.

In addition, FPL's load forecast accounts for a significant amount of efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these codes and standards are directly accounted for in FPL's load forecast and are discussed later in this summary and in Chapters II and III.

There are resource planning-related similarities when comparing FPL's 2015 and 2016 Site Plans. There is also one significant resource planning-related difference between the two Site Plans. In addition, there are also a number of factors that either have influenced, or which may influence, FPL's on-going resource planning efforts. These factors could result in future changes to the resource plan presented in this document. A brief discussion of these similarities, differences, and factors is provided below. Additional information regarding these topics is presented in Chapters II and III.

### **I. Similarities Between the 2016 and 2015 Site Plans:**

There are four (4) important resource planning-related similarities between the 2016 and 2015 Site Plans. These similarities reflect FPL's continuing effort to modernize its fleet of generating units both by adding new, highly-efficient, low-or-no emission generating units and retiring older, less efficient generating units.

#### **Similarity # 1: FPL continues to pursue new cost-effective solar generating capacity.**

As announced in FPL's 2015 Site Plan, FPL is in the process of adding three new photovoltaic (PV) facilities that will be in service by the end of 2016. Each of the PV facilities will be approximately 74.5 MW (nameplate rating, AC). As a result, FPL's solar generation capacity will triple by the end of 2016 from its

current 110 MW to approximately 333 MW. The new 2016 PV installations are sited in Manatee, Charlotte, and DeSoto counties. The economics of these specific PV projects are aided by the fact that the sites are located close to existing electric infrastructure, including transmission lines and electric substations.

In this 2016 Site Plan, FPL is also projecting the addition of another approximately 300 MW of PV that will be added by the year 2021. (For planning purposes, FPL is currently showing this addition in the Summer of 2020.) This will result in an approximate doubling of FPL's PV generation from the 333 MW level by the end of 2016 to approximately 633 MW. A final determination of the siting of this 300 MW of additional PV has not yet been made. A number of promising sites are currently under review. In addition, FPL will continue to analyze other opportunities for utilizing cost-effective solar energy.

**Similarity # 2: FPL continues to pursue cost-effective new nuclear energy generating capacity.**

Since June 2009, FPL has been in the process of attempting to secure federal Combined Operating Licenses for two new nuclear units, Turkey Point Units 6 & 7, that would be sited at FPL's Turkey Point site (where two other nuclear generating units exist). In 2014 the Nuclear Regulatory Commission significantly revised the Turkey Point Units 6 & 7 Combined Operating License Application (COLA) Review Schedule. A subsequent project schedule review based on the COLA schedule revision, and changes in Florida's nuclear cost recovery rule, indicated that the earliest practical dates for bringing the Turkey Point 6 & 7 units in-service are mid-2027 (Unit 6) and mid-2028 (Unit 7) which is beyond the 2016 through 2025 time period addressed in this Site Plan. Despite the projected timing of the two new nuclear units, the nuclear units remain as an important factor in FPL's resource planning and this Site Plan continues to present the Turkey Point site as a Preferred Site for the new units.

**Similarity # 3: FPL continues to modernize its fleet of generating units.**

In recent years, FPL has retired a number of older, less efficient generating units including: Sanford Unit 3, Cutler Units 5 & 6, Cape Canaveral Units 1 & 2, Riviera Beach Units 3 & 4, Port Everglades Units 1 – 4, and Putnam Units 1 & 2. In their place, FPL has already added new, highly fuel-efficient combined cycle (CC) natural gas-fired generation at the Cape Canaveral, Riviera Beach, and Port Everglades sites and will add another highly fuel-efficient CC unit in Okeechobee County in 2019.

In addition, an older generating unit, Turkey Point Unit 2, has been converted from generation mode to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida. Its companion unit, Turkey Point Unit 1, is also planned to begin running in synchronous condenser mode starting in 2016.

FPL is also in the process of retiring a number of its existing older gas turbine (GTs) units, including: 22 of 24 GTs at the Lauderdale site, all 12 GTs at the Port Everglades site, and 10 of 12 GTs at the Fort Myers plant site. Two of the existing GTs at the Lauderdale site, and two of the existing GTs at the Ft. Myers site, will be retained for black start capability. In conjunction with the retirement of these peaking units, FPL is adding a number of new, larger, and more fuel-efficient combustion turbines (CTs): 5 at the Lauderdale site and 2 at the Fort Myers site. Also, the two existing CTs at the Fort Myers site are undergoing capacity upgrades. At the time this Site Plan is filed, one GT, GT Unit 8 at Fort Myers, has been retired. All of the remaining GT- and CT-related changes described above are projected to be completed by the end of 2016.

**Similarity # 4: Carbon dioxide (CO<sub>2</sub>) emission reduction remains an important issue that is considered in FPL's on-going resource planning work even though uncertainty regarding CO<sub>2</sub> regulation still exists.**

FPL's resource planning work has evaluated potential CO<sub>2</sub> regulation and/or legislation for a number of years. However, there has always been considerable uncertainty regarding the extent and the cost impacts of the potential regulation/legislation. The issuance of EPA's Clean Power Plan (CPP) final rules in September 2015 appeared to remove a significant portion of this uncertainty. However, the U.S. Supreme Court's decision in February 2016 to stay the CPP implementation appears likely to result in some level of delay in implementation. Furthermore, assuming that the CPP rules move forward in their current form, there is still uncertainty regarding how the state of Florida will develop and implement a State Implementation Plan (SIP) that is required by the CPP rules. Therefore, FPL's resource planning work will continue to evaluate CO<sub>2</sub>-related issues and projected costs, but will do so – at least in the near term – in the midst of continuing uncertainty.

**II. A Difference Between the 2016 and 2015 Site Plans:**

This year there is only one important resource planning-related difference between the 2016 and 2015 Site Plans:

**Difference: FPL does not project a significant long-term additional resource need until the years 2024 and 2025.**

Forecasted lower peak load growth, plus the recently approved Okeechobee CC unit that will enter service in mid-2019, results in FPL projecting that its next significant long-term resource needs will not occur until the years 2024 and 2025. Because these resource needs are 8 and 9 years in the future, no decision regarding how to best meet those resource needs will be required for several years. Recognizing this fact,

this Site Plan shows a large CC natural gas-fired unit at a greenfield site being added in 2024. The CC unit is a reasonable resource option which could address FPL's resource needs for both of these years. However, on-going resource planning analyses in subsequent years will ultimately determine what the best resource option(s) for 2024 and 2025 will be. This decision will be addressed in future Site Plans.

### **III. Factors Which Have Impacted, or Which Could Impact, FPL's Resource Plan:**

In addition to these important similarities and difference, there are a number of factors which have impacted, or which may impact, FPL's resource plan. Five (5) such factors are summarized in the text below and these are presented in no particular order. These factors, and/or their potential impacts to the resource plan presented in this Site Plan, are further discussed in Chapters II and III.

The first and second of these factors are on-going system concerns that FPL has considered in its resource planning work for a number of years. The first factor is the objective to maintain/enhance fuel diversity in the FPL system. Diversity is sought both in terms of the types of fuel utilized by FPL and how these fuels are supplied to FPL. (Related to the fuel diversity objective, FPL also seeks to enhance the efficiency with which it uses fuel to generate electricity.) The second factor is the need to maintain a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward counties. This balance has both reliability and economic implications for FPL's system.

The third factor is also a system concern that FPL has considered in its resource planning for several years. This concern focuses upon the desirability of maintaining an appropriate balance of DSM and supply resources from a system reliability perspective. FPL addresses this through the use of a 10% generation-only reserve margin (GRM) reliability criterion in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability in a comprehensive manner.

The fourth factor is the significant and increasing impact that federal and state energy efficiency codes and standards are having on FPL's forecasted future demand and energy requirements. The incremental impacts of these energy efficiency codes and standards during the 2016 through 2025 time period are projected to reduce FPL's forecasted Summer peak load by more than 1,800 MW, and reduce annual energy consumption by more than 8,700 GWh, by 2025. In addition, energy efficiency codes and standards significantly reduce the potential for cost-effective energy efficiency that might otherwise have been obtained through FPL's DSM programs.

The fifth factor is the increasing cost competitiveness of utility-scale (or “universal”) PV facilities due to the projected continued decline in the cost of PV modules and the recent extension of federal tax credits. Utility-scale PV facilities are the most economical way to utilize PV technology and the declining costs of PV modules have resulted in utility scale PV becoming competitive on FPL’s system, especially at specific, highly advantaged sites. As a result, FPL’s current resource plan presented in this year’s Site Plan includes approximately 223 MW (nameplate, AC) of new PV facilities that are under construction and which will be in-service by the end of 2016. These PV additions are being made at three specific sites that offer particular cost advantages. In addition, the resource plan presented in this 2016 Site Plan shows an additional 300 MW (nameplate, AC) of PV that is projected to be in-service by the year 2021. (For planning purposes, this additional PV capacity is assumed to be in-service by mid-2020.)

Each of these factors will continue to be examined in FPL’s on-going resource planning work during the rest of 2016 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2016 through 2025. Although this table does not specifically identify the impacts of projected DSM additions on FPL’s resource needs and resource plan, FPL’s projected DSM additions that are consistent with its DSM Goals have been fully accounted for in the resource plan presented in this Site Plan.

In addition, Table ES-1 shows the addition of an FPL CC in Okeechobee County in 2019. The FPSC issued a determination of need order approving this CC unit on January 19, 2016. The table also shows the addition of 300 MW of additional PV in 2020 and a greenfield CC unit in 2024 as discussed above.

**Table ES-1: Projected Capacity & Firm Purchase Power Changes**

Year *	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin **
2016	Fort Myers 2	8	January 2016	
	Fort Myers 3A	25	June 2016	
	Martin 4	15	April 2016	
	Martin 8	(5)	March 2016	
	Port Everglades Next Generation Clean Energy Center	1,237	April 2016	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>1,280</b>		<b>22.0%</b>
2017	Babcock Solar Energy Center (Charlotte) ***	38	December 2016	
	Citrus Solar Energy Center (DeSoto) ***	38	December 2016	
	Manatee Solar Energy Center ***	38	December 2016	
	Unspecified Short-Term Purchase	53	April 2016	
	Turkey Point Unit 1 synchronous condenser	(396)	December 2016	
	Port Everglades GTs	(412)	October 2016	
	Cedar Bay	(250)	January 2017	
	Lauderdale GT 1-12	(343)	October 2016	
	Lauderdale GT 13-22	(412)	October 2016	
	Lauderdale GTs - 5 CT	1,155	December 2016	
	Fort Myers - 2 CT	462	December 2016	
	Fort Myers 3B	25	July 2016	
	Fort Myers GT 1- 12	(486)	June 2016	
	Martin 3	27	August 2016	
	Martin 4	13	April 2016	
Martin 8	(5)	March 2016		
Manatee 3	(11)	May 2017		
	<b>Total of MW changes to Summer firm capacity:</b>	<b>(465)</b>		<b>20.0%</b>
2018	Unspecified Short-Term Purchase	324	April 2018	
	Sanford 4	(1)	September 2017	
	Sanford 5	(1)	July 2017	
	Turkey Point Nuclear Unit #5	(15)	January 2018	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>307</b>		<b>20.0%</b>
2019	Turkey Point Nuclear Unit #3	20	Fall 2018	
	Turkey Point Nuclear Unit #4	20	Spring 2019	
	Okeechobee Next Generation Clean Energy Center	1,633	June 2019	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>1,673</b>		<b>24.6%</b>
2020	SJRPP suspension of energy	(382)	4th Qtr 2019	
	Unsitd Solar (PV)	156	June 2020	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>156</b>		<b>22.2%</b>
2021	Eco-Gen PPA firm capacity	180	January 2021	
	Cape Next Generation Clean Energy Center	88	Spring 2021	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>268</b>		<b>23.0%</b>
2022	Riviera Beach Next Generation Clean Energy Center	86	Spring 2022	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>86</b>		<b>22.5%</b>
2023	---	---	---	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>0</b>		<b>21.2%</b>
2024	Unsitd CC	1,622	June 2024	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>1,622</b>		<b>26.5%</b>
2025	---	---	---	
	<b>Total of MW changes to Summer firm capacity:</b>	<b>0</b>		<b>24.7%</b>

\* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations.

\*\* Winter Reserve Margins are typically higher than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

\*\*\* MW values shown for the PV facilities represent the firm capacity assumptions for the PV facilities.

# CHAPTER I

---

## Description of Existing Resources

***(This page is left intentionally blank.)***

## **I. Description of Existing Resources**

FPL's service area contains approximately 27,650 square miles and has a population of approximately ten million people. FPL served an average of 4,775,382 customer accounts in thirty-five (35) counties during 2015. These customers were served by a variety of resources including: FPL-owned fossil-fuel, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

### **I.A. FPL-Owned Resources**

The existing FPL generating resources are located at 14 generating sites distributed geographically around its service territory, plus one site in Georgia (partial FPL ownership of one unit) and two sites in Jacksonville, Florida (partial FPL ownership of two units and ownership of another unit). As of December 31, 2015, FPL's electrical generating facilities consisted of: four nuclear units, four coal units, 15 combined cycle (CC) units, five fossil steam units, 47 combustion gas turbines, two simple cycle combustion turbines, and two photovoltaic facilities<sup>1</sup>. The locations of these 79 generating units are shown on Figure I.A.1 and in Table I.A.1.

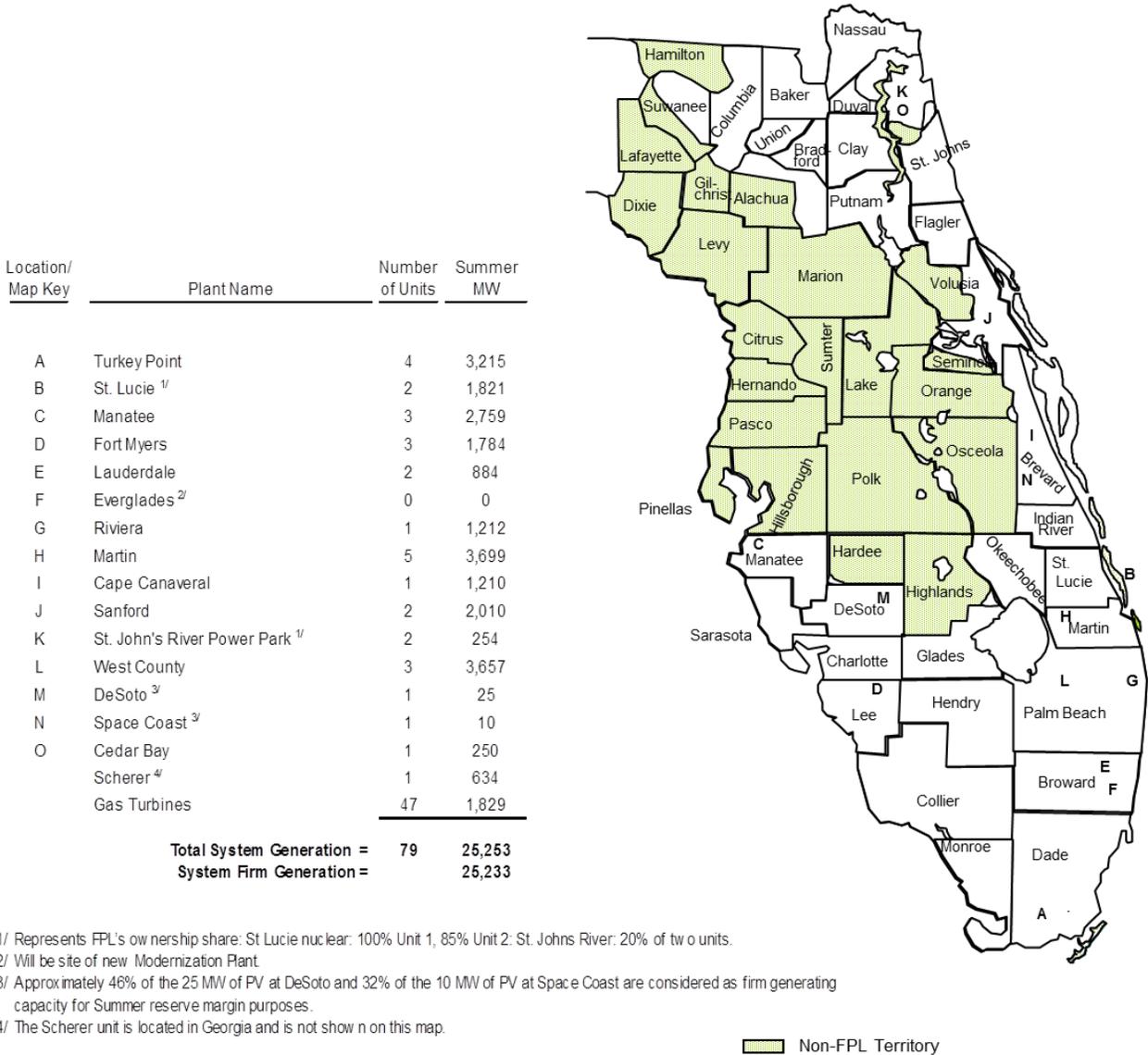
FPL's bulk transmission system, including both overhead and underground lines, is comprised of 6,897 circuit miles of transmission lines. Integration of the generation, transmission, and distribution systems is achieved through FPL's 601 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.

---

<sup>1</sup> FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

# FPL Generating Resources by Location



1/ Represents FPL's ownership share: St. Lucie nuclear: 100% Unit 1, 85% Unit 2; St. Johns River: 20% of two units.

2/ Will be site of new Modernization Plant

3/ Approximately 46% of the 25 MW of PV at DeSoto and 32% of the 10 MW of PV at Space Coast are considered as firm generating capacity for Summer reserve margin purposes.

4/ The Scherer unit is located in Georgia and is not shown on this map.

**Figure I.A.1: Capacity Resources by Location (as of December 31, 2015)**

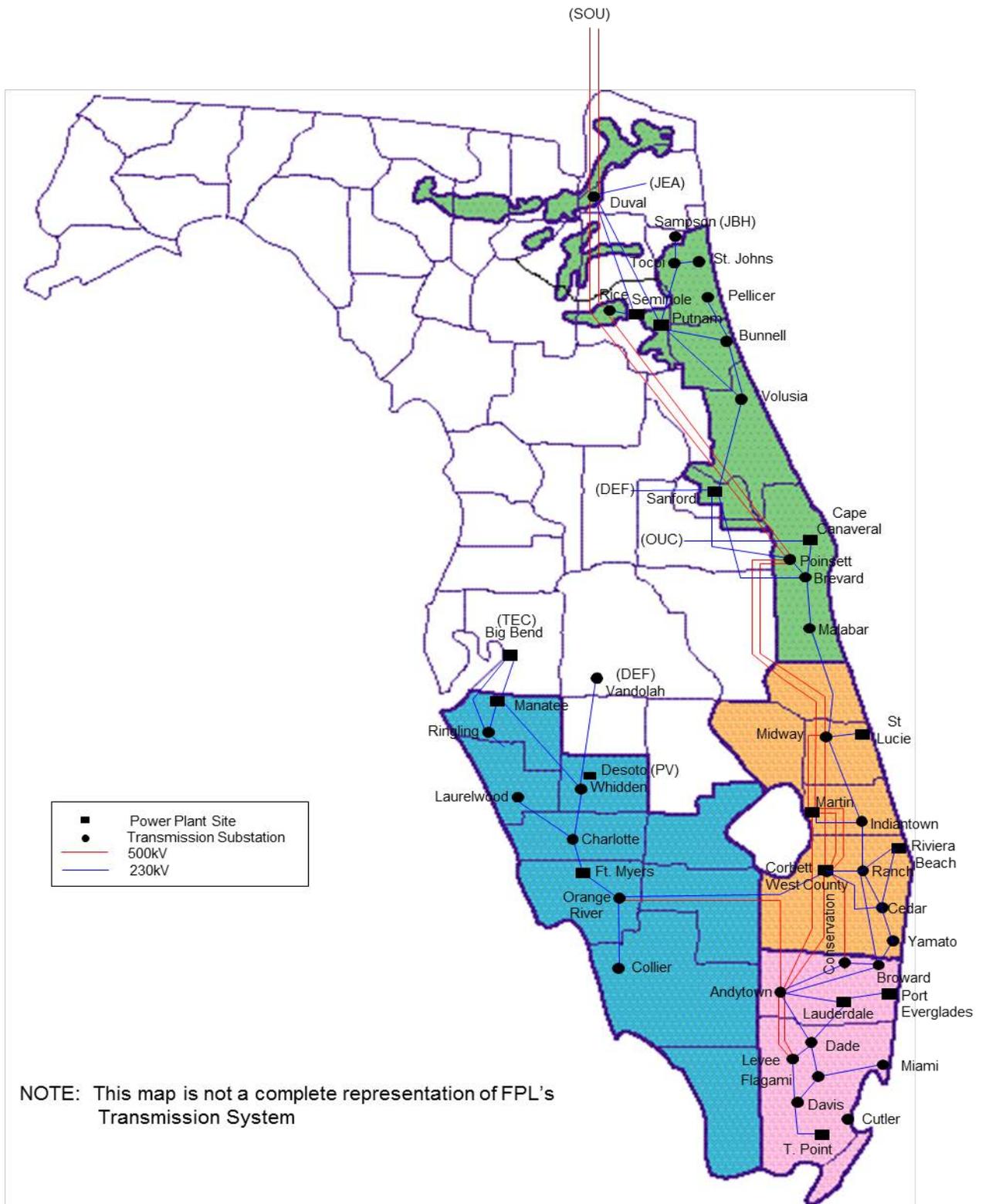
**Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2015)**

<u>Unit Type/ Plant Name</u>	<u>Location</u>	<u>Number of Units</u>	<u>Fuel</u>	<u>Summer MW</u>
<b><u>Nuclear</u></b>				
St. Lucie <sup>1/</sup>	Hutchinson Island, FL	2	Nuclear	1,821
Turkey Point	Florida City, FL	2	Nuclear	1,632
<b>Total Nuclear:</b>		<b>4</b>		<b>3,453</b>
<b><u>Coal Steam</u></b>				
Cedar Bay	Jacksonville, FL	1	Coal	250
Scherer	Monroe County, Ga	1	Coal	634
St. John's River Power Park <sup>2/</sup>	Jacksonville, FL	2	Coal	254
<b>Total Coal Steam:</b>		<b>4</b>		<b>1,138</b>
<b><u>Combined-Cycle</u></b>				
Fort Myers	Fort Myers, FL	1	Gas	1,470
Manatee	Parrish, FL	1	Gas	1,141
Martin	Indiantown, FL	3	Gas	2,073
Sanford	Lake Monroe, FL	2	Gas	2,010
Cape Canaveral	Cocoa, FL	1	Gas/Oil	1,210
Lauderdale	Dania, FL	2	Gas/Oil	884
Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,212
Turkey Point	Florida City, FL	1	Gas/Oil	1,187
West County	Palm Beach County, FL	3	Gas/Oil	3,657
<b>Total Combined Cycle:</b>		<b>15</b>		<b>14,844</b>
<b><u>Oil/Gas Steam</u></b>				
Manatee	Parrish, FL	2	Oil/Gas	1,618
Martin	Indiantown, FL	2	Oil/Gas	1,626
Turkey Point	Florida City, FL	1	Oil/Gas	396
<b>Total Oil/Gas Steam:</b>		<b>5</b>		<b>3,640</b>
<b><u>Gas Turbines(GT)</u></b>				
Fort Myers (GT)	Fort Myers, FL	11	Oil	594
Lauderdale (GT)	Dania, FL	24	Gas/Oil	823
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	412
<b>Total Gas Turbines/Diesels:</b>		<b>47</b>		<b>1,829</b>
<b><u>Combustion Turbines</u></b>				
Fort Myers	Fort Myers, FL	2	Gas/Oil	314
<b>Total Combustion Turbines:</b>		<b>2</b>		<b>314</b>
<b><u>PV</u></b>				
DeSoto <sup>3/</sup>	DeSoto, FL	1	Solar Energy	25
Space Coast <sup>3/</sup>	Brevard County, FL	1	Solar Energy	10
<b>Total PV:</b>		<b>2</b>		<b>35</b>
<b>Total System Generation as of December 31, 2015 =</b>		<b>79</b>		<b>25,253</b>
<b>System Firm Generation as of December 31, 2015 =</b>				<b>25,233</b>

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).

3/ Approximately 46% of the 25 MW of PV at DeSoto, and 32% of the 10 MW of PV at Space Coast, are considered as firm generating capacity for Summer reserve margin purposes.



**Figure I.A.2: FPL Substation and Transmission System Configuration**

## Description of Existing Resources

### I.B Capacity and Energy Power Purchases

#### **Firm Capacity: Purchases from Qualifying Facilities (QF)**

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has seven contracts with qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy during the 10-year reporting period of this Site Plan. In addition, some of these facilities provided firm capacity and energy in 2015. The 2015 actual and projected future contributions from these facilities are shown in Table I.B.1, Table I.B.2, and Table I.B.3. A change from the 2015 Site Plan to this year's Site Plan is that 11 MW of firm capacity from Broward North is no longer available to FPL at the request of Broward North.

A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses solar, wind, waste, geothermal, or other renewable resources as its primary energy source.

#### **Firm Capacity: Purchases from Utilities**

FPL has a contract with the Jacksonville Electric Authority (JEA) for the purchase of 382 MW (Summer) and 389 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in the fourth quarter of 2019. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

This purchase is shown in Table I.B.1, Table I.B.2, and Table I.B.3. FPL's ownership interest in the SJRPP units is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

**Firm Capacity: Other Purchases**

FPL has two other firm capacity purchase contracts with non-QF, non-utility suppliers. These contracts with the Palm Beach Solid Waste Authority were previously listed as QFs. However, the addition of a second unit in 2015 caused both units to no longer meet the statutory definition of a QF. Therefore, these contracts are listed as “Other Purchases” following the estimated in-service date of the new unit. Table I.B.2 and I.B.3 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

**Non-Firm (As Available) Energy Purchases**

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. The bottom half of Table I.B.1 shows the amount of energy purchased in 2015 from these facilities.

**Table I.B.1: Purchase Power Resources by Contract (as of December 31, 2015)**

<b>Firm Capacity Purchases (MW)</b>	<b>Location (City or County)</b>	<b>Fuel</b>	<b>Summer MW</b>
<b><u>I. Purchase from QF's: Cogeneration/Small Power Production Facilities</u></b>			
Indiantown Cogen LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
		<b>Total:</b>	<b>334</b>
<b><u>II. Purchases from Utilities &amp; IPP</u></b>			
Palm Beach SWA - extension	Palm Beach	Solid Waste	40
Palm Beach SWA - New Unit	Palm Beach	Solid Waste	70
SJRPP	Jacksonville	Coal	382
		<b>Total:</b>	<b>492</b>
<b>Total Net Firm Generating Capability:</b>			<b>826</b>

<b><u>Non-Firm Energy Purchases (MWH)</u></b>			
<b>Project</b>	<b>County</b>	<b>Fuel</b>	<b>Energy (MWH) Delivered to FPL in 2015</b>
Okeelanta (known as Florida Crystals and New Hope Power Partners)*	Palm Beach	Bagasse/Wood	85,015
Broward South*	Broward	Solid Waste	54,135
Broward North*	Broward	Solid Waste	19,220
Waste Management Renewable Energy*	Broward	Landfill Gas	40,802
Waste Management - Collier County Landfill*	Broward	Landfill Gas	21,099
Tropicana	Manatee	Natural Gas	5,022
Georgia Pacific	Putnam	Paper by-product	4,129
Rothenbach Park (known as MMA Bee Ridge)*	Sarasota	PV	283
First Solar*	Dade	PV	405
Customer Owned PV & Wind	Various	PV/Wind	1,460
INEOS Bio*	Indian River	Wood	450
Miami Dade Resource Recovery*	Dade	Solid Waste	95,154

\*These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, row 8, column 6.

**Table I.B.2: FPL's Firm Purchased Power Summer MW**

**Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)**

**I. Purchases from QF's**

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Indiantown Cogen L.P.	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
U.S.EcoGen Clay <sup>2/</sup>	01/01/21	12/31/49	0	0	0	0	0	60	60	60	60	60
U.S.EcoGen Okeechobee <sup>2/</sup>	01/01/21	12/31/49	0	0	0	0	0	60	60	60	60	60
U.S.EcoGen Martin <sup>2/</sup>	01/01/21	12/31/49	0	0	0	0	0	60	60	60	60	60
<b>QF Purchases Subtotal:</b>			<b>334</b>	<b>334</b>	<b>334</b>	<b>334</b>	<b>334</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>

**II. Purchases from Utilities**

	Contract Start Date	Contract End Date	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SJRPP <sup>3/</sup>	04/02/82	4 <sup>th</sup> Qtr/2019	382	382	382	382	0	0	0	0	0	0
<b>Utility Purchases Subtotal:</b>			<b>382</b>	<b>382</b>	<b>382</b>	<b>382</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>

<b>Total of QF and Utility Purchases =</b>	<b>716</b>	<b>716</b>	<b>716</b>	<b>716</b>	<b>334</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>
--	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------

**III. Other Purchases**

	Contract Start Date	Contract End Date	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Palm Beach SWA - Extension <sup>1/</sup>	01/01/12	04/01/34	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - Additional	01/01/15	04/01/34	70	70	70	70	70	70	70	70	70	70
Unspecified Purchases <sup>4/</sup>	05/01/17	09/30/17	0	53	0	0	0	0	0	0	0	0
Unspecified Purchases <sup>4/</sup>	05/01/18	09/30/18	0	0	324	0	0	0	0	0	0	0
<b>Other Purchases Subtotal:</b>			<b>110</b>	<b>163</b>	<b>434</b>	<b>110</b>						

<b>Total "Non-QF" Purchases =</b>	<b>492</b>	<b>545</b>	<b>816</b>	<b>492</b>	<b>110</b>						
-----------------------------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------

<b>Summer Firm Capacity Purchases Total MW:</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>
	<b>826</b>	<b>879</b>	<b>1,150</b>	<b>826</b>	<b>444</b>	<b>624</b>	<b>624</b>	<b>624</b>	<b>624</b>	<b>624</b>

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and it then became accounted for under "Other Purchases"

2/ The EcoGen units will enter service in 2019, however firm capacity will only be delivered starting in 2021.

3/ Contract end date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These Unspecified Purchases are short-term purchases for the summer of 2017 and 2018 that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

**Table I.B.3: FPL's Firm Purchased Power Winter MW**

**Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)**

**I. Purchases from QF's**

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Indiantown Cogen L.P.	12/22/95	12/31/26	330	330	330	330	330	330	330	330	330	330
U.S.EcoGen Clay <sup>2/</sup>	01/01/21	12/31/26	0	0	0	0	0	60	60	60	60	60
U.S.EcoGen Okeechobee <sup>2/</sup>	01/01/21	12/31/26	0	0	0	0	0	60	60	60	60	60
U.S.EcoGen Martin <sup>2/</sup>	01/01/21	12/31/24	0	0	0	0	0	60	60	60	60	60
<b>QF Purchases Subtotal:</b>			<b>334</b>	<b>334</b>	<b>334</b>	<b>334</b>	<b>334</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>

**II. Purchases from Utilities**

	Contract Start Date	Contract End Date	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SJRPP <sup>3/</sup>	04/02/82	4 <sup>th</sup> Qtr/2019	389	389	389	389	0	0	0	0	0	0
<b>Utility Purchases Subtotal:</b>			<b>389</b>	<b>389</b>	<b>389</b>	<b>389</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>

<b>Total of QF and Utility Purchases =</b>	<b>723</b>	<b>723</b>	<b>723</b>	<b>723</b>	<b>334</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>	<b>514</b>
--	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------

**III. Other Purchases**

	Contract Start Date	Contract End Date	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Palm Beach SWA - Extension <sup>1/</sup>	01/01/12	04/01/34	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - Additional	06/01/15	04/01/34	70	70	70	70	70	70	70	70	70	70
<b>Other Purchases Subtotal:</b>			<b>110</b>									

<b>Total "Non-QF" Purchases =</b>	<b>499</b>	<b>499</b>	<b>499</b>	<b>499</b>	<b>110</b>						
-----------------------------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------

<b>Winter Firm Capacity Purchases Total MW:</b>	<b>833</b>	<b>833</b>	<b>833</b>	<b>833</b>	<b>444</b>	<b>624</b>	<b>624</b>	<b>624</b>	<b>624</b>	<b>624</b>	<b>624</b>
---	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and it then became accounted for under "Other Purchases"

2/ The EcoGen units will enter service in 2019, however firm capacity will only be delivered starting in 2021.

3/ Contract end date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

## **I.C Demand Side Management (DSM)**

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2015 have resulted in a cumulative Summer peak reduction of 4,845 MW at the generator and an estimated cumulative energy saving of 74,717 Gigawatt-Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirements, FPL's DSM efforts through 2015 have eliminated the need to construct the equivalent of approximately 15 new 400 MW generating units. New DSM Goals for FPL for the 2015 through 2024 time period were set by the FPSC in December 2014. FPL accounts for these DSM goals in its planning process and extends that annual level of DSM beyond the year 2024.

## Schedule 1

Existing Generating Facilities  
As of December 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)												
Plant Name	Unit No.	Location	Unit Type	Fuel		Transport		Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Net Capability <sup>1/</sup>													
				Pri.	Alt.	Pri.	Alt.					Winter MW	Summer MW												
Cape Canaveral	3	Brevard County 19/24S/36E	CC	NG	FO2	PL	TK	Unknow n	Apr-13	Unknow n	1,295,400	1,386	1,210												
														1,295,400	1,386	1,210									
Cedar Bay	1	Duval County	ST	BIT	Other <sup>4/</sup>	RR	WA	Unknow n	Jan-94	Jan-17	291,550	250	250												
														291,550	250	250									
DeSoto <sup>2/</sup>	1	DeSoto County 27/36S/25E	PV	Solar	Solar	N/A	N/A	Unknow n	Oct-09	Unknow n	22,500	25	25												
														22,500	25	25									
Fort Myers	2	Lee County 35/43S/25E	CC	NG	No	PL	No	Unknow n	Jun-02	Unknow n	1,721,490	1,672	1,470												
														3	CT	NG	FO2	PL	TK	Unknow n	Jun-03	Unknow n	376,380	352	314
														1-7, 9-12	GT	FO2	No	TK	No	Unknow n	May-74	Jun-16 (1-9)	682,110	677	594
																							2,779,980	2,701	2,378
Lauderdale	4	Brow ard County 30/50S/42E	CC	NG	FO2	PL	PL	Unknow n	May-93	Unknow n	526,250	493	442												
														5	CC	NG	FO2	PL	PL	Unknow n	Jun-93	Unknow n	526,250	493	442
														1-12	GT	NG	FO2	PL	PL	Unknow n	Aug-70	Oct-16	410,734	440	412
														13-24	GT	NG	FO2	PL	PL	Unknow n	Aug-70	Oct-16	410,734	440	412
																							1,873,968	1,867	1,707
Manatee	1	Manatee County 18/33S/20E	ST	FO6	NG	WA	PL	Unknow n	Oct-76	Unknow n	863,300	819	809												
														2	ST	FO6	NG	WA	PL	Unknow n	Dec-77	Unknow n	863,300	819	809
														3	CC	NG	No	PL	No	Unknow n	Jun-05	Unknow n	1,224,510	1,256	1,141
Martin	1	Martin County 29/29S/38E	ST	FO6	NG	PL	PL	Unknow n	Dec-80	Unknow n	934,500	829	823												
														2	ST	FO6	NG	PL	PL	Unknow n	Jun-81	Unknow n	934,500	809	803
														3	CC	NG	No	PL	No	Unknow n	Feb-94	Unknow n	612,000	499	469
														4	CC	NG	No	PL	No	Unknow n	Apr-94	Unknow n	612,000	499	469
														8 <sup>3/</sup>	CC	NG	FO2	PL	TK	Unknow n	Jun-05	Unknow n	1,224,510	1,243	1,135
Port Everglades	1-12	City of Hollyw ood 23/50S/42E	GT	NG	FO2	PL	PL	Unknow n	Aug-71	Oct-16	410,734	440	412												
														410,734	440	412									
Riviera Beach	5	City of Riviera Beach 33/42S/432E	CC	NG	FO2	PL	WA	Unknow n	Apr-14	Unknow n	1,295,400	1,360	1,212												
											1,295,400	1,360	1,212												

1/ These ratings are peak capability.

2/ Approximately 46% of the 25 MW (Nameplate, AC) PV facility at DeSoto is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.

3/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

4/ Cedar Bay burns fiber waste (WDS) at very low levels. Plant is also permitted to burn Petcoke and Tire Derived Fuel (TDF) but has not used those options.

## Schedule 1

Existing Generating Facilities  
As of December 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel		Transport		Fuel	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Net Capability <sup>1/</sup>	
				Pri.	Alt.	Pri.	Alt.	Use				Winter MW	Summer MW
Sanford		Volusia County 16/19S/30E									<u>2,377,720</u>	<u>2,200</u>	<u>2,010</u>
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,100	1,005
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,100	1,005
Scherer <sup>2/</sup>		Monroe, GA									<u>891,000</u>	<u>635</u>	<u>634</u>
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	891,000	635	634
Space Coast <sup>3/</sup>		Brevard County 13/23S/36E									<u>10,000</u>	<u>10</u>	<u>10</u>
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River Power Park <sup>4/</sup>		Duval County 12/15/28E (RPC4)									<u>1,359,180</u>	<u>260</u>	<u>254</u>
	1		ST	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	679,590	130	127
	2		ST	BIT	Pet	RR	WA	Unknown	May-88	Unknown	679,590	130	127
St. Lucie <sup>5/</sup>		St. Lucie County 16/36S/41E									<u>2,160,000</u>	<u>1,863</u>	<u>1,821</u>
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,080,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	1,080,000	860	840
Turkey Point		Miami Dade County 27/57S/40E									<u>3,344,410</u>	<u>3,330</u>	<u>3,215</u>
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Oct-16	365,500	398	396
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	839	811
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,245	1,187
West County		Palm Beach County 29&32/43S/40E									<u>4,100,400</u>	<u>4,065</u>	<u>3,657</u>
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,355	1,219
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,355	1,219
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,355	1,219
<b>Total System Generating Capacity as of December 31, 2015 <sup>6/</sup> =</b>												<b>27,165</b>	<b>25,253</b>
<b>System Firm Generating Capacity as of December 31, 2015 <sup>7/</sup> =</b>												<b>27,130</b>	<b>25,233</b>

1/ These ratings are peak capability.

2/ These ratings relate to FPL's 76.36% share of Plant Scherer Unit 4 operated by Georgia Power, and represent FPL's 73.923% ownership share available at point of interchange.

3/ Approximately 32% of the 10 MW (Nameplate, AC) PV facility at Space Coast is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.

4/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.

5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.

6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.

7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

## **CHAPTER II**

---

### **Forecast of Electric Power Demand**

***(This page is left intentionally blank.)***

## **II. Forecast of Electric Power Demand**

### **II. A. Overview of the Load Forecasting Process**

At FPL, long-term forecasts of sales, net energy for load (NEL), and peak loads typically are developed on an annual basis for resource planning work. FPL developed new long-term forecasts in late 2015 and early 2016 that replaced the previous long-term load forecasts used by FPL during 2015 in much of its resource planning work and which were presented in FPL's 2015 Site Plan. These new load forecasts are utilized throughout FPL's 2016 Site Plan and are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast including: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include population growth, economic conditions, energy prices, weather, and energy efficiency codes and standards.

The projections for the national and Florida economies are obtained from IHS Global Insight, a leading economic forecasting firm. Population projections are also obtained from IHS Global Insight. This ensures an internal consistency between some of the key forecast drivers. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling degree-hours based on 72° F, winter heating degree-days based on 66° F, and heating degree-days based on 45° F are used to forecast energy sales.
2. The maximum temperature on the peak day and the build-up of cooling degree-hours two days prior to the peak are used to forecast Summer peaks.
3. The minimum temperature on the peak day and the square of the build-up of heating degree-hours based on 66° F on the day prior to the peak day through the morning of the peak are used to forecast Winter peaks.

The cooling degree-hours and Winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45° F are used to capture space heating load resulting from sustained periods of unusually cold weather that are not completely captured by heating degree-days based on 66° F. A composite hourly temperature profile is derived using hourly temperatures

across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations where temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling and heating degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used to calculate the weather variables used in the Summer and Winter peak models.

## **II. B. Comparison of FPL's Current and Previous Load Forecasts**

FPL's current load forecast is moderately lower over the long-term relative to the load forecast previously presented in its 2015 Site Plan. Four primary factors drive the current load forecast: projected population growth, the performance of Florida's economy, energy prices, and energy efficiency codes and standards. The combined impact of these factors result in a lower load forecast over the long-term relative to the load forecast presented in the 2015 Site Plan.

The customer forecast is based on recent population projections as well as the actual levels of customer growth experienced historically. Population projections are derived from IHS Global Insight's June 2015 forecast. The forecasted growth rates are generally consistent with population growth rates utilized in last year's site plan. On a percentage basis, the projected rates of population growth are expected to be comparable with recent growth rates. The absolute increases in population are projected to be significant. The state's population has already surpassed 20 million people in 2015 and is expected to exceed 23 million by 2025. Overall, the state's population is expected to increase by nearly three million people between 2015 and 2025.

FPL growth in its customer accounts is expected to mirror the overall level of population growth in the state. From 2015 through 2025 the total number of customer accounts is projected to increase at an annual rate of 1.4% resulting in a cumulative increase of more than 710,000 customer accounts. By 2019, the total number of customer accounts served by FPL is expected to exceed 5 million. By 2025, the total number of FPL customer accounts is expected to reach approximately 5.5 million.

The economic projections incorporated into FPL's load forecast are provided by IHS Global Insight. Although IHS Global Insight is projecting slower income growth than was projected in FPL's 2015 Site Plan, they nonetheless are expecting positive increases in employment and income levels over the 10-year forecast horizon. Consistent with past projections, economic growth is expected to moderate somewhat over the longer term.

Estimates of savings from energy efficiency codes and standards are developed by ITRON, a leading expert in this field. These estimates include savings from federal and state energy efficiency codes and standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings resulting from the use of compact fluorescent bulbs and light-emitting diodes (LEDs)<sup>2</sup>. The impact of these savings began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,517 MW by 2025, the equivalent of an approximately 12% reduction in what the forecasted Summer peak load for 2025 would have been without these energy efficiency codes and standards. The cumulative impact on NEL from these savings is expected to reach 16,238 GWh over the same period while the cumulative impact on the Winter peak is expected to be 2,011 MW by 2025. This represents a decrease of approximately 11% in the forecasted NEL for 2025 and an 8% reduction in forecasted Winter peak load for 2025.

Consistent with the forecast presented in FPL's 2015 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,572 MW by 2025, an increase of 3,613 MW over the 2015 actual Summer peak. Likewise, NEL is projected to reach 125,062 GWh in 2025, an increase of 2,306 GWh from the actual 2015 value.

## **II.C. Long-Term Sales Forecasts**

Long-term forecasts of electricity sales were developed for the major revenue classes and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2016 through 2025 are presented in Schedules 2.1 - 2.3 that appear at the end of this chapter. Econometric models are developed using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

### **1. Residential Sales**

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of the following variables: cooling degree-hours, heating degree-days, energy prices, and Florida real per capita income weighted by the percent of the population that is employed. The impact of weather is captured by the cooling degree-hours and winter heating degree-days. Two variables are used to capture the impact of electric prices on energy usage. One variable is based on increases in the price of electricity over

---

<sup>2</sup> Note that in addition to the fact that these energy efficiency codes and standards lower the forecasted load, these standards also lower the potential for energy efficiency gains that would otherwise be available through utility DSM programs.

time while another variable is based on decreases in the price of electricity over time. By using two different price terms, the fact that consumers may have proportionately different responses to price increases as to price decreases is captured in the model. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Residential energy sales are forecasted by multiplying the projected residential use per customer by the projected number of residential customers.

## **2. Commercial Sales**

The commercial sales forecast is also developed using econometric models. The commercial class is forecast using four separate models, based on customer size, including: commercial lighting accounts, small accounts (less than 20 kW of demand), medium accounts (21 kW to 499 kW of demand), and large accounts (demand of 500 kW or higher). Commercial sales are driven by economic and weather variables. Specifically, the small commercial sales model utilizes the following variables: Florida real per capita income weighted by the percent of the population that is employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, an electric price variable based on increases in the real price of electricity over time, dummy variables for the specific months of November 2005, January 2007, and February 2015, and an autoregressive term.

The medium commercial sales model utilizes the following variables: Florida real per capita income weighted by the percent of the population that is employed, cooling degree-hours, lagged cooling degree-hours, an electric price variable based on increases in the real price of electricity over time, and autoregressive terms. The large commercial sales model utilizes the following variables: Florida real per capita income weighted by the percent of the population that is employed, cooling degree-hours, lagged cooling degree-hours, an electric price variable based on increases in the real price of electricity over time, an electric price variable based on decreases in the real price of electricity over time, and dummy variables for the month of December and for the specific months of January 2007 and November 2005. Finally, the commercial lighting sales model uses a lag of commercial lighting sales, dummy variables for August 2004 and September 2004, and autoregressive terms.

## **3. Industrial Sales**

The industrial class is forecast using three separate models that are based on customer size. The industrial class is comprised of three distinct groups: small accounts (less than 20 kW of demand), medium accounts (21 kW to 499 kW of demand), and large accounts (demands of 500 kW or higher). The small industrial sales model utilizes the following variables: Florida

housing starts, cooling degree-hours, heating degree-hours, and autoregressive terms. The medium industrial sales model utilizes the following variables: cooling degree-hours, January heating degree-days, dummy variables for the specific months of February 2005, November 2005, and February 2006, and autoregressive terms. The large industrial sales model utilizes an exponential smoothing model.

#### **4. Railroad and Railways Sales and Street and Highway Sales**

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on a historical moving average.

The forecast for street and highway sales is developed by first developing a trended use per customer value, then multiplying this value by the number of forecasted customers.

#### **5. Other Public Authority Sales**

This class consists of a sports field rate schedule, which is closed to new customers, and one government account. The forecast for this class is based on its historical usage characteristics.

#### **6. Total Sales to Ultimate Customer**

Sales forecasts by revenue class are summed to produce a total sales forecast.

#### **7. Sales for Resale**

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in the respect that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. FPL's load forecast includes wholesale loads served under full and partial requirements contracts that provide other utilities all, or a portion of, their load requirements at a level of service equivalent to FPL's own native load customers. There are currently nine customers in this class: Florida Keys Electric Cooperative, Lee County Electric Cooperative, New Smyrna Beach, Wauchula, Winter Park, Blountstown, Homestead, Quincy, and Seminole Electric Cooperative<sup>3</sup>.

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. FPL previously served the Florida Keys under a

---

<sup>3</sup> FPL continues to evaluate the possibility of serving the electrical loads of other entities at the time this Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

Lee County contracted with FPL for FPL to supply a portion of the Lee County load through 2013, then to serve the entire Lee County load beginning in 2014. This contract began in January 2010. Forecasted NEL for Lee County is based on customer-supplied information and historical coincident factors.

FPL sales to New Smyrna Beach began in February 2014. The contract is projected to continue through December 2017.

FPL's sales to Wauchula began in October 2011. The contract is projected to continue through December 2016.

Sales to Winter Park began in January 2014. The contract is projected to continue through December 2019.

Blountstown became an FPL wholesale customer in May 2012 under a contract that is projected to continue through December 2016.

FPL sales to Homestead began in August 2015. The contract is projected to continue through December 2024.

Sales to Quincy began in January 2016. The contract is projected to continue through December 2023.

FPL sales to Seminole Electric Cooperative are based on delivery of 200 MW that began in June 2014 and continues through May 2021.

## **II.D. Net Energy for Load (NEL)**

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population that is employed, and electric prices. The model also includes several weather variables including cooling degree-hours and heating degree-days by calendar month, and heating degree-days based on 45° F. In addition, the model includes a variable for energy efficiency codes and

standards and a variable to account for leap year. There is also an autoregressive term in the model.

Two variables are used to capture the impact of electric prices on usage. One variable is based on increases in the real price of electricity over time while another variable is based on decreases in the real price of electricity over time. The energy efficiency variable is included to capture the impacts from major energy efficiency codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and savings resulting from the use of compact fluorescent bulbs and LEDs. The estimated impact from these codes and standards includes engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005 and their cumulative impact on NEL is expected to reach 16,238 GWh by 2025. This represents an approximately 11% reduction in what the forecasted NEL for 2025 would have been absence these codes and standards. From the end of 2015, the incremental reduction through 2025 is expected to be 8,714 GWh. An additional adjustment is made for the impact of incremental distributed generation added after July 2015. The adjustment to the forecast due to distributed generation is expected to reduce the NEL forecast by 550 GWh by 2025.

The forecast was also adjusted for the additional load added after July 2015 from new plug-in electric vehicles. This resulted in an increase of approximately 1,091 GWh by the end of the ten-year reporting period. The forecast was further adjusted for the incremental load added after 2015 from FPL's economic development riders added after July 2015. This incremental load is projected to grow to 411 GWh before leveling off in 2021.

The NEL forecast is developed by first multiplying the NEL per customer forecast by the projected total number of customers and then adjusting the forecasted results for the expected changes in load resulting from plug-in electric vehicles, new wholesale contracts, distributed generation, and FPL's economic development riders. Once the NEL forecast is determined, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts discussed previously are then adjusted to match the total billed sales. The forecasted NEL values for 2016 through 2025 are presented in Schedule 3.3 which appears at the end of this chapter.

## **II.E. System Peak Forecasts**

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, and energy efficiency codes and standards. FPL developed the peak forecast models to capture these behavioral

relationships. In addition, FPL's peak forecast also reflects changes in load expected as a result of changes in wholesale contracts, distributed generation, FPL's economic development riders, and the expected number of plug-in electric vehicles.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs and LEDs. The impact from these energy efficiency standards began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,517 MW by 2025. This reduction includes engineering estimates and any resulting behavioral changes. This reduction also represents significant energy efficiency that is not funded by FPL's customers through the Energy Conservation Cost Recovery Clause.

The cumulative 2025 impact from these energy efficiency codes and standards effectively reduces FPL's Summer peak for that year by approximately 12%. From the end of 2015, the projected incremental impact on the Summer peak from these energy efficiency codes and standards is projected to be a reduction of 1,803 MW through 2025. By 2025, the Winter peak is expected to be reduced by 2,011 MW as result of the cumulative impact from these energy efficiency standards since 2005. On an incremental basis, net of the reduction already experienced through 2015, the impact on the Winter peak from these energy efficiency standards is expected to reach 1,180 MW in 2025.

The forecast also was adjusted for additional load estimated from plug-in electric vehicles which is projected to be an increase of approximately 327 MW in the Summer and 164 MW in the Winter by the end of the ten-year reporting period. The forecast was also adjusted for the incremental load resulting from FPL's economic development riders. This incremental load is projected to grow to 43 MW in the Summer peak and 32 MW in the Winter peak before leveling off in 2021. The incremental impact of distributed generation results in an expected decrease of approximately 135 MW in the Summer and a negligible reduction in the Winter by the end of the ten-year reporting period. The incremental impact from distributed generation is based on forecasted increases in rooftop photovoltaic (PV) installations not otherwise reflected in the load forecast. The ratio of the expected Summer Peak MW reduction relative to the installed nameplate MW (DC) capacity is appropriately 34% for residential PV installations and appropriately 37% for commercial PV installations. The ratio of the expected Winter Peak MW reduction to installed nameplate MW (DC) capacity is close to 0% for both residential and commercial PV installations.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2016 through 2025 are

presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 and 7.2.

### **1. System Summer Peak**

The Summer peak forecast is developed using an econometric model. The variables included in the model are the 3-month average Consumer Price Index (CPI) for Energy, Florida real household disposable income, cooling degree-hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency codes and standards, and a dummy variable for the years 1990 and 2005. The model is based on the Summer peak contribution per customer which is multiplied by total customers. This product is then adjusted to account for the expected changes in loads resulting from plug-in electric vehicles, wholesale contracts, distributed generation, and FPL's economic development riders to derive FPL's system Summer peak.

### **2. System Winter Peak**

Like the system Summer peak model, this model also is an econometric model. The model consists of two weather-related variables: the minimum temperature on the peak day and heating degree-hours for the prior day squared. The model also includes two dummy variables; one for Winter peaks occurring on weekends and one for the year 1994. Also included in the model are a variable for housing starts per capita, and an autoregressive term. The forecasted results are adjusted for the impact of energy efficiency codes and standards. The model is based on the Winter peak contribution per customer which is multiplied by the total number of customers. This product then is adjusted for the expected changes in loads resulting from plug-in electric vehicles, changes in wholesale contracts, distributed generation, and FPL's economic development riders.

### **3. Monthly Peak Forecasts**

The forecasting process for monthly peaks consists of the following steps:

- a. The forecasted annual Summer peak is assumed to occur in the month of August which historically has accounted for more annual Summer peaks than any other month.
- b. The forecasted annual Winter peak is assumed to occur in the month of January which historically has accounted for more annual Winter peaks than any other month.
- c. The remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual Summer peak.

## **II.F. Hourly Load Forecast**

Forecasted values for system hourly load for the period 2016 through 2025 are produced using a System Load Forecasting “shaper” program. This model uses years of historical FPL hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of monthly peaks and energy.

## **II.G. Uncertainty**

Uncertainty is inherent in the load forecasting process. This uncertainty can result from a number of factors, including unexpected changes in consumer behavior, structural shifts in the economy, and fluctuating weather conditions. Large weather fluctuations, in particular, can result in significant deviations between actual and forecasted peak demands. The load forecast is based on average expected or normal weather conditions. An extreme 90% probability (P90) cold weather event, however, can add an additional 3,000 MW to the Winter peak and an extreme P90 hot weather event can add an additional 700 MW to the Summer peak.

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series’ consistency with past forecasts. As needed, FPL reviews additional factors that may affect the input variables.

Uncertainty is also addressed in the modeling process. Econometric models generally are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as these become available. An ongoing process of variance analyses is performed. To the extent that the variance analyses identify large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% total reserve margin criterion, a Loss-of-Load-Probability (LOLP) criterion of 0.1, and a 10% generation-only reserve margin (GRM) criterion, are designed to maintain reliable electric service for FPL's customers in light of forecasting (and other) uncertainty. In addition, banded forecasts of the projected Summer peak and net energy for load may be produced based on an analysis of past forecasting variances. In regard to operational planning, a banded forecast for the projected Summer and Winter peak days is developed based on historical weather variations. These bands are then used to develop similar bands for the monthly peaks.

## **II.H. DSM**

The effects of FPL's DSM energy efficiency programs implementation through June 2015 are assumed to be embedded in the actual usage data for forecasting purposes. The following projected DSM MW and MWh impacts are accounted for as "line item reductions" to the forecasts as part of the IRP process: the impacts of incremental energy efficiency that FPL has implemented in the July 2015 through December 2015 time period, incremental energy efficiency that FPL plans to implement in the future based on the DSM Goals set for FPL by the FPSC in December 2014, and the cumulative and projected incremental impacts of FPL's load management programs. FPL's DSM Goals address the years 2015 through 2024. For the year 2025 that is also accounted for in this Site Plan, an additional year of DSM impact consistent with the annual impact for 2015 through 2024 is also made. After making these adjustments to the load forecast values, the resulting "firm" load forecast is then used in FPL's IRP work as shown in Chapter III in Schedules 7.1 and 7.2.

**Schedule 2.1  
History of Energy Consumption  
And Number of Customers by Customer Class**

(1)	(2)	(3)	(4) (5) (6)			(7) (8) (9)		
Year	Population	Members per Household	Rural & Residential			Commercial		
			GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2006	8,565,331	2.19	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,620,225	2.17	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,679,431	2.17	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,747,839	2.20	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,858,545	2.21	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,995,696	2.23	54,642	4,026,760	13,570	45,052	508,005	88,685
2012	9,118,826	2.25	53,434	4,052,174	13,187	45,220	511,887	88,340
2013	9,242,356	2.26	53,930	4,097,172	13,163	45,341	516,500	87,786
2014	9,372,089	2.25	55,202	4,169,028	13,241	45,684	525,591	86,919
2015	9,500,977	2.25	58,846	4,227,425	13,920	47,369	532,731	88,916

**Historical Values (2006 - 2015):**

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

**Schedule 2.1  
Forecast of Energy Consumption  
And Number of Customers by Customer Class**

(1)	(2)	(3)	(4) (5) (6)			(7) (8) (9)		
Year	Population	Members per Household	Rural & Residential			Commercial		
			GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2016	9,627,752	2.24	57,282	4,288,888	13,356	46,420	540,219	85,927
2017	9,756,176	2.24	57,100	4,352,668	13,118	46,424	547,025	84,866
2018	9,888,636	2.24	57,493	4,418,320	13,012	46,616	553,530	84,215
2019	10,023,483	2.24	57,889	4,484,457	12,909	46,822	559,800	83,641
2020	10,158,897	2.23	58,627	4,550,120	12,885	47,245	565,960	83,478
2021	10,294,771	2.23	59,108	4,615,323	12,807	47,485	571,990	83,018
2022	10,431,246	2.23	59,557	4,680,428	12,725	47,687	577,887	82,520
2023	10,568,102	2.23	60,033	4,745,673	12,650	47,930	583,531	82,138
2024	10,705,759	2.23	60,524	4,811,139	12,580	48,235	588,896	81,907
2025	10,844,154	2.22	61,034	4,876,523	12,516	48,454	594,162	81,550

**Projected Values (2016 - 2025):**

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

**Schedule 2.2  
History of Energy Consumption  
And Number of Customers by Customer Class**

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Year	<b>Industrial</b>			Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
	<u>GWh</u>	<u>No. of Customers</u>	<u>Average kWh Consumption Per Customer</u>	<u>GWh</u>	<u>GWh</u>	<u>GWh</u>	<u>GWh</u>
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226
2013	2,956	9,541	309,772	88	442	28	102,784
2014	2,941	10,415	282,398	91	446	24	104,389
2015	3,042	11,318	268,799	92	448	23	109,820

**Historical Values (2006 - 2015):**

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

**Schedule 2.2  
Forecast of Energy Consumption  
And Number of Customers by Customer Class**

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Year	<b>Industrial</b>			Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
	<u>GWh</u>	<u>Customers</u>	<u>Average kWh Consumption Per Customer</u>	<u>GWh</u>	<u>GWh</u>	<u>GWh</u>	<u>GWh</u>
2016	3,173	12,265	258,706	91	478	23	107,467
2017	3,255	13,245	245,774	91	488	23	107,382
2018	3,319	13,860	239,502	91	499	23	108,041
2019	3,368	14,088	239,089	91	509	23	108,703
2020	3,407	14,274	238,681	91	519	23	109,913
2021	3,438	14,479	237,411	91	529	23	110,674
2022	3,461	14,603	237,024	91	539	23	111,359
2023	3,479	14,609	238,145	91	549	23	112,106
2024	3,492	14,479	241,151	91	559	23	112,924
2025	3,501	14,389	243,349	91	569	23	113,673

**Projected Values (2016 - 2025):**

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

**Schedule 2.3  
History of Energy Consumption  
And Number of Customers by Customer Class**

(1)	(17)	(18)	(19)	(20)	(21)
<u>Year</u>	Sales for Resale <u>GWh</u>	Utility Use & Losses <u>GWh</u>	Net Energy For Load <u>GWh</u>	Average No. of Other <u>Customers</u>	Total Average Number of <u>Customers</u>
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449
2013	2,158	6,713	111,655	3,722	4,626,934
2014	5,375	6,204	115,968	3,795	4,708,829
2015	6,610	6,326	122,756	3,907	4,775,382

**Historical Values (2006 - 2015):**

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012-2015 values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

**Schedule 2.3  
Forecast of Energy Consumption  
And Number of Customers by Customer Class**

(1)	(17)	(18)	(19)	(20)	(21)
<u>Year</u>	Sales for Resale <u>GWh</u>	Utility Use & Losses <u>GWh</u>	Net Energy For Load <u>GWh</u>	Average No. of Other <u>Customers</u>	Total Average Number of <u>Customers</u>
2016	6,524	5,730	119,721	4,019	4,845,390
2017	5,988	5,606	118,976	4,099	4,917,036
2018	6,013	5,702	119,756	4,179	4,989,889
2019	6,084	5,735	120,522	4,259	5,062,605
2020	6,156	5,814	121,884	4,339	5,134,692
2021	5,651	5,811	122,136	4,418	5,206,211
2022	5,202	5,817	122,378	4,496	5,277,415
2023	5,278	5,857	123,240	4,575	5,348,387
2024	5,354	5,894	124,172	4,651	5,419,165
2025	5,432	5,957	125,062	4,728	5,489,801

**Projected Values (2016 - 2025):**

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

**Schedule 3.1  
History of Summer Peak Demand (MW)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,417	833	839	19,718
2014	22,935	955	21,980	0	1,010	1,494	843	866	21,082
2015	22,959	1,303	21,656	0	878	1,523	826	873	21,255

**Historical Values (2006 - 2015):**

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2015 values which are through June.

Col. (6) value for 2015 primarily reflects a short-term hardware communications issue that is projected to be resolved by the end of 2017.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

**Schedule 3.1  
Forecast of Summer Peak Demand (MW)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2016	24,170	1,297	22,872	0	931	37	859	16	22,327
2017	24,336	1,284	23,052	0	983	51	871	29	22,401
2018	24,606	1,248	23,358	0	1,007	63	883	43	22,611
2019	24,893	1,257	23,636	0	1,016	74	895	56	22,852
2020	25,206	1,203	24,003	0	1,025	86	907	70	23,117
2021	25,316	1,009	24,307	0	1,034	98	918	85	23,180
2022	25,540	1,015	24,525	0	1,044	111	930	100	23,355
2023	25,833	1,022	24,811	0	1,053	124	942	115	23,599
2024	26,180	1,009	25,172	0	1,062	138	954	131	23,896
2025	26,572	988	25,584	0	1,070	151	965	147	24,239

**Projected Values (2016 - 2025):**

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

\* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC whose loads FPL serves.

**Schedule 3.2  
History of Winter Peak Demand (MW)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,931	348	15,583	0	843	781	567	326	14,521
2014	17,500	890	16,610	0	828	805	590	337	16,083
2015	19,718	1,329	18,389	0	822	835	551	346	18,345

**Historical Values (2006 - 2015):**

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2006 through 2015 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

**Schedule 3.2  
Forecast of Winter Peak Demand (MW)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2016	20,252	1,215	19,037	0	763	18	590	6	18,875
2017	21,140	1,203	19,937	0	801	22	596	16	19,705
2018	21,358	1,162	20,195	0	836	25	601	25	19,870
2019	21,602	1,167	20,434	0	843	29	607	35	20,087
2020	21,780	1,109	20,671	0	851	34	612	45	20,238
2021	21,992	1,111	20,881	0	858	38	618	56	20,422
2022	21,980	913	21,067	0	866	43	623	67	20,381
2023	22,195	915	21,281	0	873	48	629	79	20,567
2024	22,405	897	21,507	0	880	53	634	91	20,747
2025	22,581	872	21,709	0	888	58	639	103	20,893

**Projected Values (2016 - 2025):**

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (6) value for 2016 primarily reflects a short-term hardware communications issue that is projected to be resolved by the end of 2017.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

\* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC whose loads FPL serves.

**Schedule 3.3**  
**History of Annual Net Energy for Load (GWh)**  
**(All values are "at the generator" values except for Col (8))**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Actual Net Energy For Load GWh	Sales for Resale GWh	Utility Use & Losses GWh	Total Billed Retail Energy Sales (GWh)	Load Factor(%)
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	58.9%
2013	117,087	2,962	2,469	111,655	2,158	6,713	102,784	59.1%
2014	121,621	3,125	2,529	115,968	5,375	6,204	104,389	57.7%
2015	128,556	3,232	2,568	122,756	6,610	6,326	109,820	61.0%

**Historical Values (2006 - 2015):**

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2015 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)\*1000) / ((Col. (2) \* 8760) Adjustments are made for leap years.

**Schedule 3.3**  
**Forecast of Annual Net Energy for Load (GWh)**  
**(All values are "at the generator" values except for Col (8))**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Forecasted Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Net Energy For Load Adjusted for DSM GWh	Sales for Resale GWh	Utility Use & Losses GWh	Forecasted Total Billed Retail Energy Sales w/o DSM GWh	Load Factor(%)
2016	119,721	57	51	119,614	6,524	5,730	107,467	56.4%
2017	118,976	80	75	118,821	5,988	5,606	107,382	55.8%
2018	119,756	103	101	119,552	6,013	5,702	108,041	55.6%
2019	120,522	127	129	120,266	6,084	5,735	108,703	55.3%
2020	121,884	152	157	121,574	6,156	5,814	109,913	55.2%
2021	122,136	178	187	121,771	5,651	5,811	110,674	55.1%
2022	122,378	205	219	121,954	5,202	5,817	111,359	54.7%
2023	123,240	232	252	122,756	5,278	5,857	112,106	54.5%
2024	124,172	260	287	123,625	5,354	5,894	112,924	54.1%
2025	125,062	289	322	124,452	5,432	5,957	113,673	53.7%

**Projected Values (2016 - 2025):**

Col. (2) represents Forecasted Net Energy for Load and does not include incremental DSM from 2016 - on. The Col. (2) values are extracted from Schedule 2.3, Col(19). The effects of conservation implemented prior to mid - 2015 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2016 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly throughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2016 - 2025 using the formula: Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)\*1000) / ((Col. (2) \* 8760) Adjustments are made for leap years.

**Schedule 4**  
**Previous Year Actual and Two-Year Forecast of**  
**Retail Peak Demand and Net Energy for Load (NEL) by Month**

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2015 Actual		2016 FORECAST		2017 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	15,747	8,448	20,252	8,816	21,140	8,858
FEB	19,718	7,677	18,254	8,201	18,380	7,997
MAR	17,979	9,443	18,199	9,003	18,324	8,988
APR	21,242	10,159	19,761	9,305	19,897	9,257
MAY	21,016	10,806	21,594	10,578	21,743	10,518
JUN	22,959	11,385	23,044	11,084	23,202	11,009
JUL	22,153	11,894	23,451	11,843	23,613	11,765
AUG	22,717	12,024	24,170	12,006	24,336	11,928
SEP	22,563	11,101	22,639	11,070	22,794	10,996
OCT	20,990	10,424	21,298	10,369	21,445	10,310
NOV	20,541	9,819	18,715	8,623	18,843	8,573
DEC	18,130	9,578	17,979	8,825	18,103	8,776
<b>Annual Values:</b>		<b>122,756</b>		<b>119,721</b>		<b>118,976</b>

Col. (3) annual value shown is consistent with the value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental utility conservation, and incremental load management.

Cols. (5) and Col. (7) annual values shown are consistent with forecasted values shown in Col.(2) of Schedule 3.3.

## **CHAPTER III**

---

### **Projection of Incremental Resource Additions**

***(This page is left intentionally blank.)***

### **III. Projection of Incremental Resource Additions**

#### **III.A FPL's Resource Planning:**

FPL utilizes its well established integrated resource planning (IRP) process, in whole or in part as dictated by analysis needs, to determine: when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new generating resources, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. It also discusses some of the key assumptions, in addition to a new load forecast discussed in the previous chapter, that were used in developing the resource plan presented in this Site Plan.

#### **Four Fundamental Steps of FPL's Resource Planning:**

There are 4 fundamental steps to FPL's resource planning. These steps can be generally described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

# Overview of FPL's IRP Process

Fundamental  
IRP Steps

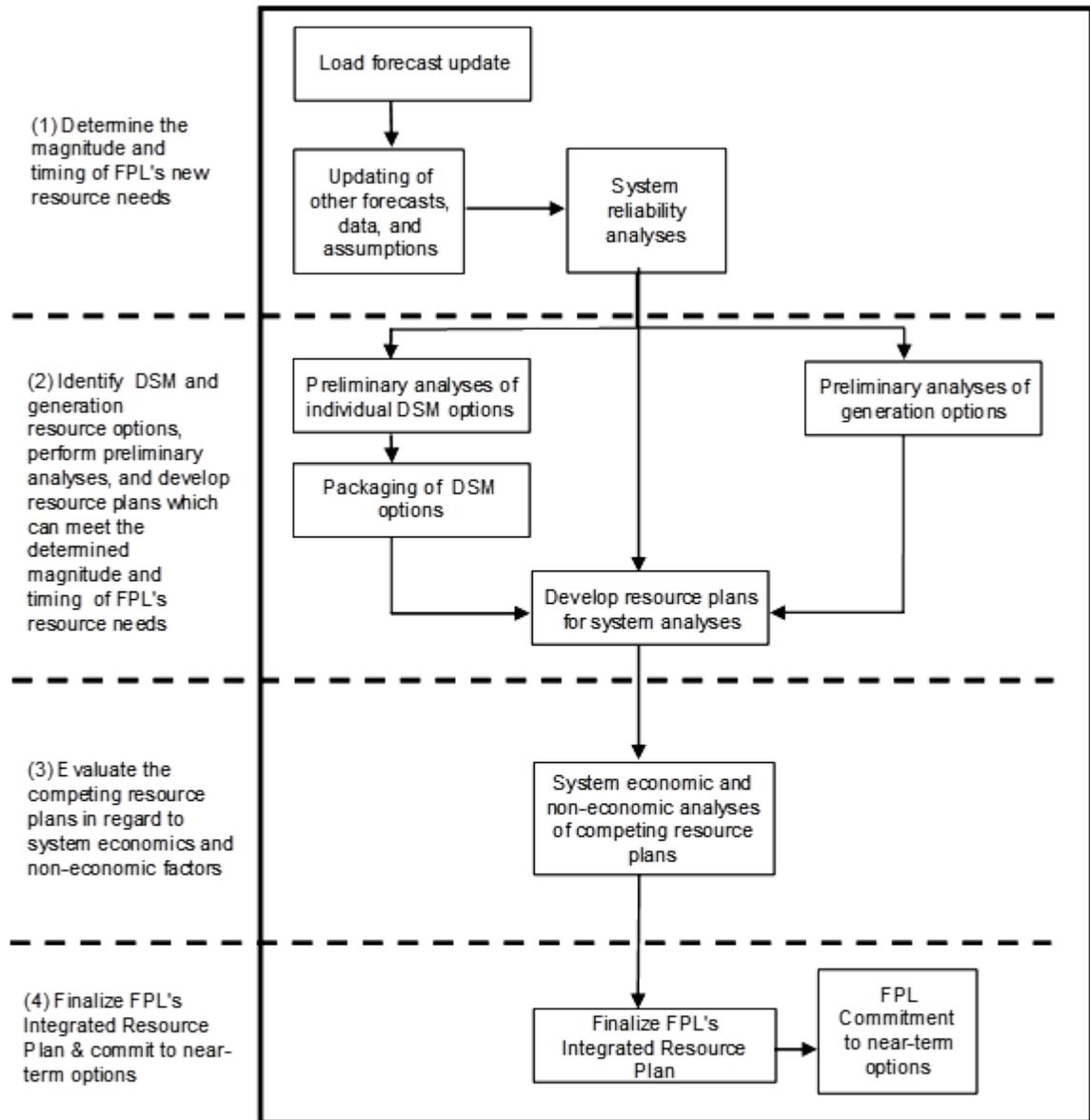


Figure III.A.1: Overview of FPL's IRP Process

## **Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:**

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, current power plant capability and operating assumptions, and current demand side management (DSM) demand and energy reduction assumptions. FPL also includes key sets of projections regarding three specific types of resources: (1) FPL unit capacity changes, (2) firm capacity power purchases, and (3) DSM implementation.

### **Key Assumptions Regarding the Three Types of Resources:**

The first set of assumptions, FPL unit capacity changes, is based on the current projection of new generating capacity additions and planned retirements of existing generating units. In FPL's 2016 Site Plan, there are four (4) such projected capacity changes through the 10-year reporting time frame of this document. These changes are listed below in general chronological order:

1) CT upgrades at existing CC plant sites:

In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components at a number of its existing CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units. 260 MW of the increased capacity from these CT upgrades are projected to be in service by the April 1, 2016 filing date of this Site Plan.

2) New Solar Facilities:

By the end of 2016, FPL will have completed the process of adding new photovoltaic (PV) facilities at three sites. These sites are FPL's existing Manatee plant site in Manatee County, the Citrus site in DeSoto County, and the Babcock Ranch site in Charlotte County. Each of the PV facilities is projected to have a rating of approximately 74.5 MW (nameplate, AC). Therefore, the three PV facilities will have a combined total rating of

approximately 223 MW (nameplate, AC). FPL's analyses of these three specific projects have led to a conclusion that approximately 52% of their nameplate (AC) rating can be accounted for as firm Summer capacity, and 0% for firm Winter capacity, in FPL's reliability analyses.

3) GT Replacement:

For economic reasons, FPL is in the process of retiring a number of its older gas turbine (GT) peaking units at its three GT sites (Lauderdale, Port Everglades, and Fort Myers) and partially replace this peaking capacity with new combustion turbine (CT) capacity at the Lauderdale and Fort Myers sites. In addition, the two existing CTs at the Fort Myers site will be upgraded which will increase their capacity. These GT- and CT-related changes are projected to be completed by the end of 2016.

4) New Combined Cycle Capacity:

FPL will be adding a new combined cycle (CC) generating unit at its Okeechobee site in mid-2019. This new generating unit was first selected as FPL's best self-build generating option. A request for proposals (RFP) was then issued to solicit capacity proposals from outside parties. However, no proposals were submitted which met the requirements of the RFP. FPL sought a determination of need from the Florida Public Service Commission (FPSC) for approval to build the Okeechobee CC unit. The FPSC issued its approval for the new unit in a final order (Order No.PSC-16-0032-FOF-EI) issued on January 19, 2016.

The second set of assumptions involves firm capacity power purchases. As discussed in last year's Site Plan, FPL terminated its then existing power purchase agreement for 250 MW of coal-fired capacity from the Cedar Bay generating facility in mid-2015 as a result of a Purchase and Sale Agreement between FPL and Cedar Bay Generating Company, L.P. that was approved by the FPSC. FPL currently owns the unit and anticipates that it will not need the unit for economic purposes after 2016 and plans to retire the unit at that time.

FPL's current projections include an additional 70 MW of waste-to-energy capacity from the Palm Beach Solid Waste Authority (SWA) that started in 2015. In addition, FPL projects that it will begin receiving a total of 180 MW of firm capacity in 2021 from biomass-based power purchase agreements with affiliates of U.S. EcoGen. Non-firm energy will be supplied by EcoGen beginning in 2019. There are only two notable changes to FPL's projections regarding firm capacity purchases. The first is that 11 MW of firm capacity from Broward North is no longer to FPL at the request of Broward North. The second change is in regard to the purchase agreement with Jacksonville Electric Authority (JEA) involving the St. Johns Regional Power Park (SJRPP). FPL

currently projects that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive under the SJRPP purchase agreement will result in the suspension of the delivery of capacity and energy to FPL in the fourth quarter of 2019, instead of the second quarter of 2019 which was the projection last year.<sup>4</sup>

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third set of assumptions involves a projection of the amount of additional DSM that FPL anticipates it will implement annually over the ten-year period of 2016 through 2025. A key aspect of FPL's IRP process is the evaluation of DSM resources. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's FPSC-approved DSM Plan will be achieved. FPL's current DSM Goals were established by the FPSC in December 2014. These DSM Goals address the years 2015 through 2024. The FPSC's DSM Goals Order No. PSC-14-0696-FOF-EU recognized that two important market forces currently were affecting the feasibility and cost-effectiveness of utility DSM programs. The first of these is the growing impact of federal and state energy efficiency codes and standards. As discussed in Chapter II, the projected incremental impacts of these energy efficiency codes and standards during the 2016 through 2025 time period are: a Summer peak reduction of approximately 1,803 MW, a Winter peak reduction of approximately 1,180 MW, and approximately 8,714 GWh of energy reduction. As a result, these energy efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs.

The second market force was FPL's lower generating costs with which DSM must compete. This is particularly noticeable in regard to current and projected fuel costs compared to those when Florida previously established DSM Goals in 2009. As an example, natural gas cost projections are more than 50% lower than natural gas costs projections were in 2009. Although lower generating costs, such as lower fuel costs, are very beneficial for FPL's customers, they also negatively impact the economics of utility DSM programs. Therefore, fewer DSM programs are now cost-effective. In addition, for some DSM programs to remain cost-effective, incentive payments to participating customers have to be lowered, thus reducing the attractiveness of these programs to potential participants.

---

<sup>4</sup> FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective and represents the earliest projected date at which the suspension of capacity and energy could occur.

The FPSC recognized the impact these market forces have on utility DSM programs and set the new DSM Goals accordingly. The new DSM Goals are appropriately lower than the previous DSM goals which will help ensure that the electric rate impacts to all of FPL's customers from pursuing DSM are minimized.

In August 2015, the FPSC approved FPL's DSM Plan that presents specific DSM programs designed to achieve the DSM Goals in Order No. PSC-15-0331-PAA-EG. The incremental DSM that is described in both the DSM Goals and DSM Plan orders is projected to be implemented in all of FPL's resource planning work, including the resource plan that is presented in this Site Plan. FPL's DSM efforts are further discussed later in this chapter in section III.D.

**The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:**

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: determining the magnitude and timing of FPL's future resource needs. This determination is accomplished by system reliability analyses. Up until 2014, FPL's reliability analyses were based on dual planning criteria of a minimum peak period total reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. Beginning in 2014, FPL began utilizing a third reliability criterion: a 10% generation-only reserve margin (GRM).

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units that can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit that can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are in use for performing system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (i.e., a measure of how often load may exceed

available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the entire firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as “the number of days per year” that the entire system firm load could not be met. FPL’s standard for LOLP, commonly accepted throughout the industry, is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

In 2010, FPL’s integrated resource planning work examined a then projected fundamental change in FPL’s resource plans. This change was a significant shift in the mix of generation and DSM resources in which FPL was becoming increasingly reliant on DSM resources, rather than generation resources, to maintain system reliability. As discussed in several subsequent FPL Site Plans, extensive analyses examined this shift from a system reliability perspective.

In these analyses, FPL developed a new metric: a generation-only reserve margin (GRM). This GRM metric reflects reserves that would be provided only by actual generating resources. The GRM value is calculated by setting to zero all incremental energy efficiency (EE) and load management (LM), plus all existing LM, to derive another version of a reserve margin calculation. The resulting GRM value provides an indication of how large a role generation is projected to play each year as FPL maintains its 20% Summer and Winter “total” reserve margins (which account for both generation and DSM resources).

These analyses examined the two types of resources, DSM and Supply options, from both an operational and a resource planning perspective. Based on these analyses, FPL concluded that resource plans for its system with identical total reserve margins, but different GRM values, are not equal in regard to system reliability. A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin value. Therefore, in 2014 FPL implemented a minimum GRM criterion of 10% as a third reliability criterion in its resource planning process. This criterion has to be met in all years beginning with the year 2019.

The 10% minimum Summer and Winter GRM criterion augments the other two reliability criteria used by FPL: a 20% total reserve margin criterion for Summer and Winter, and a 0.1 day/year LOLP criterion. All three reliability criteria are potentially useful in terms of identifying the timing and magnitude of the resource need because of the different perspectives the three criteria provide. In addition, the GRM criterion is particularly useful in providing direction regarding the mix of generation and DSM resources that should be added to maintain and enhance FPL's system reliability.

## **Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:**

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. These preliminary analyses can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step.

FPL typically utilizes a production cost model, a Fixed Cost Spreadsheet, and/or an optimization model to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM CPF model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. In addition, a years-to-payback screening test based on a two-year payback criterion is also used in the preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL uses two additional models. One of these models is FPL's non-linear programming (NLP) model that is used for analyzing the potential for lowering system peak loads through additional load management/demand response capability. The other model that FPL typically utilizes is its linear programming (LP) model, which FPL uses to develop DSM portfolios.

The individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses are then typically "packaged" into different

resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

### **Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:**

At the completion of fundamental Steps 1 & 2, the most viable new resource options have been identified and these resource options have been combined into a number of resource plans that each meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the FPL system from the competing resource options/resource plans. In FPL's 2015 and early 2016 resource planning work, once the resource plans were developed, FPL utilized the UPLAN production cost model and a Fixed Cost Spreadsheet, and/or the EGEAS optimization model, to perform the system economic analyses of the resource plans. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and/or FPSC approval, and therefore the only competing options are new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. Although these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of

dollars. These factors are often referred to by FPL as “system concerns” that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL’s system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

#### **Step 4: Finalizing FPL’s Current Resource Plan**

The results of the previous three fundamental steps are typically used to develop FPL’s current resource plan. The current resource plan is presented in the following section.

### **III.B Projected Incremental Resource Additions/Changes in the Resource Plan**

FPL’s projected incremental generation capacity additions/changes for 2016 through 2025 are depicted in Table ES-1 in the Executive Summary. These capacity additions/changes include an important resource planning-related difference between the 2016 and 2015 Site Plans previously discussed in the Executive Summary and which is described below.

Although FPL’s projected DSM additions that are developed in the IRP process are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL’s resource planning work reflected in this document. The projected MW reductions from these DSM additions are also reflected in the projected total reserve margin values shown in Table ES-1 and in Schedules 7.1 and 7.2 presented later in this chapter. DSM is further addressed later in this chapter in section III.D.

### **III.C Discussion of the Projected Resource Plan and Issues Impacting FPL’s Resource Planning Work**

As indicated in the Executive Summary, FPL’s resource planning efforts in 2015 and early 2016 resulted in one important resource planning-related difference between the 2016 and 2015 Site Plans: the fact that FPL is not projected to have a significant long-term resource need until near the end of the 10-year reporting period of this Site Plan.

A combination of the recently approved Okeechobee combined cycle that will enter service in mid-2019, plus forecasted lower peak load growth in subsequent years, results in FPL projecting that its next significant resource needs will not occur until 2024 and 2025. Because these resource needs are 8 and 9 years in the future, no decision regarding how to best meet those resource needs will be required for several years.

In addition, there are 5 other significant factors that either influenced the current resource plan presented in this document or which may result in changes in this resource plan in the future. These other factors are discussed below (in no particular order of importance).

**1. Maintaining/Enhancing System Fuel Diversity:**

FPL currently uses natural gas to generate approximately two-thirds of the total electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to remain at a high level. For this reason, and due to evolving environmental regulations, FPL is continually seeking opportunities to economically maintain and enhance the fuel diversity of its system both in regard to type of fuel and fuel delivery.

In 2007, following express direction by the FPSC to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other considerations currently unfavorable to new coal units compared to new natural gas-fired CC units. The first of these is a significant reduction in the fuel cost difference between coal and natural gas when compared to the fuel cost difference projected in 2007 which then favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital costs for coal units compared to capital costs for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, which are unfavorable to new coal units when compared to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida at this time.

Therefore, FPL has turned its attention to: adding cost-effective nuclear energy and renewable energy to enhance its fuel diversity, diversifying the sources of natural gas, diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, and using

natural gas more efficiently. In regard to nuclear energy, in 2008 the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized FPL to recover project-related expenditures that were approved as a result of annual nuclear cost recovery filings. FPL successfully completed this nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity was delivered by the project which represents an increase of approximately 30% more incremental capacity than was originally forecasted when the project began. FPL's customers are already benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that are necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. However, as discussed below, a several year delay in the Nuclear Regulatory Commission's (NRC) schedule for completing its review of FPL's Combined Operating License Application (COLA) has resulted in the earliest deployment dates for the two new nuclear units, Turkey Point Units 6 & 7, moving beyond the 2016 through 2025 reporting time period of this Site Plan (i.e., in mid-2027 and mid-2028, respectively).

FPL also has been involved in activities to investigate adding and/or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements. In addition, FPL considers new cost-effective renewable energy projects such as the power purchase agreements with U.S. EcoGen which will result in FPL receiving 180 MW of firm capacity from biomass facilities beginning in 2021. Non-firm energy will be supplied by EcoGen beginning in 2019.

In 2008, FPL also sought and received approval from the FPSC to add 110 MW of then new renewable facilities through three FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities. One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible by enabling legislation enacted by the Florida Legislature in 2008. FPL remains strongly supportive of federal and/or state legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources.

The capital costs for PV modules have steadily declined. FPL's on-going analyses of its existing PV facilities have led FPL to develop a methodology with which to determine appropriate firm capacity values for PV facilities for use in reserve margin calculations. This methodology has concluded, in general, that it is possible on FPL's system to develop a PV project-specific non-zero firm capacity value for the Summer peak hour, but not for FPL's Winter morning peak hour. Partly as a result of developing this methodology, FPL's 2015 Site Plan showed that FPL planned to add approximately 223 MW (nameplate, AC) of new utility-scale (or "universal") PV generation by the end of 2016. These three specific PV projects are projected to contribute a total of approximately 116 MW (or 52% of the nameplate AC value for each project) of firm Summer capacity, but no MW of firm Winter capacity. Construction on these three projects is underway as this document is being prepared and the three PV facilities are projected to be in-service by the end of 2016.

In this 2016 Site Plan FPL is now projecting the further addition of approximately 300 MW (nameplate, AC) of new PV by the year 2021 (a mid-2020 in-service date is assumed for planning purposes). This additional PV is expected to have roughly comparable firm capacity values to those of the 2016 PV projects once a specific site(s) for the 300 MW of additional PV is determined.

In regard to diversity in natural gas sourcing and delivery, in 2013 the FPSC approved FPL's contracts to bring more natural gas into FPL's service territory through a 3<sup>rd</sup> natural gas pipeline system into Florida. The process by the pipeline companies to obtain approval for the new pipeline system from the Federal Energy Regulatory Commission (FERC) has culminated in receiving a FERC certificate of approval for the pipelines on February 2, 2016. The pipeline entities subsequently accepted the certificate in early March, 2016. The new pipeline system will utilize an independent route that will result in a more reliable, more economic, and more diverse natural gas supply for FPL's customers and the State of Florida.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units to replace the former steam generating units on each of those sites. The Cape Canaveral modernization went into service in April 2013 and the Riviera Beach modernization went into service in April 2014. On April 9, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site. The project has been completed and the new generating unit went into service on April 1, 2016. All three of

these modernized sites have the capability of receiving water-borne delivery of Ultra-Low Sulfur Diesel (ULSD) oil as a backup fuel.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. In this regard, FPL is also maintaining the ability to utilize heavy oil and/or ULSD oil at existing units that have that capability. For this purpose, FPL has completed the installation of electrostatic precipitators (ESPs) at the two 800 MW steam generating units at its Manatee site and at the two 800 MW steam generating units at its Martin site. These installations will enable FPL to retain the ability to burn heavy oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive. In addition, the new CTs that FPL plans to install at its existing Lauderdale and Fort Myers sites, which will replace older GT units that are being retired, will have the capability to burn either natural gas or ULSD oil.

**2. Maintaining a Balance Between Load and Generation in Southeastern Florida:**

An imbalance has existed between regionally installed generation and regional peak load in Southeastern Florida. As a result of that imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods is provided by: importing energy through the transmission system from generating units located outside the region, operating less efficient generating units located in Southeastern Florida out of economic dispatch, or a combination of the two. FPL's prior planning work concluded that, as load inside the region grows, additional installed generating capacity and/or load reduction in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location in Southeastern Florida, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL has added increased capacity at its existing two nuclear units at Turkey Point as part of the previously mentioned nuclear capacity uprates project. The recently completed Port Everglades modernization project will also assist in addressing this imbalance. Implementing the additional generation capacity through the projects mentioned above has contributed to addressing the imbalance between generation, transmission capacity, and load in Southeastern Florida for much, if not all, of the 2016 through 2025 reporting time frame of this Site Plan. However, due to forecasted increasing load in the Southeastern Florida region, and the uncertainty of the location of the unsited CC unit shown in this Site Plan as being added in 2024, the Southeastern Florida imbalance issue

will remain an important consideration in FPL's on-going resource planning work in future years.

**3. Maintaining a Balance Between Generation and DSM Resources in Regard to System Reliability:**

There is another system concern that FPL has considered in its resource planning for several years. This concern surfaced beginning in 2010 when FPL's system was projected to become increasingly dependent upon DSM resources for system reliability in later years. FPL discussed this concern previously in its Site Plans from 2011 through 2014. As a result of this concern, FPL conducted extensive analyses of its system from both a resource planning perspective and a system operations perspective. Those analyses showed that system reliability risk increases, particularly from a system operations perspective, as dependence on DSM resources increases to a point where DSM resources account for more than half of FPL's 20% total reserve margin criterion value. As a result, in 2014 FPL implemented a new reliability criterion of a minimum 10% generation-only reserve margin (GRM) in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. The GRM criterion must be met each year beginning in the year 2019. Together, these three criteria allow FPL to address this specific concern regarding system reliability in a comprehensive manner.

**4. The Significant Impacts of Federal and State Energy Efficiency Codes and Standards:**

As discussed in Chapter II, FPL's load forecast includes projected impacts from federal and state energy efficiency codes and standards. The magnitude of energy efficiency that is now projected to be delivered to FPL's customers through these codes and standards is significant. FPL currently projects a cumulative Summer peak reduction impact of 3,517 MW from these codes and standards beginning in 2005 (the year the National Energy Policy Act was enacted) and extending through the year 2025 (i.e., the last year in the 2016 through 2025 reporting time period for this Site Plan) compared to what the projected load would have been without the codes and standards. The projected incremental Summer MW impact from these codes and standards during the 2016 through 2025 reporting period of this Site Plan; i.e., from year-end 2015 through 2025, is 1,803 MW compared to what the projected load would have been without the codes and standards. In regard to energy, the impact of the codes and standards has resulted in a projected reduction of 16,238 GWh since 2005. Included in this 2005 through 2025 projection is a projected reduction of 8,714 GWh from year-end 2015 through 2025. All of these projections show the significant impact of these energy efficiency codes and standards.

In addition to lowering FPL's load forecast from what it otherwise would have been, and thus serving to lower FPL's projected load and resource needs, this projection of efficiency from the codes and standards also affects FPL's resource planning in another way. The projected impacts from the energy efficiency codes and standards also lower the potential for utility DSM programs to cost-effectively deliver energy efficiency for the appliances and equipment that are directly addressed by the codes and standards. This effect was taken into account by the FPSC when FPL's current DSM Goals were set in December 2014.

#### **5. The Economic Competitiveness of Utility-Scale Photovoltaics (PV):**

A factor that is now significantly influencing FPL's resource planning is the increasing attractiveness of utility-scale PV facilities. This is due largely to the continued decline of the cost of PV modules. Because utility-scale PV facilities are approximately twice as economical on an installed \$/kw basis than distributed PV, the declining costs of PV modules has resulted, for the first time, in utility-scale PV in specific locations now being cost competitive on FPL's system. In addition, FPL's analyses of the output from its existing PV facilities in DeSoto and Brevard counties have resulted in FPL establishing a methodology for determining Summer and Winter firm capacity values for utility-scale PV facilities.

As a result, FPL's resource plan that was presented last year showed that FPL plans to add approximately 223 MW (nameplate, AC) of new PV generation by the end of 2016. In this 2016 Site plan, the resource plan that is presented shows that an additional approximate 300 MW (nameplate, AC) of PV will be added by 2021. (For planning purposes, a 2020 in-service date is assumed and shown in the resource plan.) Details regarding these new PV facilities are discussed further in this chapter in section III.F.

### **III.D Demand Side Management (DSM)**

FPL has sought and implemented cost-effective DSM programs since 1978 and DSM has been a key focus of FPL's IRP process for decades. During that time FPL's DSM programs have included many energy efficiency and load management programs and initiatives. FPL's DSM efforts through 2015 have resulted in a cumulative Summer peak reduction of 4,845 MW at the generator and an estimated cumulative energy saving of 74,717 Gigawatt-Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2015 have eliminated the need to construct the equivalent of approximately 15 new 400 MW power plants.

FPL consistently has been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2014 data (the last year for which the DOE ranking data was available at the time this Site Plan was developed), FPL ranked No. 2 nationally in cumulative DSM load management demand reduction. FPL also achieved 2,714 MW of energy efficiency-related demand reduction for the same time period. And, importantly, FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In December 2014, DSM Goals for FPL for the years 2015 through 2024 were set by the FPSC (Final Order PSC-14-0696-FOF-EIU). These DSM Goals were appropriately lower than the previous DSM Goals set in 2009 for FPL due to two factors. The first factor is the significant impact of federal and state energy efficiency codes and standards. The projected impact of these codes and standards has significantly lowered FPL's projected load and resource needs. In addition, these codes and standards have removed a significant amount of potential energy efficiency that otherwise might have been addressed by utility DSM programs. The projected impacts from these codes and standards are discussed in Chapter II.

The second factor why FPL's resource plan currently shows a diminished role for utility DSM is the decline in the projected cost-effectiveness of utility DSM measures and programs. The cost-effectiveness of DSM is driven in large part by the potential benefits that the kW (demand) reduction and kWh (energy) reduction characteristics of DSM programs are projected to provide. The diminished cost-effectiveness of utility DSM programs can be illustrated by looking at potential benefits that DSM's kWh reductions can provide as an example. There are at least two reasons for projections of lower kWh reduction-based benefits and thus projections of lower DSM cost-effectiveness.

One of these is lower fuel costs. As fuel costs are lowered, the benefit that is realized by each kWh of energy reduced by DSM is also lowered. In other words, the benefit from DSM's kWh reductions has been reduced from what it had been several years ago due to lower fuel costs. Lower forecasted natural gas costs are very beneficial for FPL's customers because they result in lower fuel costs and lower electric rates. At the same time, lower fuel costs also result in lower potential fuel savings benefits from the kWh reductions of DSM measures. These lowered benefit values result in DSM being less cost-effective.

A second reason for the decline in the cost-effectiveness of utility DSM on the FPL system is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily become more efficient in regard to its ability to generate electricity using less fossil fuel.

For example, FPL used 21% less fossil fuel to generate the same number of MWh in 2015 than it did in 2001. This is a very good thing for FPL's customers because it helps to significantly lower fuel costs and electric rates.

However, the improvements in generating system efficiency affect DSM cost-effectiveness in much the same way that lower forecasted fuel costs do: both lower the fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency further reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus further lowering potential DSM benefits and DSM cost-effectiveness.

The two reasons discussed above – lower forecasted fuel costs and greater efficiency in FPL's electricity generation – are good for FPL's customers because they will result in lower electric rates. Although beneficial for FPL's customers, these factors also contribute to lowering the cost-effectiveness of utility DSM programs. Therefore, the reduction in DSM cost-effectiveness, plus the growing impacts of energy efficiency codes and standards, led to the FPSC setting lower DSM Goals for FPL.

Although FPL's DSM Goals are appropriately lower due to these market forces, the projected cumulative effect of FPL's DSM programs from their inception through 2024 is truly significant. FPL's Summer MW Goals for the 2015 – 2024 time period are 526 MW. After accounting for the 20% total reserve margin requirements, the combination of this new Summer MW reduction value, and the Summer MW reductions from FPL's DSM programs from their inception through 2015, represent the equivalent of avoiding the need to build approximately 16 400 MW power plants. The resource plan presented in this 2016 Site Plan accounts for the DSM MW and GWh reductions set forth in FPL's DSM Goals. The MW reductions from the new DSM Goals are accounted for in Schedules 7.1 and 7.2 which appear later in this chapter. In addition, FPL also assumes that additional DSM will be added in the year 2025 at the same annual level called for in the 2015 – 2024 DSM Goals.

In August 2015 the FPSC approved FPL's DSM Plan (Order No. PSC-15-0331-PAA-EG) that describes the approach that FPL will take to meet its DSM Goals. The DSM Plan consists of 14 DSM programs and research and development efforts that are described below:

## **FPL DSM Programs and Research & Development Efforts**

### **1. Residential Home Energy Survey (HES)**

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's other DSM programs. The HES is also used to identify potential candidates for other FPL DSM programs.

### **2. Residential Load Management (On Call)**

This program allows FPL to turn off certain customer-selected appliances using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

### **3. Residential Air Conditioning**

This program encourages customers to install high-efficiency central air-conditioning systems.

### **4. Residential Ceiling Insulation**

This program encourages customers to improve the thermal efficiency of the building structure.

### **5. Residential New Construction BuildSmart®**

This program encourages builders and developers to design and construct new homes to meet ENERGY STAR® qualifications.

### **6. Residential Low-Income**

This program assists low-income customers reduce their energy costs through partnership with government and non-profit agencies, and through FPL-performed home energy retrofits.

### **7. Business Energy Evaluation (BEE)**

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's other DSM programs. The BEE is also used to identify potential candidates for other FPL DSM programs

**8. Commercial/Industrial Demand Reduction (CDR)**

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies.

**9. Commercial/Industrial Load Control (CILC)**

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies. It was closed to new participants as of December 31, 2000. It is available to existing participants who had entered into a CILC agreement as of March 19, 1996.

**10. Business On Call**

This program allows FPL to turn off customers' direct expansion central electric air-conditioning units using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

**11. Business Heating, Ventilating and Air Conditioning (HVAC)**

This program encourages customers to install high-efficiency HVAC systems.

**12. Business Lighting**

This program encourages customers to install high-efficiency lighting systems.

**13. Business Custom Incentive (BCI)**

This program encourages customers to install unique high-efficiency technologies not covered by other FPL DSM programs.

**14. Conservation Research & Development (CRD) Project**

This project consists of research studies designed to: identify new energy efficient technologies; evaluate and quantify their impacts on energy, demand, and customers; and where appropriate and cost-effective, incorporate an emerging technology into a DSM program.

**III.E Transmission Plan**

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future

additions of 230 kV and above bulk transmission lines that must be certified under the Transmission Line Siting Act.

**Table III.E.1: List of Proposed Power Lines**

(1) <b>Line Ownership</b>	(2) <b>Terminals (To)</b>	(3) <b>Terminals (From)</b>	(4) <b>Line Length CKT. Miles</b>	(5) <b>Commercial In-Service Date (Mo/Yr)</b>	(6) <b>Nominal Voltage (KV)</b>	(7) <b>Capacity (MVA)</b>
FPL	St. Johns <sup>1/</sup>	Pringle	25	Dec – 18	230	759
FPL	Levee <sup>2/</sup>	Midway	150	Jun – 23	500	2598
FPL	Raven <sup>3/</sup>	Duval	45	Dec – 18	230	759

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2018.

2/ Final order certifying the corridor was issued in April 1990. Construction of 114 miles is complete and in-service. Remaining 36 miles are scheduled to be completed by Jun-2023.

3/ TLSA was initiated in early January 2016 for the Raven to Duval project. One of the necessary approvals for the project, a need determination for the project, was issued by the Florida Public Service Commission in early March 2016.

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the PV additions in late 2016, and the new CC unit in 2019 at the Okeechobee site. At the time the 2016 Site Plan was prepared, no sites had been selected for either the 300 MW PV addition or the 2024 CC addition in the resource plan presented in this Site Plan. Therefore, no transmission information for these additions is presented.

## **II.E.1 Transmission Facilities for the PV Project at the Existing Manatee Plant Site**

The work required to connect the approximate 74.5 MW (nameplate, AC) facility at the existing Manatee site is projected to be:

### **I. Substation:**

1. Build a new 230 kV substation approximately 0.4 miles west of the existing FPL Manatee 230 kV substation.
2. Add one main step-up transformer (85 MVA) to connect the PV inverter array.
3. Construct a new 230 kV breaker bay at the Manatee switchyard.
4. Add relays and other protective equipment.
5. Breaker replacements: None.

### **II. Transmission:**

1. Construct 0.4 mile 230 kV line from new substation to the Manatee switchyard.
2. No upgrades are expected to be necessary at this time.

### **III.E.2 Transmission Facilities for the Citrus PV Project in DeSoto County**

The work required to connect the approximate 74.5 MW (nameplate, AC) Citrus PV facility in DeSoto County is projected to be:

#### **I. Substation:**

1. Construct a new 4-breaker 230 kV ring bus at the Sunshine substation.
2. Build a new 230/34.5 kV substation on the Citrus site.
3. Add one main step-up transformer (85 MVA) to connect the PV inverter array.
4. Construct a string buss to connect the Citrus PV array to the Sunshine 230 kV Substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None.

#### **II. Transmission:**

1. No upgrades are expected to be necessary at this time.

### **III.E.3 Transmission Facilities for the Babcock Ranch PV Project in Charlotte County**

The work required to connect the approximate 74.5 MW (nameplate, AC) Babcock Ranch PV facility in Charlotte County is projected to be:

#### **I. Substation:**

1. Build a new 230/34.5 kV Tuckers substation approximately 5 miles north of the planned FPL Hercules 230 kV substation.
2. Add one main step-up transformer (85 MVA) to connect the PV inverter array.
3. Add one (1) mid-breaker to complete Bay 2 at the Hercules substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None.

#### **II. Transmission:**

1. Construct 5 miles of 230 kV line from the new Tuckers substation to the Hercules substation.
2. No upgrades are expected to be necessary at this time.

### **III.E.4 Transmission Facilities for the New Combined Cycle (CC) Unit in Okeechobee County**

The work required to connect the new CC unit in Okeechobee County by Summer 2019 is projected to be:

#### **I. Substation:**

1. Build a new six breaker 500kV Okeechobee Substation switchyard on the Okeechobee generation site with a relay vault for the two generator string buses and the Martin and Poinsett line terminals.
2. Build new collector yard containing two collector busses with 4 breakers to connect the three CTs, and one ST.
3. Construct two string busses to connect the collector busses and main switchyard to Okeechobee 500kV Substation.
4. Add five main step-up transformers (5-450 MVA) one for each CT, and two for the ST (Note: at the time this Site Plan is being completed, other options were also being considered.)
5. Add relays and other protective equipment.
6. Breaker replacements:  
Poinsett Sub – Replace three 230 kV breakers.

#### **III. Transmission:**

1. No upgrades are expected to be necessary at this time.

### **III.F. Renewable Resources**

#### **Overview:**

FPL has actively been involved in renewable energy resource development since the mid-1970s. In 2009, FPL implemented 110 MW of solar energy facilities including two PV facilities totaling 35 MW (nameplate, AC) and one 75 MW solar thermal facility. Solar energy costs, especially the cost of PV, have continued to drop to the point where PV facilities have become competitive with more conventional generation options. Consequently, FPL announced in last year's Site Plan that it would construct three new PV facilities of approximately 74.5 MW (nameplate, AC) each by the end of 2016. Those facilities are under construction at the time this 2016 Site Plan is being prepared. Once these facilities go in-service in late 2016, FPL's solar generation capability will have tripled.

In addition, in this 2016 Site Plan FPL is projecting the addition of an additional approximately 300 MW (nameplate, AC) of PV by the year 2021. (A 2020 in-service date is currently assumed for planning purposes). FPL has not yet selected the site(s) for this additional PV. FPL will continue to evaluate the economic and non-economic attributes of additional solar through its resource planning work on an on-going basis.

#### **FPL's Renewable Energy Efforts Through 2015:**

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts through 2015, those efforts will be placed into five categories. FPL's plans for new renewable energy facilities during the 2016 through 2025 time period are then discussed in a separate section.

Two of these categories are Supply-Side Efforts – Power Purchases and FPL Facilities. For each year since 2011, including 2015, the combined total energy output (GWh) from these renewable energy sources has been greater than the GWh produced from oil-fired generation. The comparable values for energy delivered by renewable and oil-fired sources for the year 2015 are presented in Schedule 11.1 at the end of this chapter.

**1) Early Research & Development Efforts:**

In the late 1970s, FPL assisted the Florida Solar Energy Center (FSEC) in demonstrating the first residential PV system east of the Mississippi River. This PV installation at FSEC's Brevard County location was in operation for more than 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. In 1984, FPL installed a second PV system at its Flagami substation in Miami. This 10-kilowatt (kW) system operated for a number of years before it was removed to make room for substation expansion. In addition, FPL maintained a thin-film PV test facility at the FPL Martin Plant Site for a number of years to test new thin-film PV technologies.

**2) Demand Side & Customer Efforts:**

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (because it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques that are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, the program received a U.S. Department of Energy award for innovation and also led to a revision of the Florida Model Energy Building Code (Code). The Code was revised to incorporate one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

FPL has continued to analyze and promote the utilization of PV. These efforts have included PV research such as the 1991 research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. FPL's PV efforts also included educational efforts such as FPL's Next Generation Solar Station Program. This initiative delivered teacher training and curriculum that was tied to the Sunshine Teacher Standards in Florida. The program provided teacher grants to promote and fund projects in the classrooms.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2015, approximately 4,257 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a not-to-exceed amount of money annually to facilitate demand side solar water heater and PV applications. FPL's not-to-exceed amount of money for these applications was approximately \$15.5 million per year for five years. In response to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of three PV-based programs and three solar water heating-based programs, plus Renewable Research and Demonstration projects. FPL's analyses of the results from these programs since their inception consistently showed that none of these pilot programs was cost-effective using any of the three cost-effectiveness screening tests used by the State of Florida. As a result, consistent with the FPSC's December 2014 DSM Goals Order No. PSC-14-0696-FOF-EU, these pilot programs expired on December 31, 2015.

FPL also has been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

### **3) Supply Side Efforts – Power Purchases:**

FPL also has facilitated a number of renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.A.3, I.B.1, and I.B.2 in Chapter I).

FPL issued Renewable Requests for Proposals (RFPs) in 2007 and 2008 which solicited proposals to provide firm capacity and energy, and energy only, at or below avoided costs,

from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

On April 22, 2013, in Order No. PSC-13-1064-PAA-EQ, the FPSC approved three 60 MW power purchase agreements with affiliates of U.S. EcoGen for biomass-fired renewable energy facilities. These facilities are expected to provide non-firm energy service beginning in 2019 and to provide firm energy and capacity to FPL's customers beginning in 2021.

In regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA from a new unit. The new unit is now delivering firm capacity and energy to FPL. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

#### **4) Supply Side Efforts – FPL Facilities:**

With regard to solar generating facilities, FPL currently has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010.

These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by the Governor in June 2008. House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

**a. The Martin Next Generation Solar Energy Center:**

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first “hybrid” solar plant in the world and, at the time the facility came in-service, was the second largest solar facility in the world and the largest solar plant of any kind in the U.S. outside of California.

**b. The DeSoto Next Generation Solar Energy Center:**

This 25 MW (nameplate, AC) PV facility began commercial operation in 2009 which made it one of the largest PV facilities in the U.S. at that time. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

**c. The Space Coast Next Generation Solar Energy Center:**

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking, 10 MW (nameplate, AC) PV facility began commercial operation in 2010.

During 2014, FPL conducted analyses designed to develop a methodology with which to determine what firm capacity value at FPL’s Summer and Winter peak hours would be appropriate to apply to these existing, and potential future, utility-scale PV facilities. (Note that the Martin solar thermal facility is a “fuel-substitute” facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating.) Based on the results of these analyses, FPL has concluded that its two existing utility-scale PV facilities can be counted on to contribute certain percentages of their nameplate (AC) ratings (approximately 46% for DeSoto and 32% for Space Coast) as firm capacity at FPL’s Summer peak hour (that typically occurs in the 4 p.m. to 5 p.m. hour), but contribute no firm capacity during FPL’s Winter peak hour (that typically occurs in the 7 a.m. to 8 a.m. hour). Future FPL utility-scale PV facilities will be evaluated for potential firm capacity contribution on a case-by-case basis using this methodology. Their potential capacity contribution will be dependent upon a number of factors including (but not necessarily limited to) site location, technology, and design. For example, the three new PV facilities that will come into service by the end of 2016 are each projected to provide approximately 52% of their nameplate (AC) rating as firm capacity at FPL’s Summer peak hour, but provide no firm capacity during FPL’s Winter peak hour.

## **5) Ongoing Research & Development Efforts:**

FPL has also developed a “Living Lab” to demonstrate FPL’s solar energy commitment to employees and visitors at its Juno Beach office facility. FPL has installed five different PV arrays (using different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, two PV-covered parking structures with a total of approximately 90 kW of PV are in use at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL’s customers. FPL plans to continue to expand the Living Lab as new technologies come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives, including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

### **FPL’s Planned Renewable Energy Efforts for 2016 Through 2025:**

FPL efforts to implement cost-effective renewable energy, particularly PV, have increased. Several factors are driving these efforts and/or focusing them. First, the price of PV modules has declined in recent years, thus making PV more cost competitive. Second, as previously discussed, FPL has developed a methodology with which it can meaningfully assign a firm capacity benefit for meeting FPL’s Summer peak load to PV. Third, FPL has concluded from its implementation and analyses of utility-scale PV and PV demand side pilot programs that utility-scale PV applications are the most economical way to utilize solar energy.

FPL’s efforts to increasing use cost-effective renewable energy in the 2016 – 2025 time period are summarized below.

#### **1) FPL Utility-Scale PV Facilities:**

In the resource plan presented in both last year’s Site Plan and this year’s Site Plan, FPL projects the addition of three separate utility-scale PV facilities by the end of 2016. Each PV facility is projected to be approximately 74.5 MW (nameplate, AC). The sites of these three PV additions are: FPL’s existing Manatee plant site, a site in DeSoto County, and a site in Charlotte County. These locations are expected to have cost advantages to support early development, including:

- Current ownership of land or low cost land purchase agreement in place;
- Proximity to existing transmission lines with sufficient injection capacity;
- Proximity to existing electric substations;
- Previously performed site development and permitting work;
- Proximity to existing FPL generating facilities allows for lower operating expenses;
- Support from the associated counties and land developers, with the potential for further cost abatements;

Each of the three 2016 PV facilities is discussed below:

**a) FPL Babcock Ranch Solar Energy Center:**

This project is an approximate 74.5 MW (nameplate, AC) PV project in Charlotte County. It is located on 440 acres of land, adjacent to the future planned Babcock Ranch Community.

**b) FPL Citrus Solar Energy Center:**

This project is an approximate 74.5 MW (nameplate, AC) PV site in DeSoto County. This new project, along with the existing DeSoto Next Generation Solar Energy Center discussed above, brings the total PV MW capability in DeSoto county to 100 MW, this making DeSoto County the top producer of solar in Florida.

**c) FPL Manatee Solar Energy Center:**

This project is an approximate 74.5 MW nameplate, AC) PV project in Manatee County. It is near the existing FPL Manatee power plants and will be located on 762 acres.

Furthermore, in this 2016 Site Plan, FPL is projecting an additional approximately 300 MW (nameplate, AC) by the year 2021. (A 2020 in-service date is assumed for planning purposes). No site(s) has yet been determined for this additional PV.

**2) FPL Distributed Generation (DG) PV Pilot Programs:**

In regard to distributed generation (DG), FPL began implementation of two DG PV pilot programs and a battery storage pilot program in 2015. The first is a voluntary, community-based, solar partnership pilot to install new solar-powered generating facilities. The program is at least partially funded by contributions from customers who volunteer to participate in the pilot and will not rely on subsidies from non-participating customers. The second program will implement approximately 5 MW of DG PV. The objective of this

program is to collect grid integration data for DG PV and develop operational best practices for addressing potential problems that may be identified. The third program entails installing approximately 3 MW of battery storage systems with the objective of demonstrating the operational capabilities of batteries and learning how to integrate them into FPL's system. A brief description of these pilot programs follows.

**a) Voluntary, Community-Based Solar Partnership Pilot Program:**

The Voluntary Solar Pilot Program provides FPL customers with an additional and flexible opportunity to support development of solar power in Florida. The FPSC approved FPL's request for this three-year pilot program in Order No. PSC-14-0468-TRF-EI on August 29, 2014. This pilot program provides all customers the opportunity to support the use of solar energy at a community scale and is designed to be especially attractive for customers who do not wish, or are not able, to place solar equipment on their roof. Customers can participate in the program through voluntary contributions of \$9/month. The tariff became effective in January 2015 and the pilot program is scheduled to conclude in 2017.

These DG-scale projects differ from FPL's three utility-scale PV projects which are planned to come in-service in late 2016. These utility-scale PV projects are not projected to result in a net cost to customers over the life of these projects and, therefore, do not require additional contributions from FPL's customers. In contrast, smaller DG-scale projects have a higher cost to construct, operate, and maintain. The \$/kW cost to construct DG-scale facilities (whether utility-owned and operated or otherwise) is approximately double that of the more cost-efficient utility-scale PV projects. Furthermore, the operations and maintenance costs of DG-scale projects are projected to be three times as much as for utility-scale PV. Thus a voluntary contribution is necessary for this DG-based pilot program so that net costs, and the resulting electric rates, do not increase for non-participants.

The first 170 kW (nameplate, AC) of DG PV projects are located in the City of West Palm Beach (Zoological Society of the Palm Beaches) and in Broward County (Young at Arts Museum and the Broward County Library). Additional PV facilities under this pilot program will be built when the projected voluntary contributions are sufficient to cover on-going program costs without increasing electric rates for all customers, including non-participating customers. The locations of these additional PV facilities are being determined and will be selected based on overall project costs and local participation in the program.

**b) C&I Solar Partnership Pilot Program:**

This pilot program is conducted in partnership with interested commercial and industrial (C&I) customers over an approximate 5 year period. Limited investments will be made in PV facilities located at customer sites on selected distribution circuits within FPL's service territory. There are two objectives of this pilot program.

The primary objective is to examine the effect of high DG PV penetration on FPL's distribution system and to determine how best to address any problems that may be identified. FPL will site approximately 4 MW (nameplate, AC) of PV facilities on circuits that experience specific loading conditions to better study feeder loading impacts. PV installations at Daytona International Speedway, Daytona Kennel Club and Poker Room, and Florida International University's (FIU's) Engineering Center campus in West Miami-Dade County have been selected based largely on their interconnection with targeted circuits.

**c) Battery Storage Pilot Program:**

The purpose of the Battery Storage Pilot Program is to demonstrate and test a wide variety of battery storage grid applications including peak shaving, frequency response, and backup power for FPL's system. In addition, the pilot program is designed to help FPL learn how to integrate battery storage into the grid. Under the pilot program, FPL is installing a 1.5 MW battery storage system in Miami-Dade County primarily for peak shaving and frequency response. In addition, a battery storage system of 1.5 MW is also being installed in Monroe County for backup power and voltage support. Several smaller kilowatt-scale systems are also being installed at other locations to study distributed storage reliability applications.

### **III.G FPL's Fuel Mix and Fuel Price Forecasts**

#### **1. FPL's Fuel Mix**

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil-fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991.

The trend since the early 1990s has been a steady increase in the amount of natural gas that FPL uses to produce electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. Recently, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site in 2009. A third new CC unit was added to the WCEC site in 2011. In addition, FPL has completed the modernization of its Cape Canaveral, Riviera Beach, and Port Everglades plant sites. The new CC units at each of these three sites are providing highly efficient generation that has dramatically improved the efficiency of FPL's generation system in general and, more specifically, the efficiency with which natural gas is utilized.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 520 MW of additional nuclear capacity have been added to the FPL system. FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity.

In regard to utilizing renewable energy, FPL has 110 MW of solar generating capacity consisting of: a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010. As discussed in the preceding section, FPL is in the process of adding three new approximately 74.5 MW (nameplate, AC) PV facilities by the end of 2016 and is projecting approximately 300 MW (nameplate, AC) of additional PV by the year 2021. (A 2020 in-service date is assumed for planning purposes.)

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, securing gas reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal-fired generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over environmental regulations that would impact coal units more

negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of FPL's on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2025 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 that appear later in this chapter.

## **2. FPL's Fossil Fuel Cost Forecasts**

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. A January 2016 fuel cost forecast was used in the analyses whose results led to the resource plan presented in this 2016 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, and coal. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental requirements, and politics.

The inherent uncertainty and unpredictability of these factors today and in the future clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2015 and early 2016 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work and for the need determination docket for the new Okeechobee CC unit.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

- a. For 2016 through 2018, the methodology used the January 4, 2016 forward curve for New York Harbor 0.7% sulfur heavy oil, Ultra-Low Sulfur Diesel (ULSD) fuel oil, and Henry Hub natural gas commodity prices;
- b. For the next two years (2019 and 2020), FPL used a 50/50 blend of the January 4, 2016 forward curve and the most current projections at the time from The PIRA Energy Group;

- c. For the 2021 through 2035 period, FPL used the annual projections from The PIRA Energy Group; and,
- d. For the period beyond 2035, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal prices. Forecasted coal prices were based upon the following approach:

- a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal were provided by JD Energy; and,
- b. The coal price forecast for SJRPP and Plant Scherer assumes the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, and coal prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty that exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

### **3. Natural Gas Storage**

FPL was under contract through August 2014 for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline. FPL amended the transaction with Bay Gas on September 1, 2014 to increase the capacity to 4.0 Bcf of firm natural gas storage capacity. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems.

Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more

challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide FPL the ability to manage its supply and demand on a daily basis. FPL continues to evaluate its gas storage portfolio and is likely to subscribe for additional gas storage capacity to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

#### **4. Securing Additional Natural Gas:**

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of highly fuel-efficient CC units at Cape Canaveral, Riviera Beach, and Port Everglades due to completed modernization projects, plus the additional CC capacity at the Okeechobee site that will come in-service in 2019, will reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units. In addition, as discussed above, FPL plans to add a significant amount of new PV facilities that utilize no fossil fuel. However, these efficiency gains do not fully offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply, more firm gas transportation capacity, and secure gas reserves in the future as fuel requirements dictate. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through these two pipelines, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL issued a Request for Proposals (RFP) in December 2012 for gas transportation capacity to meet FPL's system natural gas requirements beginning in 2017. The RFP encouraged bidders to propose new gas transportation infrastructure to meet Florida's growing need for natural gas. A third pipeline would benefit FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines.

The RFP process was completed in June 2013, and the winning bidders were Sabal Trail Transmission, LLC (Sabal Trail) and Florida Southeast Connection, LLC (FSC). The contracts with Sabal Trail and FSC were reviewed by the FPSC and approved for cost recovery in late 2013. The order approving this cost recovery became final in January 2014. Sabal Trail and FSC have sought Federal Energy Regulatory Commission (FERC) approval for the new pipelines. FERC granted certificates of approval for the new pipelines on February 2, 2016. The certificates were accepted by the pipeline companies in early March 2016. The planned in-service date for the pipelines is May 2017.

## **5. Nuclear Fuel Cost Forecast**

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

### **a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants**

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

**(1) Mining:** Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U<sub>3</sub>O<sub>8</sub> (sometimes referred to as yellowcake).

**(2) Conversion:** During the second step, the U<sub>3</sub>O<sub>8</sub> is chemically converted into UF<sub>6</sub> which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

**(3) Enrichment:** The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from

approximately 2.2% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF<sub>6</sub>.

**(4) Fabrication:** During the last step, fuel fabrication, the enriched UF<sub>6</sub> is changed to a UO<sub>2</sub> powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

#### **b) Price Forecasts for Each Step**

**(1) Mining:** The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market. Current demand has declined and several of the production facilities have announced delays. Factors of importance are:

- Hedge funds are still very active in the market. This causes more speculative demand that is not tied to market fundamentals and causes the market price to move up or down just based on news that might affect future demand.
- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.
- Although a limited number of new nuclear units are scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current uranium production facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

**(2) Conversion:** The conversion market is also in a state of flux due to the Fukushima events. Planned production after 2018 is currently forecasted to be insufficient to meet a higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond the current level once more firm commitments are made including commitments to build new nuclear units. FPL expects long term price stability for conversion services to support world demand.

**(3) Enrichment:** Since the Fukushima events in March 2011, the near-term price of enrichment services has declined. However, plans for construction of several new facilities that were expected to come on-line post-2011 have been delayed. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The current supply/demand profile will most likely result in the price of enrichment services remaining stable for the next few years before starting to increase.

**(4) Fabrication:** Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

**c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast**

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. The calculations for the nuclear fuel cost forecasts used in FPL's 2015 and early 2016 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at current (i.e., power uprated) levels. The costs for each step to fabricate the nuclear fuel were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. DOE notified FPL that, effective May 2014, all high level waste payments would be suspended until further notice.

Therefore, FPL is no longer including in its nuclear fuel cost forecast a 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

**Schedule 5  
Fuel Requirements  
(for FPL only)**

Fuel Requirements	Units	Actual 1/		Forecasted									
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1) Nuclear	Trillion BTU	298	300	300	297	297	303	299	297	303	298	298	303
(2) Coal	1,000 TON	2,649	3,168	2,420	1,741	1,703	1,973	1,846	2,128	2,087	2,069	2,206	2,067
(3) Residual (FO6) - Total	1,000 BBL	409	556	824	66	50	51	24	20	26	27	16	22
(4) Steam	1,000 BBL	409	556	824	66	50	51	24	20	26	27	16	22
(5) Distillate (FO2) - Total	1,000 BBL	197	240	1,206	72	65	92	42	38	40	39	42	43
(6) Steam	1,000 BBL	4	1	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	123	100	1,142	36	39	57	23	17	24	21	25	29
(8) CT	1,000 BBL	69	139	63	35	26	35	19	21	17	18	16	14
(9) Natural Gas - Total	1,000 MCF	571,451	636,277	600,464	606,059	607,146	592,722	600,389	591,664	589,158	597,819	594,497	597,275
(10) Steam	1,000 MCF	24,488	52,731	20,915	19,838	11,694	5,933	4,330	4,161	4,536	5,493	1,934	1,488
(11) CC	1,000 MCF	542,409	577,133	579,046	581,638	592,746	585,076	594,279	586,311	582,790	590,051	591,304	594,122
(12) CT	1,000 MCF	4,555	6,414	503	4,582	2,706	1,713	1,779	1,191	1,831	2,275	1,259	1,666

1/ Source: A Schedules.

Note: Solar contributions are provided on Schedules 6.1 and 6.2.

**Schedule 6.1  
Energy Sources**

Energy Sources	Units	Actual <sup>1/</sup>		Forecasted									
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1) Annual Energy Interchange <sup>2/</sup>	GWH	4,908	4,730	1,336	829	903	919	0	0	0	0	0	0
(2) Nuclear	GWH	26,812	27,045	28,592	28,307	28,227	28,870	28,485	28,291	28,871	28,401	28,375	28,871
(3) Coal	GWH	4,482	5,275	3,977	2,710	2,660	3,171	2,922	3,472	3,404	3,379	3,648	3,388
(4) Residual(FO6) -Total	GWH	231	323	541	43	33	33	16	13	17	18	10	14
(5) Steam	GWH	231	323	541	43	33	33	16	13	17	18	10	14
(6) Distillate(FO2) -Total	GWH	128	139	1,200	53	51	75	32	28	31	29	32	35
(7) Steam	GWH	2	1	0	0	0	0	0	0	0	0	0	0
(8) CC	GWH	102	91	1,170	33	36	55	21	16	22	19	23	27
(9) CT	GWH	23	47	30	20	15	20	11	12	9	10	9	8
(10) Natural Gas -Total	GWH	79,102	85,797	81,213	83,938	84,709	84,238	86,746	85,739	85,201	86,206	86,776	87,435
(11) Steam	GWH	1,906	4,297	1,983	1,913	1,124	557	411	396	431	527	177	139
(12) CC	GWH	76,857	81,001	79,190	81,575	83,323	83,517	86,167	85,232	84,600	85,466	86,482	87,138
(13) CT	GWH	340	498	40	450	261	164	168	111	170	213	117	159
(14) Solar <sup>3/</sup>	GWH	177	157	241	682	704	701	1,404	1,393	1,393	1,389	1,390	1,362
(15) PV	GWH	68	68	115	580	579	577	1,279	1,271	1,268	1,264	1,264	1,257
(16) Solar Thermal	GWH	109	90	126	102	125	124	126	122	125	125	126	105
(17) Other <sup>4/</sup>	GWH	127	-710	2,621	2,414	2,470	2,515	2,278	3,200	3,460	3,818	3,941	3,956
Net Energy For Load <sup>5/</sup>	GWH	115,968	122,756	119,721	118,976	119,756	120,522	121,884	122,136	122,378	123,240	124,172	125,062

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report

2/ The projected figures are based on estimated energy purchases from SJRPP.

3/ Represents output from FPL's PV and solar thermal facilities.

4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.

5/ Net Energy For Load values for the years 2016- 2025 are also shown in Col. (19) on Schedule 2.3.

**Schedule 6.2  
Energy Sources %by Fuel Type**

Energy Source	Units	Actual <sup>1/</sup>		Forecasted										
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
(1) Annual Energy Interchange <sup>2/</sup>	%	4.2	3.9	1.1	0.7	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	23.1	22.0	23.9	23.8	23.6	24.0	23.4	23.2	23.6	23.0	22.9	23.1	
(3) Coal	%	3.9	4.3	3.3	2.3	2.2	2.6	2.4	2.8	2.8	2.7	2.9	2.7	
(4) Residual (FO6) -Total	%	0.2	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
(5) Steam	%	0.2	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
(6) Distillate (FO2) -Total	%	0.1	0.1	1.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
(8) CC	%	0.1	0.1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
(10) Natural Gas -Total	%	68.2	69.9	67.8	70.6	70.7	69.9	71.2	70.2	69.6	69.9	69.9	69.9	
(11) Steam	%	1.6	3.5	1.7	1.6	0.9	0.5	0.3	0.3	0.4	0.4	0.1	0.1	
(12) CC	%	66.3	66.0	66.1	68.6	69.6	69.3	70.7	69.8	69.1	69.3	69.6	69.7	
(13) CT	%	0.3	0.4	0.0	0.4	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.1	
(14) Solar <sup>3/</sup>	%	0.2	0.1	0.1	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0	
(15) PV	%	0.1	0.1	0.1	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0	
(16) Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
(17) Other <sup>4/</sup>	%	0.1	-0.6	2.2	2.0	2.1	2.1	1.9	2.6	2.8	3.1	3.2	3.2	
		100	100	100	100	100	100	100	100	100	100	100	100	

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report

2/ The projected figures are based on estimated energy purchases from SJRPP.

3/ Represents output from FPL's PV and solar thermal facilities.

4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.

**Schedule 7.1  
Forecast of Capacity, Demand, and Scheduled  
Maintenance At Time Of Summer Peak**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	% of Peak	Generation Only Reserve Margin After Maintenance MW	% of Peak
2016	26,513	492	100	334	27,238	24,170	1,842	22,327	4,911	22.0	0	4,911	22.0	3,068	12.7
2017	26,003	545	0	334	26,882	24,336	1,935	22,401	4,481	20.0	0	4,481	20.0	2,546	10.5
2018	25,984	816	0	334	27,134	24,606	1,995	22,611	4,522	20.0	0	4,522	20.0	2,527	10.3
2019	27,657	492	0	334	28,482	24,893	2,041	22,852	5,630	24.6	0	5,630	24.6	3,589	14.4
2020	27,812	110	0	334	28,256	25,206	2,088	23,117	5,138	22.2	0	5,138	22.2	3,050	12.1
2021	27,899	110	0	514	28,523	25,316	2,136	23,180	5,343	23.0	0	5,343	23.0	3,206	12.7
2022	27,984	110	0	514	28,608	25,540	2,185	23,355	5,252	22.5	0	5,252	22.5	3,068	12.0
2023	27,983	110	0	514	28,607	25,833	2,234	23,599	5,008	21.2	0	5,008	21.2	2,774	10.7
2024	29,605	110	0	514	30,228	26,180	2,284	23,896	6,332	26.5	0	6,332	26.5	4,048	15.5
2025	29,604	110	0	514	30,227	26,572	2,334	24,238	5,989	24.7	0	5,989	24.7	3,655	13.8

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated.

Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).

Col.(7) reflects the 2016 load forecast without incremental DSM or cumulative load management.

Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 6/2015-on intended for use with the 2016 load forecast.

Col.(10) = Col.(6) - Col.(9)

Col.(11) = Col.(10) / Col.(9)

Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.

Col.(13) = Col.(10) - Col.(12)

Col.(14) = Col.(13) / Col.(9)

Col.(15) = Col.(6) - Col.(7) - Col.(12)

Col.(16) = Col.(15) / Col.(7)

**Schedule 7.2  
Forecast of Capacity, Demand, and Scheduled  
Maintenance At Time Of Winter Peak**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
January of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Firm Capacity MW	Total Demand MW	DSM MW	Firm Winter Peak Demand MW	Total Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	% of Peak	Generation Only Reserve Margin After Maintenance MW	% of Peak
	2016	27,130	499	0	334	27,962	18,129	1,377	16,752	11,210	66.9	0	11,210	66.9	9,833
2017	27,848	499	0	334	28,681	21,140	1,434	19,705	8,975	45.5	0	8,975	45.5	7,541	35.7
2018	27,963	499	0	334	28,796	21,358	1,488	19,870	8,926	44.9	0	8,926	44.9	7,438	34.8
2019	27,984	499	0	334	28,817	21,602	1,514	20,087	8,730	43.5	0	8,730	43.5	7,215	33.4
2020	29,610	110	0	334	30,054	21,780	1,542	20,238	9,816	48.5	0	9,816	48.5	8,274	38.0
2021	29,610	110	0	514	30,234	21,992	1,570	20,422	9,812	48.0	0	9,812	48.0	8,242	37.5
2022	29,678	110	0	514	30,302	21,980	1,599	20,381	9,920	48.7	0	9,920	48.7	8,322	37.9
2023	29,768	110	0	514	30,392	22,195	1,628	20,567	9,825	47.8	0	9,825	47.8	8,197	36.9
2024	29,768	110	0	514	30,392	22,405	1,658	20,747	9,645	46.5	0	9,645	46.5	7,987	35.6
2025	31,363	110	0	514	31,987	22,581	1,688	20,893	11,094	53.1	0	11,094	53.1	9,406	41.7

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.

Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).

Col.(7) reflects the 2016 load forecast without incremental DSM or cumulative load management. The 2016 load is an actual load value.

Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 6/2015-on intended for use with the 2016 load forecast.

Col.(10) = Col.(6) - Col.(9)

Col.(11) = Col.(10) / Col.(9)

Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the winter peak period.

Col.(13) = Col.(10) - Col.(12)

Col.(14) = Col.(13) / Col.(9)

Col.(15) = Col.(6) - Col.(7) - Col.(12)

Col.(16) = Col.(15) / Col.(7)

**Schedule 8**  
**Planned And Prospective Generating Facility Additions And Changes<sup>(1)</sup>**

Plant Name	Unit No.	Location	Unit Type	(5) Pri.	(6) Alt.	(7) Pri.	(8) Alt.	(9) Mo./Yr.	(10) Mo./Yr.	(11) Mo./Yr.	Expected Retirement	Gen. Max. Nameplate	Firm Net Capability <sup>(2)</sup>		Status	
													KW	MW		MW
<b>ADDITIONS/ CHANGES</b>																
<b>2016</b>																
Fort Myers	2	Lee County	CC	NG	No	PL	No	-	Jan-16	Unknown	1,721,490	-	8	P		
Fort Myers	3A	Lee County	CT	NG	FO2	PL	TK	-	Jun-16	Unknown	376,380	-	25	OT		
Martin	4	Martin County	CC	NG	No	PL	No	-	Apr-16	Unknown	612,000	-	15			
Martin	8	Martin County	CC	NG	FO2	PL	TK	-	Mar-16	Unknown	1,224,510	-	(5)	OT		
Port Everglades	1	City of Hollywood	GT	NG	FO2	PL	PL	-	Apr-16	Unknown	410,734	-	1,237	U		
<b>2016 Changes/Additions Total:</b>													<b>0</b>	<b>1,280</b>		
<b>2017</b>																
Babcock Solar Energy Center <sup>(4)</sup>	1	Charlotte County	PV	Solar	Solar	N/A	N/A	-	Dec-16	Unknown	-	-	38	P		
Cedar Bay	1	Duval County	ST	BIT	No	RR	No	-	-	Jan-17	-	(250)	(250)	OT		
Citrus Solar Energy Center <sup>(4)</sup>	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	Dec-16	Unknown	-	-	38	P		
Fort Myers	2	Lee County	CC	NG	No	PL	No	-	Jan-16	Unknown	1,721,490	30	-	P		
Fort Myers	3A	Lee County	CT	NG	FO2	PL	TK	-	Jun-16	Unknown	188,190	25	-	OT		
Fort Myers	3B	Lee County	CT	NG	FO2	PL	TK	-	Jul-16	Unknown	188,190	25	25	OT		
Ft. Myers - 2 CT	4	Lee County	CC	NG	No	PL	No	-	Dec-16	Unknown	1,721,490	446	462	P		
FT. Myers GT	2-7,10-12	Lee County	GT	FO2	No	TK	No	-	-	Dec-16	744,120	(553)	(486)	P		
Lauderdale 5CT	6	Broward County	CC	NG	FO2	PL	PL	-	Dec-16	Unknown	526,250	1,115	1,155	P		
Lauderdale GT	1-2, 4, 6-12	Broward County	GT	NG	FO2	PL	PL	-	-	Oct-16	410,734	(367)	(343)	P		
Lauderdale GT	13-22	Broward County	GT	NG	FO2	PL	PL	-	-	Oct-16	410,734	(440)	(412)	P		
Manatee	3	Manatee County	CC	NG	No	PL	No	-	May-17	Unknown	1,224,510	-	(11)	OT		
Manatee Energy Center <sup>(4)</sup>	1	Manatee County	PV	Solar	Solar	N/A	N/A	-	Dec-16	Unknown	-	-	38	P		
Martin	3	Martin County	CC	NG	No	PL	No	-	Aug-16	Unknown	612,000	35	27			
Martin	4	Martin County	CC	NG	No	PL	No	-	Apr-16	Unknown	612,000	18	13			
Martin	8	Martin County	CC	NG	FO2	PL	TK	-	Mar-16	Unknown	1,224,510	27	(5)	OT		
Port Everglades	1	City of Hollywood	GT	NG	FO2	PL	PL	-	-	Unknown	410,734	1,429	-	OT		
Port Everglades GT	1-12	City of Hollywood	GT	NG	FO2	PL	PL	-	Oct-16	Unknown	410,734	(440)	(412)	P		
Sanford	4	Volusia County	CC	NG	No	PL	No	-	Oct-16	Unknown	1,188,860	7	-	OT		
Sanford	5	Volusia County	CC	NG	No	PL	No	-	Dec-16	Unknown	1,188,860	5	-	OT		
Turkey Point <sup>(3)</sup>	1	Miami Dade County	ST	FO6	NG	WA	PL	-	-	Dec-16	402,050	(398)	(396)	OT		
<b>2017 Changes/Additions Total:</b>													<b>714</b>	<b>(518)</b>		

(1) Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.B.1 and I.B.2.

(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after August each year will be picked up for reserve margin calculation purposes in the following year.

(3) This generating unit will serve as a synchronous condenser and will no longer be included in reserve margin calculations.

(4) Solar values reflect firm capacity only values, not nameplate ratings.

**Schedule 8**  
**Planned And Prospective Generating Facility Additions And Changes <sup>(1)</sup>**

(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)										
														Unit	Unit	Fuel		Const. Start	Comm. In-Service	Expected Retirement	Gen. Max. Nameplate	Firm Net Capability <sup>(2)</sup>	
																Fuel	Transport					Mo./Yr.	Mo./Yr.
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Mo./Yr.	Mo./Yr.	Mo./Yr.	KW	MW	MW	Status									
<b>ADDITIONS/ CHANGES</b>																							
<b>2018</b>																							
Manatee	3	Manatee County	CC	NG	No	PL	No	-	May-17	Unknown	1,224,510	50	-	OT									
Martin	4	Martin County	CC	NG	No	PL	No	-	Mar-17	Unknown	612,000	18	-	OT									
Martin	8	Martin County	CC	NG	FO2	PL	TK	-	Feb-17	Unknown	1,224,510	26	-	OT									
Sanford	4	Volusia County	CC	NG	No	PL	No	-	Sep-17	Unknown	1,188,860	6	(1)	OT									
Sanford	5	Volusia County	CC	NG	No	PL	No	-	Jul-17	Unknown	1,188,860	6	(1)	OT									
Turkey Point	5	Miami Dade County	CC	NG	FO2	PL	TK	-	Nov-17	Unknown	1,224,510	5	(15)	OT									
												<b>2018 Changes/Additions Total:</b>	<b>111</b>	<b>(17)</b>									
<b>2019</b>																							
Okeechobee Energy Center	1	Okeechobee County	CC	NG	FO2	PL	TK	Jun-17	Jun-19	Unknown	-	-	1,633	P									
Turkey Point	3	Miami Dade County	ST	Nuc	No	TK	No	-	Fall 2018	Unknown	877,200	20	20	OT									
Turkey Point	4	Miami Dade County	ST	Nuc	No	TK	No	-	Spring 2019	Unknown	877,200	-	20	OT									
Turkey Point	5	Miami Dade County	CC	NG	FO2	PL	TK	-	Jan-18	Unknown	1,224,510	2	-	OT									
												<b>2019 Changes/Additions Total:</b>	<b>22</b>	<b>1,673</b>									
<b>2020</b>																							
Okeechobee Energy Center	1	Okeechobee County	CC	NG	FO2	PL	TK	Jun-17	Jun-19	Unknown	-	1,606	-	P									
Turkey Point	4	Miami Dade County	ST	Nuc	No	TK	No	-	Spring 2019	Unknown	877,200	20	20	OT									
Unsitd Solar <sup>(3)</sup>									Jun-20				156	P									
												<b>2020 Changes/Additions Total:</b>	<b>1,626</b>	<b>156</b>									
<b>2021</b>																							
Cape Canaveral Energy Center	3	Brevard County	CC	NG	FO2	PL	TK	-	Spring 2021	Unknown	1,295,400	-	88	OT									
Unsitd Solar									Jun-20				-	P									
												<b>2021 Changes/Additions Total:</b>	<b>0</b>	<b>88</b>									
<b>2022</b>																							
Cape Canaveral Energy Center	3	Brevard County	CC	NG	FO2	PL	TK	-	Spring 2021	Unknown	1,295,400	68	-	OT									
Riviera Beach Energy Center	5	City of Riviera Beach	CC	NG	FO2	PL	WA	-	Spring 2022	Unknown	1,295,400	-	86	OT									
												<b>2022 Changes/Additions Total:</b>	<b>0</b>	<b>86</b>									
<b>2023</b>																							
Riviera Beach Energy Center	5	City of Riviera Beach	CC	NG	FO2	PL	WA	-	Spring 2022	Unknown	1,295,400	90	-	OT									
												<b>2023 Changes/Additions Total:</b>	<b>90</b>	<b>0</b>									
<b>2024</b>																							
Unsitd CC			CC	NG	FO2	PL	TK	-	Jun-24	Unknown	-	-	1,622	P									
												<b>2024 Changes/Additions Total:</b>	<b>0</b>	<b>1,622</b>									
<b>2025</b>																							
Unsitd CC			CC	NG	FO2	PL	TK	-	Jun-25	Unknown	-	1,595	-	P									
												<b>2025 Changes/Additions Total:</b>	<b>1,595</b>	<b>0</b>									

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.

(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after August each year will be picked up for reserve margin calculation purposes in the following year.

(3) Solar values reflect firm capacity only values, not nameplate ratings.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Citrus Solar Energy Center (DeSoto County)
- (2) **Capacity**
- |                     |         |
|---------------------|---------|
| a. Nameplate (AC)   | 74.5 MW |
| b. Summer Firm (AC) | 38.7 MW |
| c. Winter Firm (AC) | -       |
- (3) **Technology Type:** Photovoltaic (PV)
- (4) **Anticipated Construction Timing**
- |                                   |      |
|-----------------------------------|------|
| a. Field construction start-date: | 2015 |
| b. Commercial In-service date:    | 2016 |
- (5) **Fuel**
- |                   |     |
|-------------------|-----|
| a. Primary Fuel   | Sun |
| b. Alternate Fuel | Sun |
- (6) **Air Pollution and Control Strategy:** Not applicable
- (7) **Cooling Method:** Not applicable
- (8) **Total Site Area:** 841 Acres
- (9) **Construction Status:** P (Planned Unit)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**
- |  |                                 |
|--|---------------------------------|
| Planned Outage Factor (POF):               | Not applicable                  |
| Forced Outage Factor (FOF):                | Not applicable                  |
| Equivalent Availability Factor (EAF):      | Not applicable                  |
| Resulting Capacity Factor (%):             | 26% (First Full Year Operation) |
| Average Net Operating Heat Rate (ANOHR):   | Not applicable                  |
| Base Operation 75F, 100%                   |                                 |
| Average Net Incremental Heat Rate (ANIHR): | Not applicable                  |
| Peak Operation 75F, 100%                   |                                 |
- (13) **Projected Unit Financial Data \***
- |                                    |   |
|------------------------------------|---|
| Book Life (Years):                 | 30 years                                  |
| Total Installed Cost (2016 \$/kW): | 1,835                                     |
| Direct Construction Cost (\$/kW):  | 1,775                                     |
| AFUDC Amount (2016 \$/kW):         | 60  |
| Escalation (\$/kW):                | Accounted for in Direct Construction Cost |
| Fixed O&M (\$/kW-Yr): (2016 \$)    | 5.39 (First Full Year Operation)          |
| Variable O&M (\$/MWH): (2016 \$)   | 0.00                                      |
| K Factor:                          | 1.11                                      |

\* \$/kW values are based on nameplate capacity.

**Note:** Total installed cost includes transmission interconnection and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Manatee Solar Energy Center (Manatee County)
- (2) **Capacity**
- |                     |         |
|---------------------|---------|
| a. Nameplate (AC)   | 74.5 MW |
| b. Summer Firm (AC) | 38.7 MW |
| c. Winter Firm (AC) | -       |
- (3) **Technology Type:** Photovoltaic (PV)
- (4) **Anticipated Construction Timing**
- |                                   |      |
|-----------------------------------|------|
| a. Field construction start-date: | 2015 |
| b. Commercial In-service date:    | 2016 |
- (5) **Fuel**
- |                   |     |
|-------------------|-----|
| a. Primary Fuel   | Sun |
| b. Alternate Fuel | Sun |
- (6) **Air Pollution and Control Strategy:** Not applicable
- (7) **Cooling Method:** Not applicable
- (8) **Total Site Area:** 762 Acres
- (9) **Construction Status:** P (Planned Unit)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**
- |  |                                 |
|--|---------------------------------|
| Planned Outage Factor (POF):               | Not applicable                  |
| Forced Outage Factor (FOF):                | Not applicable                  |
| Equivalent Availability Factor (EAF):      | Not applicable                  |
| Resulting Capacity Factor (%):             | 26% (First Full Year Operation) |
| Average Net Operating Heat Rate (ANOHR):   | Not applicable Btu/kWh          |
| Base Operation 75F, 100%                   |                                 |
| Average Net Incremental Heat Rate (ANIHR): | Not applicable Btu/kWh          |
| Peak Operation 75F, 100%                   |                                 |
- (13) **Projected Unit Financial Data \***
- |                                    |   |
|------------------------------------|---|
| Book Life (Years):                 | 30 years                                  |
| Total Installed Cost (2016 \$/kW): | 1,835                                     |
| Direct Construction Cost (\$/kW):  | 1,775                                     |
| AFUDC Amount (2016 \$/kW):         | 60  |
| Escalation (\$/kW):                | Accounted for in Direct Construction Cost |
| Fixed O&M (\$/kW-Yr): (2016 \$)    | 5.39 (First Full Year Operation)          |
| Variable O&M (\$/MWH): (2016 \$)   | 0.00                                      |
| K Factor:                          | 1.11                                      |

\* \$/kW values are based on nameplate capacity.

**Note:** Total installed cost includes transmission interconnection and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Babcock Solar Energy Center (Charlotte County)
- (2) **Capacity**
- |                     |         |
|---------------------|---------|
| a. Nameplate (AC)   | 74.5 MW |
| b. Summer Firm (AC) | 38.7 MW |
| c. Winter Firm (AC) | -       |
- (3) **Technology Type:** Photovoltaic (PV)
- (4) **Anticipated Construction Timing**
- |                                   |      |
|-----------------------------------|------|
| a. Field construction start-date: | 2015 |
| b. Commercial In-service date:    | 2016 |
- (5) **Fuel**
- |                   |     |
|-------------------|-----|
| a. Primary Fuel   | Sun |
| b. Alternate Fuel | Sun |
- (6) **Air Pollution and Control Strategy:** Not applicable
- (7) **Cooling Method:** Not applicable
- (8) **Total Site Area:** 443 Acres
- (9) **Construction Status:** P (Planned Unit)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**
- |  |                                 |
|--|---------------------------------|
| Planned Outage Factor (POF):               | Not applicable                  |
| Forced Outage Factor (FOF):                | Not applicable                  |
| Equivalent Availability Factor (EAF):      | Not applicable                  |
| Resulting Capacity Factor (%):             | 26% (First Full Year Operation) |
| Average Net Operating Heat Rate (ANOHR):   | Not applicable Btu/kWh          |
| Base Operation 75F, 100%                   |                                 |
| Average Net Incremental Heat Rate (ANIHR): | Not applicable Btu/kWh          |
| Peak Operation 75F, 100%                   |                                 |
- (13) **Projected Unit Financial Data \***
- |                                    |   |
|------------------------------------|---|
| Book Life (Years):                 | 30 years                                  |
| Total Installed Cost (2016 \$/kW): | 1,835                                     |
| Direct Construction Cost (\$/kW):  | 1,775                                     |
| AFUDC Amount (2016 \$/kW):         | 60  |
| Escalation (\$/kW):                | Accounted for in Direct Construction Cost |
| Fixed O&M (\$/kW-Yr): (2016 \$)    | 5.39 (First Full Year Operation)          |
| Variable O&M (\$/MWH): (2016 \$)   | 0.00                                      |
| K Factor:                          | 1.11                                      |

\* \$/kW values are based on nameplate capacity.

**Note:** Total installed cost includes transmission interconnection and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Fort Myers CT (2 CTs will be added)
- (2) **Capacity (for each CT)**  
a. Summer 231 MW  
b. Winter 223 MW
- (3) **Technology Type:** Combustion Turbine
- (4) **Anticipated Construction Timing**  
a. Field construction start-date: 2015  
b. Commercial In-service date: 2016
- (5) **Fuel**  
a. Primary Fuel Natural Gas  
b. Alternate Fuel Ultra-low sulfur distillate
- (6) **Air Pollution and Control Strategy:** Dry Low NO<sub>x</sub> Burners, Natural Gas,  
0.0015% S. Distillate and Water Injection on Distillate
- (7) **Cooling Method:** Water to Air Heat Exchangers
- (8) **Total Site Area:** Existing Site 460 Acres
- (9) **Construction Status:** U (Under Construction)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**  
Planned Outage Factor (POF): 3.0%  
Forced Outage Factor (FOF): 1.0%  
Equivalent Availability Factor (EAF): 96.0%  
Resulting Capacity Factor (%): Approx. 3% (First Full Year Base Operation)  
Average Net Operating Heat Rate (ANOHR): 10,075 Btu/kWh on Gas  
Base Operation 75F, 100%  
Average Net Incremental Heat Rate (ANIHR): 7,644 Btu/kWh on Gas  
Peak Operation 75F, 100%
- (13) **Projected Unit Financial Data \*,\*\***  
Book Life (Years): 30 years  
Total Installed Cost (2016 \$/kW): 501  
Direct Construction Cost (\$/kW): 477  
AFUDC Amount (2016 \$/kW): 24  
Escalation (\$/kW): Accounted for in Direct Construction Cost  
Fixed O&M (\$/kW-Yr): 2.63  
Variable O&M (2016 \$/MWH): 0.00  
K Factor: 1.38

\* \$/kW values are based on Summer capacity.

\*\* Levelized value includes Fixed O&M and Capital Replacement

**Note:** Total installed cost includes transmission interconnection and integration, escalation, and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Lauderdale CT (5 CTs will be added)
- (2) **Capacity (for each CT)**
- |           |        |
|-----------|--------|
| a. Summer | 231 MW |
| b. Winter | 223 MW |
- (3) **Technology Type:** Combustion Turbine
- (4) **Anticipated Construction Timing**
- |                                   |      |
|-----------------------------------|------|
| a. Field construction start-date: | 2015 |
| b. Commercial In-service date:    | 2016 |
- (5) **Fuel**
- |                   |                             |
|-------------------|-----------------------------|
| a. Primary Fuel   | Natural Gas                 |
| b. Alternate Fuel | Ultra-low sulfur distillate |
- (6) **Air Pollution and Control Strategy:** Dry Low NO<sub>x</sub> Burners, Natural Gas, 0.0015% S. Distillate and Water Injection
- (7) **Cooling Method:** Water to Air Heat Exchangers
- (8) **Total Site Area:** Existing Site 392 Acres
- (9) **Construction Status:** U (Under Construction)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**
- |  |   |
|--|---|
| Planned Outage Factor (POF):               | 3.0%  |
| Forced Outage Factor (FOF):                | 1.0%  |
| Equivalent Availability Factor (EAF):      | 96.0%                                       |
| Resulting Capacity Factor (%):             | Approx. 3% (First Full Year Base Operation) |
| Average Net Operating Heat Rate (ANOHR):   | 10,075 Btu/kWh on Gas                       |
| Base Operation 75F, 100%                   |   |
| Average Net Incremental Heat Rate (ANIHR): | 7,644 Btu/kWh on Gas                        |
| Peak Operation 75F, 100%                   |   |
- (13) **Projected Unit Financial Data <sup>\*,\*\*</sup>**
- |                                    |   |
|------------------------------------|---|
| Book Life (Years):                 | 30 years                                  |
| Total Installed Cost (2016 \$/kW): | 470                                       |
| Direct Construction Cost (\$/kW):  | 453                                       |
| AFUDC Amount (2016 \$/kW):         | 17  |
| Escalation (\$/kW):                | Accounted for in Direct Construction Cost |
| Fixed O&M (\$/kW-Yr):              | 3.26                                      |
| Variable O&M (2016 \$/MWH):        | 0.00                                      |
| K Factor:                          | 1.39                                      |

\* \$/kW values are based on Summer capacity.

\*\* Levelized value includes Fixed O&M and Capital Replacement

**Note:** Total installed cost includes transmission interconnection and integration, escalation, and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Okeechobee Clean Energy Center
- (2) **Capacity**
- |           |          |
|-----------|----------|
| a. Summer | 1,633 MW |
| b. Winter | 1,606 MW |
- (3) **Technology Type:** Combined Cycle
- (4) **Anticipated Construction Timing**
- |                                   |      |
|-----------------------------------|------|
| a. Field construction start-date: | 2017 |
| b. Commercial In-service date:    | 2019 |
- (5) **Fuel**
- |                   |                             |
|-------------------|-----------------------------|
| a. Primary Fuel   | Natural Gas                 |
| b. Alternate Fuel | Ultra Low Sulfur Distillate |
- (6) **Air Pollution and Control Strategy:** Dry Low Nox Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection
- (7) **Cooling Method:** Mechanical Draft Cooling Towers
- (8) **Total Site Area:** 2,842 Acres
- (9) **Construction Status:** P (Planned Unit)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**
- |  |  |
|--|--|
| Planned Outage Factor (POF):               | 3.5%   |
| Forced Outage Factor (FOF):                | 1.0%   |
| Equivalent Availability Factor (EAF):      | 95.5%  |
| Resulting Capacity Factor (%):             | Approx. 80% (First Full Year Base Operation) |
| Average Net Operating Heat Rate (ANOHR):   | 6,249 Btu/kWh                                |
| Base Operation 75F, 100%                   |  |
| Average Net Incremental Heat Rate (ANOHR): | 7,669 Btu/kWh                                |
| Peak Operation 75F, 100%                   |  |
- (13) **Projected Unit Financial Data \*,\*\***
- |                                     |   |
|-------------------------------------|---|
| Book Life (Years):                  | 30 years                                  |
| Total Installed Cost ( 2019 \$/kW): | 754                                       |
| Direct Construction Cost (\$/kW):   | 679                                       |
| AFUDC Amount (2019 \$/kW):          | 75  |
| Escalation (\$/kW):                 | Accounted for in Direct Construction Cost |
| Fixed O&M (\$/kW-Yr):               | 16.78                                     |
| Variable O&M (2019 \$/MWH):         | 0.26                                      |
| K Factor:                           | 1.45                                      |

\* \$/kW values are based on Summer capacity.

\*\* Levelized value includes Fixed O&M and Capital Replacement

**Note:** Total installed cost includes transmission interconnection and integration, and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Unsited Solar
- (2) **Capacity**
- |                     |        |
|---------------------|--------|
| a. Nameplate (AC)   | 300 MW |
| b. Summer Firm (AC) | 156 MW |
| c. Winter Firm (AC) | -      |
- (3) **Technology Type:** Photovoltaic (PV)
- (4) **Anticipated Construction Timing**
- |                                   |      |
|-----------------------------------|------|
| a. Field construction start-date: | 2019 |
| b. Commercial In-service date:    | 2020 |
- (5) **Fuel**
- |                   |     |
|-------------------|-----|
| a. Primary Fuel   | Sun |
| b. Alternate Fuel | Sun |
- (6) **Air Pollution and Control Strategy:** Not applicable
- (7) **Cooling Method:** Not applicable
- (8) **Total Site Area:** Not applicable Acres
- (9) **Construction Status:** P (Planned Unit)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**
- |  |                                 |
|--|---------------------------------|
| Planned Outage Factor (POF):               | Not applicable                  |
| Forced Outage Factor (FOF):                | Not applicable                  |
| Equivalent Availability Factor (EAF):      | Not applicable                  |
| Resulting Capacity Factor (%):             | 27% (First Full Year Operation) |
| Average Net Operating Heat Rate (ANOHR):   | Not applicable                  |
| Base Operation 75F, 100%                   |                                 |
| Average Net Incremental Heat Rate (ANIHR): | Not applicable                  |
| Peak Operation 75F, 100%                   |                                 |
- (13) **Projected Unit Financial Data \***
- |                                    |   |
|------------------------------------|---|
| Book Life (Years):                 | 30 years                                  |
| Total Installed Cost (2020 \$/kW): | 1,676                                     |
| Direct Construction Cost (\$/kW):  | 1,646                                     |
| AFUDC Amount (2020 \$/kW):         | 30  |
| Escalation (\$/kW):                | Accounted for in Direct Construction Cost |
| Fixed O&M (\$/kW-Yr): (2020 \$)    | 4.05                                      |
| Variable O&M (\$/MWH): (2020 \$)   | 0.00                                      |
| K Factor:                          | 1.21                                      |

\* \$/kW values are based on nameplate capacity.

**Note:** Total installed cost includes transmission interconnection and AFUDC.

**Schedule 9**  
**Status Report and Specifications of Proposed Generating Facilities**

- (1) **Plant Name and Unit Number:** Unsited 3x1 CC
- (2) **Capacity**  
a. Summer 1,622 MW  
b. Winter 1,595 MW
- (3) **Technology Type:** Combined Cycle
- (4) **Anticipated Construction Timing**  
a. Field construction start-date: 2022  
b. Commercial In-service date: 2024
- (5) **Fuel**  
a. Primary Fuel Natural Gas  
b. Alternate Fuel Ultra-low sulfur distillate
- (6) **Air Pollution and Control Strategy:** Dry Low NO<sub>x</sub> Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection
- (7) **Cooling Method:** Mechanical Draft Cooling Towers
- (8) **Total Site Area:** TBD Acres
- (9) **Construction Status:** P (Planned Unit)
- (10) **Certification Status:** ---
- (11) **Status with Federal Agencies:** ---
- (12) **Projected Unit Performance Data:**  
Planned Outage Factor (POF): 3.5%  
Forced Outage Factor (FOF): 1.0%  
Equivalent Availability Factor (EAF): 95.5%  
Resulting Capacity Factor (%): Approx. 80% (First Full Year Base Operation)  
Average Net Operating Heat Rate (ANOHR): 6,304 Btu/kWh  
Base Operation 75F, 100%  
Average Net Incremental Heat Rate (ANOHR): 7,731 Btu/kWh  
Peak Operation 75F, 100%
- (13) **Projected Unit Financial Data \* , \*\***  
Book Life (Years): 30 years  
Total Installed Cost (2024 \$/kW): 818  
Direct Construction Cost (\$/kW): 738  
AFUDC Amount (2024 \$/kW): 80  
Escalation (\$/kW): Accounted for in Direct Construction Cost  
Fixed O&M (2024 \$/kW-Yr): 18.99  
Variable O&M (2024 \$/MWH): 0.29  
K Factor: 1.45

\* \$/kW values are based on Summer capacity.

\*\* Levelized value includes Fixed O&M and Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, and AFUDC.

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Citrus Solar Energy Center (DeSoto)**

The Citrus Solar Energy Center (DeSoto) will require one new line to connect the PV inverter array to the expanded Sunshine Substation.

(1)	Point of Origin and Termination:	Skylight – Sunshine Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL – Owned
(4)	Line Length:	1.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2015 End date: 2016
(7)	Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on schedule 9
(8)	Substations:	Skylight Substation and Sunshine Substation
(9)	Participation with Other Utilities:	None

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Manatee Solar Energy Center (Manatee)**

The Manatee Solar Energy Center will require one new line to connect the PV inverter array to the expanded Manatee Switchyard.

(1)	Point of Origin and Termination:	Helios – Manatee Switchyard
(2)	Number of Lines:	1
(3)	Right-of-way	FPL – Owned
(4)	Line Length:	1.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2015 End date: 2016
(7)	Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on schedule 9
(8)	Substations:	Helios Substation and Manatee Switchyard
(9)	Participation with Other Utilities:	None

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Babcock Solar Energy Center (Charlotte)**

The Babcock Solar Energy Center (Charlotte) will require one new line to connect the PV inverter array to the planned Freeland Substation.

(1)	Point of Origin and Termination:	Tuckers – Hercules Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL – Owned
(4)	Line Length:	5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2015 End date: 2016
(7)	Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on schedule 9
(8)	Substations:	Tuckers Substation and Hercules Substation
(9)	Participation with Other Utilities:	None

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Fort Myers Plant Gas Turbine Replacement and CT Upgrade**

The Fort Myers Plant gas turbine replacement and CT upgrade projects do not require any “new” transmission lines.

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Lauderdale Plant Gas Turbine Replacement**

The Lauderdale Plant Gas Turbine Replacement project does not require any “new” transmission lines.

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Okeechobee Next Generation Clean Energy Center**

The Okeechobee Next Generation Clean Energy Center with an in-service date of 2019 does not require any “new” transmission lines.

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Unsite 300 MW of PV**

No site(s) has been determined for this projected generation addition by 2021. (A 2020 in-service date assumed in this document for planning purposes.) Therefore, no transmission analysis is possible.

**Schedule 10**  
**Status Report and Specifications of Proposed Transmission Lines**

**Unsited 3x1 CC**

No site has been determined for this projected generation addition in 2024. Therefore, no transmission analysis is possible.

**Schedule 11.1**

**Existing Firm and Non-Firm Capacity and Energy by Primary Fuel Type  
Actuals for the Year 2015**

	(1) Generation by Primary Fuel	(2) - (5) Net (MW) Capability				(6) NEL GWh <sup>(2)</sup>	(7) Fuel Mix %
		Summer (MW)	Summer (%)	Winter (MW)	Winter (%)		
(1)	Coal	1,138	4.4%	1,145	4.1%	5,275	4.3%
(2)	Nuclear	3,453	13.2%	3,550	12.7%	27,045	22.0%
(3)	Residual	3,640	14.0%	3,674	13.1%	323	0.3%
(4)	Distillate	594	2.3%	677	2.4%	139	0.1%
(5)	Natural Gas	16,393	62.9%	18,084	64.6%	85,797	69.9%
(6)	Solar (Firm & Non-Firm)	35	0.1%	35	0.1%	68	0.1%
(7)	<b>FPL Existing Units Total <sup>(1)</sup>:</b>	<b>25,253</b>	<b>96.8%</b>	<b>27,165</b>	<b>97.0%</b>	<b>118,646</b>	<b>96.7%</b>
(8)	Renewables (Purchases)- Firm	114.0	0.4%	114.0	0.4%	227	0.2%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	316	0.3%
(10)	<b>Renewable Total:</b>	114.0	0.4%	114.0	0.4%	543	0.44%
(11)	<b>Purchases Other :</b>	712.0	2.7%	719.0	2.6%	3,567	2.9%
(12)	<b>Total:</b>	<b>26,079.0</b>	<b>100.0%</b>	<b>27,998.0</b>	<b>100.0%</b>	<b>122,756</b>	<b>100.0%</b>

Note:

- (1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Total Generating Capacity values found on Schedule 1 for Summer and Winter.
- (2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2015.

**Schedule 11.2**

**Existing Non-Firm Self-Service Renewable Generation Facilities  
Actuals for the Year 2015**

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers
Customer-Owned Renewable Generation (0 kW to 10 kW)	24.43	30,373	264,918	780	294,511
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	11.03	13,679	235,212	426	248,465
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	15.56	48,772	152,638	254	201,156
<b>Totals</b>	<b>51</b>	<b>92,824</b>	<b>652,768</b>	<b>1,460</b>	<b>744,132</b>

Notes:

- (1) There were 4257 customers with renewable generation facilities interconnected with FPL on December 31, 2015.
- (2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of December 31, 2015. Three systems do not have a DC rating. These are 3 non-solar facilities:  
 Tropicana - Landfill gas reciprocating generator: 1600 kW AC  
 Manatee Landfill gas: 1600 kW AC  
 Bio Mass - Palm Beach County: 750 kW AC  
 These AC values are included in the (> 100 kW < 2 MW) row.
- (3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
- (4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2015.
- (5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2015.
- (6) The Projected Annual Energy Used by Customers is a projected value that equals:  
 (Renewable Projected Annual output + Annual Energy Purchased ) minus the Annual Energy Sold to FPL.

***(This page is left intentionally blank.)***

## **CHAPTER IV**

---

### **Environmental and Land Use Information**

***(This page is left intentionally blank.)***

## **IV. Environmental and Land Use Information**

### **IV.A Protection of the Environment**

Clean, affordable energy is the lifeblood of Florida's growing population, expanding economy, and environmental resource restoration and management. Through FPL's commitment to environmental excellence, FPL is helping to solve Florida's energy challenges sustainably and responsibly. With one of the cleanest, most efficient power-generation fleets in the nation, FPL has reduced its use of foreign oil by 98 percent – from 40 million barrels annually in 2001 to fewer than 800,000 barrels annually in 2015. FPL is also the largest producer of solar energy in Florida. By the end of 2016, FPL will have tripled its solar energy-based generating capacity from 110 MW to approximately 333 MW (nameplate, AC). FPL is also projecting to increase that value to approximately 633 MW (nameplate, AC) by 2021. (A 2020 in-service date is assumed for planning purposes).

FPL maintains its commitment to environmental stewardship through proactive collaboration with communities and organizations working to preserve Florida's unique habitat and natural resources. The many projects and programs in which FPL is an active participant include the creation and management of the Everglades Mitigation Bank, Crocodile Management Program, preservation of the Barley Barber Swamp, and development of the Manatee Lagoon viewing and learning center at FPL's Riviera Beach Next Generation Clean Energy Center.

FPL and its parent company, NextEra Energy, Inc., have continuously been recognized as leaders among electric utilities for their commitment to the environment. That commitment is ingrained in FPL's corporate culture. FPL has one of the lowest emissions profiles among U.S. utilities and in 2015 its carbon dioxide (CO<sub>2</sub>) emission rate was 35% lower (better) than the industry national average.

NextEra Energy in 2015 was ranked as the top "green utility" in the United States and No. 4 in the world based on carbon emissions and renewable energy capacity, according to the latest annual report from EI Energy Intelligence, an independent provider of global energy and geopolitical news, analysis, data, and research. In the world rankings, NextEra Energy trailed only Acciona (Spain), China General Nuclear (China), and Iberdrola (Spain). To evaluate their "greenness," utilities were awarded points based on three criteria: greenhouse gas emissions, measured as CO<sub>2</sub> emissions per megawatt hour of electricity produced; the company's renewable energy capacity (MW) in proportion to total capacity (MW); and the company's renewable energy by volume (GWh).

For the eighth year, NextEra Energy in 2015 has been named a World's Most Ethical Company<sup>®</sup> by the Ethisphere Institute. This year, only 132 companies across more than 50 industries worldwide were selected for this prestigious honor. NextEra Energy was one of only five energy and electric utility companies named to the list. Scoring is based upon a weighted scoring of company's ethics and compliance program (35% weighting), corporate citizenship and responsibility (20%), culture of ethics (20%), governance (15%), and leadership, innovation and reputation (10%).

NextEra Energy, Inc. was named on the FORTUNE "World's Most Admired Companies" 2015 list and, for the first time, is among the top 10 companies in the world in both the categories of innovativeness and community responsibility. NextEra Energy also ranked first among electric and gas utilities for innovation, social responsibility, and quality of products/services.<sup>5</sup> In February, 2016, NextEra Energy was named No. 1 overall among electric and gas utilities on Fortune's 2016 list of "Most Admired Companies." This is the ninth year out of the last 10 that FPL has received this honor.

NextEra Energy's Juno Beach, Florida, campus, including FPL's headquarters, has achieved the prestigious Leadership in Energy and Environmental Design (LEED) Gold certification for existing buildings. LEED is the U.S. Green Building Council's leading rating system for designating the world's greenest, most energy-efficient, and high performing buildings. Key achievements that led to the certification include heating, ventilation and air conditioning improvements, lighting upgrades, water management and recycling programs, and changes to specifications for paper, carpet, and other materials.

In 2015, FPL supported a broad base of environmental organizations with donations, event sponsorships, and memberships totaling in excess of \$365,000. The organizations that were supported include, but were not limited to: the Everglades Foundation, the Conservancy of Southwest Florida, the Busch Wildlife Sanctuary, Inc., and the Loggerhead Marinelife Center, Inc.

FPL and NextEra, Inc. employees serve as board members for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Martin County Environmental Studies Center, Marine Resources Council, Grassy Waters Conservancy, Sustainable Florida, the Palm Beach County Loggerhead Marinelife Center, and the Arthur R. Marshall Foundation.

---

<sup>5</sup> FORTUNE and The World's Most Admired Companies are registered trademarks of Time Inc. and are used under license. From FORTUNE Magazine, March 1, 2015<sup>®</sup> Time Inc. citation is used under license. FORTUNE and Time Inc. are not affiliated with, and do not endorse products or services of, NextEra Energy.

## **IV.B FPL's Environmental Policy**

FPL and its parent company, NextEra Energy, Inc., are committed to being an industry leader in environmental protection and stewardship, not only because it makes business sense, but because it is the right thing to do. This commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives the sustainable management of our business planning, operations, and daily work.

In accordance with commitments to environmental protection and stewardship, FPL and NextEra Energy, Inc. endeavor to:

### **Comply**

- Comply with all applicable environmental laws, regulations, and permits
- Proactively identify environmental risks and take action to mitigate those risks
- Pursue opportunities to exceed environmental standards
- Participate in the legislative and regulatory process to develop environmental laws, regulations, and policies that are technically sound and economically feasible
- Design, construct, operate, and maintain facilities in an environmentally sound and responsible manner

### **Conserve**

- Prevent pollution, minimize waste, and conserve natural resources
- Avoid, minimize, and/or mitigate impacts to habitat and wildlife
- Promote the efficient use of energy, both within our company and in our communities

### **Communicate**

- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence
- Maintain an open dialogue with stakeholders on environmental matters and performance
- Communicate this policy to all employees and publish it on the corporate website

### **Continuously Improve**

- Establish, monitor, and report progress toward environmental targets
- Review and update this policy on a regular basis
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices.

FPL's parent company, NextEra Energy, Inc. updated this policy in 2013 to reflect changing expectations and ensure that employees are doing the utmost to protect the environment. FPL complies with all environmental laws, regulations, and permit requirements. FPL designs, constructs, and operates its facilities in an environmentally sound and responsible manner. It also responds immediately and effectively to any known environmental hazards or non-compliance situations. FPL's commitment to the environment does not end there. FPL proactively pursues opportunities to perform better than current environmental standards require, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout its operations and day-to-day work activities. FPL also encourages the efficient use of energy, both within the Company and in communities served by FPL. These actions are just a few examples of how FPL is committed to the environment.

To ensure that FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program and Corporate Environmental Governance Council. Through these programs, FPL conducts periodic environmental self-evaluations to verify that its operations are in compliance with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

#### **IV.C Environmental Management**

In order to successfully implement the Environmental Policy, FPL has developed a robust Environmental Management System to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program, which is described in section IV.D below. Other components of the system include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

As part of its commitment to excellence and continuous improvement, FPL created an enhanced Environmental Data Management Information System (EDMIS). Environmental data management software systems are increasingly viewed as an industry best-management practice to ensure environmental compliance. FPL's top goals for this system are to: 1) improve the flow of

environmental data between site operations and corporate services to ensure compliance, and 2) improve operating efficiencies. In addition, the EDMIS helps to standardize environmental data collection, thus improving external reporting to the public.

#### **IV.D Environmental Assurance Program**

FPL's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is an environmental audit. An environmental audit may be defined as a management tool comprised of a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The primary objective of performing an environmental audit is to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies. In addition to FPL facility audits, through the Environmental Assurance Program, FPL performs audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

FPL has also implemented a Corporate Environmental Governance System in which quarterly reviews are performed by each business unit deemed to have potential for significant environmental exposure. Quarterly reviews evaluate operations for potential environmental risks and consistency with the company's Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress / changes since the most recent review.

In addition to periodic environmental audits, FPL's Environmental Construction Compliance Assurance Program provides routine onsite inspections during construction and site specific environmental training to everyone anticipated to be onsite during construction. Similar to an environmental audit, these inspections are performed to ensure compliance with the requirements of environmental permits, licenses, and FPL policies.

## IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of energy efficiency, environmental awareness, and through public education. Some of FPL's 2015 environmental outreach activities are summarized in Table IV.E.1.

**Table IV.E.1: 2015 FPL Environmental Outreach Activities**

<b>Activity</b>	<b>Count (#)</b>
Visitors to FPL's Energy Encounter at St. Lucie	>2,700
Visitors to Manatee Park, Ft. Myers	238,678
Number of website visits to FPL's Environmental & Corporate Responsibility Websites	>58,000
Visitors to Barley Barber Swamp (Treasured Lands Partnership)	101
Visitors to Martin Energy Center Solar & DeSoto Solar Tours	378
Environmental Brochures Distributed	>70,000
Home Energy Surveys	Field Visits: 27,795 Phone: 50,563 Online: 70,567 <b>Total: 148,925</b>

## IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified seven (7) Preferred Sites and six (6) Potential Sites for adding future generation. Some of these sites currently have existing generation at the sites and some do not. Preferred Sites are those locations where FPL has conducted significant reviews, and has either taken action, is currently committed to take action, or is likely to take action, to site new generation. Potential Sites are those sites that have attributes that would support the siting of generation and are under consideration as a location for future generation. The identification of a Potential Site does not necessarily indicate that FPL has made a definitive decision to pursue new generation (or generation expansion or modernization in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generating resource has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

#### **IV.F.1 Preferred Sites**

For the 2016 Ten Year Site Plan, FPL has identified seven (7) Preferred Sites. These include a combination of existing and new sites for the development of natural gas combined cycle, combustion turbines, and/or solar generation facilities.

The 7 sites include the following (which are presented in general chronological order of when resources are projected to be added to the FPL system): Babcock Ranch Solar Energy Center, Citrus Solar Energy Center, Manatee Solar Energy Center, Lauderdale Plant Peaking Facilities, Ft Myers Plant Peaking Facilities, Okeechobee Clean Energy Center Unit 1, and Turkey Point Units 6 & 7.

In regard to the Turkey Point 6 & 7 nuclear units, FPL's Combined Operating License Application (COLA) is still pending with the Nuclear Regulatory Commission at the time this Site Plan is being prepared. Based on the COLA schedule, the earliest practical date for bringing the Turkey Point 6 & 7 units in-service is now beyond the 2016 through 2025 time period addressed in this Site Plan. Despite this, Turkey Point is discussed as a Preferred Site for the new nuclear units.

#### **Preferred Site # 1: Babcock Ranch Solar Energy Center, Charlotte County**

The Babcock Ranch Solar Energy Center, with a photovoltaic (PV) facility of approximately 74.5 MW (nameplate, AC), will be located in Charlotte County on approximately 443 acres donated by the Babcock Ranch Community Independent Special District. Construction commenced on the Babcock Ranch Solar Energy Center in Charlotte County on December 15, 2015 and Commercial Operation is projected to begin in December 2016.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter.

**b. Proposed Facilities Layout**

See Figures at the end of this chapter.

**c. Map of Site and Adjacent Areas**

See Figures at the end of this chapter

**d. Existing Land Uses of Site and Adjacent Areas**

1. **Site** Agricultural production (sod and pasture)
2. **Adjacent Areas** Agricultural production

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

The site contains agriculture, pine flatwoods and freshwater marsh.

**2. Listed Species**

The site is located in the USFWS Panther Focus Area as well as the Core Foraging Area of known wood stork colonies.

**3. Natural Resources of Regional Significance Status**

The site is in the Babcock Preserve and east of the Cecil Webb Wildlife Management Area.

**4. Other Significant Features**

FPL is not aware of any other significant features on the site.

**f. Design Features and Mitigation Options**

The design includes an approximately 74.5 MW (nameplate, AC) PV facility, on-site transmission substation, and site stormwater system.

**g. Local Government Future Land Use Designations**

Local government designation regarding land use on this site is agricultural production and barren land.

**h. Site Selection Criteria Process**

The site selection criteria included system load, transmission interconnection, economics and environmental compatibility (e.g. wetlands, wildlife, threatened and endangered species, etc.).

**i. Water Resources**

Existing permitted onsite water resources will be used to meet water requirements.

**j. Geological Features of Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Beneath the Surficial Aquifer System is approximately 750 feet of the Intermediate Aquifer System, which is itself above the Floridan Aquifer System that consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal, existing permitted supply

Panel Cleaning: Minimal and only in absence of sufficient rainfall.

**l. Water Supply Sources by Type**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable and Panel Cleaning: Delivered to the site by truck or via existing permitted supply.

**m. Water Conservation Strategies Under Consideration**

PV does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.

**n. Water Discharges and Pollution Control**

Best Management Practices will be employed to prevent and control inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

PV does not require fuel and no waste products will be generated at the site.

**p. Air Emissions and Control Systems**

Fuel: PV energy generation does not use any type of combustion fuel. Therefore, there will be no air emissions or need for Control Systems.

Combustion Control: Not Applicable

Combustor Design: Not Applicable

**q. Noise Emissions and Control Systems**

PV energy generation does not emit noise and, therefore, there will be no need for noise control systems.

**r. Status of Applications**

USACE Section 404 Permit received: December 28, 2011

Florida Environmental Resources Permit (ERP) Modification received: July 30, 2015

Charlotte County Development Approval received: September 15, 2015

**Preferred Site # 2: Citrus Solar Energy Center, DeSoto County**

The Citrus Solar Energy Center, consisting of a PV facility of approximately 74.5 MW (nameplate, AC), will be located in Arcadia in Citrus County on approximately 841 acres. Construction commenced on December 15, 2015 and Commercial Operation is projected to begin in December 2016. This location is also being evaluated as a potential future site for additional PV capacity.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter.

**b. Proposed Facilities Layout**

See Figures at the end of this chapter.

**c. Map of Site and Adjacent Areas**

See Figures at the end of this chapter

**d. Existing Land Uses of Site and Adjacent Areas**

- |                          |  |
|--------------------------|--|
| 1. <u>Site</u>           | Agricultural production                                    |
| 2. <u>Adjacent Areas</u> | Agricultural production, forested and non-forested uplands |

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

The site is comprised of agricultural production with some wetland areas.

**2. Listed Species**

Burrowing owls and gopher tortoises may be present. If these are discovered they will be relocated prior to construction under permits from the Florida Fish and Wildlife Conservation Commission (FFWCC).

**3. Natural Resources of Regional Significance Status**

No natural resources of regional significance status exist at or adjacent to the site.

**4. Other Significant Features**

FPL is not aware of any other significant features of the site.

**f. Design Features and Mitigation Options**

The design includes an approximately 74.5 MW (nameplate, AC) PV facility, on-site transmission substation, and site stormwater system.

**g. Local Government Future Land Use Designations**

Local government future land use on this site is Electrical Generating Facility.

**h. Site Selection Criteria Process**

The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g. wetlands, wildlife, threatened and endangered species, etc.).

**i. Water Resources**

Existing permitted onsite water resources will be used to meet water requirements.

**j. Geological Features of Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Beneath the Surficial Aquifer System is approximately 450 feet of the Intermediate Aquifer System, which is itself above the Floridan Aquifer System that consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal, existing permitted supply

Panel Cleaning: Minimal and only in absence of sufficient rainfall.

**i. Water Supply Sources by Type**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable and Panel Cleaning: Delivered to the site by truck or via existing permitted supply.

**m. Water Conservation Strategies Under Consideration**

PV does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.

**n. Water Discharges and Pollution Control**

Best Management Practices will be employed to prevent and control inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

PV does not require fuel and no waste products will be generated at the site.

**p. Air Emissions and Control Systems**

Fuel: PV energy generation does not use any type of combustion fuel. Therefore, there will be no air emissions or need for Control Systems.

Combustion Control: Not Applicable

Combustor Design: Not Applicable

**q. Noise Emissions and Control Systems**

PV energy generation does not emit noise and, therefore, there will be no need for noise control systems.

**r. Status of Applications**

USACE Section 404 Permit received: June 24, 2015

Florida Environmental Resources Permit (ERP) Modification received: October 5, 2015

DeSoto County Development Approval received: November 15, 2015.

**Preferred Site # 3: Manatee Solar Energy Center, Manatee County**

The Manatee Solar Energy Center, consisting of a PV facility of approximately 74.5 MW (nameplate, AC), will be located in north-central Manatee County on approximately 762 acres.

Construction commenced on December 15, 2015 and Commercial Operation is projected to begin in December 2016.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter.

**b. Proposed Facilities Layout**

See Figures at the end of this chapter.

**c. Map of the Site and Adjacent Areas**

See Figures at the end of this chapter.

**d. Existing Land Uses of Site and Adjacent Areas**

**1. Site**

Agricultural production

**2. Adjacent Areas**

Agricultural production, upland forested, forested uplands, power plant, transportation, communication, and utilities.

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

Site is predominately agricultural with a lack of suitable onsite habitat.

**2. Listed Species**

Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.

**3. Natural Resources of Regional Significance Status**

No natural resources of regional significance status at or adjacent to the site.

**4. Other Significant Features**

FPL is not aware of any other significant features of the site.

**f. Design Features and Mitigation Options**

The design includes an approximately 74.5 MW (nameplate, AC) PV facility, on-site transmission substation, and site stormwater system.

**g. Local Government Future Land Use Designations**

Local government future land use designations include Agricultural and Planned Development / Public Interest.

**h. Site Selection Criteria Process**

The site selection criteria used were system load, transmission interconnection, economics, and environmental compatibility (e.g. wetlands, wildlife, threatened and endangered species, etc.).

**i. Water Resources**

Existing permitted onsite water resources will be used to meet water requirements.

**j. Geological Features of the Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Beneath the Surficial Aquifer System is approximately 750 feet of the Intermediate Aquifer System, which is itself above the Floridan Aquifer System that consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal, existing permitted supply

Panel Cleaning: Minimal and only in absence of sufficient rainfall.

**l. Water Supply Sources by Type**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable and Panel Cleaning: Delivered to the site by truck or via existing permitted supply.

**m. Water Conservation Strategies Under Consideration**

PV does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.

**n. Water Discharges and Pollution Control**

Best Management Practices will be employed to prevent and control inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Solar does not require fuel and no waste products will be generated at the site.

**p. Air Emissions and Control Systems**

Fuel: PV energy generation does not use any type of combustion fuel. Therefore, there will be no air emissions or need for Control Systems.

Combustion Control: Not Applicable

Combustor Design: Not Applicable.

**q. Noise Emissions and Control Systems**

PV energy generation does not emit noise and, therefore, there will be no need for noise control systems.

**r. Status of Applications**

USACE Section 404 Permit received: November 9, 2015.

Florida Environmental Resources Permit (ERP) Modification received: November 12, 2015

Manatee County Development Approval received: November 20, 2015

Manatee County Rezoning Approval received: August 6, 2015

**Preferred Site # 4: Lauderdale Plant Peaking Facilities, Broward County**

This site is located at the existing Lauderdale Plant property and consists of approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County. The Lauderdale Plant currently includes two combined cycle units and two banks of 12 first generation simple cycle gas turbines (GTs) that began operation in the early 1970s. At the time this Site Plan will be filed, all 24 existing GTs are operational. However, FPL will retire 22 of the 24 existing GTs by the end of 2016 and partially replace this peaking capacity with 5 new and larger combustion turbines (CTs). Construction commenced on the Lauderdale Plant Peaking Facilities in Broward County in September 2015 with Commercial Operation projected to begin in December 2016.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter.

**b. Proposed Facilities Layout**

See Figures at the end of this chapter

**c. Map of Site and Adjacent Areas**

See Figures at the end of this chapter.

**d. Existing Land Uses of Site and Adjacent Areas**

1. **Site** Commercial and electric power generation
2. **Adjacent Areas** Low to high density urban, transportation, communication, utilities, commercial, water, and some open land.

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

The site is comprised of facilities related to electric power generation and approximately 14 acres of forested wetlands and upland spoil.

**2. Listed Species**

Due to the lack of suitable habitat and the surrounding area land use, listed species are not anticipated to utilize the site.

**3. Natural Resources of Regional Significance Status**

No natural resources of regional significance status exist at, or are adjacent to, the site.

**4. Other Significant Features**

FPL is not aware of any other significant features of the site.

**f. Design Features and Mitigation Options**

The project includes five new highly efficient simple cycle CTs that will partially replace 22 GTs at the existing Lauderdale Plant (plus 12 simple cycle GTs at the Port Everglades Plant). The CTs will operate using natural gas and Ultra-Low Sulfur Distillate (ULSD).

**g. Local Government Future Land Use Designations**

The site is zoned General Industrial.

**h. Site Selection Criteria Process**

The site selection criteria included system load, transmission interconnection, economics, environmental compatibility (e.g. wetlands, wildlife, threatened and endangered species, etc.), and to maximize opportunities at existing utility infrastructure.

**i. Water Resources**

The CTs will obtain water from an existing permitted onsite water resource.

**j. Geological Features of Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, including the Biscayne Aquifer, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Below the Surficial Aquifer System is at least 600 feet of the Hawthorn formation which is itself underlain by the Floridan Aquifer System which consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: Not Applicable because no heat dissipation system is needed for simple cycle CT operation

Process: No additional water required

Potable: No additional water required

Panel Cleaning: Not Applicable

**l. Water Supply Sources by Type**

Cooling: Not Applicable for simple cycle CT operation

Process: As existing, Broward County Utilities

Potable: As existing, City of Hollywood

**m. Water Conservation Strategies Under Consideration**

No additional water resources are required.

**n. Water Discharges and Pollution Control**

No surface water discharges are required for operation of the proposed facilities. Best Management Practices will be employed to prevent and control inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas will be transported via an existing pipeline. ULSD will be piped or trucked to the facility and stored in double-walled ULSD tanks.

**p. Air Emissions and Control Systems**

Fuel: Use of cleaner Natural Gas and Ultra-Low Sulfur Distillate (ULSD) will minimize SO<sub>2</sub>, sulfuric acid mist (SAM), particulates, and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards.

Combustion Control / Combustor Design: Will limit formation of NO<sub>x</sub>, CO, and VOCs. Further NO<sub>x</sub> reduction will be achieved by water injection during oil firing.

**q. Noise Emissions and Control Systems**

Construction and operation of the CTs will not exceed the maximum permissible sound levels in Section 17-86 of the Code of City of Dania Beach.

**r. Status of Applications**

USACE Section 404 Permit received: June 27, 2014

Prevention of Significant Deterioration (PSD) Air Permit received: August 25, 2015

PSD-GHG Modification received: August 25, 2015

**Preferred Site # 5: Ft Myers Plant Peaking Facilities, Lee County**

FPL plans to retire, replace, and upgrade components of the peaking facilities at the Fort Myers Power Plant. This site consists of approximately 460 acres located in the City of Tice (Fort Myers) in Lee County, Florida. The existing Fort Myers Plant consists of one natural gas combined cycle (CC) unit, two natural gas- and oil-fired combustion turbine (CT) units, and one bank of 12 oil-fired gas turbines (GTs) which started operation in the early 1970s. FPL is adding two new, larger CTs and has retired one of the existing GTs. FPL will retire 9 more existing GTs by the end of 2016, and will upgrade the two existing CTs to produce additional generation capacity. Construction commenced on the Ft Myers Plant Peaking Facilities in October 2015 with Commercial Operation projected to begin in December 2016.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter.

**b. Proposed Facilities Layout**

See Figures at the end of this chapter.

**c. Map of Site and Adjacent Areas**

See Figures at the end of this chapter.

**d. Existing Land Uses of Site and Adjacent Areas**

**1. Site**

Transportation, communication, electrical generating facilities, barren land, and agricultural.

**2. Adjacent Areas**

Low density urban, commercial, rangeland, open land, transportation, communication, and utilities.

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

The site is comprised of facilities related to electric power generation.

**2. Listed Species**

Due to the existing disturbed nature of the site, no impacts to listed species are projected to occur.

**3. Natural Resources of Regional Significance Status**

The Caloosahatchee and Orange Rivers are adjacent to the site.

**4. Other Significant Features**

FPL is not aware of any other significant features of the site.

**f. Design Features and Mitigation Options**

The design includes two new highly efficient simple cycle CTs which will replace 10 existing GTs. Two existing CTs will be upgraded to produce additional capacity.

**g. Local Government Future Land Use Designations**

The site is zoned Industrial Light by Lee County.

**h. Site Selection Criteria Process**

The site selection criteria included various factors such as existing utility infrastructure, system load, transmission interconnection, economics, and environmental compatibility (e.g. wetlands, wildlife, threatened and endangered species, etc.).

**i. Water Resources**

Existing permitted onsite water resources will be used to meet water requirements.

**j. Geological Features of Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Beneath the Surficial Aquifer System is approximately 750 feet of the Intermediate Aquifer System, which is itself above the Floridan Aquifer System that consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: Not Applicable, because no heat dissipation system is needed for simple cycle CT operation.

Process: No additional water required

Potable: No additional water required

Panel Cleaning: Not Applicable

**l. Water Supply Sources by Type**

Cooling: Not Applicable for simple cycle CT operation

Process: As existing, Lee County Utilities

Potable: As existing, Lee County Utilities

**m. Water Conservation Strategies under Consideration**

No additional water resources are required.

**n. Water Discharges and Pollution Control**

No surface water discharges are required for operation of the proposed facilities. Best Management Practices will be employed to prevent and control inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas will be transported via an existing pipeline. Ultra-Low Sulfur Diesel (ULSD) will be barged or trucked to the facility and stored in existing ULSD tanks.

**p. Air Emissions and Control Systems**

Fuel: Use of cleaner natural gas and ULSD will minimize SO<sub>2</sub>, sulfuric acid mist (SAM), particulates, and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards.

Combustion Control / Combustor Design: Will limit formation of NO<sub>x</sub>, CO and VOCs. Further NO<sub>x</sub> reduction will be achieved by water injection during oil firing.

**q. Noise Emissions and Control Systems**

Noise from the new and upgraded CTs will not exceed the maximum permissible sound levels in Lee County noise control ordinance No. 93-15 and noise is expected to be below existing noise levels. The design includes components and an enclosure which mitigate the emission of noise to the surrounding environment.

**r. Status of Applications**

Prevention of Significant Deterioration Air Permit received: September 10, 2015

Florida Environmental Resources Permit Modification received: August 3, 2015

Lee County Development Approval received: July 8, 2015

**Preferred Site # 6: Okeechobee Site, Okeechobee County**

Clean and efficient natural gas-fired combined cycle (CC) generation at the site is possible due to the proximity to existing and planned natural gas pipelines. A new natural gas CC at this site was chosen to meet a need for new resources beginning in 2019 to maintain reliable electric service. In addition, FPL currently views the Okeechobee site as a potential site to be used for future large-scale PV and gas-fired generation facilities.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter.

**b. Proposed Facilities Layout**

See Figures at the end of this chapter.

**c. Map of Site and Adjacent Areas**

See Figures at the end of this chapter.

**d. Existing Land Uses of Site and Adjacent Areas**

1. **Site** Agricultural production (cattle and citrus)
2. **Adjacent Areas** Agricultural production, conservation, and existing electrical transmission

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

The site is comprised of unimproved pasture, fallow citrus, pine flatwoods, mixed forested wetlands, saw palmetto prairie, and freshwater marsh.

**2. Listed Species**

No adverse impacts are expected due to previous development and lack of suitable onsite habitat for listed species.

**3. Natural Resources of Regional Significance Status**

The Okeechobee site is adjacent to the Ft. Drum Marsh Conservation Area.

**4. Other Significant Features**

FPL is not aware of any other significant features of the site.

**f. Design Features and Mitigation Options**

The design includes one new approximately 1,600 MW CC unit consisting of three CTs, three heat recovery steam generators, and a steam turbine. Future options at the site include PV and gas-fired technology. Mitigation for unavoidable impacts, if required, would occur through a combination of on- and off-site mitigation.

**g. Local Government Future Land Use Designations**

Local government future land use designation includes agricultural production and power generation.

**h. Site Selection Criteria Process**

The site selection criteria included system load, transmission interconnection, proximity of the natural gas pipelines, economics, and environmental compatibility (e.g. wetlands, wildlife, threatened and endangered species, etc.).

**i. Water Resources**

Water resources include groundwater from the Surficial Aquifer System and the Floridan Aquifer System.

**j. Geological Features of Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Beneath the Surficial Aquifer System is at least 600 feet of the Hawthorn formation which is itself underlain by the Floridan Aquifer System that consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: 9 million gallons per day (mgd) daily average, 11 mgd maximum

Process: 0.08 mgd

Potable: 0.001 mgd

Panel Cleaning: Not Applicable

**l. Water Supply Sources by Type**

Cooling: Floridan Aquifer System

Process: Surficial Aquifer System

Potable: Surficial Aquifer System

**m. Water Conservation Strategies Under Consideration**

Cooling will utilize a closed system that will cycle cooling water approximately five times prior to disposal. The heat recovery steam generator blowdown will be reused to the maximum extent practicable. Additional water conservation strategies will be identified during the project's detailed design phase.

**n. Water Discharges and Pollution Control**

The site will utilize a closed cycle cooling (towers) system for heat dissipation. Heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge to an Underground Injection Control system. Reverse osmosis reject water will be mixed with the plant's cooling water flow prior to discharge to the UIC. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ Best Management Practices and Spill Prevention, Control, and Countermeasure plans to prevent and control the inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas will be delivered via a new natural gas pipeline. Ultra-low Sulfur Diesel fuel will be delivered via truck and stored in a new above-ground storage tank.

**p. Air Emissions and Control Systems**

Fuel: Use of cleaner natural gas and Ultra-Low Sulfur Distillate

- Natural Gas - Dry-low NOx combustion technology and Selective Catalytic Reduction will control NOx emissions, Greenhouse gas emissions will be substantially lower than the Environmental Protection Agency's proposed new source performance standard.
  - ULSD - Water injection and selective catalytic reduction will be used to reduce NOx emissions
- Combustion Control - will minimize formation of sulfur dioxide, particulate matter, nitrogen oxides (NOx), and other fuel-bound contaminant
- Combustor Design - will limit formation of carbon monoxide and volatile organic compounds

**q. Noise Emissions and Control Systems**

Offsite noise impacts from construction and operation are expected to be limited.

**r. Status of Applications**

Underground Injection Control Exploratory Well and associated Dual Zone Monitoring Well Permit received: April 14, 2015

Need Determination Request Filed: September 3, 2015

Need Determination Granted: January 19, 2016

Fl. Site Certification Application Submitted: September 25, 2015

Fl. Site Certification Anticipated: October 2016

Prevention of Significant Deterioration (PSD) Application Submitted: September 25, 2015

PSD Permit Received: March 9, 2016

USACE Section 404 Permit Application Filed: July 30, 2015, Deemed Complete August 12, 2015

USACE Section 404 Permit Anticipated: November 2017

**Preferred Site # 7: Turkey Point Plant, Miami-Dade County**

Turkey Point site is the location at which FPL plans to construct two new nuclear units, Turkey Point Units 6 & 7. On May 14, 2014, the Florida Power Plant Siting Board authorized the site certification, with conditions, of Turkey Point 6 & 7. Each of these two units would provide 1,100 MW of nuclear generating capacity. In 2014 the Nuclear Regulatory Commission (NRC)

significantly revised the Turkey Point Units 6 & 7 Combined Operating License Application (COLA) Review Schedule. A subsequent project schedule review based on the COLA schedule revision, and changes in Florida's nuclear cost recovery rule, indicated that the earliest practical deployment dates for bringing the Turkey Point 6 & 7 units in-service are mid-2027 (Unit 6) and mid-2028 (Unit 7) which is beyond the 2016 through 2025 time period addressed in this Site Plan. Despite the projected timing of the two new nuclear units, the nuclear units remain as an important factor in FPL's resource planning work and this Site Plan continues to present the Turkey Point site as a Preferred Site for the new units.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter

**b. Proposed Facilities Layout**

See Figures at the end of this chapter

**c. Map of Site and Adjacent Areas**

See Figures at the end of this chapter

**d. Existing Land Uses of Site and Adjacent Areas**

**1. Site**

Electrical generating facilities

**2. Adjacent Areas**

Undeveloped, the Everglades Mitigation Bank, South Florida Water Management District Canal L-31E, Biscayne Bay, and state owned land on Card Sound

**e. General Environmental Features On and In the Site Vicinity**

**1. Natural Environment**

The site includes hypersaline mud flats, man-made active cooling canals and remnant canals, previously filled areas / roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water / discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.

**2. Listed Species**

Listed species known to occur at the site or associated linear features include the peregrine falcon, wood stork, American crocodile, roseate spoonbill, little blue heron,

snowy egret, American oystercatcher, least tern, white ibis, Florida manatee, eastern indigo snake, snail kite, white-crowned pigeon, and bald eagle. Some listed flora species likely to occur include pine pink, Florida brickell-bush, Florida lantana, mullien nightshade, and Lamarck's trema. The construction and operation of Turkey Point Units 6 & 7 are not expected to adversely affect any listed species.

**3. Natural Resources of Regional Significance Status**

Significant features in the vicinity of the site include Biscayne Bay, Biscayne National Park (BNP), Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park.

**4. Other Significant Features**

FPL is not aware of any other significant features of the site.

**f. Design Features and Mitigation Options**

The technology proposed is the Westinghouse AP1000 pressurized water reactor. This design is certified by the Nuclear Regulatory Commission under 10 CFR 52. The Westinghouse AP1000 consists of the reactor, steam generators, pressurizer, and steam turbine / electric generator. Condenser cooling will use six circulating water cooling towers. The structures to be constructed include the containment building, shield building, auxiliary building, turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect to FPL's transmission system.

**g. Local Government future Land Use Designations**

Current future land use designations include Industrial, Utilities, Communications, and Unlimited Manufacturing with a dual designation of Mangrove Protection Area. There are also areas of the site designated Interim District.

**h. Site Selection Criteria Process**

Site selection included the following criteria: existing transmission and transportation infrastructure to support new generation, the size and seclusion of the site while being relatively close to the load center, economics, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

**i. Water Resources**

Water requirements will be met by reclaimed water from Miami-Dade County and a back-up supply of saltwater from the marine environment of Biscayne Bay.

**j. Geological Features of Site and Adjacent Areas**

The site is underlain by the Surficial Aquifer System, including the Biscayne Aquifer, made up of Pleistocene-Holocene sediments, Miami Limestone, Key Largo Limestone, Anastasia Formation, Fort Thompson Formation, Caloosahatchee Marl, and the Tamiami Formation. Beneath the Surficial Aquifer System is approximately 350 to 600 feet of the Hawthorn formation which is itself underlain by the Floridan Aquifer System which consists of Suwannee Limestone, Ocala Limestone, Avon Park Formation, Oldsmar Formation, Cedar Keys Formation and the Sub-Floridan Confining unit.

**k. Projected Water Quantities for Various Uses**

Cooling: 55.3 million gallons per day (mgd)

Process: 1.3 mgd

Potable: .05 mgd

Panel Cleaning: Not Applicable

**l. Water Supply Sources and Type**

Cooling: Miami-Dade reclaimed water and saltwater from Biscayne Bay via radial collector wells

Process: Miami-Dade Water and Sewer Department

Potable: Miami-Dade Water and Sewer Department

**m. Water Conservation Strategies**

Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.

**n. Water Discharges and Pollution Control**

Blowdown water or discharge from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be released to the closed-loop cooling canal system.

Turkey Point Units 6 & 7 will employ Best Management Practices plans and Spill Prevention, Control, and Countermeasure plans to prevent and control the inadvertent release of pollutants.

**o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

The Turkey Point Units 6 & 7 reactors will contain enriched uranium fuel assemblies. New fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation (DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the permitted spent fuel pool while short half-life isotopes decay.

After a sufficient decay period, the fuel would be transferred to a permitted on-site independent spent fuel storage installation facility or a permitted off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material.

The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.

**p. Air Emissions and Control Systems**

Fuel: The units will minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power.

Combustion Control / Combustor Design: Not Applicable.

Note: The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards Subpart IIII emission limits.

**q. Noise Emissions and Control Systems**

Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.

**r. Status of Applications**

Need Determination Issued: April 2008

Fl. Site Certification Received: May 14, 2014

A COLA Application for Units 6 & 7: submitted to the NRC in June 2009. In 2014 the NRC informed FPL that their decision on the COLA was going to be delayed several years until late 2016/early 2017. As a result of this delay, and changes in Florida's nuclear cost recovery rules, the earliest practical in-service dates of Turkey Point Units 6 & 7 (June 2027 and June 2028, respectively) have moved beyond the 10-year reporting window (2016 through 2025) of this Site Plan.

Miami-Dade County Unusual Use approvals: issued in 2007 and 2013

Land Use Consistency Determination: issued in 2013.

Prevention of Significant Deterioration: issued in 2009.

Underground Injection Control exploratory well: issued in 2010, and a permit to convert the exploratory well, to an injection well and to operationally test the system: issued in 2013.

Federal Aviation Administration permits for the containment structure: originally issued in 2009, renewed in 2012, and again in 2015.

#### **IV.F.2 Potential Sites**

Six (6) sites, denoted by counties, are currently identified as Potential Sites for future generation additions to meet FPL's projected capacity and energy needs.<sup>6</sup> Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that would require further definition and attention. Unless otherwise noted, the water quantities discussed below are in reference to gas-fired CC generation.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. At this time, FPL considers each site to be equally viable. The Potential Sites briefly discussed below are presented in alphabetical order.

#### **Potential Site # 1: Alachua County**

FPL is currently evaluating potential sites in Alachua County for a future PV facility. No specific locations have been selected at this time.

---

<sup>6</sup> As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other greenfield sites. Specific greenfield sites may not be specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

a. **U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter

b. **Existing Land Uses of Site and Adjacent Areas**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

c. **Environmental Features**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

d. **Water Quantities Required**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal and only in absence of sufficient rainfall

e. **Supply Sources**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal, trucked in if and when needed

## **Potential Site # 2: Hendry County**

FPL currently views Hendry County as a region likely to be used for future large-scale generation including gas-fired and/or PV generation. This includes existing FPL-owned sites as well as other potential future sites.

a. **Geological Survey (USGS) Map**

See Figures at the end of this chapter

b. **Existing Land Uses of Site and Adjacent Areas**

The existing FPL-owned sites and adjacent areas consist of agricultural and upland forest as well as the Seminole Big Cypress Reservation. Land use information is not available at the time of publication of this report on an additional location as a specific site has not been selected.

**c. Environmental Features**

The existing FPL-owned sites include woodland pasture that includes wetlands, upland scrub, pine and hardwoods. Environmental feature information is not available at the time of publication of this report on an additional location as a specific site has not been selected.

**d. Water Quantities Required**

Cooling: 9 - 12 million gallons per day (mgd) daily average

Process: 0.24 mgd

Potable: 0.001 mgd

Panel Cleaning (if the site is selected for PV generation): Minimal and only in absence of sufficient rainfall.

**e. Supply Sources**

Cooling: Groundwater

Process: Groundwater

Potable: Existing Supply

**Potential Site # 3: Martin County**

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been definitively selected at this time.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter

**b. Existing Land Uses of Site and Adjacent Areas**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

**c. Environmental Features**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

**d. Water Quantities Required**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal and only in absence of sufficient rainfall

**e. Supply Sources**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal, trucked in if and when needed

**Potential Site # 4: Miami-Dade County**

FPL is currently evaluating potential sites in Miami-Dade County for a future PV facility. No specific locations have been definitively selected at this time.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter

**b. Existing Land Uses of Site and Adjacent Areas**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

**c. Environmental Features**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

**d. Water Quantities Required**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal and only in absence of sufficient rainfall

**e. Supply Sources**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal, trucked in if and when needed

## **Potential Site # 5: Putnam County**

FPL currently views Putnam County as a region likely to be used for future large-scale generation including gas-fired and/or PV generation. This includes existing FPL-owned sites as well as other potential future sites.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter

**b. Existing Land Uses of Site and Adjacent Areas**

The existing FPL-owned sites and adjacent areas consist of industrial, power generation and associated facilities, mixed wetland hardwoods, residential, and hardwood. Land use information is not available at the time of publication of this report on an additional location as a specific site has not been selected.

**c. Environmental Features**

FPL is not aware of any other significant features on or adjacent to the site.

**d. Water Quantities Required**

Cooling: 9 – 12 million gallons per day (mgd) daily average

Process: 0.24 mgd

Potable: 0.001 mgd

Panel Cleaning: Minimal and only in absence of sufficient rainfall.

**e. Supply Sources**

Cooling: St. John's River

Process: Groundwater

Potable: Putnam County Municipal Water Supply

## **Potential Site # 6: Volusia County**

FPL is currently evaluating potential sites in Volusia County for a future PV facility. No specific locations have been definitively selected at this time.

**a. U.S. Geological Survey (USGS) Map**

See Figures at the end of this chapter

**b. Existing Land Uses of Site and Adjacent Areas**

This information is not available at the time of publication of this report because a specific site has not been selected.

**c. Environmental Features**

This information is not available at the time of publication of this report because a specific site has not been definitively selected.

**d. Water Quantities Required**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal and only in absence of sufficient rainfall

**e. Supply Sources**

Cooling: Not Applicable for PV

Process: Not Applicable for PV

Potable: Minimal

Panel Cleaning: Minimal, trucked in if and when needed

## **CHAPTER V**

---

### **Other Planning Assumptions & Information**

***(This page is left intentionally blank.)***

## Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

### **Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.**

---

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important because they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance that is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system that provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting potential new units at different locations, evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. When analyzing DSM portfolios, such as in a DSM Goals docket, FPL also examines the potential for utility DSM energy efficiency programs to avoid/defer regional

transmission expenditures that would otherwise be needed to import power into that region by lowering electrical load in Southeastern Florida. In addition, transfer limits for capacity and energy that can be imported into the Southeastern Florida region (Miami-Dade and Broward Counties) of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region of FPL's system, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate generating units in FPL's resource plans, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

**Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.**

---

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, and only supply options are being analyzed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements (CPVRR) for its system.<sup>7</sup>

The load forecast that is presented in FPL's 2016 Site Plan was developed in late 2015 and early 2016. The only load forecast sensitivities analyzed during 2015/early 2016 were extreme weather sensitivities developed to analyze potential near-term operational scenarios and a higher load forecast scenario that was used to examine the projected future need for natural gas for the FPL system. These load forecast sensitivities and scenario did not result in a change in the resource plan.

---

<sup>7</sup> FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements (CPVRR) basis approach yield identical results in terms of which resource options are more economic. In such cases, FPL evaluates resource options on the simpler-to-calculate (but equivalent) lowest CPVRR basis.

**Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.**

---

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost forecasts in analyses supporting its 2015 nuclear cost recovery filing. Also, in response to a request from the FPSC Staff, FPL used three fuel cost forecasts in sensitivity case analyses for the 2015 need determination of need filing for its Okeechobee combined cycle unit which will go into service in 2019.

A Medium fuel cost forecast is developed first. Then the Medium fuel cost forecast is adjusted, upwards (for the High fuel cost forecast) or downwards (for the Low fuel cost forecast), by multiplying the annual cost values from the Medium fuel cost forecast by a factor of  $(1 + \text{the historical volatility in the 12-month forward price, one year ahead})$  for the High fuel cost forecast, or by a factor of  $(1 - \text{the historical volatility of the 12-month forward price, one year ahead})$  for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. In addition, FPL is now using updated forecasts for both fuel costs and environmental compliance costs. On-going resource planning analyses during 2016 will continue to examine sensitivities to both forecasts to determine potential impacts to the resource plan presented in this document. However, based on FPL's projected resource needs, no FPL decision is needed this year regarding any major resource option addition.

**Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.**

---

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2015/early 2016 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

**Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.**

---

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options that FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

**Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.**

---

At the start of 2015, FPL used the following financial assumptions: (i) an incremental capital structure of 40.38% debt and 59.62% equity; (ii) a 5.14% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.54%. In February 2015, the cost of debt changed to 5.05% and the after-tax discount rate changed to 7.51%. These financial assumptions remain valid at the time the 2016 Site Plan is being prepared. No sensitivities of these financial assumptions were used in FPL's 2015/early 2016 resource planning work.

**Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.**

---

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of revenue requirement (CPVRR) perspective for the system yield identical results in terms of which resource options are more economical when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler-to-calculate, CPVRR perspective was utilized.

**Discussion Item # 8: Define and discuss the electric utility’s generation and transmission reliability criteria.**

---

FPL uses three system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One criterion is a minimum 20% Summer and Winter reserve margin. Another reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). The third criterion is a minimum 10% generation-only reserve margin (GRM) criterion. These three reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (<http://www.nerc.com/>).

In addition, FPL has developed a *Facility Interconnection Requirements* (FIR) document that is available on the internet under the “Interconnection Request Information” directory at the following internet address: <https://www.oatioasis.com/FPL/index.html>.

Generally, FPL limits its transmission facilities to operate at no more than 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

<u>Voltage Level (kV)</u>	<u>Normal/Contingency</u>	
	<u>Vmin (p.u.)</u>	<u>Vmax (p.u.)</u>
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(\*) Voltage range criteria for FPL’s Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, and transmission system performance.

**Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.**

---

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load management equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allow FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis. Based on testing during 2015, FPL has temporarily reduced its estimated residential load management MW reduction capabilities due to customer-premise equipment communications issues that FPL projects will be resolved by year-end 2017.

**Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.**

---

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors that FPL typically considers when choosing between resource options. These include: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else is equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those that minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state-of-the-art environmental controls, generating technologies that do not utilize fossil fuels (such as nuclear and solar), etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decision-making, including its decisions to construct capacity or purchase power.

**Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.**

---

As shown in this 2016 Site Plan, FPL's resource plan currently reflects the following major supply-side or generation resource additions: the replacement of existing GT capacity with new CT capacity, the on-going upgrading of CTs in several existing CCs throughout FPL's system, the implementation of the previously executed EcoGen PPA, the projected addition of new PV facilities, and the projected addition of new CC capacity.

CT upgrades are currently taking place at several CC units throughout the FPL system. FPL was approached by the original equipment manufacturer (OEM) of the CTs regarding the possibility of upgrading these units. Following negotiations with the OEM, and economic analyses that showed upgrading was cost-effective for FPL's customers, the decision was made to proceed with the CT upgrades. The first series of upgrades was completed in 2015. Additional upgrades are in progress with expected completion in 2018.

The EcoGen PPAs, which were approved by the Commission in Order No. PSC-13-0205-CO-EQ dated May 21, 2013, were the result of negotiations between U.S. EcoGen and FPL. In regard to the three PV facilities that will be in service by the end of 2016, the selection of equipment and installation contractors for these facilities has been done via competitive bidding.

To the extent possible, identification of projected/potential self-build generation resources beyond those units already approved by the FPSC and Governor and Siting Board or units, such as the PV projects to be completed by the end of 2016, the additional PV capacity to be added by 2021 (a mid-2020 in-service date is assumed for planning purposes), and the new CC capacity shown as a potential addition in 2024, is required of FPL in its Site Plan filings. FPL's identification of these resources represents FPL's current view of alternatives that appear to be the best, most cost-effective self-build options at present. FPL reserves the right to refine its planning analyses and to identify and evaluate other options before making decisions regarding future capacity additions. Such refined analyses have the potential to yield a variety of self-build options, some of which may not require a request for proposals (RFP). If an RFP is issued for generation resources, FPL will choose the best alternative for its customers, regardless of whether it is a third party proposal to an RFP or an FPL self-build option. If an RFP for generation resources is not required, FPL will typically utilize a competitive bidding process to select equipment suppliers and installation contractors based on its assessment of price and supplier capability to realize the best generation option for its customers.

**Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.**

---

FPL has identified the need for three new transmission lines that require certification under the Transmission Line Siting Act (as shown on Table III.E.1 in Chapter III). The first is a 230 kV line that was certified in April 2006. The new line will connect FPL's St. Johns Substation to its Pringle Substation. The line will be constructed in two phases. Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 will connect St. Johns to Pellicer and it is scheduled to be completed by December 2018. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

The second is a 500 kV line corridor that was certified in April 1990. The line(s), when fully constructed, will provide an additional connection between FPL's Midway substation and its Levee substation in Miami-Dade County. A portion of this corridor was utilized in 1994 to connect FPL's Corbett substation (located along the corridor) in Palm Beach County to its Conservation substation in western Broward County. The next phase, which is currently scheduled to be in service by 2023, will utilize a portion of the corridor from Corbett to Levee. The line will be needed to increase transfer capability into the southeastern Florida region, unless additional generation resources are developed within the region to meet local load growth.

The third is another 230 kV line which will connect FPL's Duval Substation to a new Raven 230/115 KV Substation. A determination of need for the line was granted by the Florida Public Service Commission on March 4, 2016 and the line is currently scheduled to be completed by December 2018. The construction of this line and substation are necessary to serve existing and future FPL customers in the north Florida areas in and around Columbia County in a reliable and effective manner.

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 12, IEEFA, Risks  
Associated with Natural Gas Pipeline Expansion in  
Appalachia, April 2016.**

# **Risks Associated With Natural Gas Pipeline Expansion in Appalachia**

## **Proposed Atlantic Coast and Mountain Valley Pipelines Need Greater Scrutiny**



**Institute for Energy Economics  
and Financial Analysis**  
IEEFA.org

**April 2016**

**By Cathy Kunkel and Tom Sanzillo**

# EXECUTIVE SUMMARY

Major utilities, pipeline companies and natural gas producers are proposing construction of two new natural gas pipelines into Virginia and North Carolina from the Marcellus and Utica shale region of West Virginia.

Developers of the Atlantic Coast Pipeline and the Mountain Valley Pipeline, which would cost a total of nearly \$9 billion to complete, have applied to the Federal Energy Regulatory Commission for approval.

The pipelines are proposed to go into service in 2018. They would be part of a larger expansion of natural gas pipeline infrastructure from the Marcellus and Utica shale region in Appalachia that has been described by Moody's Investors Services as an "once-in-a-lifetime build-out cycle" driven by the recent boom in natural gas production.

Some participants have openly acknowledged the likelihood of overbuilding, as when Kelcy Warren, CEO of Energy Transfer Partners, said in an earnings call last year that overbuilding is part-and-parcel of the industry ("The pipeline business will overbuild until the end of time," Warren said).

This report shows how the Atlantic Coast and Mountain Valley pipelines are emblematic of the risks that such expansion creates for ratepayers, investors and landowners.

Among its conclusions:

- Pipelines out of the Marcellus and Utica region are being overbuilt.
- Overbuilding puts ratepayers at risk of paying for excess capacity, landowners at risk of sacrificing property to unnecessary projects, and investors at risk of loss if shipping contracts are not renewed and pipelines are underused.
- The Federal Energy Regulatory Commission facilitates overbuilding. The high rates of return on equity that FERC grants to pipeline companies (allowable rates of up to 14%), along with the lack of a comprehensive planning process for natural gas infrastructure, attracts more capital into pipeline development than is necessary.
- FERC's approach to assessing the need for such projects is insufficient.
- Industry leaders recognize and acknowledge that current expansion plans will likely result in overbuilding.



- The arguments for the Atlantic Coast Pipeline have not been adequately scrutinized. While the pipeline developers have asserted that some of the gas supplied is needed by Dominion Resources for its new Brunswick and Greenville natural gas plants, Dominion has told the Virginia State Corporation Commission that it can supply those plants through the existing Transco pipeline.
- While ratepayers of the utilities (largely Duke Energy and Dominion Virginia Electric and Power) that have contracted to ship gas through the Atlantic Coast Pipeline would be burdened with the costs of building the pipeline (which would include a profit to the developers, largely Duke and Dominion), they will probably not realize the economic benefits promised by the developers.
- Communities along the Mountain Valley Pipeline face the risk that EQT Corporation (which owns the largest stake in that pipeline and has contracted for the largest volume of capacity on the pipeline) will continue to be harmed financially by weak natural gas prices and will not be a long-term, stable partner for these communities.

This report notes also that much of the \$9 billion costs of the projects—aside from the costs embedded in the price of any natural gas that is exported—would ultimately be either added to the price consumers pay for natural gas or absorbed as a loss to project investors.

And it points out that regulators have not considered whether these pipelines are the best use of ratepayer dollars. None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas - energy efficiency, renewable energy or other forms of power generation - may be cheaper.

Given all of these circumstances, IEEFA recommends the following:

- That the applications for the Atlantic Coast and Mountain Valley pipelines be suspended until a regional planning process can be developed for pipeline infrastructure;
- That FERC lower the returns on equity granted to pipeline developers; and
- That an investigation be conducted into the relatively high failure rate of new pipelines.

# INTRODUCTION

The Federal Energy Regulatory Commission is considering applications for construction of two major natural gas pipelines that would run from West Virginia into North Carolina and Virginia: the Atlantic Coast Pipeline and the Mountain Valley Pipeline.

These pipelines, which together would stretch for approximately 850 miles, are being contemplated during a time of major natural gas infrastructure expansion in the U.S.

In October 2014, Moody's Investors Service characterized the proposed pipeline build-out from the Marcellus and Utica shale region as "the start of a once-in-a-lifetime build-out cycle."<sup>1</sup>

This report examines the risks these projects pose to consumers, investors, and communities along the proposed routes.



Part 1 of the report describes the rapid buildout of Marcellus and Utica pipeline infrastructure in order to place the Atlantic Coast and Mountain Valley pipelines in the context of the larger expansion of pipeline infrastructure. Part 2 considers specific risks associated with the proposed Atlantic Coast and Mountain Valley pipelines.

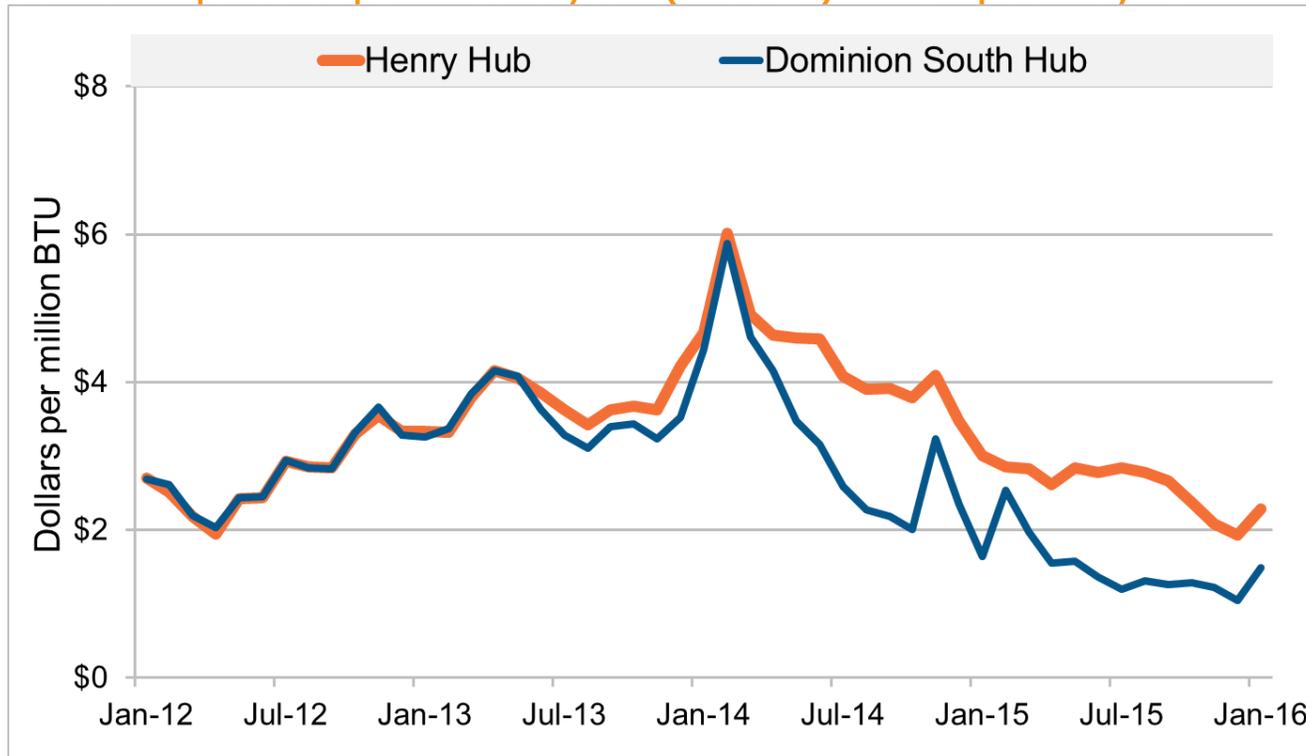
## PART 1: THE POTENTIAL FOR OVERBUILDING PIPELINES FROM THE MARCELLUS AND UTICA REGION

The boom in natural gas pipeline construction associated with the Marcellus and Utica shale region is driven fundamentally by the low price of shale gas and the desire on the part of developers to transport that gas to higher-priced markets, perhaps even to export markets. The following graph shows prices since January 2012 at the Dominion South Hub in southwestern Pennsylvania versus those at the Henry Hub in Louisiana. Henry Hub prices are often used as the benchmark for natural gas prices in the U.S. The Henry Hub has historically been where the largest volumes of gas have traded. In recent years, larger or comparable volumes have been

<sup>1</sup> "Shale-Fueled Inflection Point for Pipeline Operators; Offshore Rig Oversupply to Persist," Moody's Investors Service, October 15, 2014.

traded at the Dominion South Hub, reflecting the upsurge in natural gas production in the Marcellus and Utica regions.<sup>2</sup> The price of natural gas at the Dominion South Hub has recently been very low, averaging \$1.50 per MMBTU in 2015 while Henry Hub prices averaged well over \$2 per MMBTU. And 2015 was no anomaly. Over the past three years, prices at the Dominion South Hub have decoupled from Henry Hub prices, remaining consistently lower.

**Figure 1. Natural gas prices at the Dominion South Hub (southwestern Pennsylvania) have decoupled from prices at Henry Hub (Louisiana) over the past few years.**



Source: SNL Financial

The low price of Marcellus natural gas is partially a factor of limited takeaway capacity (the gas is less valuable if it cannot be tapped) for moving this natural gas to market. As a result, numerous proposals have been made to build new pipelines to move this natural gas out of West Virginia, western Pennsylvania and Ohio.

The financial dynamics of the natural gas industry encourage overbuilding of natural gas pipelines, i.e. the construction of excess capacity. A weak regulatory process and a lack of coordinated planning for natural gas infrastructure facilitate this process.

The next several sections here explore the causes and consequences of overbuilding pipeline capacity.

<sup>2</sup> In 2012 and 2013, the volume of gas traded at the Dominion South Hub exceeded the volume traded at the Henry Hub. In 2014, 84,000 MMBTU were traded at the Dominion South Hub versus 90,000 at the Henry Hub, and in 2015, 60,000 MMBTU were traded at the Dominion South Hub versus 61,000 at the Henry Hub. (Source: SNL Financial)

## A. Industry Dynamics Encourage Overbuilding of Gas Pipelines

Various economic interests drive pipeline investment that tends toward building excess capacity. In the past, pipeline development in the U.S. has been done by a set of companies that specialize in the pipeline field, including Kinder Morgan, Columbia Pipeline Group and Williams Company. However, in recent years, electric and natural gas utilities, as well as natural gas producers, have begun to move into the natural gas pipeline business. All of these entities—traditional pipeline developers, utilities and producers—can have incentives to overbuild.

For example, current low natural gas prices in the Marcellus and Utica region are driving a race among natural gas pipeline companies that want to capitalize on low prices by building new pipeline capacity to higher-priced markets. An individual pipeline company acquires a competitive advantage if it can build a well-connected pipeline network that offers more flexibility and storage to customers; thus, pipeline companies competing to see who can build out the best networks the quickest.<sup>3</sup> This is likely to result in more pipelines being proposed than are actually needed to meet demand in those higher-priced markets.

Additionally, utilities—which have been attracted to the natural gas pipeline business because of its traditionally high returns and to further integrate their supply chains as electric power generation becomes increasingly reliant on natural gas—have an economic interest in building new lines. A regulated electric or gas utility that is purchasing natural gas for power generation or for use as a heating fuel passes the cost of its pipeline contracts, which include a FERC-approved profit for the pipeline developer, on to its customers.<sup>4</sup> If the regulated utility's parent company can build its own pipeline for use by its regulated subsidiary, it can capture this profit, giving a utility holding company an incentive to prioritize building its own pipeline rather than utilizing that of another company.<sup>5</sup> This structure also shifts some of the risk of

**“None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas — energy efficiency, renewable energy or other forms of power generation— may be cheaper.”**

<sup>3</sup> Tyler Crowe, “5 Things Energy Transfer’s Management Wants You to Know,” The Motley Fool, September 10, 2015.

<sup>4</sup> Some utility holding companies are becoming involved in the natural gas pipeline business even though they do not own any power plants. In New England, regulated electric distribution utilities are proposing to enter into contracts for natural gas capacity on new pipelines in order to re-sell that capacity on the secondary market to natural gas power plants, with the goal of bringing down prices for natural gas generation. The costs or benefits of this transaction (the costs of long-term capacity contracts, net the revenues received from re-selling that capacity to generators) are to be passed on to the customers of the regulated distribution utilities. Some of the regulated utilities involved in these contracts are subsidiaries of holding companies, including National Grid and Eversource, that are investors in building the new pipelines. (Sources: M. Serreze, “National Grid seeks Massachusetts DPU approval of gas pipeline capacity contracts,” MassLive, January 22, 2016; S. Sullivan, “Algonquin Gas introduces nearly 1-Bcf/d Access Northeast to FERC early review,” SNL Financial, November 3, 2015;).

<sup>5</sup> State public utilities commissions often have a role in regulating contracts between regulated utilities and their affiliates (in this case, between the regulated utility and the affiliate that owns a share in the pipeline). State commissions also must ensure that the regulated utility acted prudently in sourcing its supply of natural gas. To our knowledge, no regulated utility has been denied cost recovery, in whole or in part, for a contract with an affiliated natural gas pipeline, but this is a potential risk to utilities in the future.

pipeline development from the developer and its shareholders to the regulated utility's ratepayers.

Some upstream producers of natural gas, such as EQT Corporation, have also moved into the pipeline construction business. For such companies, investment in pipelines promises a relatively stable revenue stream compared to the volatility of the natural gas drilling business. EQT, for example, has taken advantage of investors' willingness to fund pipeline development by creating an EQT-controlled master limited partnership (EQT Midstream), which has been able to raise equity through public offerings both for new pipeline projects and for buying gathering and processing infrastructure formerly owned by EQT, leaving EQT in a much better cash position than many other drillers. Such short-term balance sheet considerations for a company like EQT do not translate into rational planning of long-term infrastructure. These dynamics will be explored in more detail in Part 2, Section B below.

None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas—energy efficiency, renewable energy or other forms of power generation—may be cheaper. There is little discussion of how long-term natural gas demand will evolve over the lifetime of a proposed pipeline as alternatives become increasingly cost-effective and widespread.

## **B. Lack of Planning Process For Natural Gas Infrastructure Facilitates Building Excess Capacity**

A coordinated planning process for natural gas infrastructure could serve as a check on the tendency of individual pipeline developers to overbuild.

But the U.S. has no overarching national or regional planning process for natural gas infrastructure development. This planning void contrasts sharply with established planning processes for electricity transmission lines, interstate highways and many other types of infrastructure. Electricity transmission in states with deregulated electricity markets, for instance, is overseen by Regional Transmission Organizations (regulated by the Federal Energy Regulatory Commission<sup>6</sup>) that have planning processes to determine whether proposed new transmission lines are needed and whether there are more cost-effective alternatives to building new lines. While electric transmission lines ultimately must be approved by FERC and by state public utilities commissions, the RTO-level transmission planning process has informed decision making and sometimes led to the cancellation of proposed new electric transmission lines that are shown to be unnecessary.<sup>7</sup>

---

<sup>6</sup> The Federal Energy Regulatory Commission, FERC, regulates electric transmission under the Federal Power Act and natural gas pipeline infrastructure under the Natural Gas Act. The Federal Power Act, as amended by the Energy Policy Act of 2005, has explicit provisions for transmission planning (see Federal Power Act Section 217(b)(4)). FERC Orders 890 and 890-A relied on this authority in “mandating coordinated, open and transparent transmission planning on a local and regional level.” These orders require transmission providers to incorporate nine principles into their planning process, including “coordination” with customers and neighboring transmission providers, “regional participation” (coordination with interconnected systems) and “economic planning studies.” (See: Lawrence Greenfield, “An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States,” Office of the General Counsel, Federal Energy Regulatory Commission, December 2010).

<sup>7</sup> For example, PJM's Regional Transmission Expansion Plan process allowed the Virginia State Corporation Commission to see that the PATH power line proposed through West Virginia, Virginia and Maryland was unnecessary because the reliability

No such planning process exists for the build-out of natural gas pipeline infrastructure. While FERC must approve the construction of new pipelines, it does not conduct any long-term assessment of regional natural gas demand in assessing the need for new pipelines.

Instead, FERC primarily relies on whether a pipeline developer has been able to recruit enough companies to contract for capacity on the line. If a pipeline is fully or near fully subscribed, FERC considers this strong evidence that the pipeline is necessary.

This approach by FERC is highly likely to result in excess capacity that will be underutilized. For example, in situations in which a pipeline developer contracts with an affiliate company to ship gas through a new pipeline, this is strong evidence that it is doing so because of the financial advantage to the parent company from building the pipeline, but not necessarily that there is a need for the pipeline. As described in the previous section, the private financial interests of individual pipeline developers do not necessarily align with the public interest.

## C. Favorable Federal Regulatory Treatment Further Facilitates Overbuilding

Not only do the dynamics of the natural gas and pipeline industries tend to favor building excess capacity, but federal regulatory policy toward pipelines does too.

**“...because there is no planning process for natural gas pipeline infrastructure, there is a high likelihood that more capital will be attracted into pipeline construction than is actually needed.”**

FERC is in charge of regulating the rates that pipeline companies charge to shippers (the entities that are contracted to ship gas through pipelines). Pipeline rates are required to be cost-based, meaning that they must reflect the cost to the pipeline company of providing the service. This cost includes a return on equity (profit) to the pipeline company for the capital that it has invested in building the line.<sup>8</sup> Pipelines are financed partially with debt and partially with equity.

In theory, without FERC regulation, a pipeline company could take advantage of a shipper by charging exorbitant rates, because the shipper may have no other option for delivering gas. In order to prevent this, FERC sets the “recourse rate,” which is the rate that a shipper is allowed to demand and receive. This prevents the pipeline company from gouging a shipper. Both the Atlantic Coast Pipeline and the Mountain Valley Pipeline have applied for recourse rates that include a return on equity of 14%. This is a relatively common request, and one that has been granted on many recent greenfield pipelines, including the Constitution

---

problems that PATH would solve could be solved less expensively through rebuilding existing transmission lines. (Sources: Virginia State Corporation Commission, “Hearing Examiner’s Ruling,” Case No. PUE-2010-00115, January 19, 2011; PATH Allegheny Virginia Transmission Corporation, “Motion to Withdraw Application,” Case No. PUE-2010-00115, February 28, 2011).

<sup>8</sup> It is worth noting that, at least in the case of the Atlantic Coast pipeline, this “capital” includes more than the actual construction costs of the pipeline. The Atlantic Coast Pipeline is seeking to earn a return on landowner outreach, community and government meetings regarding the route, and preparation of regulatory filings. (See: Atlantic Coast Pipeline, LLC & Dominion Transmission, Inc., FERC Docket Nos. CP15-554-000 & CP15-555-000, Response to Data Request, December 15, 2015.)

Pipeline<sup>9</sup> approved in 2014, the Sierrita Gas Pipeline in 2014,<sup>10</sup> the Ruby Pipeline in 2011,<sup>11</sup> the Bison Pipeline in 2010<sup>12</sup> and the ETC Tiger Pipeline in 2010.<sup>13</sup>

A 14% return on equity is high relative to returns that one could expect to receive by investing capital elsewhere in the utility business. In 2014, the average return on equity granted by state public utilities commissions to investor-owned electric utilities was 9.92%.<sup>14</sup> And FERC has recently lowered its allowed return on equity for electric transmission companies in New England to a maximum of 11.74% and is expected to lower returns for transmission companies in the Midwest as well this year.<sup>15</sup>

FERC has provided little justification to support recourse rates that include a 14% return on equity for new pipelines. In comments opposing a 14% return on equity for the Atlantic Coast Pipeline, the North Carolina Utilities Commission (NCUC) noted that FERC has never required pipeline companies to provide much evidence to support such requests. Indeed, the only support the developers of the Atlantic Coast Pipeline provided to justify its request were citations to previous FERC orders granting 14% returns on equity for new pipelines, but those FERC orders themselves did not provide any justification for granting 14% returns. The NCUC stated that “[w]hile the NCUC recognizes that in the past the Commission has merely accepted recourse rates based on cases citing previous cases, application of that policy would appear to conflict with the unambiguous statutory requirement that a filing entity demonstrate that its filing, including the recourse rates, comports with the public convenience and necessity.”<sup>16</sup>

In practice, most major contracts between pipelines and shippers are not based on recourse rates, but on negotiated rates. Because a pipeline company needs to prove to FERC that it has attracted customers to ship gas on its pipeline in order to obtain FERC approval to build the line, it needs to negotiate long-term contracts with shippers in advance of proposing the pipeline to FERC. So-called “anchor” or “foundation” shippers who agree to enter into these long-term (15- to 20-year) contracts are typically granted preferential rate treatment, i.e. with negotiated rates that are lower than the recourse rates.

Negotiated rates do not have to be approved by FERC, but they must be filed with FERC between 30 and 60 days before the pipeline is placed into service.<sup>17</sup> This means that the negotiated rates for the Atlantic Coast and Mountain Valley pipelines are not currently publicly available, so there is no way of knowing what return on equity is embedded in these negotiated rates.

Even though the return on equity embedded in the recourse rate is not necessarily what the pipeline earns, because the negotiated rate may be based on a different return on equity, the recourse rate still provides an important benchmark. Interruptible rates for non-firm pipeline

---

<sup>9</sup> 149 FERC ¶ 61,199 (2014)

<sup>10</sup> 147 FERC ¶ 61,192 (2014)

<sup>11</sup> 136 FERC ¶ 61,054 (2011)

<sup>12</sup> 131 FERC ¶ 61,013 (2010)

<sup>13</sup> 131 FERC ¶ 61,010 (2010)

<sup>14</sup> Edison Electric Institute, “Industry Financial Performance,” 2014, online at [http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview\\_2014\\_02\\_IndustryFinPerf.pdf](http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2014_02_IndustryFinPerf.pdf), accessed April 13, 2016.

<sup>15</sup> R. Walton “Breaking down FERC’s recent, and pending, ROE decisions,” Utility Dive, November 17, 2014; and J. O’Reilly, “RRA Focus on FERC – January 2016: Downward pressures on ROEs continues as FERC ALJ recommends significant reduction in MISO, new complaints filed against Duke in NC, SC,” SNL Financial, January 15, 2016.

<sup>16</sup> FERC Docket No. CP15-554, “Comments in support of project and protest of proposed recourse rates of the North Carolina Utilities Commission,” October 23, 2015.

<sup>17</sup> 133 FERC ¶ 61,220 (2010)

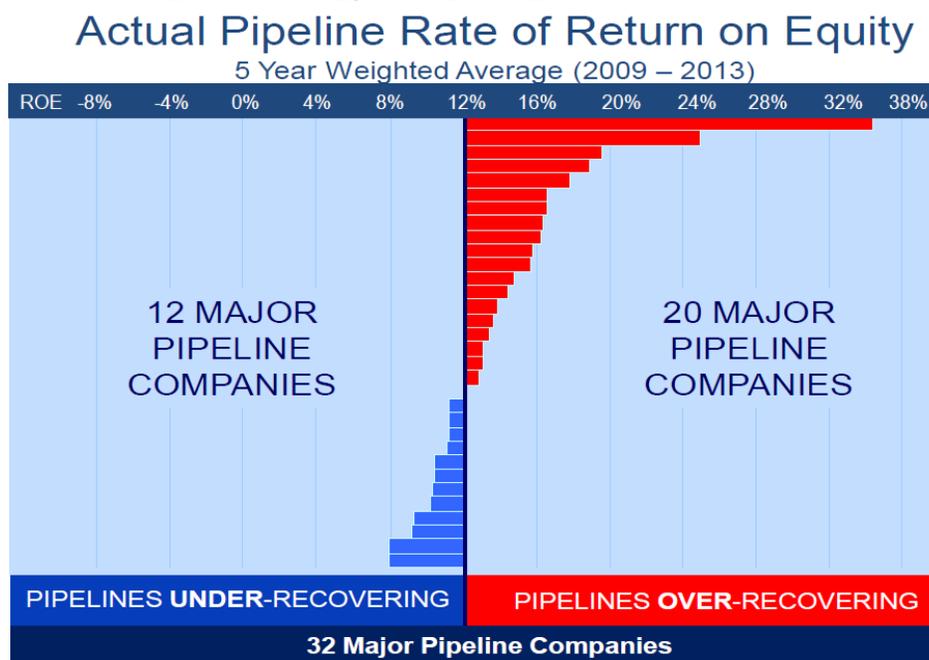
service are based on the recourse rates. And the rates of return embedded in the recourse rates define what is considered to be a reasonable return for pipeline companies, which is important for any entity seeking to file a complaint with FERC that a pipeline company is over-earning.

A pipeline's rates can be challenged by FERC Staff or by outside entities if the pipeline appears to be earning an excessive rate of return.<sup>18</sup> (Just because rates are set based on an expected return does not preclude the pipeline company from earning higher than that return, if it is able to reduce other costs). Such challenges are typically based on annual financial data that must be filed with FERC after a pipeline has been placed into service. While the FERC complaint process can result in new, lower rates being established, the excess earnings that the pipeline is found to have received in past years do not have to be refunded to customers.<sup>19</sup>

In practice, many pipelines appear to be earning higher returns than authorized in their recourse rates. A recent study from the National Gas Supply Association, an association of natural gas suppliers, producers and marketers, looked at the returns on equity from 2009-2013 of 32 major natural gas pipeline companies, comprising 75% of interstate natural gas market capacity. Fewer than 40% of the companies were earning returns on equity of 8-12%. The majority of companies earned returns on equity greater than 12%, with two of those companies earning returns on equity in excess of 24%.<sup>20</sup>

In short, the regulatory environment created by FERC encourages pipeline overbuild. The high returns on equity that pipelines are authorized to earn by FERC and the fact that, in practice, pipelines tend to earn even higher returns, mean that the pipeline business is an attractive place to invest capital. And because, as discussed previously, there is no planning process for natural gas pipeline infrastructure, there is a high likelihood that more capital will be attracted into pipeline construction than is actually needed.

**Figure 2. The Majority of Major Pipeline Companies Earned Returns In Excess of 12% For 2009-2013.**



Source: Natural Gas Supply Association

<sup>18</sup> For example, FERC opened an investigation into a Kinder Morgan pipeline in 2011 that FERC Staff estimated had earned a return on equity of 19.55% in 2010 and 18.51% in 2011. (Source: S. Sullivan, "WIC submits settlement to take care of FERC rate investigation," SNL Financial, June 25, 2013)

<sup>19</sup> American Public Gas Association, "Section 5," Online at <http://www.apga.org/issues/issues-section-5>, last accessed April 13, 2016.

<sup>20</sup> Pen Cankardes Ulrey, "Pipeline Cost Recovery Report: 32 Major Pipelines, 2009-2013," Natural Gas Supply Association (no date).

## D. State Regulatory Processes Have Little Power to Prevent Overbuilding

State regulatory commissions play a very limited role in regulating interstate natural gas pipelines.

Although regulations vary from state to state, state public service commissions often regulate contracts and transactions between regulated utilities and their affiliates. Thus, if a regulated utility seeks to enter into a contract for pipeline capacity with a corporate affiliate that is developing the pipeline, it may require approval from the commission to enter into the contract. In the case of the Atlantic Coast Pipeline, the North Carolina Public Utilities Commission has granted approval for Duke Energy Progress, Duke Energy Carolinas and Piedmont Natural Gas to become shippers on the pipeline. Dominion Virginia Electric and Power has not yet sought similar approval from the Virginia State Corporation Commission.

State regulatory commissions also have a role in approving the pass-through of the costs of pipeline contracts to the rates of regulated utility customers. The cost of shipping natural gas on a pipeline, including the return on equity for the pipeline company, is an operating cost for the end-use utility and is therefore a cost that is passed through to utility customers, as long as the state commission agrees that this cost has been prudently incurred.<sup>21</sup> A commission could disallow all or part of the costs paid pursuant to a natural gas contract if the commission finds that such costs were not prudently incurred (for example, if the utility knowingly contracted for too much capacity or failed to secure a lower-priced contract). The commission would have to find that the utility's decision at the time of entering into the contract was imprudent, not that the contract turned out to be expensive for ratepayers in hindsight.

Such a potential disallowance would of course occur after the pipeline has been placed into service. In the absence of affiliate contracts, utilities have no incentive not to enter into prudent contracts with third-party suppliers. The transaction structure in which a regulated utility contracts to ship gas on a pipeline developed by an affiliate company is a relatively recent development that tends to shift risk from shareholders to ratepayers. It is not yet clear whether state public utilities commissions will scrutinize pipeline capacity procured under such contracts more closely in rate-making.

Additionally, if a state commission believes that a pipeline is earning excessive returns, it can challenge the pipeline's rates at FERC (as described above) but it does not have authority to alter recourse or negotiated rates.

**“The cost of shipping natural gas on a pipeline, including the return on equity for the pipeline company, is an operating cost for the end-use utility and is therefore a cost that is passed through to utility customers.”**

---

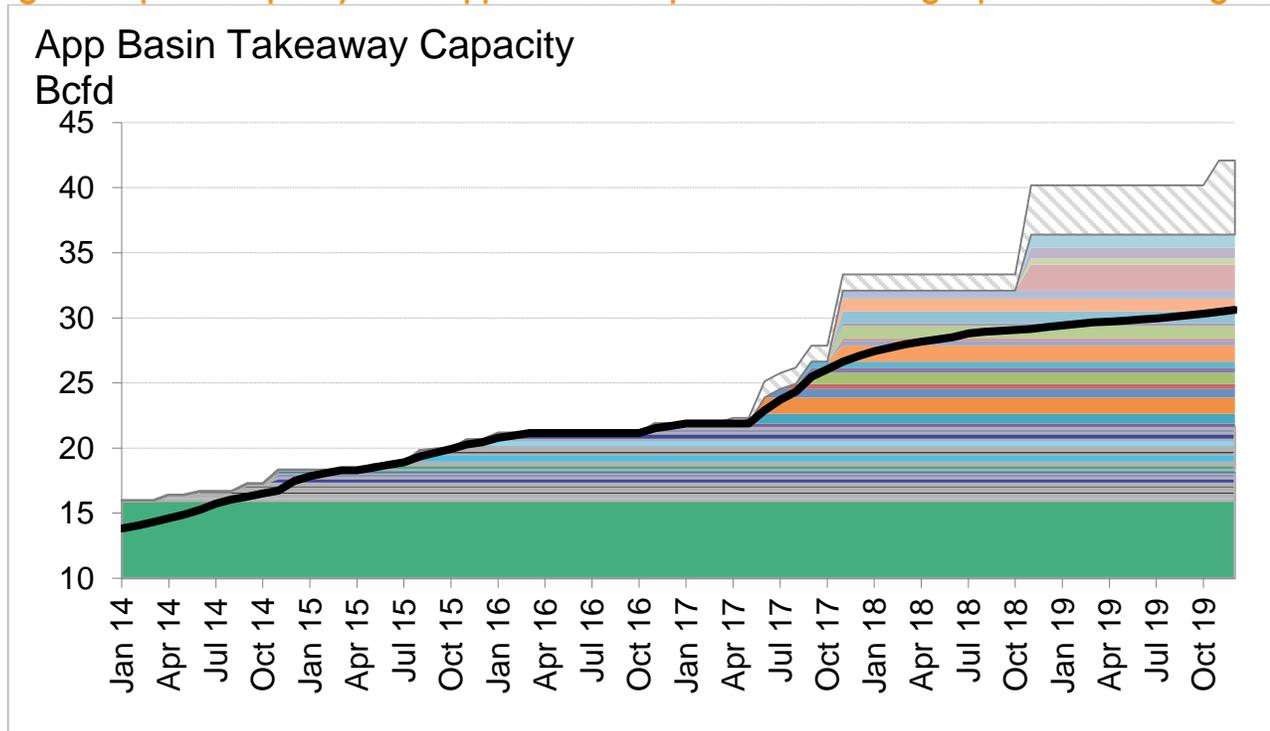
<sup>21</sup> For example, Dominion Virginia Electric and Power has entered into a contract for capacity on the Atlantic Coast Pipeline. That contract contains, embedded in it, a return on equity for the pipeline developer (in which Dominion Resources has an interest). The payments made pursuant to that contract are expenses that Dominion Virginia Electric and Power will be allowed to pass through to its ratepayers, as long as the Virginia State Corporation Commission agrees that those expenses were prudently incurred.

Thus, state regulatory commissions only play a role in approving the initial construction of a pipeline to extent that they are required to approve a regulated utility's decision to enter into a contract with an affiliate that is building the pipeline. The state regulatory commission's role in regulating the cost of natural gas contracts embedded in the rates of utility customers occurs after a pipeline has been constructed and therefore has little impact on the potential for overbuilding pipelines.

## E. The Natural Gas Industry Expects Pipelines to Be Overbuilt

Industry financial dynamics, coupled with favorable federal regulatory treatment, will likely result in excess pipeline capacity being built out of the Marcellus and Utica shale region. **The pipeline capacity being proposed exceeds the amount of natural gas likely to be produced from the Marcellus and Utica formations over the lifetime of the pipelines.** An October 2014 analysis by Moody's Investors Service stated that pipelines in various stages of development will transport an additional 27 billion cubic feet per day from the Marcellus and Utica region. This number dwarfs current production from the Marcellus and Utica (approximately 18 billion cubic feet per day).<sup>22</sup> The following graph from Bloomberg New Energy Finance shows that pipeline capacity out of the Marcellus and Utica will exceed expected production by early 2017.<sup>23</sup>

**Figure 3. Pipeline capacity out of Appalachia is expected to exceed gas production starting in 2017.**



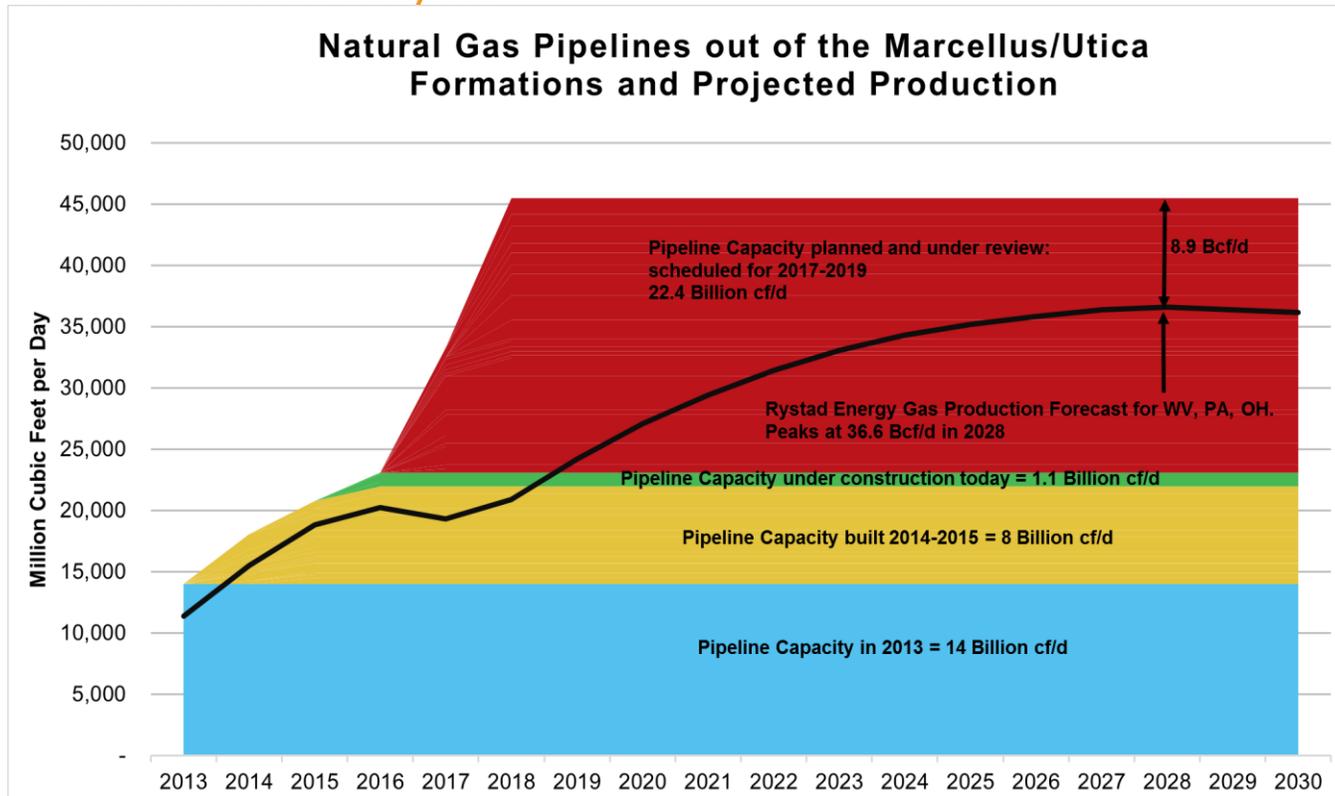
Source: Bloomberg New Energy Finance, 2016. The black line represents expected production and the bars represent planned capacity. Billion cubic feet per day (Bcfd).

<sup>22</sup> U.S. Energy Information Administration, "Utica Region: Drilling Productivity Report," April 2016, and U.S. Energy Information Administration, "Marcellus Region: Drilling Productivity Report," April 2016.

<sup>23</sup> Joanna Wu, "US Gas Insight: Midstream Madness," Bloomberg New Energy Finance, March 8, 2016.

Over the long term, as shown in the following chart from a forthcoming paper by Oil Change International, pipeline capacity is expected to exceed Marcellus and Utica production through 2030, with production peaking around 2028.<sup>24</sup>

**Figure 4. Natural gas pipeline capacity is expected to exceed production through 2030. Production forecast from Rystad.**



Source: Oil Change International, 2016

Industry leaders are well aware that the dynamics of the pipeline industry lend themselves towards overbuilding.

**'The pipeline business will overbuild until the end of time.'**

Kelcy Warren, CEO of Energy Transfer Partners (ETP), said as much in comment last year on the company's second quarter 2015 earnings call: "The pipeline business will overbuild until the end of time. I mean that's what competitive people do."<sup>25</sup> In a subsequent earnings call, he provided the specific example of the Barnett shale in Texas: "There is no question there are certain areas that are overbuilt. For example, we overbuilt in Barnett shale. The production peaked and it's now down."<sup>26</sup> Energy Transfer Partners would know. It is the largest transporter of

<sup>24</sup> Discrepancies between the timing and extent of capacity additions shown in Figures 3 and 4 may be attributable to (a) the fluidity of projects in early stages of development in terms of proposed capacity; and/or (b) differences in attempting to distinguish between pipelines that are expected to add new takeaway capacity versus provide greater connectivity between pipeline networks.

<sup>25</sup> Energy Transfer Partners 2<sup>nd</sup> quarter 2015 earnings call, August 6, 2015.

<sup>26</sup> Energy Transfer Partners 3<sup>rd</sup> quarter 2015 earnings call, November 5, 2015.

natural gas out of the Barnett shale of northeast Texas; ETP's pipeline capacity alone now exceeds the total 2015 natural gas production in the Barnett shale, which is down 24% from its peak in 2012.<sup>27,28</sup>

Southwestern Energy, a driller in the Fayetteville shale of northwest Arkansas and in Appalachia, predicts overbuilt pipeline capacity by 2018.<sup>29</sup> And Elie Atme, vice president for Marketing and Midstream Operations for Range Resources, one of the largest Appalachian shale drillers, has stated that Range expects that "the Appalachian Basin's takeaway capacity will be largely overbuilt by the 2016-2017 timeframe."<sup>30</sup>

In the meantime, existing natural gas pipeline capacity is going underutilized, even as companies propose new pipelines. A 2015 report by the Department of Energy found that from 1998 to 2013, existing pipelines in the U.S. had an average capacity utilization of 54%.<sup>31,32</sup>

As noted in a recent article in American Oil and Gas Reporter, new construction and potential overbuilding of pipelines may lead to existing pipelines losing shippers, "thus creating the irony of unused capacity at the same time new capacity is being constructed."<sup>33</sup>

**"Range expects that 'the Appalachian Basin's takeaway capacity will be largely overbuilt by the 2016-2017 timeframe.'"**

## **F. Risks to Ratepayers, Investors and Communities of Overbuilding Natural Gas Pipelines**

Overbuilding of natural gas pipeline infrastructure poses risks to ratepayers, investors and communities along pipeline routes.

Excluding natural gas destined for export, the rates charged for shipping gas on pipelines are ultimately passed through to the consumers of the gas, largely customers of electric and natural gas utilities. That leaves ratepayers at risk of paying for unnecessary new capacity.

<sup>27</sup> Energy Transfer Partners, "Press Release: Energy Transfer Adds Vital Capacity out of the Barnett Shale," January 8, 2009.

<sup>28</sup> Texas Railroad Commission Production Data Query System, "Texas Barnett Shale Total Natural Gas Production 2000 through 2015," February 22, 2016. Online at: [http://www.rrc.state.tx.us/media/22204/barnettshale\\_totalnaturalgas\\_day.pdf](http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf)

<sup>29</sup> Southwestern Energy 2<sup>nd</sup> quarter 2015 earnings call, July 28, 2015.

<sup>30</sup> Kallanish Energy Daily News & Analysis, "Marcellus-Utica could soon be 'overpiped,'" February 1, 2016.

<sup>31</sup> U.S. Department of Energy, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," February 2015.

<sup>32</sup> Existing pipelines in West Virginia, Virginia and North Carolina are even more underutilized. According to EIA data, average capacity utilization in 2014 for pipelines flowing out of West Virginia was 33%. Utilization of pipelines flowing into Virginia was 23% and, into North Carolina, 37%. (Source: U.S. Energy Information Administration, "International & Interstate Movements of Natural Gas By State," 2016 online at [http://www.eia.gov/dnav/ng/ng\\_move\\_ist\\_a2dcu\\_nus\\_a.htm](http://www.eia.gov/dnav/ng/ng_move_ist_a2dcu_nus_a.htm); U.S. Energy Information Administration, "U.S. State to State Capacity," online at <http://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xls>).

<sup>33</sup> Tom Seng, "Resource Plays Spur Big Infrastructure Rebuild", American Oil and Gas Reporter, August 2013.

Overbuilding creates the risk for investors that a pipeline developer will be unable to renew its contract with shippers after the initial (typically 15- to 20-year) contracts expire. If a pipeline proves to be unnecessary, shippers may not want to renew their contracts. Because pipeline finances are structured so that the costs of the project are recovered over a period longer than the initial contract, investors lose out if the contracts cannot be renewed. This risk is greatly reduced if the shipper is a regulated utility affiliate of the developer.

**“Landowners are at risk from having their land seized and potentially damaged for pipeline projects that are not needed.”**

Additionally, the boom in pipeline development is encouraging companies for whom pipeline development is not their core business to diversify into the sector. This poses its own risks for investors. Whether it is a supplier or utility-driven investment in natural gas pipelines, the companies involved are pursuing higher returns, based presumably on an assessment of their business models that point to a ceiling on the profitability of core business. For these companies, investing in a natural gas pipeline can look like an investment in an area with tightly drawn market adjacencies to their current core businesses, thus minimizing future risk. These investments outside the core can produce returns, but they can also produce pain.<sup>34</sup>

Landowners are at risk from having their land seized and potentially damaged for pipeline projects that are not needed. Additionally, landowners and communities along pipeline routes may be at risk of greater safety problems. As reported in SNL Financial, “the push to build new pipelines to transport abundant shale supplies appears to be having a materially adverse impact on pipeline safety.” Data from the Pipeline Safety Trust shows that pipelines built in the 2010s are failing at a rate similar to the failure rate for pipelines constructed pre-1940 (see figure 5).<sup>35</sup> Though it is not clear the specific reasons for the high failure rate of the new pipelines, this data has led to speculation that the boom in construction of natural gas pipelines has led contractors to cut corners.<sup>36</sup>

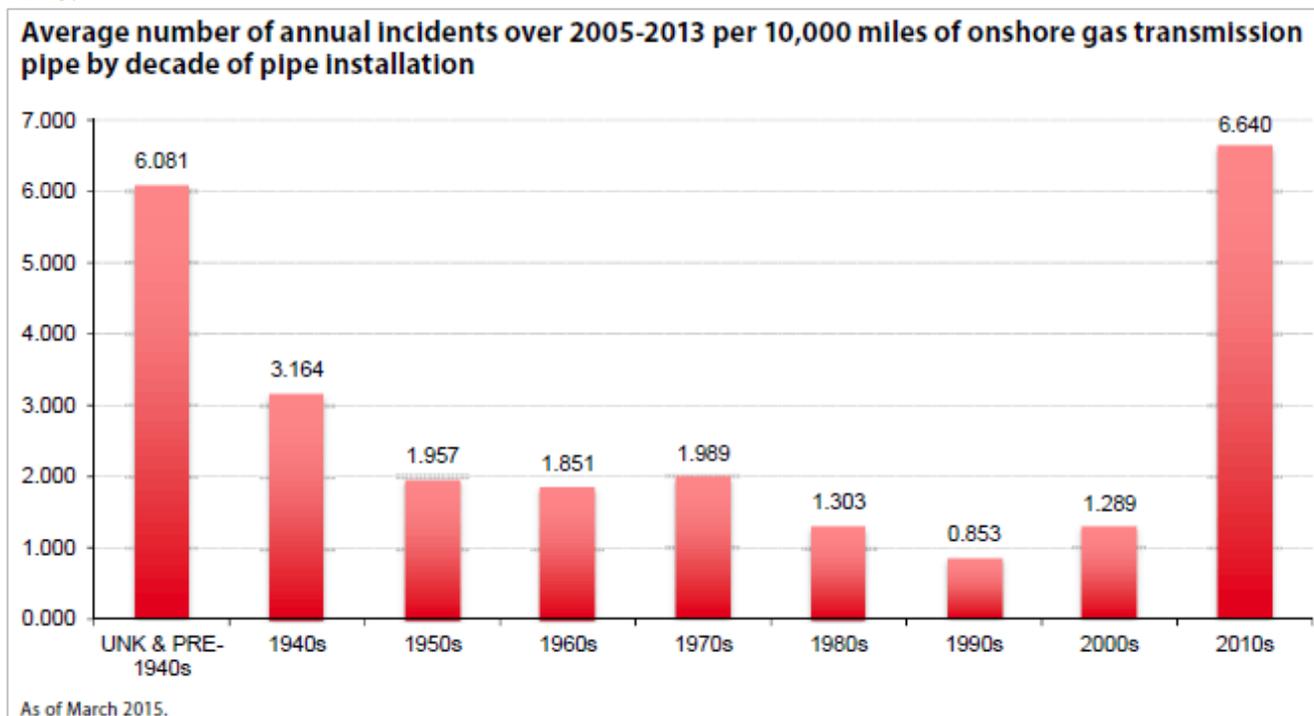
---

<sup>34</sup> For example, FirstEnergy, an Ohio-based utility that owns many coal-fired power plants, bought into the Signal Peak coal mine in Montana in 2008, an investment related to, but outside of, FirstEnergy’s core utility business. Signal Peak was seen as an attractive investment because it could feed FirstEnergy’s own coal fleet and as could sell coal into a growing export market. The investment has since floundered as the coal mining business entered a downturn. FirstEnergy has recently incurred a significant asset impairment on this mine (Source: M. Brown, “Signal Peak Owner Says the Mine is Worth Nothing,” Billings Gazette, February 24, 2016).

<sup>35</sup> S. Smith, “As U.S. rushes to build gas lines, failure rate of new pipes has spiked,” SNL Financial, September 9, 2015.

<sup>36</sup> Ibid.

Figure 5. Pipeline incidents on newly installed pipelines are comparable to those installed pre-1940.



Source: U.S. Pipeline and Hazardous Materials Safety Administration, Pipeline Safety Trust

## PART 2: THE ATLANTIC COAST AND MOUNTAIN VALLEY PIPELINES

One core similarity between the Atlantic Coast Pipeline and the Mountain Valley Pipeline is that they both have been proposed as affiliate transactions, meaning that the majority of the capacity on both of the lines has been reserved by companies that are affiliates of the same companies that are building the lines.

The projects are structured differently, however. Construction of the Atlantic Coast Pipeline is driven by natural gas utilities. Suppliers, not utilities, are driving construction of the Mountain Valley pipeline. This is a difference that raises ratepayer and investor risks that are unique to each project. In particular, IEEFA finds that the utility-driven Atlantic Coast Pipeline places most of the risk on ratepayers, whereas the Mountain Valley Pipeline poses greater risks for investors.

## A. The Atlantic Coast Pipeline

Developers of the proposed 550-mile Atlantic Coast Pipeline propose bringing gas from the Marcellus region of northern West Virginia into Virginia and North Carolina.<sup>37</sup> The pipeline would carry up to 1.5 million dekatherms per day. The pipeline would be developed, owned and operated by a joint venture of Dominion Resources (which has a 45% interest in the venture), Duke Energy (40%), Piedmont Natural Gas Company (10%) and AGL Resources (5%).<sup>38</sup> AGL Resources is the target of a possible acquisition by the Southern Company, a deal which is expected to close in the second half of 2016.<sup>39</sup> Piedmont Natural Gas Company is the target of a pending acquisition by Duke Energy, also expected to close in the second half of 2016.<sup>40</sup> If both acquisitions go through, the ownership stake in the pipeline would be 48% Dominion, 47% Duke and 5% Southern.<sup>41</sup> The pipeline is expected to cost \$5 billion, and developers anticipate putting the project into service in late 2018.<sup>42</sup>

Developers applied to FERC for a certificate of need in October 2015 with 96% of the capacity of the pipeline already subscribed. The contracts for the majority of this capacity are with utility - companies that are subsidiaries of the companies proposing the project. That is, developers of Atlantic Coast justify need for the line based on contracts negotiated with shippers who are affiliates of the same companies building the pipeline. The following table shows the six companies that have contracted to ship gas on the Atlantic Coast Pipeline.<sup>43</sup>



<sup>37</sup> As originally proposed, the Atlantic Coast Pipeline route starts in Harrison County WV, traversing Lewis, Upshur, Randolph and Pocahontas counties in WV; Highland, Augusta, Nelson, Buckingham, Cumberland, Prince Edward, Nottoway, Dinwiddie, Brunswick and Greenville counties in VA; and Northampton, Halifax, Nash, Wilson, Johnston, Sampson, Cumberland and Robeson counties in North Carolina. In February 2016, the developers proposed a revised route for the pipeline after the National Forest Service objected to the original route because of impacts to endangered species. The new route adds Bath County, VA to the list of counties traversed by the pipeline. (Sources: Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1, Exhibit F," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015; X. Mosqueda-Fernandez, "Forest Service staff rejects Atlantic Coast pipeline route," SNL Financial, January 21, 2016; X. Mosqueda-Fernandez, "Atlantic Coast Pipeline forges alternative route with Forest Service," SNL Financial, February 12, 2016).

<sup>38</sup> More specifically, each of these companies has set up subsidiaries to hold their interests in the project. The ownership interests therefore belong to Dominion Atlantic Coast Pipeline, LLC; Duke Energy ACP, LLC; Piedmont ACP Company, LLC; and Maple Enterprise Holdings, Inc., a subsidiary of AGL.

<sup>39</sup> "Southern Company acquires AGL Resources Inc.: Deal Profile," SNL Financial, last accessed April 12, 2016.

<sup>40</sup> D. Sweeney, "In NC merger application, Duke Energy, Piedmont outline benefits of combined company," SNL Financial, January 19, 2016.

<sup>41</sup> J. Dumoulin-Smith, M. Weinstein and P. Zimbaro, "Dominion Resources: A Plainer Dominion," UBS Global Research, January 29, 2016.

<sup>42</sup> X. Mosqueda-Fernandez, "Atlantic Coast Pipeline forges alternative route with Forest Service," SNL Financial, February 12, 2016.

<sup>43</sup> Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-11.

**Table 1. Utilities contracted to ship gas on the Atlantic Coast Pipeline. All but Public Service Company of North Carolina are subsidiaries of companies involved in developing the pipeline.**

Utility	Parent	Contracted capacity (dekatherms/day)
Virginia Power Services	Dominion	300,000
Duke Energy Progress	Duke	452,750
Duke Energy Carolinas	Duke	272,250
Piedmont	Piedmont Natural Gas	160,000
Public Service Company of North Carolina	SCANA Corporation	100,000
Virginia Natural Gas	AGL Resources	155,000

According to Atlantic Coast's application to FERC, a large portion of the gas (79%) that would be shipped through the pipeline would be destined for power generation in Virginia and North Carolina.<sup>44</sup> Of this amount, 86% would go to Duke and Dominion.<sup>45</sup>

The extent to which Dominion needs this new pipeline capacity to deliver natural gas to planned and proposed new natural gas plants in Virginia is questionable. The application to FERC cites the need for natural gas to supply Dominion's new Brunswick natural gas plant (currently under construction) and its planned Greenville natural gas plant. Both plants have received approval from the Virginia State Corporation Commission. In seeking approval for the Brunswick plant, Dominion represented that the plant would have a contract for firm natural gas supply from Transcontinental Gas Pipe Line Company ("Transco"), which was to construct nearly 100 miles of new pipeline to connect to the Brunswick Plant.<sup>46</sup> This pipeline was completed and placed into service in September 2015.<sup>47</sup> Similarly, for the Greenville plant, Dominion represented that the plant "will be fueled using 250,000 Dth per day of natural gas with reliable firm transportation provided by Transcontinental Gas Pipe Line Company, LLC" though it also noted that Greenville "will also have access to" Atlantic Coast.<sup>48</sup> The Transco pipeline is expected to be placed into service by December 2017.<sup>49</sup> Thus, in its applications to the Virginia State Corporation Commission, Dominion has represented that the Brunswick and Greenville plants will be supplied with natural gas from Transco. The Virginia State Corporation

<sup>44</sup> The remainder will be used for natural gas heating, industrial uses and commercial uses such as vehicle fuel. (Source: Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-5.)

<sup>45</sup> Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-12.

<sup>46</sup> State Corporation Commission of Virginia, Case No. PUE-2012-00128, "Application of Virginia Electric and Power Company for approval and certification of the proposed Brunswick County Power Station electric generation and related transmission facilities under §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider BW, under § 56-585.1 A 6 of the Code of Virginia," November 2, 2012.

<sup>47</sup> Williams, "Press release: Williams' Transco Completes Virginia Southside Expansion," September 1, 2015, online at: <http://investor.williams.com/press-release/williams/williams-transco-completes-virginia-southside-expansion>.

<sup>48</sup> State Corporation Commission of Virginia, Case No. PUE-2015-00075, "Application of Virginia Electric and Power Company for approval and certification of the proposed Greenville County Power Station and related transmission facilities pursuant to §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider GV, pursuant to § 56-585.1 A 6 of the Code of Virginia," July 1, 2015.

<sup>49</sup> Williams, "Virginia Southside Expansion Project II," online at <http://co.williams.com/expansionprojects/virginia-southside-expansion-project-ii/>, last accessed April 13, 2016.

Commission has already approved construction of both gas plants without requiring any additional natural gas contracts.

The Atlantic Coast pipeline could be used as a back-up gas supply for Dominion's Brunswick and Greenville plants. Contracting for some amount of redundant natural gas supply may be prudent. But the Virginia State Corporation Commission approved the plants without any discussion of need for a redundant pipeline.<sup>50</sup> The question of how much redundant supply might be prudent is not likely to be addressed when FERC considers the need for the Atlantic Coast pipeline.

Moreover, Dominion's most recent integrated resource plan, which lays out its long-term plan for electricity supply, does not provide a clear vision for Dominion's natural gas expansion plans. The IRP describes four scenarios that are compliant with the Clean Power Plan; these scenarios vary substantially in the amount of new natural gas generation called for. The least gas-intensive scenario calls for building one additional 1,585 MW natural gas baseload combined cycle power plant in 2022 and two 457 MW natural gas peaking plants by 2030. The most gas-intensive scenario calls for building two 1,585 MW baseload plants, three 457 MW peaking plants and repowering several existing plants with natural gas. The IRP does not express a preference between these scenarios.<sup>51</sup>

While Duke and Dominion are required to file integrated resource plans showing their detailed natural gas capacity expansion plans with state regulators in Virginia and North Carolina, these plans have not been filed with FERC. Thus, FERC will not be able to scrutinize these plans in assessing the need for the Atlantic Coast Pipeline.

## ***Risks to Ratepayers***

Ratepayers—specifically the customers of Dominion Virginia Power, Piedmont, Virginia Natural Gas, Public Service Company of North Carolina, Duke Energy Progress and Duke Energy Carolinas—are on the hook for 96% of the project's costs through the rates that they are charged to ship gas on the pipeline.

These ratepayers will bear the following risks.

One is that the Atlantic Coast pipeline would go underutilized. As described above, it is not clear that the utilities that have contracted to ship gas on the pipeline actually need all of the gas that they are contracted to purchase. The utilities have the option to sell the capacity that they're not using on the secondary market and crediting this money back to ratepayers. If the excess capacity cannot be sold, ratepayers will pay for the capacity that their utilities are under contract to purchase. If the excess capacity can be sold, ratepayers still bear the risk that the price received for this capacity is less than what they are paying for it.

---

<sup>50</sup> State Corporation Commission of Virginia, "Final Order," Case No. PUE-2012-00128, August 2, 2013.

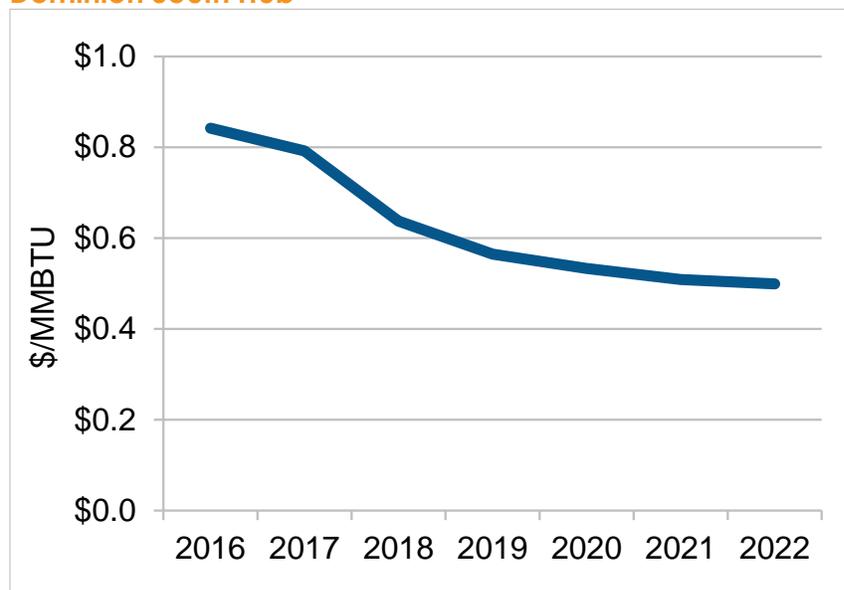
<sup>51</sup> Dominion, Integrated Resource Plan, as filed with the Virginia State Corporation Commission and the North Carolina Utilities Commission, July 1, 2015, pp. 5-8.

Ratepayers are also at risk that natural gas prices from the Marcellus and Utica region will not continue to be significantly cheaper than Henry Hub prices. Part of the supposed rationale for building the Atlantic Coast Pipeline is that ratepayers will benefit from a cheap supply of natural gas from the Marcellus and Utica region. But ratepayers would benefit only if the cost advantage of sourcing gas from the Marcellus/Utica outweighs the cost to ratepayers of building the pipeline. While a study conducted on behalf of the developers by ICF International to justify the economic benefits of the pipeline does not provide a forecast of future natural gas prices from the Marcellus region, it does assert that Marcellus/Utica natural gas will continue to be \$1-\$1.75/MMBTU cheaper than natural gas from the Henry Hub through 2035, which would mean that the Atlantic Coast pipeline would generate savings for ratepayers over the lifetime of the pipeline. However, ICF's projection of a widening spread between Henry Hub and Marcellus/Utica gas (at the Dominion South Hub) contradicts current market expectations. ICF projects the price difference between the Dominion South Hub and the Henry Hub narrowing to about \$0.50/MMBTU by 2018 but then steadily increasing to about \$1/MMBTU by 2022 and \$2/MMBTU by 2028.<sup>52</sup> By contrast, current market expectations, as revealed by futures prices, project the spread between the two hubs steadily narrowing to \$0.50/MMBTU by 2022.

**“Ratepayers—specifically the customers of Dominion Virginia Power, Piedmont, Virginia Natural Gas, Public Service Company of North Carolina, Duke Energy Progress and Duke Energy Carolinas—are on the hook for 96% of the project’s costs”**

As more pipelines are built out of the Marcellus and Utica region, the excess pipeline capacity will further narrow the price differential between the hubs. That is, as natural gas pipeline capacity increases to meet or exceed the glut of natural gas supply, natural gas prices in the Marcellus should rise. A January 2016 article in Midstream Business noted that “new Marcellus Shale regional pipelines are beginning to pressure Henry Hub prices, sapping differentials in gas value as more of the area’s production escapes regional lockdown” (emphasis added).<sup>53</sup>

**Figure 6. Projected price difference between Henry Hub and Dominion South Hub\***



\*based on OTC Global Holding futures prices retrieved 2/26/16

<sup>52</sup> ICF International, “The Economic Impacts of the Atlantic Coast Pipeline,” February 9, 2015

<sup>53</sup> Darren Barbee, “Contents Under Pressure: New Pipelines Ease Marcellus Takeaway Troubles,” Midstream Business, January 12, 2016.

It is clear that the current low natural gas prices in the Marcellus and Utica are not sustainable for drillers, a factor that will likely drive Marcellus and Utica gas prices higher over the long term, likely reducing the price differential with the Henry Hub and affecting ratepayers who are on the hook for shipping contracts for the next 20 years. Many of the companies with the greatest production in Appalachia operated at a loss in 2015. Of the top 10 Appalachian drilling companies, only two (EQT and Antero) posted positive net income in 2015.<sup>54</sup> Chesapeake Energy, the largest Appalachian driller, is widely expected to go bankrupt (though the company is currently denying that it will file for bankruptcy).

In response to continued low prices, drillers have cut back on capital expenditures. Capital expenditures by the top eight Appalachian shale drillers in the fourth quarter of 2015 were 54% lower than in the fourth quarter of 2014. And capital expenditures for the first quarter of 2016 are expected to be 49% lower than in the first quarter of 2015.<sup>55</sup> This reduction in capital expenditures is reflected in production volumes; according to the most recent figures from the Energy Information Administration, production growth has slowed over the past several months and a decline is projected from February to April 2016.<sup>56</sup>

Low oil prices since late 2014 have also hurt many Appalachian drillers who had previously been able to use profitable wet gas drilling operations to prop up less profitable dry gas drilling. Low oil prices have driven down prices for natural gas liquids, making wet gas drilling less profitable.<sup>57</sup>

In spring 2016, banks will be re-determining the revolving credit lines for many shale gas drillers. They are widely expected to cut back on lending.<sup>58</sup>

It is all but certain that the instability and financial problems brought about by current low natural gas prices will drive some of the shale gas drilling companies into bankruptcies. According to JP Morgan there have been 48 bankruptcies in the oil and gas exploration and production sector since 2014,<sup>59</sup> and further bankruptcies are expected in 2016.

Production will be scaled back and prices will stabilize at a higher level. It is not clear over what timeframe this will occur, though natural gas prices are generally expected to remain low at least through 2016. According to Standard & Poor's, "commodity prices will remain low in 2016, impeding cash flows and increasing the risk for negative rating and outlook actions as leverage measures and liquidity continue deteriorating."<sup>60</sup>

While most analysts are not projecting a near-term rise in gas prices (and futures prices show Dominion South Hub prices remaining below \$2.50 per MMBTU through 2022), shale drillers cannot continue to produce below cost indefinitely. In the longer term (10-15 years), it is likely that Marcellus and Utica gas prices will stabilize at a somewhat higher level. These longer-term prices will have a significant impact on the long-term economics of the Atlantic Coast Pipeline, which is designed as a 40-year project.

---

<sup>54</sup> List of top 10 Appalachian drillers from B. Holland, "Appalachian drillers vow to slow down after brutal Q3," SNL Financial, November 12, 2015. Net incomes obtained from individual company 2015 Form 10-K Securities and Exchange Commission filings.

<sup>55</sup> B. Holland, "Billions evaporate from gas industry as Northeast drillers gut spending," SNL Financial, January 8, 2016.

<sup>56</sup> Energy Information Administration, "Drilling Productivity Report: Report Data," March 7, 2016. <https://www.eia.gov/petroleum/drilling/xls/dpr-data.xlsx>

<sup>57</sup> X. Mosqueda-Fernandez, "NGL projects could struggle under low crude price future," SNL Financial, June 17, 2015.

<sup>58</sup> B. Holland, "JP Morgan clamping down on oil, gas clients, expects more bankruptcies," SNL Financial, February 24, 2016.

<sup>59</sup> Ibid.

<sup>60</sup> B. Holland, "Lack of oil, gas hedging could lead drillers to spring defaults, S&P warns," SNL Financial, December 21, 2015.

Thus, ratepayers run the risk of paying higher than expected natural gas prices for gas delivered on the Atlantic Coast pipeline as the difference between Marcellus and Henry Hub natural gas prices narrows.

Ratepayers also bear risks associated with delays in project construction. It is not clear how much of the risk of project delay would be borne by ratepayers versus investors in the project. According to Atlantic Coast's application to FERC, "in an agreed-upon risk sharing agreement, the negotiated rates would be decreased by specified amounts for certain delays in the Project in-service date."<sup>61</sup> The developers offer no further detail on how the risk of delay would be shared among project investors and ratepayers. Given that the negotiated rates were negotiated between affiliated companies, it seems likely that the burden of the risk would be placed on ratepayers, not project investors.

Ratepayers may also bear some risk of construction cost overruns. Dominion has noted that the terrain that the Atlantic Coast pipeline will traverse accentuates the risk of construction cost overruns and delays: "The large diameter of the pipeline and difficult terrain of certain portions of the proposed pipeline route aggravate the typical construction risks with which DTI [Dominion Transmission Inc] is familiar. In-service delays could lead to cost overruns and potential customer termination rights."<sup>62</sup>

Atlantic Coast pipeline's application to FERC provides no additional detail on these "potential customer termination rights." It is not clear whether customers would be able to terminate their contracts and walk away with the project without any losses, or whether they would still end up paying for a portion of the project if their contract is terminated.

Finally, ratepayers face the risk of future regulation of greenhouse gas emissions. The Atlantic Coast Pipeline is designed to recover its construction costs from ratepayers over a 40-year period, i.e. through 2058. It is reasonable to expect significant policies requiring reductions in greenhouse gas emissions by then, changes that will constrain the use of natural gas.

## **Risks to Investors**

Generally speaking, the Atlantic Coast pipeline does not appear to be particularly risky to investors. The pipeline will be paid for through shipping rates paid by financially stable, regulated utilities with captive customers.

Nevertheless, there are still investor risks.

First is that a state utilities commission (either the North Carolina Utilities Commission or the Virginia State Corporation Commission) will disallow some of the costs of the pipeline from being passed through to ratepayers based on a decision that the costs were imprudently incurred. Such a decision would likely be predicated on a conclusion that the utility had contracted for more capacity than it needs, based on what was known about future natural gas demand at the time the contract was entered into.

Investors also face the risk of delays or construction cost overruns that cause shippers to back out of the project or to receive lower rates. As described in the previous section, delays and

---

<sup>61</sup> Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 32.

<sup>62</sup> Dominion Resources, 2014 Form 10K, p. 26.

cost overruns could trigger shippers to pull out of the project, though it is not clear what level of delay or cost overrun would be required to allow a shipper to terminate its contract. Furthermore, developers of the Atlantic Coast project have apparently agreed to lower negotiated rates if the project is delayed by a certain amount though, again, there are no details on these agreements. Given that these contracts are largely between affiliated entities, it seems reasonable to assume that the risks of delay and cost overruns will be borne more by ratepayers than by investors.

Investors are also at risk that the pipeline owners would not be able to renew shipping contracts after 20 years. The contracts that Atlantic Coast has signed with shippers are all 20-year contracts. Yet the rates charged in these contracts are designed to recover the costs of the constructing the pipeline over a 40-year period.<sup>63</sup> Thus, Atlantic Coast is banking on its ability to renew shipping contracts in order to fully recover the costs of building the pipeline. The risk of not being able to renew these contracts is, in theory, borne by the project's investors. However, given that almost all of Atlantic Coast's shipping contracts are with affiliates, there will be strong pressure on the regulated utilities to renew the contracts. IEEFA therefore views this as a minimal risk to investors.

## B. Mountain Valley Pipeline

The Mountain Valley Pipeline is a proposed 300-mile pipeline that originates in West Virginia and terminates in Virginia.<sup>64</sup> The Mountain Valley Pipeline would carry up to 2 million dekatherms per day. It is a joint venture of EQT Midstream (45.5% ownership interest), NextEra Energy (31%), Con Edison (12.5%), WGL Holdings (7%), Vega Energy Partners (3%) and RGC Resources (1%) and will be operated by a subsidiary of EQT.<sup>65</sup> The pipeline is expected to cost \$3.7 billion and to go into service in the fourth quarter of 2018.<sup>66</sup>

All of the capacity on the Mountain Valley Pipeline has been reserved by shippers. The companies that have entered into shipper contracts are EQT (64.5%), Consolidated Edison (12.5%), USG Properties Marcellus Holdings, a subsidiary of NextEra (12.5%), WGL Midstream (10%) and Roanoke Gas (0.5%). EQT and USG Properties Marcellus Holdings, which together have contracted for 77% of the capacity of the pipeline, are natural gas supply companies.

The Mountain Valley Pipeline is very different from the Atlantic Coast Pipeline in that it is a supplier-driven pipeline, rather than a customer-driven pipeline. That is, the entities that have entered into long-term contracts for the majority of the capacity on the Mountain Valley Pipeline are producers of natural gas.

As shown in the following table, the entities that have entered into contracts for capacity on the Mountain Valley Pipeline are all affiliates of the companies that are partners in the joint

---

<sup>63</sup> Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1, Exhibit P," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015

<sup>64</sup> The proposed route starts in Wetzel County and traverses Harrison, Doddridge, Lewis, Braxton, Webster, Nicholas, Greenbrier, Summers and Monroe counties in WV; and Giles, Craig, Montgomery, Roanoke, Franklin and Pittsylvania counties in VA. The pipeline route terminates at an intersection with the Transco line, a pipeline owned by Williams Corporation that is a backbone of the East Coast natural gas transmission system, connecting the Gulf Coast to New York. (Source: Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit F," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015.)

<sup>65</sup> Mountain Valley Pipeline, "Frequently Asked Questions," <http://mountainvalleypipeline.info/faqs/>, last accessed April 12, 2016.

<sup>66</sup> S. Sullivan, "Mountain Valley applies to FERC for 2-Bcf/d gas pipeline," SNL Financial, October 23, 2015.

venture. The pipeline is fully subscribed. EQT is, by far, the largest shipper, as well as being the dominant partner in the joint venture to build the pipeline.

**Table 2. All of the shippers on the Mountain Valley Pipeline are affiliates of companies involved in developing the project.**

Pipeline owner	Ownership interest	Shipper	Capacity contracted (dekatherms/day)	Capacity contracted (%)
EQT Midstream Partners, LP	45.5%	EQT Energy, LLC	1,290,000	64.5%
NextEra Energy US Gas Assets, LLC	31%	USG Properties Marcellus Holdings, LLC	250,000	12.5%
Con Edison Gas Midstream, LLC	12.5%	Consolidated Edison Company of New York	250,000	12.5%
WGL Midstream, Inc.	7%	WGL Midstream, Inc.	200,000	10%
Vega Midstream MVP LLC	3%			
RGC Midstream LLC	1%	Roanoke Gas Company	10,000	0.5%

Investors in the Mountain Valley Pipeline are at greater risk of being harmed by financial problems with the shippers than investors in the Atlantic Coast Pipeline are because natural gas producers are much less financially stable than regulated utilities. According to Moody's Investor Services, the long-term credit rating of EQT is Baa3 (the lowest investment-grade credit rating), whereas the largest shippers on the Atlantic Coast pipeline have credit ratings of A1 (Duke Energy Carolinas) and A2 (Duke Energy Progress and Dominion Virginia Electric and Power Company).

In recent months, investors have grown increasingly aware of the risks of supplier-driven pipelines, like the Mountain Valley Pipeline, because of the weak financial position of many shale drilling companies. As described by SNL Financial:

“Firm transportation contracts with counterparties that have credit ratings below investment grade, such as Chesapeake Energy Corp., have the potential to disrupt operators if the shippers cannot keep up with reservation payments for the duration of the contracts.

As oil and gas prices remain depressed, exploration and production companies have continued to watch their valuations fall. These upstream problems may work their way down the value chain, putting previously stable revenue for midstream companies at risk as their contract counterparties look to renegotiate pricing, or in some instances, file for bankruptcy. Pipelines with higher proportions of volume contracted with these companies are more exposed to these effects.”<sup>67</sup>

Two pending bankruptcy proceedings are raising the issue of whether drillers' contracts with pipelines are likely to be honored if the drillers go bankrupt. In its pending bankruptcy

<sup>67</sup> M. Bearden, “Exploring interstate pipeline exposure to lower-rated E&Ps,” SNL Financial, February 18, 2016.

proceeding, Sabine Oil & Gas successfully terminated its contracts with natural gas pipeline companies for gathering and processing natural gas.<sup>68</sup> Quicksilver Resources, also in bankruptcy, is following suit, seeking to terminate its contracts for gathering and processing.<sup>69</sup> Similarly, while Chesapeake Energy – the largest company drilling in the Marcellus shale—has denied plans to file for bankruptcy,<sup>70</sup> it is experiencing serious financial troubles and a bankruptcy would potentially jeopardize its payments to pipeline companies with which it is contracted to ship gas.

In the case of the Mountain Valley Pipeline, the financial health of EQT is critical to how the project moves forward. EQT is a major shale gas drilling company whose operations are concentrated in the Marcellus and Utica shale region (78% of its proved reserves are in the Marcellus).<sup>71</sup> As described in the previous section, the shale drilling sector in general is in turmoil because of prolonged low natural gas prices. While EQT is positioned better than many other major Appalachian shale drillers (it was one of only two of the top ten Appalachian drillers to post positive net income in 2015, for example), it is still not immune to the effects of low prices. EQT's stock price has fallen 26% since January 2014, a period in which the Dow Jones Industrial Average has increased 8%.<sup>72</sup> Its long-term credit ratings from S&P, Moody's and Fitch are all one notch above junk status.<sup>73</sup> Additionally, as of December 2015, EQT had only 37% of its production hedged for 2016, lower than Antero, Range and several other major Appalachian drillers.<sup>74</sup>

**“Two pending bankruptcy proceedings are raising the issue of whether drillers’ contracts with pipelines are likely to be honored if the drillers go bankrupt.”**

EQT has had negative free cash flow for the past nine years, meaning that the cash generated from drilling operations is not sufficient to finance the ongoing capital expenditures of the company. While it is standard industry practice to rely upon equity and debt cash infusions during a period of growth, this is done with the expectation that project returns will occur over a longer period and cash flow will flip from negative to positive as projects start generating returns. EQT's long period of negative free cash flow reflects a decision to continue investing in the drilling business despite the poor short-term future outlook. In a time when many companies are facing distressed financial scenarios, a nine-year negative free cash flow raises the company's risk profile. EQT's situation appears to be worsening, with free cash flow declining from -\$450 million in 2013 to -\$1,217 million in 2015.

EQT's business outlook remains focused on growth and, so far, investors have been willing to continue investing in EQT. Despite low prices, EQT's natural gas production volume increased 27% in 2015 over 2014.<sup>75</sup> Part of EQT's growth strategy has been to grow its pipeline business, a less risky line of business than natural gas drilling. EQT launched the master limited partnership EQT Midstream in 2012. EQT has sold pipeline assets to EQT Midstream to raise cash, and EQT Midstream has raised money through public offerings. In 2015, for example, EQT raised \$1.1

<sup>68</sup> B. Holland, “E&P bankruptcy ruling brings clouds for midstream and a ‘kind of silver lining,” SNL Financial, March 9, 2016.

<sup>69</sup> N. Amarnath, “More trouble for midstream MLPs as struggling producers seek to ditch contracts,” SNL Financial, February 9, 2016.

<sup>70</sup> M. Passwaters, “Chesapeake says it is not seeking bankruptcy as shares plummet,” SNL Financial, February 8, 2016.

<sup>71</sup> EQT, 2015 Form 10-K, page 10.

<sup>72</sup> SNL Financial, “EQT Corporate Profile,” retrieved April 17, 2016.

<sup>73</sup> Baa3 from Moody's, BBB from S&P and BBB- from Fitch. (Source: SNL Financial)

<sup>74</sup> B. Holland, “Lack of oil, gas hedging could lead drillers to spring defaults, S&P warns,” SNL Financial, December 21, 2015.

<sup>75</sup> EQT, 4Q 2015 earnings call transcript, February 4, 2016.

billion from sales of assets to EQT Midstream, and EQT Midstream was able to raise \$1.2 billion through public offerings.<sup>76</sup> The Mountain Valley Pipeline represents a major area of growth for EQT Midstream.

In part because of its infusions of cash from EQT Midstream, EQT would be in a strong position to be able to buy up the assets of other natural gas drillers who are in financial distress due to low natural gas prices. EQT's basic business strategy is to continue growing and hope that it will be well-positioned to take advantage of higher natural gas prices in the future.

The key question, of course, is how long natural gas prices will stay low. The longer they do, the riskier EQT's business strategy becomes. Natural gas prices at the Dominion South Hub averaged \$1.50/MMBTU in 2015 and futures prices project prices falling further to \$1.22/MMBTU in 2016, before rising to \$1.70 in 2017 and \$1.93 in 2018. Fitch has estimated that the average cost of production in the Marcellus shale is \$2.50, implying that futures prices for the next few years are expected to be below the average cost of gas production.<sup>77</sup> As noted in a recent article in SNL Financial, "Most independent gas drillers have finally resigned themselves to low prices indefinitely (the highest price on the NYMEX gas futures strip is \$4.611/MMBtu all the way at the end, December 2028) and are now in a race to wrangle their expenses inside their cash flow before they default."<sup>78</sup>

Even if EQT is better positioned to withstand continued low natural gas prices than other Appalachian drillers, it would be adversely affected by the bankruptcies that are widely expected in the sector, which will likely drive capital out of the entire drilling sector.

## **Risks to Investors**

In addition to the fundamental risk posed by EQT's weak financial condition, other risks to investors include the risk that the pipeline owners will be unable to renew shipping contracts after 20 years. As with the Atlantic Coast pipeline, the rates for the Mountain Valley Pipeline are designed to recover the costs of the pipeline over 40 years, which is longer than the length of the initial shipping contracts.<sup>79</sup> Pipeline investors bear the risk that Mountain Valley will not be able to renew its shipping contracts after 20 years or that it will not be able to renew them with as favorable terms.

This risk is compounded by the risk that greenhouse gas regulations imposed over the next 20 years will restrict the use of natural gas.

Investors also may be vulnerable to cost-overrun risks. Mountain Valley's shipping contracts includes a provision for adjusting the negotiated rates if the actual construction cost differs from the estimated cost, but the nature of this adjustment is not publicly available.<sup>80</sup>

---

<sup>76</sup> EQT Form 10-K, February 11, 2016, pp. 78-79.

<sup>77</sup> B. Holland, "Fitch warns Marcellus prices fail to cover costs as Pa. cash hubs drop below \$1," SNL Financial, November 2, 2015.

<sup>78</sup> B. Holland, "Gas world faces reckoning of drillers' 'growth at the expense of profit'," SNL Financial, December 28, 2015.

<sup>79</sup> Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 38.

<sup>80</sup> Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit I," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 160.

## ***Risks to Communities***

Communities and landowners along the pipeline route also bear risks that stem from EQT's financial weakness. EQT does not appear to be a stable, long-term partner for these communities.

EQT's weakened financial position suggests it will adopt only a limited commitment to communities or perhaps be forced to sell its ownership interests to a new company that is not part of current deliberations. Natural gas pipelines are not just long-term investments between companies and investors, they are long-term partnerships between the companies and their host communities. Company culture matters.

Another risk to communities directly affected by the proposed project: Pipeline safety problems are on the rise, as documented in Figure 5, and how a company perceives such risk, monitors for it, seeks to prevent it, and communicates about it to affected communities is paramount. Closely related to this risk are those that stem from a company's land management and reclamation activities. Companies involved in positive corporate citizenship buy locally to stimulate local businesses, hire locally, and invest locally in new businesses and community projects.

## ***Risks to Ratepayers***

The clearest risks to ratepayers from the Mountain Valley Pipeline are the risks to the customers of the regulated utilities that have contracted as shippers on the pipeline. These are Consolidated Edison and Roanoke Gas.

The risks to ratepayers on the Mountain Valley Pipeline are similar to those posed by the Atlantic Coast Pipeline.

These include the risk of project delay. According to the contracts that have been signed by shippers on the Mountain Valley pipeline, a shipper may terminate its contract if the pipeline has not been placed into service by June 1, 2020, but it is still required to pay its share of the expenses incurred to that date, plus fifteen percent unless the developer can re-sell the shipper's capacity to a third party. In other words, ratepayers may be on the hook for a share of construction costs even if the utilities ultimately pull out of the project.<sup>81</sup>

Ratepayers are at risk that natural gas prices from the Marcellus shale will not turn out to be substantially lower than Henry Hub prices over the long term. Customers of the regulated utilities that have contracted to ship gas on the Mountain Valley Pipeline will pay for their share of the construction cost of the pipeline through their rates. If the expense of the pipeline outweighs the savings from access to a lower-cost supply of natural gas, then this cost will be borne by ratepayers.

Finally, the potential for greenhouse gas regulations poses a ratepayer risk. As with the Atlantic Coast pipeline, it is likely that ratepayers will bear the cost of their utilities' share of the stranded capacity on the Mountain Valley pipeline if and when greenhouse gas emissions regulations restrict the use of natural gas.

---

<sup>81</sup> Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit I," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 166.

# RECOMMENDATIONS

## **To limit the potential for overbuild pipeline capacity out of the Marcellus and Utica region, IEEFA recommends:**

- The establishment of a comprehensive planning process for natural gas pipeline development. FERC's current practice of considering the need for projects on an individual basis is insufficient.
- Lower returns on pipeline development. The returns on equity embedded in recourse rates for new interstate natural gas pipelines exceed authorized returns for state-regulated electric utilities and federally regulated electric transmission lines. This is especially egregious given that the growing trend of transactions between regulated utilities and affiliated pipeline developers tends to shift risk from utility shareholders to ratepayers. FERC should lower the returns it allows on equity for pipeline development.
- An investigation into the safety of new pipelines with a focus on the relatively high failure rate of newly installed pipelines.

## **Additionally, with regard to the Atlantic Coast Pipeline, IEEFA recommends that:**

- The Virginia State Corporation Commission closely examine the prudence of contracts signed by regulated utilities to ship gas on a pipeline owned by affiliated companies.
- FERC consider information presented to state regulators by Duke and Dominion in integrated resource plans and in certificate applications regarding their planned buildout of regional natural gas power generation.

## **Finally, IEEFA recommends that:**

- FERC acknowledge that it lacks sufficient evidence to evaluate the need for the Atlantic Coast and Mountain Valley Pipelines and that applications for those project be suspended until such time that an appropriate regional planning process is developed.
- FERC should recognize that pipelines are being proposed with different corporate structures that involve very different risk profiles. In assessing supplier-driven pipelines, FERC should assess industry trends and the short and long term financial condition of companies along the chain (with careful attention paid to leverage and free cash flow). FERC could also consider a range of recourse rates that would reflect different risks.

# CONCLUSION

Natural gas pipeline infrastructure out of the Marcellus and Utica region of Appalachia will probably become overbuilt within the next several years, an outcome recognized by many in the industry itself. The economic and financial factors that incentivize companies to invest in the development of new natural gas pipelines—from drilling companies that seek to diversify into a sector with more stable income to traditional pipeline companies angling to build larger and better-connected networks—will not produce a socially rational outcome. Without a coordinated approach to natural gas pipeline planning, as exists for many other types of infrastructure, the Federal Energy Regulatory Commission cannot make an honest determination of the need for these pipelines. Ratepayers and communities will shoulder much of the costs and risks of the Atlantic Coast and Mountain Valley pipelines, investments of nearly \$9 billion that are poised for approval without adequate scrutiny.

## About the Authors

**Cathy Kunkel, Energy Analyst**, is an independent West Virginia-based consultant focusing on energy efficiency and utility regulation. She has testified on multiple occasions before the West Virginia Public Service Commission for the nonprofit coalition Energy Efficient West Virginia. She has done graduate work for the Energy and Resources Group at the University of California-Berkeley and is a former senior research associate at Lawrence Berkeley National Laboratory. Kunkel has an undergraduate degree in physics from Princeton University and graduate degree in physics from Cambridge University.

**Tom Sanzillo, director of finance for IEEFA**, is the author of several studies on coal plants, rate impacts, credit analyses, and public and private financial structures for the coal industry. He has testified as an expert witness, taught energy-industry finance training sessions, and is quoted frequently by the media. Sanzillo has 17 years of experience with the City and the State of New York in various senior financial and policy management positions. He is a former first deputy comptroller for the State of New York, where he oversaw the finances of 1,300 units of local government, the annual management of 44,000 government contracts, and where he had oversight of over \$200 billion in state and local municipal bond programs and a \$156 billion pension fund. Sanzillo recently contributed a chapter to the Oxford Handbook of New York State Government and Politics on the New York State Comptroller's Office.

## **APPENDIX: QUESTIONS ABOUT THE RISKS OF THE ATLANTIC COAST AND MOUNTAIN VALLEY PIPELINES**

Many details about the Atlantic Coast and Mountain Valley pipelines have not yet come to light in the FERC application process. These details may never come to light through that process because they are not necessarily issues that FERC prioritizes in deciding on the “need” for a pipeline. Nevertheless these are questions that need to be answered if there is to be appropriate public scrutiny over whether these pipelines are worth the risks.

### **A. Questions regarding the Atlantic Coast Pipeline:**

- Why are ratepayers being asked to pay for redundant natural gas supply for Dominion Virginia Electric and Power's Brunswick and Greensville natural gas plants?
- Which specific proposed natural gas plants do Duke and Dominion plan to supply with gas from that Atlantic Coast pipeline? When are these plants expected to be constructed?
- Why have there recently been so many safety problems with new pipelines?
- Dominion's 2014 10-K states, “certain portions of the proposed pipeline route aggravate ... typical construction risks.” Which portions of the route? What is Dominion doing to minimize these risks?
- Who will be the construction contractor for the Atlantic Coast pipeline? What is this contractor's recent safety track record?
- Who will be liable for damages from pipeline explosions?
- Who will pay for construction cost overruns, shippers or the pipeline developer?
- If a shipper terminates their contract due to project cost overruns or delays, to what extent is that shipper still liable for construction costs of the pipeline?
- What are the rates that have been negotiated between Atlantic Coast and its shippers? What return on equity is embedded in these rates?
- How much do negotiated rates decrease if there are delays in putting the pipeline into service?

### **B. Questions regarding the Mountain Valley Pipeline:**

- Who will be the construction contractor for the Mountain Valley pipeline? What is this contractor's recent safety track record?
- Who will be liable for damages from pipeline explosions?
- Who will pay for construction cost overruns, shippers or the pipeline developer?
- What are the rates that have been negotiated between Mountain Valley and its shippers? What return on equity is embedded in these rates?
- How much do negotiated rates decrease if there are delays in putting the pipeline into service?
- If a shipper goes bankrupt, how likely is it that the shipper's contract with Mountain Valley pipeline will be terminated?

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 13**, Docket No. CP15-115, Commissioner Bay Separate Statement, p.3.

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

National Fuel Gas Supply Corporation  
Empire Pipeline, Inc.

Docket Nos. CP15-115-000  
CP15-115-001

ORDER GRANTING ABANDONMENT AND ISSUING CERTIFICATES

(Issued February 3, 2017)

BAY, Commissioner, *Separate Statement*

The shale revolution has upended U.S. energy markets. Only a decade ago, the United States was thought to be running out of oil and gas, and imports of both were growing. Today, we are the world's leading producer of oil and gas, with new production coming from shale formations across the United States.<sup>1</sup> To serve the new production areas and to satisfy increasing demand, the interstate pipeline industry has built and is planning to build a large amount of infrastructure. In 2016, daily gas production in the United States stood at 72.4 billion cubic feet per day (Bcfd).<sup>2</sup> That same year, the Commission certificated 17.6 Bcfd of pipeline capacity. This infrastructure expansion, coupled with growing production, has resulted in declining natural gas prices and a significant reduction in basis differentials – the difference in prices between Henry Hub and other gas trading hubs – across most of the United States.

This week the Commission has issued a series of orders that certificate, in aggregate, more than several billion cubic feet of new gas pipeline capacity. This infrastructure can provide significant economic, reliability, and resiliency benefits. Gas is the marginal fuel in most wholesale power markets, and the wholesale price of electricity has dropped by double-digit amounts in 2015<sup>3</sup> and 2016 across the

---

<sup>1</sup> *United States remains largest producer of petroleum and natural gas hydrocarbons*, U.S. ENERGY INFORMATION ADMINISTRATION: TODAY IN ENERGY (May 23, 2016), <http://www.eia.gov/todayinenergy/detail.php?id=26352>.

<sup>2</sup> *Short-Term Energy Outlook: Natural Gas*, U.S. ENERGY INFORMATION ADMINISTRATION: ANALYSIS AND PROJECTIONS (Jan. 10, 2017), <https://www.eia.gov/outlooks/steo/report/natgas.cfm>.

<sup>3</sup> *Wholesale power prices decrease across the country in 2015*, U.S. ENERGY INFORMATION ADMINISTRATION: TODAY IN ENERGY (Jan. 11, 2016), <https://www.eia.gov/todayinenergy/detail.php?id=24492>.

United States.<sup>4</sup> It is also true that carbon emissions from the power sector have dropped 24 percent from 2005 levels.<sup>5</sup> For comparison purposes, the Clean Power Plan targets a 32 percent reduction from 2005 levels by 2030, so the United States is three-quarters of the way there with 13 years to go.<sup>6</sup> While the increased use of renewable energy has helped, fuel switching from coal to gas has driven much of the reduction since gas emits about half the carbon as coal. In 2016, for the first time ever, more electricity was produced from gas than from coal.<sup>7</sup> Natural gas-fired generators, because of their fast-ramping characteristics, also complement renewable resources and can support a higher penetration of renewables.<sup>8</sup>

Nevertheless, it is also true that the development of natural gas pipeline infrastructure has become increasingly controversial.<sup>9</sup> While FERC does not regulate the production of natural gas, methane emissions, or the use of fracking, many commenters have raised environmental concerns in our certificate proceedings. Moreover, because our certificate authority under the Natural Gas Act carries with it the ability to invoke eminent domain, property rights advocates have also objected to pipeline projects, alleging that private property is not being taken for a public use. As a result, the public interest in our work on energy projects is considerable. In order to respond to this

---

<sup>4</sup> *Wholesale power prices in 2016 fell, reflecting lower natural gas prices*, U.S. ENERGY INFORMATION ADMINISTRATION: TODAY IN ENERGY (Jan. 11, 2017), <http://www.eia.gov/todayinenergy/detail.php?id=29512>.

<sup>5</sup> U.S. Energy Information Administration, *January 2017 Monthly Energy Review* 185 (2017), <https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf>.

<sup>6</sup> *Fact Sheet: Overview of the Clean Power Plan*, U.S. ENVIRONMENTAL PROTECTION AGENCY: THE CLEAN POWER PLAN (Aug. 3, 2015), <https://www.epa.gov/sites/production/files/2015-08/documents/fs-cpp-overview.pdf>.

<sup>7</sup> *Natural Gas Expected to Surpass Coal in Mix of Fuel Used for U.S. Power Generation in 2016*, U.S. ENERGY INFORMATION ADMINISTRATION: TODAY IN ENERGY (Mar. 11, 2016), <http://www.eia.gov/todayinenergy/detail.php?id=25392>.

<sup>8</sup> *Pathways to Decarbonization: Natural Gas and Renewable Energy*, JOINT INSTITUTE FOR STRATEGIC ENERGY ANALYSIS (Apr. 2015), <http://www.nrel.gov/docs/fy15osti/63904.pdf>.

<sup>9</sup> See, e.g., Sierra Club, *The Gas Rush: Locking America into Another Fossil Fuel for Decades* 1 (2017) (noting concern over methane emissions and the “gas rush”), [http://content.sierraclub.org/sites/content.sierraclub.org.coal/files/1466-Gas-Rush-Report%2004\\_web.pdf](http://content.sierraclub.org/sites/content.sierraclub.org.coal/files/1466-Gas-Rush-Report%2004_web.pdf).

interest, I write separately to encourage the Commission to build on the progress that has been made to date and, in particular, to explore two other issues.

One is how the Commission establishes need in doing its certificate reviews under section 7(c) of the Natural Gas Act. The certificate policy statement, which was issued in 1999, lists a litany of factors for the Commission to consider in evaluating need.<sup>10</sup> Yet, in practice, the Commission has largely relied on the extent to which potential shippers have signed precedent agreements for capacity on the proposed pipeline. This is a useful proxy for need, because presumably shippers would not sign up for capacity unless it was needed. But focusing on precedent agreements may not take into account a variety of other considerations, including, among others: whether the capacity is needed to ensure deliverability to new or existing natural gas-fired generators, whether there is a significant reliability or resiliency benefit; whether the additional capacity promotes competitive markets; whether the precedent agreements are largely signed by affiliates; or whether there is any concern that anticipated markets may fail to materialize. As an example of the latter consideration, LNG import terminals that were built during the early 2000 time period became stranded as shale gas increasingly substituted for LNG imports from overseas.

There are other long-term issues that weigh in favor of examining whether other evidence, in addition to precedent agreements, can help the Commission evaluate project need. It is in the public interest to foster competition for pipeline capacity but also to ensure that the industry remains a healthy one, not subject to costly boom-and-bust cycles. Pipelines are capital intensive and long-lived assets. It is inefficient to build pipelines that may not be needed over the long term and that become stranded assets. Overbuilding may subject ratepayers to increased costs of shipping gas on legacy systems. If a new pipeline takes customers from a legacy system, the remaining captive customers on the system may pay higher rates. Under such circumstances, a cost-benefit analysis may not support building the pipeline.

Adding to the uncertainty, there is fluidity in where gas is being produced in the United States. Some of the first-producing shale plays have already seen output decline as lower-cost basins, like the Marcellus and Utica, gained prominence.<sup>11</sup> Major new

---

<sup>10</sup> *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, at 61,748 (1999) (“The types of public benefits that might be shown are quite diverse but could include 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.”), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000).

<sup>11</sup> U.S. Energy Information Administration, *Drilling Productivity Report 2* (2017), <http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf>.

production areas are being discovered that may impact gas flows on existing and proposed pipelines.<sup>12</sup> For decades, pipeline flows generally went from south to north and west to east. Production in the Marcellus and Utica led to flow reversals, with gas being transported from east to west and north to south. What happens to infrastructure developed to ship Marcellus and Utica gas west, if gas is cheaper to produce in Texas and Oklahoma? To the extent that producer-shippers are driving the development of new infrastructure, pipeline developers may now be exposed to market risk not present with shippers that are local distribution companies with a reliable rate base and predictable revenue stream. Similarly, it is important to ask what happens if basis differentials largely disappear at major gas trading hubs across the United States. A shipper would not need to transport gas from a more distant hub if it can be readily obtained for the same price from a closer one. This, too, might reduce the revenues of large interstate gas pipelines.

The other issue the Commission should address is how we conduct our environmental reviews of pipeline projects. With respect to upstream impacts, the Commission has concluded in many cases that the pipelines do not cause the production of gas. Under the National Environmental Policy Act (NEPA), in my view, the strongest legal argument against causation is based on *Department of Transportation v. Public Citizen*.<sup>13</sup> *Public Citizen* holds that “where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant ‘cause’ of the effect.”<sup>14</sup> Here, of course, FERC has no authority to regulate the production of natural gas; unless federal lands are involved, in general, that authority resides with the states.

Despite the growing importance of Marcellus and Utica gas production – it was 22.5 Bcfd in 2016 and is projected to surpass 44 Bcfd by 2050 – the Commission has never conducted a comprehensive study of the environmental consequences of increased

---

<sup>12</sup> *USGS Estimates 20 Billion Barrels of Oil in Texas’ Wolfcamp Shale Formation*, U.S. GEOLOGICAL SURVEY (Nov. 15, 2016), <https://www.usgs.gov/news/usgs-estimates-20-billion-barrels-oil-texas-wolfcamp-shale-formation>. In addition, the SCOOP-STACK play in Oklahoma is another major recent find. *Information on the Oklahoma Liquids Plays*, NATURAL GAS INTEL: SHALE DAILY, <http://www.naturalgasintel.com/oklahomaliquinfo>.

<sup>13</sup> 541 U.S. 752 (2004).

<sup>14</sup> *Id.* at 770. See also *EarthReports v. FERC*, 828 F.3d 949, 956 (2016) (following *Public Citizen*); *Sierra Club v. FERC*, 827 F.3d 59, 68 (D.C. Cir. 2016) (same); *Sierra Club v. FERC*, 827 F.3d 36, 46 (D.C. Cir. 2016) (same).

production from that region.<sup>15</sup> Nor has the Commission performed a programmatic review of gas production in the different shale formations. This review is not required unless there is a proposed federal plan or program to develop the resources at issue.<sup>16</sup> FERC does not have such a plan or program with respect to shale gas. Thus, there is no legal requirement for the Commission to do such a review of gas production from shale formations.

Even if not required by NEPA, in light of the heightened public interest and in the interests of good government, I believe the Commission should analyze the environmental effects of increased regional gas production from the Marcellus and Utica. The Department of Energy has conducted a similar study in connection with the exercise of their obligations under Section 3(a) of the Natural Gas Act.<sup>17</sup> Where it is possible to do so, the Commission should also be open to analyzing the downstream impacts of the use of natural gas and to performing a life-cycle greenhouse gas emissions study, both of which DOE has conducted in issuing permits for LNG exports. This information may be of use to the Commission, the public, and industry in examining the broader issues raised in certification proceedings.

Beyond the two issues I have highlighted, there may well be other issues that could usefully be examined by the Commission. Such an examination would be consistent with the best traditions of FERC, where, time and again, the Commission has sought the views of a diverse range of stakeholders when exploring important issues. Indeed, a recent example of such outreach occurred after the EPA issued its proposed rulemaking on the Clean Power Plan; FERC held a series of technical conferences to examine the implications of the Clean Power Plan for the electric industry. As important as infrastructure development is, it must also occur through processes that continue to promote public participation, transparency, and confidence.

---

<sup>15</sup> U.S. Energy Information Administration, *Annual Energy Outlook 2017 with Projections to 2050* 53 (2017), <http://www.eia.gov/outlooks/aeo/pdf/0383> (2017).pdf.

<sup>16</sup> *Kleppe v. Sierra Club*, 427 U.S. 390, 400-01 (1976).

<sup>17</sup> See U.S. Department of Energy, *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States* 19 (Aug. 2014), <http://energy.gov/sites/prod/files/2014/08/f18/Addendum.pdf>.

For all those reasons, I respectfully offer this separate statement.

---

Norman C. Bay  
Commissioner

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 14**, Comments of the New Jersey Division of Rate Counsel on PennEast Pipeline, FERC Docket No. CP15-558, Sept. 12, 2016.

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

PennEast Pipeline Company, LLC

| Docket No. CP15-558-000

**COMMENTS OF THE NEW JERSEY DIVISION OF  
RATE COUNSEL**

This proceeding concerns a request by PennEast Pipeline Company, LLC (“PennEast”) for Commission authorization to construct and operate a 118.8-mile greenfield pipeline. If constructed as proposed, PennEast’s pipeline will have a significant impact on New Jersey consumers. The proposed pipeline’s route consists of 115.1 miles of new 36-inch-diameter pipeline extending from Luzerne County, Pennsylvania to Mercer County, New Jersey; the 2.1-mile Hellertown Lateral consisting of 24-inch-diameter pipe in Northampton County, Pennsylvania; the 0.1-mile Gilbert Lateral consisting of 12-inch-diameter pipe in Hunterdon County, New Jersey; and the 1.5-mile Lambertville Lateral consisting of 36-inch-diameter pipe in Hunterdon County, New Jersey (the “Project”). The Project’s price tag is estimated to be \$1.13 billion.

In response to the Commission’s July 22, 2016 Notice,<sup>1</sup> intervenor New Jersey Division of Rate Counsel (“NJ Rate Counsel”) respectfully submits its comments on the “Draft Environmental Impact Statement for the Proposed PennEast Pipeline Project.”<sup>2</sup> As explained herein and in the accompanying affidavit of David E. Dismukes, Ph.D. (“Dismukes Affidavit”), the record does not support Commission authorization of the

---

<sup>1</sup> *PennEast Pipeline*, Notice of Availability of the Draft Environmental Impact Statement for the Proposed PennEast Pipeline Project (July 22, 2016), eLibrary No. 20160722-4010.

<sup>2</sup> *PennEast Pipeline*, Draft Environmental Impact Statement for the PennEast Pipeline Project (July 22, 2016), eLibrary No. 20160722-4001 (“DEIS”).

Project. PennEast has failed to demonstrate that the Project is in fact “needed,” and the DEIS gives overly short shrift to the “no action” alternative. Moreover, the terms under which the Project has been proposed are unduly generous to PennEast and unfair to consumers.

## I. COMMUNICATIONS AND CORRESPONDENCE

Correspondence and communications concerning these comments should be directed to:

Stefanie Brand  
Felicia Thomas-Friel  
Brian Lipman  
Henry Ogden  
THE DIVISION OF RATE COUNSEL  
140 East Front Street 4th Floor  
P.O. Box 003  
Trenton, NJ 08625  
Phone: (609) 984-1460  
Fax: 609-292-2923  
sbrand@rpa.state.nj.us  
fthomas@rpa.state.nj.us  
blipman@rpa.state.nj.us  
hogden@rpa.state.nj.us

Scott H. Strauss  
Stephen C. Pearson  
Amber L. Martin  
SPIEGEL & MCDIARMID LLP  
1875 Eye Street, NW  
Suite 700  
Washington, DC 20006  
Phone: (202) 879-4000  
Fax: (202) 393-2866  
scott.strauss@spiegelmc.com  
steve.pearson@spiegelmc.com  
amber.martin@spiegelmc.com

## II. COMMENTS

- A. *The DEIS analysis of the no action alternative is deficient because it fails to include a sufficient examination of whether the Project is necessary to fulfill a legitimate need.*

Section 1502.14(d) of the regulations implementing the National Environmental Policy Act, 40 C.F.R. § 1502.14(d), requires the Commission to evaluate “the alternative of no action.” In its current form, the Project DEIS is deficient in that it fails to give fair consideration to the no action alternative. The DEIS does not evaluate fully whether the Mid-Atlantic region in fact needs the proposed additional pipeline capacity. Instead, in analyzing the no-action alternative, the DEIS accepts at face value PennEast’s assertion

that additional pipeline capacity into the Mid-Atlantic is necessary, thereby failing to examine whether PennEast has in fact demonstrated that need.

The DEIS rejects the potential no action alternative because while doing so would obviously avoid the Project's short- and long-term environmental impacts, "the objectives of the Project would not be met." DEIS at 3-3. The DEIS describes the Project as a "response to market demands and interest from shippers that require transportation capacity to accommodate increased demand and greater reliability of natural gas in the region," intended to "provide a long-term solution to bring the lowest cost natural gas available . . . to homes and businesses in Pennsylvania, New Jersey, and surrounding states." *Id.* In short, and as explained in the DEIS, the no action alternative is not preferable because it will not satisfy "the objectives of the Project, provide an equivalent supply of energy, or meet the demands of the Project shippers." *Id.* at ES-15 and 5-18; *see also PennEast Pipeline Co., Application of PennEast for Certificates of Public Convenience and Necessity and Related Authorizations* at 4 (Sept. 24, 2015), eLibrary No. 20150925-5028 ("Application"). More specifically, the DEIS asserts that "[i]f PennEast's proposed facilities are not constructed, the Project shippers may need to obtain an equivalent supply of natural gas from new or existing pipeline systems." DEIS at 3-3. This determination misses the mark because PennEast has not demonstrated that the purported "increased demand [for] . . . natural gas in the region" in fact exists. *Id.*

PennEast bases its claim of need on "precedent agreements with seven foundation shippers and twelve total shippers, which together combine for a commitment of firm capacity of 990,000 dekatherms per day ('Dth/d')," approximately 90% of the Project's total capacity. *Application* at 2, 10-11. Although the Commission views "long-term firm

capacity as important evidence of market demand,”<sup>3</sup> NEPA requires FERC to examine more “rigorously” the need for a proposed project before rejecting potential alternatives, including no action.<sup>4</sup> In this case, approximately 610,000 Dth/d of the 990,000 Dth/d of capacity has been contracted by affiliates of the Project owners. Application at 10. PennEast is a joint venture owned by Spectra Energy Partners, LP together with subsidiaries of AGL Resources Inc., New Jersey Resources, South Jersey Industries, UGI Energy Services, LLC, and Public Service Enterprise Group (“PSEG”). *Id.* at 7-8. Of the twelve shippers that have subscribed to Project capacity, five of them are affiliates of companies that collectively own PennEast. Specifically, Pivotal Utility Holdings, Inc. (D/B/A Elizabethtown Gas), a subsidiary of AGL Resources, Inc., has contracted for 100,000 Dth/d. New Jersey Resources is the parent company of New Jersey Natural Gas Company, which has contracted with PennEast for 180,000 Dth/d of firm transportation capacity. Similarly, South Jersey Industries subsidiary South Jersey Gas Company has contracted with PennEast for firm capacity of 105,000 Dth/d. UGI Energy Services, LLC, the parent of PennEast stakeholder UGI PennEast LLC, has contracted for firm capacity 100,000 Dth/d. And PSEG Power LLC, a member of the PSEG corporate family, has likewise contracted for 125,000 Dth/d. *Id.* Thus, two-thirds of the demand for the pipeline exists because the Project’s stakeholders have said it is needed. This self-dealing undermines the assertion of need that the DEIS relies upon to dismiss the no action alternative.

---

<sup>3</sup> *Id.* at 10 citing *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, at 61,744 (1999), *corrected*, 89 FERC ¶ 61,040 (1999), *clarified in* 90 FERC ¶ 61,128, *further clarified in* 92 FERC ¶ 61,094 (2000)

<sup>4</sup> See 40 C.F.R. § 1502.14(a) (requiring an agency preparing an environmental impact statement to “[r]igorously explore and objectively evaluate all reasonable alternatives”).

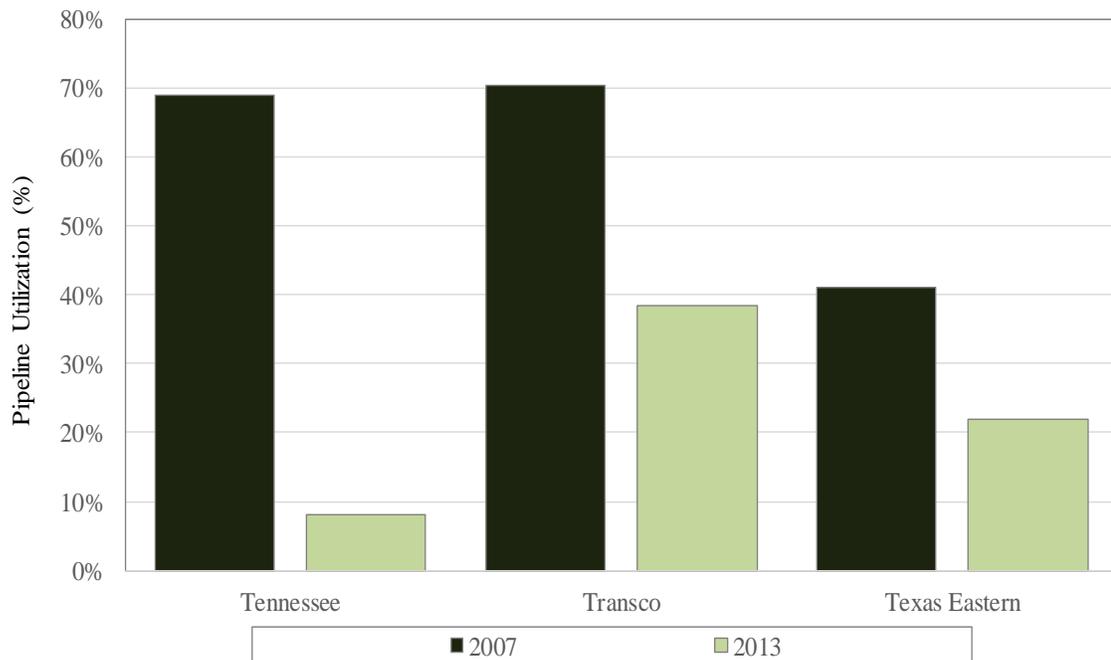
Given that two-thirds of the capacity under precedent agreements is with affiliates of the owners, the DEIS should have included an independent analysis of the need for the capacity the proposed Project will provide. NJ Rate Counsel asserts that such an independent analysis would have revealed that the forecasted supply and demand requirements for New Jersey and Pennsylvania local gas distribution companies (“LDCs”) can be met through existing supply arrangements. The table below provides peak day requirement—i.e., the highest 24-hour usage of natural gas during a year—and total supply projections for three New Jersey LDCs and three Pennsylvania LDCs, as reported to the New Jersey Board of Public Utilities (“NJ BPU”) and the Pennsylvania Public Utility Commission, respectively.

	PSE&G			South Jersey Gas			Elizabethtown Gas		
	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)
2015 - 2016	3,075,400	3,072,400	100%	n.a.	n.a.	n.a.	189,820	397,820	210%
2016 - 2017	3,089,600	3,074,500	100%	512,891	554,755	108%	285,070	402,610	141%
2017 - 2018	3,113,200	3,075,900	99%	520,555	564,755	108%	288,440	423,890	147%
2018 - 2019	3,141,000	3,078,500	98%	528,351	564,755	107%	n.a.	n.a.	n.a.
2019 - 2020	3,181,100	3,079,900	97%	536,280	564,755	105%	n.a.	n.a.	n.a.
	UGI Utilities			UGI Penn			PECO		
	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)
2015 - 2016	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
2016 - 2017	827,320	812,343	98%	208,303	208,303	100%	802,834	720,017	90%
2017 - 2018	844,804	828,120	98%	209,752	209,187	100%	n.a.	n.a.	n.a.
2018 - 2019	862,288	843,288	98%	211,201	209,957	99%	n.a.	n.a.	n.a.
2019 - 2020	879,772	858,456	98%	212,650	210,727	99%	n.a.	n.a.	n.a.

### LDC Forecast Peak Day Requirement and Total Natural Gas Supply

As Dr. Dismukes explains, these LDCs’ own projections suggest peak day requirements will remain relatively stable through 2020—and indicate that there is no imminent need for significant amounts of additional capacity. Dismukes Aff. ¶¶ 10-12. Further, the displacement of Gulf Coast supplies by emerging natural gas production from the

Marcellus Shale and the Utica Shale at traditional market area receipt points has left long-haul pipelines, including those that serve New Jersey LDCs, with underutilized upstream capacity. Dismukes Aff. ¶¶ 13. Specifically, Tennessee Gas Pipeline (“Tennessee”), Transcontinental Gas Pipeline (“Transco”), and Texas Eastern Transmission (“Texas Eastern”), all of which serve New Jersey LDCs, have seen significant drops in capacity utilization since 2007, as demonstrated in the table below. *Id.*



**Average Annual Utilization of Natural Gas Transportation Pipelines<sup>5</sup>**

In addition to the glut of underutilized capacity on existing gas transmission systems into the Mid-Atlantic, New Jersey LDC Public Service Electric & Gas Company (“PSE&G”) reports that it has *turned back* 145,000 Dth/d of firm transportation capacity in the past

---

<sup>5</sup> Denny Young, Black & Veatch, *Has Emerging Natural Gas Shale Production Affected Financial Performances of Interstate Pipelines?* (2013), <http://bv.com/energy-strategies-report/august-2013-issue/has-emerging-natural-gas-shale-production-affected-financial-performances-of-interstate-pipelines>.

year.<sup>6</sup> Several New Jersey LDCs also report sufficient access to production from the Marcellus Shale.<sup>7</sup> For example, in its most recent annual review and revision of its basic gas supply service, New Jersey Natural Gas Company reported that “[t]he majority of the market area assets of the Company are positioned to take advantage of the natural gas produced in the Marcellus Shale.”<sup>8</sup> As Dr. Dismukes makes clear, the data suggest that that the market does not demand additional transportation capacity or, more specifically, additional access to the Marcellus Shale.

This significant evidence notwithstanding, the DEIS accepts at face value PennEast’s assertion of need for the Project, and relies on that assertion almost exclusively in dismissing the no action alternative. Specifically, the DEIS suggests that

[i]f PennEast’s proposed facilities are not constructed, the Project shippers may need to obtain an equivalent supply of natural gas from new or existing pipeline systems. In response, PennEast or another natural gas transmission company would likely develop a new project or projects to provide the volume of natural gas contracted through the Project’s binding precedent agreements with the Project shippers. Alternatively, customers of the Project shippers could seek to use alternative fuel or renewable energy sources, which could require new facilities. In either case, construction of new pipelines or other energy infrastructure would result in environmental impacts that could be equal to or greater than those of the Project.

---

<sup>6</sup> PSE&G, Initial Filing Motion, Supporting Testimony, and Tariff Modifications at Item 18, § 3, *In the Matter of Pub. Serv. Elec. & Gas Co.’s 2016/2017 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge*, Docket No. GR16060486 (N.J. Bd. Pub. Utils. Jun. 1, 2016).

<sup>7</sup> *Id.* (“The ability of the Company to buy more economical gas supplies in the Marcellus region has provided the ability to turn back [] capacity at the expiration of [its] pipeline contracts,” with “both Trunkline and Panhandle.”); *see also* Pre-filed Direct Testimony and Exhibits of Jayana S. Shah at 6:10-11, attached to N.J. Natural Gas Co., Petition, *In the Matter of the Petition of N.J. Natural Gas Co. for the Annual Review & Revision of Its Basic Gas Supply Serv. (BGSS) & Conservation Incentive Program (CIP) Rates for F/Y 2017*, Docket No. GR16060482 (N.J. Bd. Pub. Utils. Jun. 1, 2016) (“The Company’s transport and storage assets are positioned to flow supply from Marcellus Shale.”).

<sup>8</sup> *Id.* at 6:17-19.

DEIS at 3-3. For these reasons, the DEIS states that “the No Action Alternative would not be preferable to or provide a significant environmental advantage over the Project.”

*Id.* But the “need” that the Project purports to fill, which has been asserted by affiliates of the Project owners, is contrary to the utilization data presented above. Those data show that the forecasted demands of the LDCs that PennEast is designed to supply are already being met by existing gas supply arrangements and available transportation capacity. For these reasons, NJ Rate Counsel asks that the Commission not accept the findings of the DEIS, and urges that the Commission take a much closer look at the fundamental question of whether the capacity of the Project is, in fact, “needed.”

***B. PennEast’s requested rate of return is excessive.***

As described above, PennEast’s justification of the Project’s “need” consists of precedent agreements with affiliates of the Project owners—notwithstanding that those same affiliates appear to have sufficient capacity to meet demand through at least 2020. NJ Rate Counsel is concerned that the DEIS does not address that the “need” for the Project appears to be driven more by the search for higher returns on investment than any actual deficiency in gas supply or pipeline capacity to transport it. Even if there were in fact a demonstrated need for the transportation capacity PennEast proposes to offer, a reasonable, compensatory rate should be sufficient to bring that capacity to market. By contrast, and as explained below, PennEast is requesting rates calculated using a substantially above-market return on equity (“ROE”) of 14%, an equally above-market and unsupported 6.00% cost of debt, and a 60% equity-heavy capital structure. Application at 32. But the pursuit of rich financial incentives does not constitute a showing of “need” and is insufficient to justify the Project.

1. The potential to obtain a high award of a rate of return is creating the “need” for the PennEast Project.

As the Commission is well aware from its consideration in the last few years of both pipeline rate cases and a large number of Federal Power Act complaints, ROEs have been trending down significantly as a reflection of capital market realities. The Commission has been presented with applications of its Discounted Cash Flow (“DCF”) methodology that support ROEs in the 8% range.<sup>9</sup> In this financial environment, the opportunity to receive a Commission-regulated return of 14% is tantamount to winning the lottery. NJ Rate Counsel is concerned that this opportunity may be a key motivating factor behind the Project.

As noted above, PennEast is 90% owned by affiliates of LDCs in Pennsylvania and New Jersey. Application at 10-11. Moreover, New Jersey Natural Gas, South Jersey Gas, and Pivotal Utility Holdings, Inc. (D/B/A Elizabethtown Gas) have signed precedent agreements for 385,000 Dth/d, or nearly 40%, of the subscribed capacity. Application at 10. At present, the NJ BPU has authorized New Jersey Natural Gas, South Jersey Gas, and Elizabethtown Gas to earn returns on common equity of up to 9.75%,<sup>10</sup> 9.75%,<sup>11</sup> and

---

<sup>9</sup> See, e.g., *Sw. Power Pool, Inc.*, Prepared Direct and Answering Testimony of Commission Trial Staff Witness Sophia Z. Luo, Ex. S-8, Docket No. ER16-204-001 (Aug. 2, 2016), eLibrary No. 20160802-5114 (recommending an ROE of 8.36%, which was the median of a zone of reasonableness of 6.51% to 9.50% for a six-month study period ending June 30, 2016 using a proxy group for a utility with an S&P credit rating of “A” and Moody’s credit rating of Baa1).

<sup>10</sup> *In the Matter of Petition of New Jersey Natural Gas Co. for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Serv., Approval of Safe Program Extensions, and Approval of Safe Extension and NJ Rise Rate Recovery Mechanisms Pursuant to N.J.S.A. 48:2-21, 48:2-21.1 and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18* at 17, 22, line 30, Docket No. GR15111304 (N.J. Bd. Pub. Utils. Aug. 17, 2016).

<sup>11</sup> *In the Matter of the Petition of S. Jersey Gas Co. For Approval of Increased Base Tariff Rates and Charges for Gas Serv. and Other Tariff Revisions*, Decision and Order Approving Stipulations at 4, Docket No. GR13111137 (N.J. Bd. Pub. Utils. Sept. 30, 2014).

11.3%,<sup>12</sup> respectively. However, if these New Jersey LDCs buy transport on PennEast under Commission-regulated rates that provide a 14% ROE, New Jersey retail customers will pay that 14% return, not the return authorized by New Jersey regulators.

And the establishment by New Jersey regulators of rates of return in the 9-10% range is far from out-of-step with national trends; their rulings are consistent with both state commission decisions elsewhere and actual conditions in the capital markets. The table below provides data collected by Regulatory Research Associates that summarizes state regulator decisions establishing ROE and capital structure for gas utilities.

<b>Average State Commission-Approved Rates of Return for Gas Utilities</b>		
<u>Year</u>	<u>ROE</u>	<u>Equity Ratio</u>
2012	9.94%	51.13%
2013	9.68	50.60
2014	9.78	51.11
2015	9.60	49.93
2016	9.45	50.42

---

*Source:* Regulatory Research Associates, *Major Rate Case Decisions, January-June 2016*, July 15, 2016 at 5. (Note: 2016 figures are derived from year-to-date data through June 2016.)

Notably, the data show that, over the last five years, state regulators have consistently approved ROEs of less than 10% for natural gas utilities. If FERC uses a 14% ROE, however, to establish transportation rates, state regulators must permit LDCs to recover those costs. When a pipeline is owned by an affiliate of an LDC, and that affiliate is permitted by the Commission to recover an ROE above that approved by the state

---

<sup>12</sup> *In the Matter of the Petition of Pivotal Util. Holdings, Inc. d/b/a Elizabethtown Gas for Approval of Increased Based Tariff Rates and Charges for Gas Servs. and Other Tariff Revisions*, Decision and Order Approving Stipulation and Adopting Initial Decision at 3, Docket No. GR09030195 (N.J. Bd. Pub. Utils. Dec. 17, 2009).

regulator, the end result is that the parent of the affiliates receives the substantially higher return awarded by the Commission—the state commission decision notwithstanding.

2. The Commission should not reflexively award the Project a 14% ROE simply because other pipelines have been awarded 14% ROEs.

PennEast has provided no evidence or analysis that links the high ROE it seeks with the need to obtain investor capital to build the pipeline. To the contrary, the Project lacks the hallmarks that would justify assessing its risk as “extraordinary” as compared to other greenfield projects. Specifically, PennEast boasts that approximately 90% of the Project’s transportation capacity has been subscribed.<sup>13</sup> The majority of the subscribed capacity consists of LDCs in New Jersey, Pennsylvania, and New York—meaning that it is subscribed by entities who are all but guaranteed to pay their bills. Moreover, even the non-LDC subscribers—predominantly electric power generators—have strong credit. Thus, there would seem to be little or no risk of either unsubscribed capacity or customer default.

PennEast’s capital structure is conservative. As can be seen from the utility data compiled by Regulatory Research Associates in the table above, regulated gas utilities have consistently been required to maintain an equity ratio around 50% equity. In contrast, PennEast proposes to maintain an equity-heavy capital structure of 60% equity.<sup>14</sup> By comparison, the Commission has also awarded a 14% ROE in connection with proposed capital structures that included up to 75% debt,<sup>15</sup> but PennEast’s proposed

---

<sup>13</sup> Application at 10.

<sup>14</sup> *Id.* at 32.

<sup>15</sup> *Cross Bay Pipeline Co.*, 97 FERC ¶ 61,165, at 61,757-758 (2001), *vacated on other grounds*, 98 FERC ¶ 61,080 (2002) (“Cross Bay”) (awarding a 14% ROE with a 25% equity and 75% debt).

60% equity capital structure is significantly less risky. Accordingly, the proposed capital structure does not justify PennEast's proposed 14% ROE.

Rather than justify its requested ROE through Project-specific substantive evidence, PennEast asserts that awarding the exorbitant ROE it seeks is simply a matter of "keeping up with the Joneses," noting that there are "[o]ther new greenfield pipelines with approved overall rates of return that equal the 14% return on equity that PennEast proposes here."<sup>16</sup> NJ Rate Counsel acknowledges that the Commission has awarded generous 14% rates of return to other greenfield pipelines in recent years. But in and of itself that does not justify a reflexive award of that same ROE, as the extant circumstances and those surrounding the first award of a 14% ROE are substantially different.

The Commission began granting ROEs of 14% nearly two decades ago,<sup>17</sup> though those ROEs were initially granted in connection with imputed capital structures consisting of as much as 75% debt and no less than 50% debt.<sup>18</sup> In the period since the Commission's 1997 *Alliance* decision, capital markets have changed significantly. The years since have included, *inter alia*, the "Great Recession," and the proliferation of

---

<sup>16</sup> Application at 33.

<sup>17</sup> See e.g., *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224, P 53 & n.54 (2009), *subsequent history omitted* (citing *Mid-Atlantic Express, LLC*, 126 FERC ¶ 61,019, P 31 (2009), *vacated on other grounds*, 145 FERC ¶ 61,113 (2013) (capital structure of 70% debt); *MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165, P 27 (2008) ("the Commission has approved equity returns of up to 14 percent as long as the equity component of the capitalization is no more than 50 percent"); *Ingleside Energy Center, LLC*, 112 FERC ¶ 61,101, PP 32-33 (2005), *vacated on other grounds*, 136 FERC ¶ 61,114 (2011) (reducing the proposed 70% equity capital structure to 50%)). The Commission's award of a 14% ROE, provided the equity structure is less than 50%, goes back even further. See e.g., *Cross Bay*, 97 FERC ¶ 61,165, at 61,757-758 (2001), *vacated on other grounds*, 98 FERC ¶ 61,080 (2002) (awarding a 14% ROE with a 25% equity and 75% debt); *Vector Pipeline L.P.*, 85 FERC ¶ 61,083 at 61,303 (1998), *subsequent history omitted* (awarding a 14.5% ROE); *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149, at 61,592 (1997), *subsequent history omitted* (proposing a 12% base ROE with incentives enabling a maximum of 14% ROE).

<sup>18</sup> See *supra* note 17.

hydraulic fracturing to recover previously inaccessible natural gas from substantial domestic shale gas reserves. Rather than approving facilities to import liquefied natural gas (“LNG”), the Commission is now approving facilities used for LNG exports. Given these seismic shifts in the facts on the ground, it is irrational to assume that the same return that was required in 1997 is appropriate now. There is no basis for the Commission approving a 14% ROE simply because earlier pipelines have received that ROE.

Present capital markets require much lower returns and investors no longer require the same returns that they required twenty years ago. While the median result of the Commission’s Discounted Cash Flow analysis may not yield the appropriate ROE for a greenfield pipeline, it provides the measure of the return investors require. For example, although not a greenfield pipeline, the Commission recently ordered a new pipeline company to use the 10.55% ROE<sup>19</sup> that the Commission determined to be the just and reasonable ROE in *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC 61,040, at P 642 (2013), *denying stay*, 145 FERC ¶ 63,107 (2013), *denying reconsideration*, 146 FERC ¶ 63,001 (2014), *reh’g denied*, Opinion No. 528-A, 154 FERC ¶ 61,120 (2016). If a 10.55% ROE provides a sufficient return for a start-up pipeline company, a 14% ROE is not required for a pipeline that claims a 90% subscription rate, largely by LDCs whose affiliates own the pipeline. As such, it would be arbitrary and capricious for the Commission to approve a 14% ROE for PennEast simply because it has awarded other pipelines such a return.

---

<sup>19</sup> *First ECA Midstream LLC*, 155 FERC ¶ 61,222, P 23 (2016).

3. PennEast should be limited to a 50% equity capital structure.

As noted above, the genesis of the Commission's award of 14% ROEs was in the context of capital structures that were heavily weighted with debt—as much as 75%.<sup>20</sup> The Commission reduced what it then deemed to be equity-heavy proposed capital structures to reflect that its prior approvals were for debt-heavy structures.<sup>21</sup> If the Commission determines—notwithstanding the significant changes in the capital markets and the natural gas industry over the last twenty years—that the Project requires a 14% ROE, then the Commission must also limit PennEast's capital structure to 50% equity.

***C. PennEast's proposed 6.0% cost of debt is unsupported and excessive because it substantially exceeds the current market.***

PennEast has not supported its request for a 6.00% cost of debt, but points again to other pipelines filings that were certificated more than five years ago and involve different markets.<sup>22</sup> PennEast offers no objective evidence as to what the cost of debt will be for the Project.

The Commission, however, knows what interest rates utility bond issuances command. Moody's reports that the monthly trend of long-term utility bond rates, whether for "A" rated or "Baa" rated, has been down during 2016. According to Moody's, "A" rated bonds have declined from 4.27% in January to 3.57% in July. Even if PennEast bonds are considered to be nearly junk and rated at "Baa", a highly unlikely scenario given its ownership by affiliates of regulated utilities and which regulated

---

<sup>20</sup> See *supra* note 17.

<sup>21</sup> *Ingleside Energy Center, LLC*, 112 FERC ¶ 61,101, at PP 32-33 (2005), *vacated on other grounds*, 136 FERC ¶ 61,114 (2011) (reducing a proposed 70% equity structure to 50%).

<sup>22</sup> Application at 32 & n. 21.

utilities have signed precedent agreements reserving substantially all of the pipeline's capacity, Moody's reports that "Baa" bonds have declined from 5.49% in January to 4.16% in July. The table below provides the monthly data.

Long-term Bond Yields in 2016				
Month	Moody's Utility		U.S. Treasury	
	A	Baa	10-year	30-year
January	4.27%	5.49%	2.09%	2.86%
February	4.11	5.28	1.78	2.62
March	4.16	5.12	1.89	2.68
April	4.00	4.75	1.81	2.62
May	3.93	4.60	1.81	2.63
June	3.78	4.47	1.64	2.45
July	3.57	4.16	1.50	2.23

Source: Bd. of Governors of the Fed. Reserve Sys., *Selected Interest Rates (Daily)* – H.15, <https://www.federalreserve.gov/releases/h15/data.htm> (follow (1) "U.S. government securities," (2) "Treasury constant maturities," (3) "Nominal," (4) "10-year" and select "Monthly" hyperlink; then repeat these steps but replace "10-year" with "30-year" in step (4) (last visited Sept. 9, 2016); Moody's Bond Record, August 2016.

This table also illustrates the parallel decline in ten-year and thirty-year Treasury yields. Compared with this data, PennEast's assertion of a debt cost of 6.00% is substantially above market.

In a more recent decision, the Commission has imputed a much more realistic debt rate. In the *First ECA Midstream* proceeding, the pipeline requested—and the Commission accepted—an imputed debt rate of 3%.<sup>23</sup> NJ Rate Counsel understands that this decision was issued after PennEast's application was filed, but urges the Commission

---

<sup>23</sup> *First ECA Midstream LLC*, 155 FERC ¶ 61,222, PP 22-23.

not to ignore that PennEast's unsupported imputed cost of debt is double what the Commission has just accepted.

The Commission should recognize the reality of the financial market in which PennEast will issue its debt, and should impute a debt cost consistent with its recent precedent and consistent with actual debt market rates.

### **III. CONCLUSION**

NJ Rate Counsel respectfully requests that the Commission take the forgoing comments and the accompanying Dismukes Affidavit into consideration in determining the actions that should be taken concerning PennEast's request for authorization to construct and operate the Project.

Respectfully submitted,

*/s/ Scott H. Strauss*

---

Scott H. Strauss  
Stephen C. Pearson  
Amber L. Martin

Attorneys for  
New Jersey Division of Rate  
Counsel

Law Offices of:  
Spiegel & McDiarmid LLP  
1875 Eye Street, NW  
Suite 700  
Washington, DC 20006  
(202) 879-4000

September 12, 2016

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 12th day of September, 2016.

*/s/ Amber L. Martin*

---

Amber L. Martin

Law Offices of:  
Spiegel & McDiarmid LLP  
1875 Eye Street, NW  
Suite 700  
Washington, DC 20006  
(202) 879-4000

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

PennEast Pipeline Company, LLC

)  
)  
)  
)

Docket No. Docket No. CP15-558-000

**AFFIDAVIT OF DAVID E. DISMUKES, PH.D.**

## **I. Introduction**

1. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with Acadian Consulting Group (“ACG”), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, and public policy issues associated with energy and infrastructure industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

2. I hold both M.S. and Ph.D. degrees in economics from Florida State University. Over the past twenty-eight years, I have been actively involved in research, government service, and consulting involving energy and infrastructure industries. My professional experience includes the examination of economic, statistical, and public policy issues in regulated and energy industries.

3. I have participated in over 300 regulatory proceedings in twenty-five states and have prepared expert witness testimony, reports, and affidavits in Arkansas, Arizona, Colorado, Delaware, Florida, Indiana, Illinois, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Mississippi, Missouri, Nebraska, Nevada, New Jersey, Ohio, South Carolina, Tennessee, Texas, Utah, Vermont, Washington, the District of Columbia, and before the Federal Energy Regulatory Commission (“FERC”). I have also testified before the U.S. Congress and various state legislatures.

4. In addition to my consulting work, I serve as a Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University (“LSU”). I am also a full Professor in the College of the Coast and the Environment where I serve on the faculty of the Department of Environmental Sciences and as the Director of the

Coastal Marine Institute. I am also an Adjunct Professor in the E.J. Ourso College of Business Administration and I am a full member of the LSU Graduate Faculty.

5. I have published over 200 articles, professional papers, reports, book chapters, books, and manuscripts on energy and infrastructure industries. My professional research experience includes the analysis of a wide range of issues related to regulated energy companies, particularly electric and natural gas utilities. This research includes the examination of resource planning issues, power and natural gas market restructuring, ratemaking and cost recovery issues, power plant efficiency, multi-area dispatch modeling issues, ratemaking and cost of service modeling, and the integration of environmental considerations on utility operations.

6. A copy of my academic vitae has been provided as Attachment 1 to this affidavit and includes a list of my professional employment positions, publications, technical reports, presentations, and expert reports, testimonies, and affidavits.

7. I have worked as an advisor or consultant to the New Jersey Division of Rate Counsel (“NJ Rate Counsel”) for over 10 years. My work has primarily been associated with advising NJ Rate Counsel on a variety of ratemaking, public policy, infrastructure, and energy market issues. I have specifically worked on a number of natural gas policy, ratemaking, natural gas infrastructure replacement and resiliency, and natural gas procurement issues associated with New Jersey’s investor-owned natural gas utilities.

8. I have reviewed the peak day requirements for three New Jersey Local Distribution Companies (“LDCs”): Public Service Electric & Gas Company (“PSE&G”); South Jersey Gas Company (“SJG”); and Elizabethtown Gas Company (“Elizabethtown”), as well as three Pennsylvania LDCs: UGI Utilities; UGI Central Penn Gas; and PECO.<sup>1</sup> These LDCs serve

---

<sup>1</sup> The relevant data for New Jersey’s fourth LDC, New Jersey Natural Gas, was unavailable and therefore not included in this analysis.

customers located in and around the PennEast facilities and, if the PennEast Pipeline is built, can be expected to be target customers of the Project.

9. For natural gas LDCs, a peak day is the highest 24-hour usage of natural gas during a year, and (for LDCs located in the Northeast) typically occurs during the winter heating season. LDCs use peak day requirement projections for planning purposes to ensure that enough supply capacity is available to meet demand and maintain reliable service to firm customers on the coldest days of the year. Because LDCs must be able to maintain firm deliveries of natural gas to retail customers on even the coldest day of winter, even if that coldest day reaches historically low temperatures, the peak day requirement is necessarily very conservative.

10. I have analyzed the forecasted peak day requirements of PSE&G, SJG, Elizabethtown, UGI Utilities, UGI Central Penn Gas, and PECO through 2020. A forecast through 2020 may seem to be a short period given the time necessary to permit, construct, and place an interstate pipeline in service. However, the 2020 forecast is appropriate because it reflects a reasonable time period in which an LDC could identify and procure capacity resource needs and alternatives. The peak day forecasts I examined show that these LDCs have stable loads with little forecasted growth. At this time, there is no evidence to suggest that these LDCs will experience any sudden or dramatic changes in these usage trends beyond 2020.

11. I have also reviewed the means by which PSE&G, SJG, Elizabethtown, UGI Utilities, UGI Central Penn Gas, and PECO presently serve their peak day requirements. This information is included in a series of 2016 filings made by each of these LDCs before their respective state regulators.<sup>2</sup> Through a mix of firm capacity on existing interstate pipelines,

---

<sup>2</sup> See, *In the Matter of Pub. Serv. Elec. & Gas Co.'s 2016/2017 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge*, Docket No. GR16060486 (N.J. Bd. Pub. Utils.); *In The Matter of The Petition of S. Jersey Gas Co. to Revise the Level of its Basic Gas Supply Service ("BGSS") Charge and to Revise the Level of its Conservation Incentive*

seasonal storage and liquefied natural gas (“LNG”) supplies, each LDC has natural gas supply service that is at or nearly at 100 percent of that LDC’s peak day requirement through 2020. I have not seen any evidence at this point suggesting that a continuation of each of the LDCs existing natural gas supply resources will become a challenge after 2020.

12. In the table below, I summarize my analysis of the state regulatory filings by PSE&G, South Jersey Gas, Elizabethtown Gas, UGI Utilities, UGI Penn, and PECO:

	PSE&G			South Jersey Gas			Elizabethtown Gas		
	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)
2015 - 2016	3,075,400	3,072,400	100%	n.a.	n.a.	n.a.	189,820	397,820	210%
2016 - 2017	3,089,600	3,074,500	100%	512,891	554,755	108%	285,070	402,610	141%
2017 - 2018	3,113,200	3,075,900	99%	520,555	564,755	108%	288,440	423,890	147%
2018 - 2019	3,141,000	3,078,500	98%	528,351	564,755	107%	n.a.	n.a.	n.a.
2019 - 2020	3,181,100	3,079,900	97%	536,280	564,755	105%	n.a.	n.a.	n.a.
	UGI Utilities			UGI Penn			PECO		
	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)	Peak Day Requirement ----- (Dth)	Total Gas Supply -----	Percent of Total (%)
2015 - 2016	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
2016 - 2017	827,320	812,343	98%	208,303	208,303	100%	802,834	720,017	90%
2017 - 2018	844,804	828,120	98%	209,752	209,187	100%	n.a.	n.a.	n.a.
2018 - 2019	862,288	843,288	98%	211,201	209,957	99%	n.a.	n.a.	n.a.
2019 - 2020	879,772	858,456	98%	212,650	210,727	99%	n.a.	n.a.	n.a.

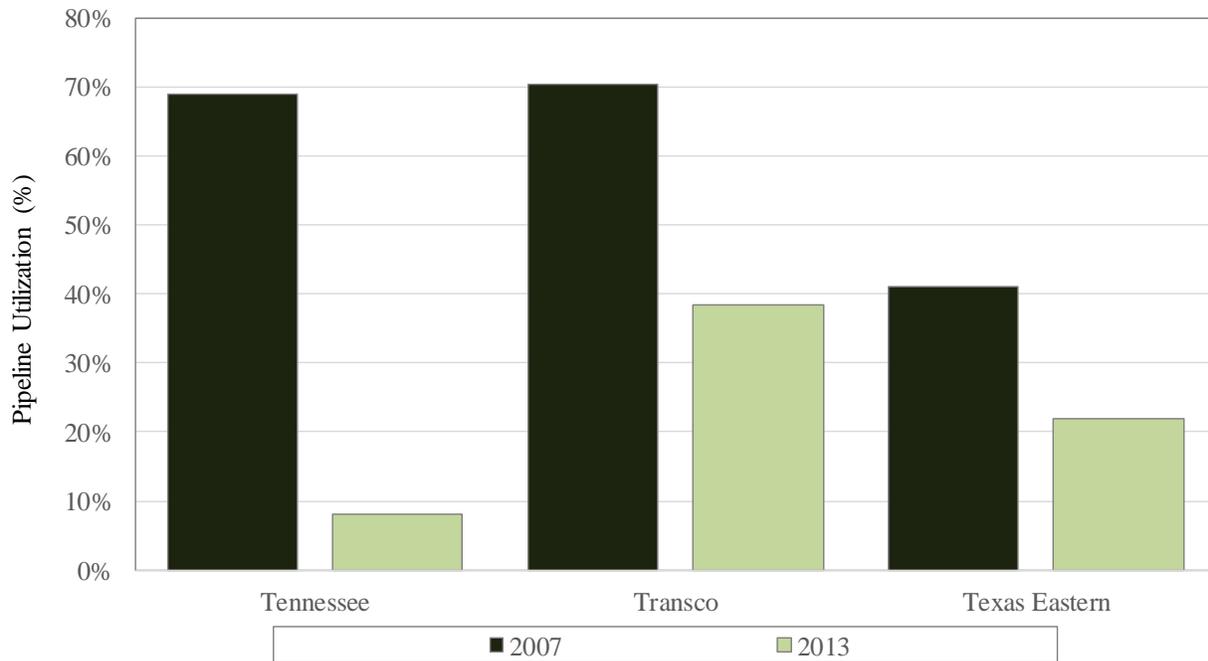
**Table 1. LDC Forecast Peak Day Requirement and Total Natural Gas Supply**

13. I have also prepared a chart based on information compiled by industry consultants showing the average annual utilization of existing interstate natural gas pipelines that have historically transported natural gas to New Jersey, including Tennessee Gas Pipeline (“Tennessee”), Transcontinental Gas Pipeline (“Transco”), and Texas Eastern Transmission

---

*Program (“CIP”) Charges for the Year Ending Sept. 30, 2017, Docket No. GR16060483 (N.J. Bd. Pub. Utils.); In The Matter of The Petition Of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas To Review Its Periodic Basic Gas Supply Serv. Rate, Docket No. GR16060485 (N.J. Bd. Pub. Utils.); In Re: UGI Utilities, Inc. 1307(f) Annual Purchased Gas Cost Filing 2016, Docket No. R-2016-2543309 (Pa. Pub. Util. Comm’n); In Re: UGI Penn Gas, Inc. 1307(f) Annual Purchased Gas Cost Filing 2016, Docket No. R-2016-2543311 (Pa. Pub. Util. Comm’n); and In Re: PECO Purchased Gas Cost No. 33 Filing Effective Dec. 1, 2016, Docket No. R-2016-2545925 (Pa. Pub. Util. Comm’n).*

System (“Texas Eastern”). Specifically, the data shown below are culled from a 2013 Black & Veatch publication entitled, “Has Emerging Natural Gas Shale Production Affected Financial Performances of Interstate Pipelines?”<sup>3</sup> The data show that the annual average utilization rates of these pipelines has significantly declined over the past few years.



**Figure 1. Average Annual Utilization of Natural Gas Transportation Pipelines**

14. While Tennessee, Transco, and Texas Eastern have historically transported natural gas from the Gulf Coast region, each of these pipelines has interconnections with other pipelines that directly serve the shale gas regions that supply much of the natural gas used in the Mid-Atlantic region.

<sup>3</sup> The publication is available at: Denny Yeung, Black & Veatch, *Has Emerging Natural Gas Shale Production Affected Financial Performances of Interstate Pipelines?* (2013) <http://bv.com/energy-strategies-report/august-2013-issue/has-emerging-natural-gas-shale-production-affected-financial-performances-of-interstate-pipelines>.

15. My review of state regulatory filings has also revealed that PSE&G has turned back 145,000 Dth/d of firm capacity in the past year.<sup>4</sup> Not only is this firm capacity now available to other LDCs, but it also demonstrates that the region currently has adequate alternative means to obtain natural gas supply. In my experience, an LDC that is concerned about its ability to access gas supplies does not turn back such substantial capacity.

---

<sup>4</sup> PSE&G, Initial Filing Motion, Supporting Testimony and Tariff Modifications at Item 18, §3, *In the Matter of Pub. Serv. Elec. & Gas Co.'s 2016/2017 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge*, Docket No. GR16060486 (N.J. Bd. Pub. Utils. June 1, 2016).

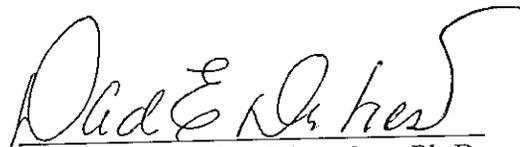
UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

PennEast Pipeline Company, LLC ) Docket No. CP15-558-000  
)  
State of Louisiana )  
Parish of East Baton Rouge )  
)  
)  
)  
)  
)

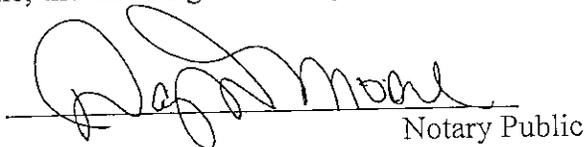
AFFIDAVIT OF DAVID E. DISMUKES, PH.D.

I, David E. Dismukes, being duly sworn, depose and state that the contents of the foregoing Affidavit on behalf of the New Jersey Division of Rate Counsel, are true, correct, accurate and complete, to the best of my knowledge, information and belief.

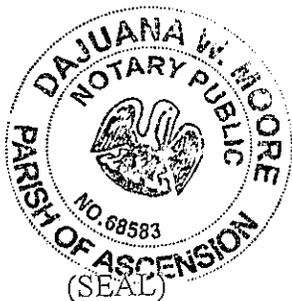
THIS DOCUMENT NOT  
PREPARED BY  
THE UNDERSIGNED NOTARY  
ATTESTING TO SIGNATURES ONLY

  
David E. Dismukes, Ph.D.

SUBSCRIBED AND SWORN TO before me, the undersigned Notary Public, this 9<sup>th</sup>  
day of September 2016.

  
Notary Public

Dajuana W. Moore, Notary Public No. 68583



17590 Perkins Rd. Ste A Baton Rouge  
(Address of Notary) LA 70810

My Commission Expires:  
"Commissioned for Life"

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 15**, Atlantic Coast  
Pipeline Benefits Review, Synapse Energy, June 12,  
2015.

---

# Atlantic Coast Pipeline Benefits Review

Chmura and ICF Economic Benefits Reports

---

**Southern Environmental Law Center**

June 12, 2015

AUTHORS

Elizabeth A. Stanton, PhD

Tyler Comings

Sarah Jackson

Ezgi Karaca



485 Massachusetts Avenue, Suite 2  
Cambridge, Massachusetts 02139

617.661.3248 | [www.synapse-energy.com](http://www.synapse-energy.com)

---

# CONTENTS

- EXECUTIVE SUMMARY ..... 1
  
- 1. REVIEWING ICF'S ACP ANALYSIS ..... 2
  
- 2. REVIEWING CHMURA'S ACP ANALYSIS ..... 8
  
- 3. HIDDEN COSTS OF THE ACP ..... 9

## EXECUTIVE SUMMARY

In September 2014, Dominion Resources—together with its partners Duke Energy, Piedmont Natural Gas and AGL Resources—announced their joint investment in the 550-mile interstate Atlantic Coast Pipeline (ACP). The proposed pipeline would bring natural gas from West Virginia through Virginia and into eastern North Carolina.

The Southern Environmental Law Center commissioned Synapse Energy Economics (Synapse) to review two reports—one by ICF International and one by Chmura Economics & Analytics—released by Dominion and its partners that assessed the projected economic, job, and tax benefits associated with building and operating the ACP. Synapse identified a number of problems with the reports' conclusions. Importantly, neither report accounted for any of the environmental and societal costs that the pipeline may impose on local communities. Without consideration of these costs, the ICF and Chmura reports can only present an incomplete accounting of the pipeline's net benefits.

Regarding the results of the ICF International report, Synapse concluded that ICF likely overestimates the economic benefits of the pipeline for the following reasons:

- ICF's assumption of a large difference between Henry Hub and Dominion South natural gas prices may not be justified based on available price data.
- The study's method of allocating electric savings to Virginia customers from the ACP is inadequately explained and seems unlikely given regional electric-market dynamics.
- The conclusion that all energy savings to businesses from the ACP will be used to create new jobs is not supported by evidence.
- ICF's characterization of jobs stimulated by energy savings from the ACP as "permanent" is not supported.
- The ICF study does not make clear whether or not it has included costs to build new natural gas generation—a key component in calculating the net economic impacts of the pipeline.
- The report erroneously presents reliability impacts not relevant to Virginia and North Carolina.
- Finally, the study inaccurately conflates wholesale electric price volatility with retail electric rate volatility.

It is worth noting that even if we accept ICF's numbers, the ACP would not produce net benefits until 2027, almost ten years after its construction.

Furthermore, Synapse's review found both the ICF report and the Chmura report to be largely inauditable, meaning they lack the transparency and verifiable data necessary for independent review. Such reports, funded by companies with a financial interest in building the ACP, do not provide the



useful, objective tools necessary to inform a public decision-making process meant to ensure the public good. Analyses that are included in a productive public discourse should be defensible and have well-defined methodology and assumptions, combined with the use of publicly available information. For these reasons, we recommend that elected officials, agency staff, and the public view the conclusions of the ICF report and the Chmura report with skepticism. The wholly transparent analysis described here is necessary before it can be determined what, if any, economic benefits will result from the ACP.

The following report provides additional details of the Synapse review.

## 1. REVIEWING ICF'S ACP ANALYSIS

In February 2015, ICF International released a report prepared for Dominion Transmission entitled, *The Economic Impacts of the Atlantic Coast Pipeline*.<sup>1</sup> The purpose of the report was to assess the ACP's impacts on the economies and natural gas and electricity markets within North Carolina and Virginia. The study broadly concluded that over the next 20 years, the two states combined could expect the ACP to generate \$7.5 billion in energy cost savings, nearly 45,000 job years, and billions in labor income, in addition to increased reliability, reduced price volatility and state economies enhanced by over \$4 billion collectively. Based on the flaws that were identifiable in the report, it is likely that the results overestimate the benefits of the pipeline. Furthermore, our review found that ICF produced a report using data that are not publicly available and therefore not auditable without the release of additional information. That is, the lack of details on the assumptions, data inputs, and methodologies used by ICF in their analysis greatly impedes adequate third-party review of the study.

**ICF's assumption of large difference between the Henry Hub and Dominion South natural gas prices may not materialize.** ICF does not make available the Henry Hub and Dominion South natural gas price forecasts used in its study. Instead, it reports the projected difference between these two price points. While Henry Hub prices were generally higher than Dominion South prices in 2014, price spreads between the two points as recent as the week of February 11, 2015 have been as low as 2 cents.<sup>2</sup> On average in 2015, the price spread has been 81 cents.<sup>3</sup> The average spread and the volatility of the price

---

<sup>1</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc.

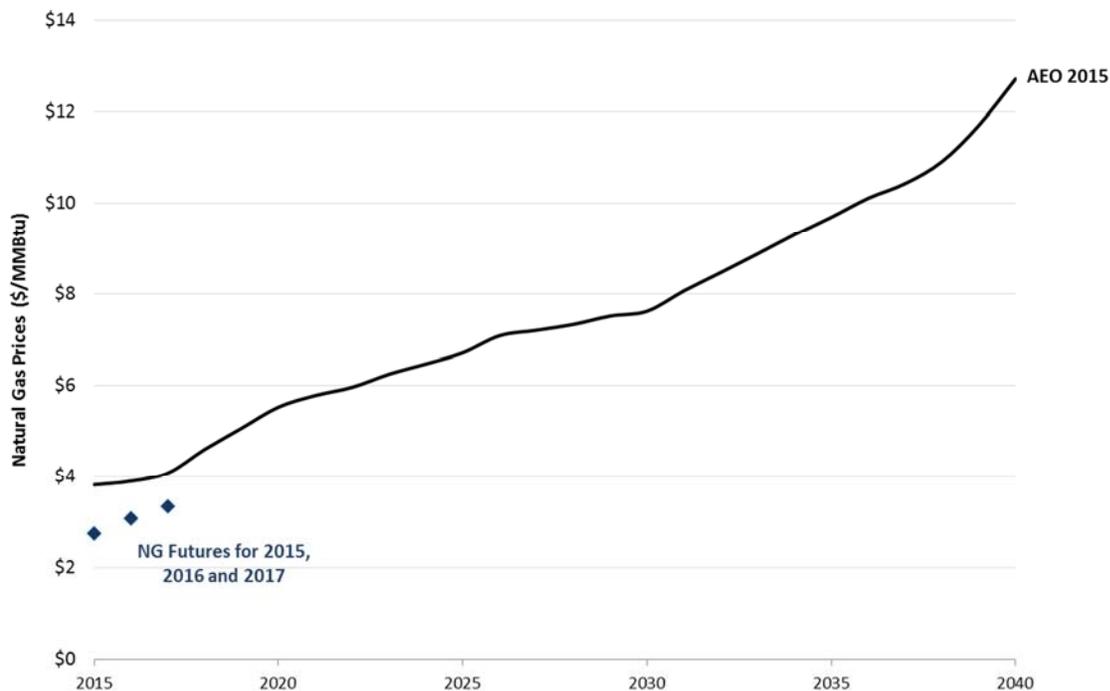
<sup>2</sup> EIA Natural Gas Weekly Update (February 11, 2015). Available here: [http://www.eia.gov/naturalgas/weekly/archive/2015/02\\_12/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2015/02_12/index.cfm)

<sup>3</sup> EIA Natural Gas Weekly Update. Average of 14 weeks of price data available in 2015. Data is available here: <http://www.eia.gov/naturalgas/weekly/archive/>

spread calls into question whether ICF’s predicted spread of between \$1.50 and \$1.75 will actually materialize.<sup>4</sup>

In addition, the short-term outlook for prices (using NYMEX futures) remains low—as depicted in Figure 1. The short-term expectations for Henry Hub prices in 2015, 2016, and 2017 are lower than the projections in the most recent EIA long-term forecast. The study’s results depend on the continuing divergence of Dominion South and Henry Hub prices. If these price points are actually converging, the implied savings—and resulting economic impacts—would decrease or perhaps disappear. Again, it is unclear how publicly available price projections compare to ICF’s assumptions, but the study should incorporate more up-to-date expectations for Henry Hub and Dominion South prices. The report also, confusingly, switches between using Henry Hub and Transco Zone 5 prices to compare to Dominion South prices. It is not clear which price spread is more valid: 1) Dominion South compared to Henry Hub in ICF’s Exhibit 6, or 2) Dominion South compared to Transco Z5 in ICF’s Exhibit 8.

**Figure 1: EIA natural gas price forecast and NYMEX futures**



Source: EIA Annual Energy Outlook 2015 (Reference Case), available here: <http://www.eia.gov/oiaf/aeo/tablebrowser/>. NYMEX Futures are averages of monthly settlements (pulled on April 15, 2015), available here: <http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html>

<sup>4</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Exhibit 6.

ICF determined economic impacts based on its estimate of cost savings from accessing natural gas from Dominion South in southwestern Pennsylvania instead of Henry Hub in Louisiana. The bulk of the savings would arise from the reduced costs of generating electricity by burning natural gas, with additional savings to direct natural gas customers. ICF's savings estimates, however, rest on the insufficiently documented expectation that Henry Hub prices will continue to be significantly higher than Dominion South prices.<sup>5</sup> As discussed above, these prices may be converging.

Even accepting ICF's assumptions about the spread of gas prices, there appear to be no annual net savings from the ACP until 2027.<sup>6</sup> In Exhibit 8, ICF presents the "projected price spread" per MMBtu (i.e. the savings from switching from Transco Z5 to Dominion South), along with the "demand charge" which is the unit cost associated with the pipeline per MMBtu. The savings from switching gas sources would have to outweigh the costs of the pipeline for the project to generate net savings. The exhibit shows that the lines representing the price spread and cost of the pipeline cross in 2027. This means, using ICF's assumptions about gas prices and the other information presented, it appears that the price spread *per MMBtu* does not begin to cover the additional pipeline expense *per MMBtu* until 2027.<sup>7</sup> The study does not present estimated savings in terms of *total dollars*, making it impossible to determine at what point the total cost of the pipeline is projected to break even.

**The study's method of allocating electric savings to Virginia customers from the ACP is inadequately explained and seems unlikely given PJM market dynamics.** ICF estimates projected natural gas savings for direct gas customers and pass-through savings to electricity customers due to lower natural gas plant generating costs. ICF appears to assume that lower natural gas prices would mean that Virginia utilities' cheaper electricity would—due to the state's membership in the PJM capacity and energy markets—suppress energy prices throughout the PJM region by \$0.94/MWh over the analysis period.<sup>8</sup> ICF expected price suppression would seem to require that Virginia natural gas plants are on the margin in PJM (i.e. set the regional wholesale electric price) for a significant share of hours in a year. PJM includes part or all of 13 states and the District of Columbia. A reduction in generating costs for natural gas power plants in Virginia may have a small impact on wholesale costs for the entire region to the extent that the marginal price of energy is reduced. However, since Virginia generators are serving load throughout the PJM region, any price suppression would affect the region at large, and not be captured by Virginia customers alone. It is unclear if ICF allocated savings across the PJM region or assumed that any savings in Virginia power generation would only affect Virginia customers. If it is the latter, the

---

<sup>5</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Exhibit 6.

<sup>6</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Exhibit 8.

<sup>7</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Exhibit 8.

<sup>8</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Page 11.

study's economic impacts on Virginia are significantly overstated—even after assuming that ICF's price spread materializes.

**The conclusion that all energy savings to businesses from the ACP will be used to create new jobs is not supported by evidence.** ICF's economic impact estimates depend on residents and businesses in Virginia and North Carolina re-spending net energy savings. According to ICF, businesses' electric and gas savings generate "more than 2,200 permanent, full-time jobs across the two states" which are "driven mainly by large energy savings for the commercial sector and increased residential consumption expenditures."<sup>9</sup> The study did not provide any underlying data to support this claim. Critical inputs and assumptions—such as the assumed direct energy savings by sector—are necessary to satisfactorily review this finding. While not explained explicitly, it is possible that ICF assumed that all commercial and industrial energy savings would translate into new job creation. While it is reasonable to assume that residents would re-spend most or all of their energy savings within the state, applying this same assumption to businesses' savings would be difficult to support.<sup>10</sup> Some of businesses' savings on energy bills may go to support hiring more employees, while the remainder may be invested in capital or materials, or returned to owners as profit. Business investment and profit are unlikely to support new in-state jobs in the same way as an increase to consumer spending. Therefore, economic impacts resulting from commercial and industrial savings may be overstated.

**ICF's characterization of jobs stimulated by energy savings from ACP as "permanent" is not supported.** The study estimates 44,600 job-years over a 20-year period, or approximately 2,225 annual jobs on average over that period, but these are not necessarily long-term jobs.<sup>11</sup> If energy savings fluctuate by year, then so will the resulting job impacts. Unfortunately, the study shows neither energy savings nor job impacts on a year by year basis. Therefore, it is impossible to verify how the job impacts are sustained over time. Policymakers should have access to information such as whether the job impacts are more pronounced in the early years, later years or evenly distributed in order to better plan for the long-term well-being of their constituencies.

**The study inaccurately conflates wholesale electric price volatility with retail electric rate volatility.** The ICF study claims that the ACP will protect consumers against "extreme electricity price spikes and

---

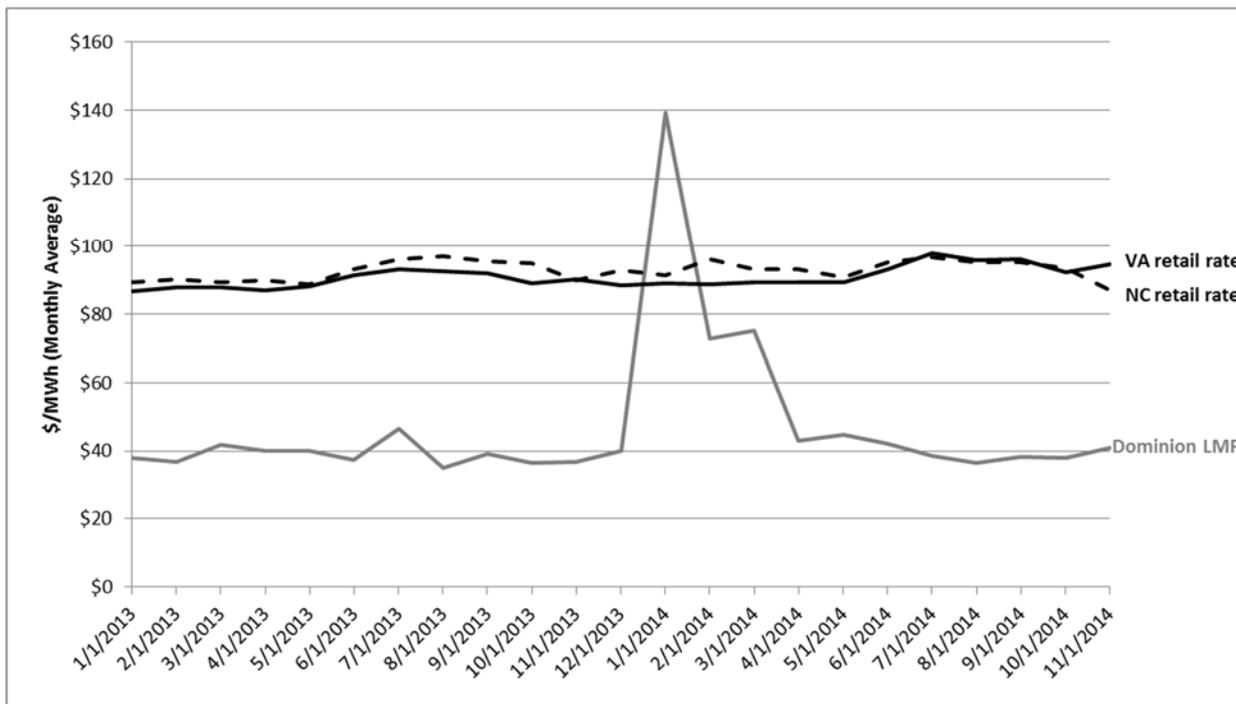
<sup>9</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Page 12.

<sup>10</sup> While the U.S. average personal savings rate is currently approximately 5 percent (<https://research.stlouisfed.org/fred2/data/PSAVERT.txt>), many studies evaluating economic impacts from energy efficiency assume that 100 percent of residential energy savings is re-spent on household goods. See Bower, S., S. Huntington, T. Comings, W. Poor. 2012. *Economic Impacts of Efficiency Spending in Vermont: Creating an Efficient Economy and Jobs for the Future. Optimal Energy*, Synapse Energy Economics, for the Vermont Department of Public Service and American Council for an Energy-Efficient Economy (ACEEE). Available here: [http://synapse-energy.com/sites/default/files/SynapsePaper.2012-08.ACEEE\\_Economic-Impacts-of-EE-in-VT.S0073.pdf](http://synapse-energy.com/sites/default/files/SynapsePaper.2012-08.ACEEE_Economic-Impacts-of-EE-in-VT.S0073.pdf).

<sup>11</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Exhibit 12.

volatility.”<sup>12</sup> Retail electric prices faced by consumers, however, do not track wholesale price movements and are largely insulated from abrupt price fluctuations in the wholesale electric market. For example, volatile wholesale electric prices in the eastern United States in January 2014 did not result in price spikes for retail customers, as shown in Figure 2.

**Figure 2: Wholesale (LMP) versus retail electric prices (\$/MWh monthly average)**



Source: EIA “Average Retail Price of Electricity Monthly”, available here: <http://www.eia.gov/electricity/data/browser/#/topic/7?agg=0>. Wholesale prices are based on Dominion LMP, available here: <http://www.pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx>

A wholesale price spike over several hours or even days does not translate into higher electric charges in customers’ monthly bills. Rather, it may result in a smaller increase in rates for all hours of the year, usually after a long delay. Regulated utilities’ fuel and energy costs are not immediately passed through to customers; instead, they are typically “trued up” on an annual or biannual basis.

**The ICF study does not make clear whether or not it has included costs to build new natural gas generation—a key component in calculating the net economic impacts of the pipeline.** The study presents the economic impacts of new natural gas electric generation that would be built as a result of the ACP. However, the costs to construct these facilities would be passed through to ratepayers, most directly in North Carolina. In Virginia, the costs of new facilities would have to be recovered by the

<sup>12</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Page 6.

revenues on the PJM markets; these costs would be socialized throughout the PJM region. In both cases, for accuracy, the costs of construction that flow through to customers should be accounted for in this study, if they are not already reflected in ICF's electricity bill impacts. If these costs are not included, then the electricity savings to customers is overstated.

**The report erroneously presents reliability impacts not relevant to Virginia and North Carolina.** ICF claims that the pipeline “enhances electric reliability in the region” yet does not present any direct evidence or quantification of this benefit.<sup>13</sup> ICF presents electric reliability impacts based on a Pepco filing in Maryland.<sup>14</sup> (Note that the study claims that Pepco serves parts of Virginia, but that is not the case.<sup>15</sup>) Savings from improved reliability, such as those presented by Pepco, are often based on customers' willingness-to-pay to avoid an outage and not on dollars that would actually flow in the economy. For instance, if a residential customer were willing to pay \$20 to avoid the trouble of an outage, that does not mean that the outage actually costs them \$20. Avoiding an outage is beneficial but does not necessarily translate to money in hand. Moreover, ICF implies that reliability would be improved through the additional natural gas plants assumed in their modeling. However, these new plants would be built in response to “regional load growth and capacity needs under the market assumptions used in this analysis”—not directly due to the ACP. ICF has not presented a reliability impact related to the ACP. Therefore, its claim that the pipeline improves reliability is unfounded.

**ICF's study of the ACP lacks the transparency necessary for third party review and verification.** The study does not provide critical data needed to confirm or critique its results. In an economic and jobs benefits analysis, a complete set of modeling assumptions, inputs, and outputs would typically include—in addition to the projected job and gross domestic product impacts provided by ICF—the following key data points:

a) Modeling inputs:

- Natural gas price forecasts: ICF does not provide natural gas price forecasts for Henry Hub and Dominion South, making it impossible to determine whether the study's expected gas price savings are reasonable. While historical and projected Henry Hub prices are available from other sources—including the U.S. Energy Information Administration (EIA)—projected Dominion South prices are not publicly available and historical prices are only available on an intermittent basis in EIA's “Natural Gas Weekly Update.”

---

<sup>13</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Page 14.

<sup>14</sup> ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Fairfax, VA: ICF International for Dominion Transmission, Inc. Exhibit 15.

<sup>15</sup> Pepco serves parts of Maryland and all of the District of Columbia, none of Virginia: <http://www.pepco.com/my-business/builders-and-inspectors/resources/service-area-map/>.

- Load forecasts: ICF does not provide their projections of how the region’s electric demand will change over time.
- Annual electric generation capacity build-out: ICF does not provide their assumptions regarding what types and sizes of energy generation facilities will be built in the region (or, in the case of Virginia, in the greater PJM region) and in what years these generators will be built.
- Conversion rate of gas to electric savings: ICF does not provide their assumptions regarding the gas-burning efficiency of the region’s electric generators.
- Rate impacts of new gas plants: ICF does not provide their assumptions regarding how much electric ratepayers will pay for new generation facilities and in what years.
- Annual pipeline construction and operation costs: ICF does not provide annual pipeline construction and operation costs.

b) Modeling outputs:

- Annual gas and electric cost savings: The study focuses on the economic impacts modeled in IMPLAN, the underlying economic assumptions of which are reasonably available and auditable. The inputs to IMPLAN used by ICF, however, are developed using its own proprietary Gas Market Model (GMM) and Integrated Planning Model (IPL), and have not been made available for review.
- Allocation of gas and electric savings by state: ICF does not provide a break-down of what gas and electric savings are projected to occur in what states.
- Annual economic and job impacts by sector: Economic impacts are not provided by year or by customer sector (residential, commercial and industrial) in the ICF study. Therefore, it is not possible to trace how purported savings are distributed over time and throughout the economy.

## 2. REVIEWING CHMURA’S ACP ANALYSIS

Synapse conducted a review of a 2014 analysis by Chmura entitled *The Economic Impact of the Atlantic Coast Pipeline in West Virginia, Virginia, and North Carolina*.<sup>16</sup> The Chmura analysis studied selected potential economic benefits of the ACP, during the expected construction phase and also after construction. The study estimated benefits such as tax revenue and job creation throughout the three-state region. As previously noted, this study is inadequate to inform a public decision-making process.

---

<sup>16</sup> Chmura Economics & Analysis. 2014. *The Economic Impact Of The Atlantic Coast Pipeline In West Virginia, Virginia, And North Carolina*. Richmond, VA: Chmura Economics & Analysis for Dominion Resources.

We found that the accuracy of the Chmura study cannot be assessed without additional information on their modeling assumptions and data inputs. In particular, a third-party audit of the Chmura report requires the release of detailed information on the expected spending categories and magnitude for building and operating the pipeline.

**Neither Chmura in its report nor Dominion and ACP in their background materials offer an appropriate level of detail regarding capital and operations spending for the pipeline.** In the absence of critical assumptions and inputs to Chmura’s modeling, we can only make inferences from observing the results of their economic analysis. Without detailed capital and operations spending assumptions provided either by Chmura or ACP, it is not possible to satisfactorily verify or critique these economic projections.

**The Chmura study provides detailed tax revenue benefits for three states, but fails to provide any underlying data or assumptions for these tax revenue calculations.** Chmura notes that it uses some IMPLAN assumptions to calculate total employment spending and business profits from total annual capital expenditures. For example, the study assumes that 34.5 percent of total revenue is paid as employment compensation while 1.4 percent is profit. However, the study provides no information regarding specific employment and business profit dollar values. Without this information, it is impossible to assess the accuracy of Chmura’s income and corporate tax calculations benefits. For income tax calculations, critical assumptions not provided in the study include what average wages and, therefore which income brackets and tax rates, have been assumed. Furthermore, Chmura neglects to provide either the method for calculating the cumulative tax revenues or the assumed interest rate. Without these critical details it is impossible to assess the accuracy of Chmura’s findings or to evaluate the expected job impacts of the ACP.

### 3. HIDDEN COSTS OF THE ACP

The ICF and Chmura reports do not include discussion of many serious costs associated with pipeline construction and operation. The ACP will pass through hundreds of communities and natural ecosystems, and the resulting impacts can be difficult to value in terms of dollars and cents. Pipeline construction and operation will involve real costs—in terms of public safety, human health and welfare, and impacts to property and natural resource values—which have been ignored in these reports. Below, we highlight a few of these hidden costs.

- **Very large, high-pressure natural gas transmission pipelines like the one proposed by Dominion pose substantial public safety risks to nearby residents.** The proposed 42-inch ACP would be one of the largest interstate natural gas pipelines in the United States. Accidents at natural gas transmission lines are particularly dangerous because the distance between shut-off valves is significant, meaning a rupture or leak would be fed by great quantities of gas even after being shut-down. Despite the passage of the Pipeline Safety Improvement Act in 2002, there have been more than 3,000 significant accidents, causing more than 150 fatalities, hundreds of injuries, and billions of dollars

in property damage,<sup>17</sup> including four major incidents in North Carolina, Virginia, and West Virginia in the last few years.<sup>18</sup> One of the most infamous recent accidents occurred on a 30-inch pipeline in San Bruno, California where the blast killed eight people, destroyed 38 homes, and registered as magnitude 1.1 earthquake.

- **The ACP project could have detrimental effects on property values in communities where the pipeline will be located.** The 550-mile, 42-inch pipeline will pass through 26 counties and hundreds of communities. Research by Boxall, et al. (2005) and Hansen, et al. (2006) show nearby pipelines may have negative impacts on property values, particularly following catastrophic events like the explosions cited above.<sup>19</sup> The Forensic Appraisal Group, LTD, found that the negative impact on property values could be “up to 30% or more of the whole property value.” Resale value is also a concern, particularly in states that require disclosure of potentially hazardous conditions. Reduced property values would lead to lower assessed real estate values and, therefore, lower tax revenues.
- **The presence of a 42-inch, high pressure natural gas pipeline like the ACP may lead to insurance and mortgage issues.** With increased media coverage of catastrophic events like the recent explosions in West Virginia and California, there is concern that insurance underwriters may already be increasing rates or even denying coverage for properties located near natural gas transmission lines.<sup>20</sup>
- **The construction of the ACP could lead to an increase in natural gas drilling in areas along the pipeline route that were not previously developed, including the George Washington National Forest, which is located on the southern edge of the Marcellus Shale formation.** Increased drilling activity brings with it a host of negative socio-economic impacts, such as air pollution, degradation of surface and groundwater, noise, significant heavy truck traffic, and damage to local roads and infrastructure, the burden for which falls on local residents and taxpayers. Further, interstate pipelines require compressor stations—typically located every 40-100 miles along the line—to move the

---

<sup>17</sup> See *Pipeline and Hazardous Materials Safety Administration’s Significant Incident Files*. Available at: <http://www.phmsa.dot.gov/pipeline/library/data-stats>.

<sup>18</sup> In September 2008 in Appomattox, VA, the 36-inch Transco pipeline ruptured. The explosion burned an area 1,125 feet in diameter. Twenty-three families were evacuated, two homes were destroyed, and five people were hurt. In late 2012, an explosion on a 20-inch gas pipeline in Sissonville, WV destroyed several homes and a section of Interstate 77 in both directions. A large explosion on a 12-inch pipeline in Asheville, NC in January 2014 damaged several homes and vehicles as well as two local businesses. At the beginning of 2015, an explosion at a 20-inch pipeline in Brooke County, WV sent two families from their homes.

<sup>19</sup> Boxall, P. C., W. H. Chan and M. L. McMillan. “The impact of oil and natural gas facilities on rural residential property values: a spatial hedonic analysis.” *Resource and Energy Economics*, 2005, 27:248-269; Hansen, J. L., E. D. Benson and D. A. Hagen. “Environmental Hazards and Residential Property Values: Evidence from a Major Pipeline Event.” *Land Economics*, 2006, 82:4, 529-541.

<sup>20</sup> See Pipeline Safety Trust’s “Landowners Guide to Pipelines,” 2014. Available at: [http://pstrust.org/wp-content/uploads/2014/07/pst\\_LandOwnersGuide\\_2014\\_forweb.pdf](http://pstrust.org/wp-content/uploads/2014/07/pst_LandOwnersGuide_2014_forweb.pdf).

gas from West Virginia to North Carolina.<sup>21</sup> Compressor stations can be noisy and produce air pollutants such as nitrogen oxides, hydrogen sulfides, and formaldehyde.

- **In addition to water impacts from increased gas development in the area, the construction of the pipeline itself could lead to water quality impacts.** Run-off and sedimentation during construction and chemical additives used to keep rights-of-way clear can impact local surface waters. Blasting and excavation could also affect aquifers and water tables. Gas companies are not subject to the Safe Drinking Water Act, and therefore are not required to disclose any chemicals that are in the gas they transport. Chemicals are used mainly for preventing corrosion of the pipeline and can include desiccants, coolants, and biocides for inhibiting microbial growth.<sup>22</sup> These chemicals could potentially leak into groundwater.
- **Pipeline construction may damage productive farmland and forest land.** Construction of the ACP will require land and forest clearing, with an estimated total land requirement of 4,600 acres. The pipeline operator will need to keep rights-of-way clear, and construction equipment may lead to soil compaction, which can affect crop production. Further, many trees will be removed to make way for the pipeline and access roads.
- **Pipeline construction and maintenance can have detrimental impacts on wildlife through habitat loss and fragmentation.** The ACP will cut through forests, wetlands, and other important wildlife habitat, putting pressure on native species' ability to survive. According to the U.S. Fish and Wildlife Service: "ROWs [rights-of-way] and other linear developments like transmission lines, roads, seismic lines and trails can increase human access into new areas, displace wildlife from their habitat, act as barriers to wildlife movement and affect migration routes. ROWs may cross different ecosystems and can fragment habitat, lead to the clearing of sensitive vegetation and create pathways for the spread of invasive species. ROW stream crossings can result in significant biological and engineering problems."<sup>23</sup>
- **Pipeline construction could affect the natural beauty and recreational value of areas like the Blue Ridge Mountains, Monongahela National Forest, and the George Washington National Forest.** Landscapes will be permanently scarred by pipeline rights-of-way, which could have significant impacts on tourism and the aesthetic value of these protected areas.

---

<sup>21</sup> See *The Transportation of Natural Gas*. Available at: <http://naturalgas.org/naturalgas/transport/>.

<sup>22</sup> Thompson, Neil G. "Gas and Liquid Transmission Pipelines." Available at: [http://www.dnvusa.com/Binaries/gasliquid\\_tcm153-378807.pdf](http://www.dnvusa.com/Binaries/gasliquid_tcm153-378807.pdf)

<sup>23</sup> <http://www.fws.gov/ecological-services/energy-development/pipelines.html>

**People's Dossier: FERC's Abuses of Power and Law**  
→ **Deficient Needs Analysis**

**Deficient Needs Analysis Attachment 16**, Motion to Intervene out-of-time of the PPL Electric Utilities Corporation re the Transcontinental Gas Pipeline Company, FERC Docket No. CP15-138-000, March 6, 2017.

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

Transcontinental Gas Pipe Line ) Docket No. CP15-138-000  
Company

**MOTION TO INTERVENE OUT-OF-TIME OF  
OF PPL ELECTRIC UTILITIES CORPORATION**

Pursuant to Rules 211 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“Commission”),<sup>1</sup> PPL Electric Utilities Corporation (“PPL Electric”) hereby moves to intervene out-of-time in the above-captioned proceeding.

**I. COMMUNICATIONS**

Communications regarding this filing should be directed to:

Michael J. Shafer, Esq.  
2 North Ninth Street, GENTW4  
Allentown, PA 18101-1179  
Tel: (610) 774-6077  
Fax: (610) 774-2881  
Email: mjshafer@pplweb.com

Sandra E. Rizzo  
Rebecca J. Michael  
Renee Beaver  
Arnold & Porter Kaye Scholer LLP  
601 Massachusetts Ave., N.W.  
Washington, D.C. 20001  
Tel: (202) 942-5000  
Fax: (202) 942-5999  
Email: Sandra.Rizzo@apks.com  
Rebecca.Michael@apks.com  
Renee.Beaver@apks.com

**II. DESCRIPTION OF MOVANT**

PPL Electric is a Pennsylvania corporation and a wholly owned subsidiary of PPL Corporation. PPL Electric is an owner of transmission facilities in PJM

---

<sup>1</sup> 18 C.F.R. §§ 385.212, 385.214 (2016).

Interconnection, L.L.C., and distributes electricity to all retail customers within its service territory in central eastern Pennsylvania. The proposed construction corridor for the Atlantic Sunrise Project crosses through PPL Electric's service territory and Transco is seeking to condemn a PPL Electric right-of-way that will adversely impact PPL Electric's transmission infrastructure development plans.

### **III. INTERVENTION**

Rule 214(d) directs the Commission to consider the following when deciding whether to grant a late intervention: (1) whether the movant had good cause for failing to file the motion with the time prescribed; (2) whether any disruption of the proceeding might result from permitting the intervention; (3) whether the movant's interest is not adequately represented by other parties in the proceeding; and (4) whether any prejudice to, or additional burdens upon, the existing parties might result from permitting the intervention.<sup>2</sup> PPL Electric has good cause for not having filed earlier to intervene in this proceeding, its interest cannot be represented by any other party, and its participation will not prejudice or impose a burden on any other party. Therefore, PPL Electric should be permitted to intervene in this proceeding.

Good cause exists for the Commission to grant PPL Electric leave to intervene out-of-time in this proceeding. PPL Electric recently has become aware of the extent to which Transco intends to use PPL Electric's right-of-way during the construction and operation of the Atlantic Sunrise Project. Rather than constructing its pipeline on the periphery of the right-of-way to minimize impacts

---

<sup>2</sup> See 18 C.F.R. § 385.214(d).

on PPL Electric, Transco plans to construct its path centrally within the right-of-way, which is expected to interfere with PPL Electric's ability to construct a transmission line on the right-of-way to meet customer needs and improve transmission system resiliency.

Transco's assurances that it understood PPL Electric's transmission needs and could construct the pipeline on the periphery of the right-of-way to minimize impact, led PPL Electric to believe that the impacts of Transco's plans were minimal when in fact, the opposite is true. In prior proceedings where a party was not provided with adequate notice of a project's scope and/or impact, the Commission determined that good cause existed to grant a late intervention.<sup>3</sup>

PPL Electric recognizes that the Commission's disfavors granting motions to intervene made at the rehearing stage of a proceeding. However, good cause exists in this instance. PPL Electric accepts the record as it currently exists, and its interest as a property owner who -- in the near term -- has necessity to use its existing right-of-way for its own construction project cannot adequately be represented by any other party.

PPL Electric's late intervention will impose no disruption or delay in this proceeding. Numerous parties have already filed motions for rehearing of the Commission's February 3, 2017 Order Issuing Certificate<sup>4</sup> and for a stay of these proceedings. The Commission will already need comprehensively to address concerns regarding the order in light of those pleadings.

---

<sup>3</sup> See, e.g., *Florida Gas Transmission Co.*, 100 FERC ¶ 61,282 at P10-11 (2002)

<sup>4</sup> *Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 (2017).

#### IV. CONCLUSION

WHEREFORE, for the foregoing reasons, PPL Electric respectfully requests that the Commission grant its Motion to Intervene Out-of-Time, making it a party to his proceeding.

Respectfully submitted,

/s/ Sandra E. Rizzo

Sandra E. Rizzo

Rebecca J. Michael

Renée Tyndell Beaver

Arnold & Porter Kaye Scholer LLP

601 Massachusetts Avenue, N.W.

Washington, D.C. 20001

Tel: (202) 942-5826

Fax: (202) 942-5999

E-mail: Sandra.Rizzo@apks.com

Rebecca.Michael@apks.com

Renee.Beaver@apks.com

*Attorneys for PPL Electric Utilities  
Corporation*

March 6, 2017

## CERTIFICATE OF SERVICE

I hereby certify that I served a copy of the foregoing pleading this March 6th, 2017, upon each person designated on the official service list compiled by the Secretary in this proceeding.

*/s/ Darrell Reddix*

---

Darrell Reddix