



June 16, 2014

**VIA ELECTRONIC FILING**

Kimberley D. Bose, Secretary  
Federal Energy Regulatory Commission  
888 First Street NE, Room 1A  
Washington, DC 20426

**Re: Comments on Environmental Assessment for Dominion Cove Point LNG, LP  
Docket No. CP13-113-000**

Dear Secretary Bose:

On behalf of the Intervenor Chesapeake Climate Action Network (“CCAN”), EarthReports, Inc. (dba Patuxent Riverkeeper); Potomac Riverkeeper, Inc.; Shenandoah Riverkeeper; Sierra Club; and Stewards of the Lower Susquehanna, Inc. (collectively, “Intervenor”), the undersigned respectfully submit these comments on the “Environmental Assessment for the Cove Point Liquefaction Project” (“EA”) issued by the Federal Energy Regulatory Commission (“FERC”) on May 15, 2014.

TABLE OF CONTENTS

- I. PROJECT BACKGROUND .....1
- II. REVIEW UNDER THE NATIONAL ENVIRONMENTAL POLICY ACT.....3
- III. FERC HAS NOT SUPPORTED ITS CONCLUSION THAT IDENTIFIED IMPACTS WILL BE INSIGNIFICANT.....4
  - A. FERC Improperly Discounts the Potentially Significant Safety Impacts of Constructing a Liquefaction Facility on a Compressed Footprint, in a Residential Neighborhood. ....4
  - B. FERC Improperly Discounts Potentially Significant Air Quality Impacts of Constructing and Operating the Facility.....9
  - C. FERC Improperly Discounts the Potentially Significant Impacts of Increasing Industrial Shipping in the Chesapeake Bay.....14
    - 1. FERC Improperly Disregards the Potentially Significant Impacts Associated with Ballast Discharges. ....15
    - 2. FERC Improperly Disregarded the Potentially Significant Impacts from Fouling Organisms. ....18
  - D. FERC Improperly Discounts the Potentially Significant Impacts on the Highly Endangered North Atlantic Right Whale.....18
  - E. FERC Ignores the Reality of Climate Change, a Factor that Contributes to the Significance of the Project’s Impacts.....25
- IV. FERC COMPLETELY FAILS TO TAKE A HARD LOOK AT POTENTIALLY SIGNIFICANT INDIRECT IMPACTS. ....29
  - A. FERC Fails to Take a Hard Look at the Potentially Significant Impacts from Upstream Gas Development. ....30
    - 1. Additional Natural Gas Production and Pipeline Development Is a Reasonably Foreseeable Indirect Effect of the Project. ....32
    - 2. Recent Announcements Confirm that the Project Will Spur Additional Natural Gas Production in the Marcellus Shale.....34
    - 3. Induced Natural Gas Production Is Likely to Impose Significant Environmental Harms. ....40
      - a. Natural Gas Production Is a Major Source of Air Pollution. ....40
      - b. Natural Gas Production Disrupts Landscapes and Habitats. ....43

c.	Natural Gas Production Poses Risks to Ground and Surface Water.....	45
d.	Impacts of Additional Development at Cabot’s Wells Are Potentially Significant.....	49
B.	FERC Fails to Take a Hard Look at the Potentially Significant Impacts of Natural Gas Transmission to Cove Point.....	50
1.	Additional Pipeline Development.....	51
2.	Additional Compressor Station.....	54
C.	FERC Fails to Take a Hard Look at the Fact that the Project Will Contribute to Climate Change. ....	56
V.	FERC’S ANALYSIS OF PROJECT ALTERNATIVES IS DEFICIENT. ....	60
A.	The Description of the No Action Alternative Fails to Meet NEPA’s Requirements. ....	61
B.	The EA Impermissibly Limits the Scope of FERC’s Alternatives Analysis. ....	62
VI.	THE DRAFT EA IS BASED ON INCOMPLETE INFORMATION.....	63
VII.	THE PROJECT IS NOT IN THE PUBLIC INTEREST AND IS NOT REQUIRED BY THE PUBLIC CONVENIENCE AND NECESSITY. ....	65
VIII.	CONCLUSION.....	66

## **I. Project Background**

On April 1, 2013, Dominion Cove Point LNG, LP (“Dominion”) filed an application with FERC seeking authorization to construct, install, modify, own, operate, and maintain facilities for liquefaction and export of natural gas at Cove Point, Maryland, and for a Certificate of Public Convenience and Necessity. In particular, Dominion sought permission to (1) construct and operate liquefaction facilities capable of processing 5.75 million metric tons per annum of liquefied natural gas (“LNG”) at its existing LNG import terminal in Cove Point, Maryland; (2) install additional compression at the Pleasant Valley Compressor Station, complete piping and measurement upgrades at the Pleasant Valley Metering and Regulating (“M&R”) Facility, and install and replace the Pleasant Valley Suction/Discharge Pipelines in Virginia; (3) complete piping and measurement upgrades at the Loudon M&R Facility at the Loudon Compressor Station in Loudon County, Virginia; and (4) use temporary locations in Maryland and Virginia to support construction (collectively, the “Project”).

Dominion is proposing substantially to expand its industrial operations in Calvert County. If approved, the Project would resuscitate the largely defunct Cove Point LNG import terminal near Lusby, Maryland, converting Cove Point into a bustling center for LNG exports. Dominion is seeking a green light to build a new liquefaction facility and a new utility-scale power plant to power the liquefaction—all within 59.5 acres at its existing site. That site, unlike most other proposed LNG facilities, will be located in the midst of a populated area, within 1,000 feet of a residential community. The facility is situated just off of Cove Point Road, the only emergency evacuation route for those living on the Cove Point peninsula. That route also will be used to truck hazardous and combustible chemicals needed for the liquefaction process through the surrounding residential community for storage on site. Moreover, the Cove Point peninsula is particularly susceptible to the effects of climate change, such as increased and more severe hurricanes and flooding. The potential superstorms could damage the facility’s infrastructure and complicate evacuation efforts, heightening the safety risks created by crowding so much infrastructure onto a small footprint and close to residences.

In addition, construction of the facility threatens to emit harmful amounts of nitrogen oxides, carbon monoxides, and particulates. Operation of the facility likewise will increase emissions of nitrogen dioxide, as well as sulfur dioxide, to levels at or exceeding air quality standards and harmful to human health. Emissions of nitrogen dioxide, an ozone precursor, are all the more troubling considering that Cove Point is located in an area that already fails to attain air quality standards established to protect human health from ozone.

Moreover, the Project threatens the health of the already impaired Chesapeake Bay. As soon as 2017, Dominion would begin receiving at least 85 massive LNG tankers per year at its pier on the Chesapeake Bay. Each of the tankers will dump an estimated 16 to 25 million gallons of foreign ballast water, likely drawn from the coastal waters of India and Japan, into the Chesapeake Bay before loading and transporting LNG from Cove Point. Marine experts have raised concerns that increasing shipping to Cove Point could introduce invasive species, while ballast water discharges could release into the Bay not only invasive species but also radioactive contamination and cholera bacteria. Moreover, each tanker is expected to travel directly in the migratory path of the critically endangered North Atlantic right whale, increasing the risk of ship strike and threatening the species’ recovery.

In addition to these direct impacts, exporting natural gas from Cove Point will spur additional natural gas production, likely in the Marcellus shale. Natural gas production in the Marcellus shale will require the controversial process of hydraulic fracturing, which risks serious impacts to air and water quality. Moreover, as new wells are drilled and fractured, industry is likely to build additional pipelines and compressor stations to bring the gas to market. All of this development threatens environmental quality. Finally, the new liquefaction facility and associated utility-scale power plant that Dominion is proposing to build would emit more heat-trapping carbon dioxide than all but three of Maryland's existing coal plants. Including the greenhouse gas emissions from extraction, transportation, and processing of the LNG produced at Cove Point, the Project could cause more greenhouse gas emissions than all seven of the state's coal-fired power plants combined.

Given the breadth of impacts, the Project has garnered local and national attention. Patuxent Riverkeeper, Potomac Riverkeeper, Inc., Shenandoah Riverkeeper, Sierra Club, and Stewards of the Lower Susquehanna, filed comments on Dominion's application on May 3, 2013,<sup>1</sup> and CCAN submitted comments on October 23, 2013.<sup>2</sup> Intervenors supplemented those comments throughout the proceeding, as new information and analyses emerged.<sup>3</sup> The comments identified many potentially significant adverse impacts that the Project might cause—from risking the introduction of invasive species into the sensitive waters of the Chesapeake Bay, to contributing 26 million tons of greenhouse gases to the already warming atmosphere, to polluting the gas-producing areas in the Marcellus shale. Given the severity of harmful impacts, Intervenors called on FERC to conduct a comprehensive review of the Project in an Environmental Impact Statement ("EIS").

Nonetheless, on May 15, 2014, FERC issued the EA, with a recommended finding that, with appropriate mitigation, Dominion's Project would not significantly impact the environment, a finding formally called a mitigated "Finding of No Significant Impact" ("FONSI"). EA at 186. After the publication of the EA, Intervenors filed a request with FERC for a 60-day extension of the comment period to allow Intervenors and the public time to provide meaningful comments on the technical issues and significant environmental impacts associated with the Project.<sup>4</sup> Senator Mikulski, Senator Cardin, Congressman Hoyer, and Congressman Van Hollen also formally requested that the comment period be extended for an additional 30 days.<sup>5</sup> Region III of the Environmental Protection Agency ("EPA") similarly asked FERC for 30 additional days "to

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<sup>1</sup> Comment of Sierra Club et al., dated May 3, 2013, Accession No. 20130503-5215.

<sup>2</sup> Comment of Chesapeake Climate Action Network, dated October 23, 2013, Accession No. 20131023-5087.

<sup>3</sup> See Comment of EarthReports et al., dated April 24, 2014, Accession No. 20140424-5205; Comment of EarthReports et al., dated April 4, 2014, Accession No. 20140416-5141; Comment of EarthReports et al., dated Feb. 24, 2014, Accession No. 20140224-5140; Comment of EarthReports et al., dated February 19, 2014, 20140219-5145; Comment of EarthReports et al., dated November 8, 2013, Accession No. 20131108-5136; Comment of EarthReports et al., dated September 26, 2013, Accession No. 20130926-5042; and Comment of EarthReports et al., dated July 9, 2013, Accession No. 20130709-5054. These comments are incorporated by reference herein.

<sup>4</sup> Letter from CCAN and Earthjustice to Kimberly D. Bose, Secretary, FERC, dated May 21, 2014, Accession No. 20140521-5113.

<sup>5</sup> Letter from Congressman Steny H. Hoyer, Senator Barbara Mikulski, Senator Ben Cardin, and Congressman Chris Van Hollen to Cheryl A. LaFleur, Acting Chairman, FERC, dated May 23, 2014, Accession No. 20140602-0029.

conduct a complete and comprehensive review of the EA.”<sup>6</sup> FERC flatly rejected these requests on June 11, 2014, with no explanation.<sup>7</sup>

## II. Review Under the National Environmental Policy Act.

The National Environmental Policy Act (“NEPA”) is our “basic national charter for protection of the environment.” 40 C.F.R. § 1500.1(a). The statute makes environmental protection a part of the mandate of every federal agency, and requires federal agencies to take environmental considerations into account in their decision-making “to the fullest extent possible.” 42 U.S.C. § 4332; *Calvert Cliffs Coordinating Comm. v. U.S. Atomic Energy Comm’n*, 449 F.2d 1109, 1112 (D.C. Cir. 1971). Accordingly, each agency must take a “hard look” at the environmental consequences of its proposed actions. *Marsh v. Or. Natural Res. Council*, 490 U.S. 360, 378 (1989). Under the “hard look” standard, the burden rests entirely on the agency to make a “convincing case” for its FONSI. *Grand Canyon Trust v. FAA*, 290 F.3d 339, 341 (D.C. Cir. 2002) (quoting *Sierra Club v. U.S. Dep’t of Transp.*, 753 F.2d 120, 127 (D.C. Cir. 1985)). A FONSI is legally inadequate when, for example, “1) it does not adequately investigate all the environmental issues raised by the plaintiffs, and 2) with respect to a number of environmental issues considered, it does not include a statement of reasons why those effects are not significant.” *Joseph v. Adams*, 467 F. Supp. 141, 155 (E.D. Mich. 1978). Moreover, where the agency has not made a convincing case that the impact was insignificant, it must prepare an EIS. *See Ocean Advocates v. U.S. Army Corps of Engineers*, 402 F.3d 846, 864 (9th Cir. 2005) (explaining that to avoid preparing an EIS, the agency bears the burden of “put[ting] forth a ‘convincing statement of reasons’ that explains why the project will impact the environment no more than insignificantly”).

Under NEPA, FERC must fully assess and disclose the complete range of environmental consequences of Dominion’s proposal to expand and significantly overhaul its industrial operations on the shores of the Chesapeake Bay. Such consequences include “ecological [effects] (such as the effects on natural resources and on the components, structures, and functioning of affected ecosystems), aesthetic, historic, cultural, social, [and] health [effects] . . . whether direct, indirect, or cumulative.” 40 C.F.R. § 1508.8; *see also id.* §§ 1502.16(a), (b). Direct effects are “caused by the action and occur at the same time and place.” *Id.* § 1508.8(a). Indirect effects are caused by the action “later in time or farther removed in distance, but are still reasonably foreseeable.” *Id.* § 1508.8(b). Indirect effects may include “growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems.” *Id.* Cumulative impacts are “impact[s] on the environment which result[] from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions.” *Id.* § 1508.7. As the regulations make clear, “[c]umulative impacts can result from individually minor but collectively significant actions taking place over a period of time.” *Id.* In addition, NEPA requires that FERC take a hard look at the ways to avoid or mitigate the Project’s impacts. *See id.* § 1508.20.

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<sup>6</sup> Letter from John Pompanio, Director, Environmental and Assessment Division, United States Environmental Protection Agency, Region III, to Kimberly D. Bose, Secretary, FERC, dated June 9, 2014, Accession No. 20140609-0017.

<sup>7</sup> Notice Denying Extension of Time, Docket No. CP13-113, dated June 11, 2014, Accession No. 20140611-4006.

The EA glosses over the many of the Project’s significant impacts, and completely ignores many others. The Project’s unique geographic setting—its context and the intensity of its effects—contribute to the significance of the impacts. *See id.* § 1508.27(a) (the significance of the action must be evaluated in light of its context, including “the affected region, the affected interests, and the locality”); *id.* § 1508.27(b) (intensity refers to the “severity of impact,” taking into account the degree to which a project affects public health or safety, ecologically critical areas, and endangered and threatened species or habitat). The residential character of the neighborhood surrounding the proposed export terminal; the compressed footprint on which Dominion will be operating the industrial equipment and storing hazardous chemicals; the limited evacuation routes off the Cove Point peninsula; the location on the currently impaired Chesapeake Bay; and the fact that Calvert County is not currently meeting air quality standards designed to protect human health from ozone pollution all enhance the significance of the Project’s impacts. Given the numerous potential significant impacts described below, FERC should have prepared an EIS for the Project. *Grand Canyon Trust*, 290 F.3d at 340 (“If any ‘significant’ environmental impacts *might* result from the proposed agency action then an EIS must be prepared before agency action is taken.” (quoting *Sierra Club v. Peterson*, 717 F.2d 1409, 1415 (D.C. Cir. 1983))).

### **III. FERC Has Not Supported Its Conclusion That Identified Impacts Will Be Insignificant.**

Dominion’s Project is poised to threaten public safety, to disturb air quality, to introduce invasive species into the Chesapeake Bay, and to jeopardize recovery of the critically endangered North Atlantic right whale. Notwithstanding FERC’s claims in the EA, available evidence strongly suggests that the Project’s impacts on these resources will be significant. Without a convincing rationale for its conclusion to the contrary, FERC has not supported its FONSI, and the EA is deficient. Instead, given the potential significance of the impacts described below, FERC should have prepared an EIS for the Project.

#### **A. FERC Improperly Discounts the Potentially Significant Safety Impacts of Constructing a Liquefaction Facility on a Compressed Footprint, in a Residential Neighborhood.**

The degree to which the Project could affect public safety is central to the determination of significance under NEPA. *See* 40 C.F.R. § 1508.27(b)(2); *see also* 18 C.F.R. § 380.12(m) (requiring applications for new LNG facilities to include a Resource Report addressing “the potential hazard to the public from failure of facility components resulting from accidents or natural catastrophes, how these events would affect reliability, and what procedures and design features have been used to reduce potential hazards”). The EA fails to establish that FERC evaluated the significance of community safety impacts in the context of the Project’s local setting or that it considered the intensity of those potential impacts, as required under Council on Environmental Quality (“CEQ”) regulations. *See* 40 C.F.R. § 1508.27(a)-(b). Proper consideration of the Project’s context and the potential severity of impacts on nearby residents from an accident at the facility demonstrates that the safety risks of the Project alone warrant the preparation of an EIS. *See Ctr. for Biological Diversity v. Nat’l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1185 (9th Cir. 2008) (“If there is a substantial question whether an action ‘may have a significant effect’ on the environment, then the agency must prepare an [EIS].” (citing

*Blue Mountains Biodiversity Project v. Blackwood*, 161 F.3d 1208, 1212 (9th Cir. 1998)); *see also Ocean Advocates*, 402 F.3d at 865 (citing *Nat'l Parks & Conservation Ass'n v. Babbitt*, 241 F.3d 722, 731 (9th Cir.2001)).

The Project also is closer to a residential community than the other LNG export project FERC has evaluated to date. Dominion's facility is directly across Cove Point Road from a significant number of homes, with some residences located fewer than 500 feet from the fenced area.<sup>8</sup> The Project also is directly adjacent to Cove Point Park, a popular recreational facility with baseball fields and a swimming pool.

In addition, the Project site has a much smaller footprint than those of the LNG terminals considered by FERC to date. The "land affected during operation" of the Project's liquefaction facility is 59.5 acres. EA at 32. By comparison, the "operational footprint" of the Freeport LNG "liquefaction plant and associated facilities" is 259.7 acres.<sup>9</sup> The draft EIS for the Cameron LNG facility does not provide acreage for the operation of the liquefaction facility, but lists the "land affected during operation" of the terminal at 502.2 acres.<sup>10</sup> Even factoring in the different number of liquefaction trains at each facility—Dominion has proposed to operate one train, while the owners of the Cameron and Freeport facilities have proposed to operate three trains at each facility—Dominion is proposing to use a much more limited area to produce and store LNG on a per train basis than any other LNG terminal that FERC has considered. The small land area available for the Project facilities increases the likelihood that an accident would result in a cascading event involving multiple different components of the Project. For example, an explosion involving the tanks of condensate could create shrapnel capable of piercing the nearby single containment LNG storage tanks.

Calvert County also is a particularly risky location for an LNG export terminal because of the unique geography of the area. The County is located on a peninsula, with limited transportation routes through and out of the region. Any accident or incident affecting Cove Point Road, including a chemical spill or an explosion is likely, therefore, to cut off the evacuation route for many local residents and pose a significant threat to their safety. FERC's failure to consider the context of the Project in determining the significance of the associated impacts, calls the proposed FONSI into serious question. *See* 40 C.F.R. § 1508.27; *see also Barnes v. U.S. Dep't of Transp.*, 655 F.3d 1124, 1139 (9th Cir. 2011) (determining whether an action "significantly" affects the quality of the human environment... requires consideration[] of [the] context" or "setting in which the agency's action takes place").

The County is located, moreover, on the Chesapeake Bay, an area that is susceptible to natural disasters.<sup>11</sup> The Bay coast is particularly vulnerable to threats such as hurricanes, shore

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<sup>8</sup> The fenced area is the 131-acre space on Dominions property within which Dominion is able to construct and operate industrial equipment. EA at 3.

<sup>9</sup> Draft Environmental Impact Statement for the Freeport LNG Liquefaction Project at 2-9, Docket CP12-509-000, Accession No. 20140314-4002 (Mar. 14, 2014).

<sup>10</sup> Draft Environmental Impact Statement for the Cameron Liquefaction Project at 2-14, Docket CP13-25-000. Accession No. 20140110-4001 (Jan. 10, 2014) ("Cameron DEIS").

<sup>11</sup> Raymond G. Najjar et al., *Potential Climate-Change Impacts on the Chesapeake Bay*, 86 *Estuarine, Coastal and Shelf Science* 2 (2010), available at [http://www.ocvts.org/classroomconnect/classrooms/jwnek/documents/Oceanography/Global\\_Change\\_Chesapeake.pdf](http://www.ocvts.org/classroomconnect/classrooms/jwnek/documents/Oceanography/Global_Change_Chesapeake.pdf).

erosion, coastal flooding, storm surge, and inundation.<sup>12</sup> During Hurricane Isabel which made landfall in North Carolina as a Category 2 hurricane in 2003, tides in the Chesapeake Bay ran five to eight feet above normal.<sup>13</sup> The remnants of Hurricane Isabel that affected the area near the proposed export terminal also were quite powerful. Wind gusts reached 69 miles per hour at the Patuxent Naval Air Station, located across the Patuxent River from the Project.<sup>14</sup> The area also has experienced sea level rise of nearly twice the global average over the last 100 years due to naturally-occurring regional land subsidence.<sup>15</sup> As is discussed below, climate change has the potential to significantly augment the impacts the Chesapeake Bay area will face from hurricanes and flooding. *See infra* Section III.E. Among other impacts, hurricanes and storm surge can wreak havoc on the pier, and the LNG carriers en route to the pier. The coastal location of the export facilities is an aspect of the context that must be considered in assessing the significance of Project impacts on safety.

FERC also must to consider the intensity of the impacts of the Project, including the “degree to which the proposed action affects public health or safety.” 40 C.F.R. § 1508.27(b); *see also Klamath-Siskiyou Wildlands Ctr. v. U.S. Forest Serv.*, 373 F. Supp. 2d 1069, 1078-79 (E.D. Cal. 2004). The unique characteristics of the geographic setting of the Project discussed above intensify safety impacts. *See* 40 C.F.R. § 1508.27(b)(2). The constrained footprint of the facility also elevates risks of severe impacts on public safety. Considerations of both context and intensity thus require preparation of an EIS for the Project.

Given the unique setting of the Project and the potential intensity of impacts on the community, FERC’s refusal to require a Quantitative Risk Assessment (“QRA”) of the Project’s threats to public safety leaves the FONSI without adequate support.<sup>16</sup> FERC claims that a QRA is not possible because “differing failure rate data (often by several orders of magnitude), choice of consequence models, and hazard scenario selection that can be used under its QRA method can lead to inconsistent results for essentially identical facilities.” EA at 148. FERC also states that it is waiting for the National Fire Protection Association (“NFPA”) to develop specific assumptions, databases, and models to use as a basis for the QRA before FERC undertakes QRAs on LNG facilities. The Maryland Department of Natural Resources managed, however, to conduct a QRA for one of the phases of Dominion’s LNG import facility as long ago as 2006. Moreover, the NFPA’s failure to develop a methodology for LNG facilities does not relieve FERC of its responsibility to conduct its own analysis, contrary to the agency’s assertion. *See id.* The Project would be a complex industrial development involving the addition of multiple hazardous components, each of which presents potentially significant risks both alone and in combination with other components at the site. Dominion also is proposing the relatively novel idea of using a 60-foot-high sound wall to protect the community from LNG vapor clouds. EA

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<sup>12</sup> *See* Maryland Commission on Climate Change Adaptation and Response Working Group, Report: Comprehensive Strategy for Reducing Maryland’s Vulnerability to Climate Change, Phase I: Sea-Level Rise and Coastal Storms 3 (July 2008), *available at* <http://www.mde.state.md.us/assets/document/Air/ClimateChange/Chapter5.pdf>.

<sup>13</sup> Kevin Ambrose, *Remembering Hurricane Isabel, 10 Years Later*, Washington Post (Sept. 18, 2013) *available at* <http://www.washingtonpost.com/blogs/capital-weather-gang/wp/2013/09/18/remembering-hurricane-isabel-10-years-later-photos/>.

<sup>14</sup> *Id.*

<sup>15</sup> Maryland Commission on Climate Change Adaptation and Response Working Group, *supra* note 12, at 3.

<sup>16</sup> *See* Comments by Susan Allison, Docket CP13-113, Accession No. 20140522-5099 (May 22, 2014); Comments by Dale Allison, Docket CP13-113, Accession No. 20140205-5035 (Feb. 5, 2014).

at 150. There is a clear need for FERC to assess the risks of locating an LNG liquefaction facility, with all its attendant hazardous constituents on a small footprint, within less than 1,000 feet of residences, in an area with limited evacuation routes, and in a region that experiences severe Atlantic weather systems, including major hurricanes. Without conducting a QRA or similar study cumulatively evaluating all of the risk scenarios the Project poses to the community, FERC cannot carry its burden of showing that the Project impacts will be insignificant, as required under NEPA.

The EA also fails to consider other substantial safety risks to the surrounding community and the workers at the Project, including: (1) the safety impacts of the trucks carrying refrigerant to and condensate from the Project, (2) the close proximity of the ground flare to the truck loading/unloading area, and (3) the potential for a leak of LNG into the tunnel connecting the LNG facility to the pier. Rather than discussing risks presented by the trucks Dominion will use to deliver refrigerant components to the site, FERC baldly asserts that the trucks are nonjurisdictional and therefore need not be evaluated in the EA. EA at 17. This approach evades analysis of a key safety issue that the community would not face but for the Project. It is clear from the measures taken to protect the storage tanks in which these same components will be stored at the Project that these materials present a significant safety risk. Indeed, Dominion has agreed to “mound” or partially bury the condensate and refrigerant make-up tanks “in a minimum of 2-feet of soil to mitigate radiant heat from nearby fires.” EA at 128. No such protective measures have been provided for the delivery trucks. The potential consequences of a Boiling Liquid Expanding Vapor Explosion (“BLEVE”) caused by exposure of an ethylene or propane tanker truck to fire could be catastrophic, particularly if the BLEVE occurred while the truck was in the loading/unloading facility at the Project. Recognized and generally accepted means of calculating thermal radiation exposure suggest that the trucking area design might not meet acceptable separation distance criteria for ethylene and propane, and a leak from that area could result in impacts beyond the property line.<sup>17</sup> Vessel fragments could be hurled between 8,000 feet and 13,000 feet. It is very likely that such distances will extend beyond the property lines for this LNG site. The EA fails to consider this issue, to evaluate whether any residences across the road from the Project site would be impacted, or to consider how the 60 foot sound wall would be impacted by a BLEVE. FERC also has not addressed the risks posed by two these trucks carrying hazardous materials to and from the facility along community roads every day. See EA at 17. There also is no indication that any mitigation measures have been proposed to address this significant risk.

The tank truck loading/unloading installation also is adjacent to a ground flare that contains numerous continually burning pilots. *Id.* at 151 Fig. 2.8.6-1. If a spill occurred at the loading/unloading installation, the vapors from the spill could drift into the ground flare area at concentrations above the lower flammable limits. Once the flammable vapor cloud reaches a source of ignition, a flame could propagate through the vapor cloud, fatally burning anyone within the vapor cloud.<sup>18</sup> The EA does not discuss the risk of siting the ground flare and the

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<sup>17</sup> Kevin B. McGrattan et al., Nat’l Inst. of Standards and Tech., U.S. Dep’t of Commerce, *Thermal Radiation from Large Pool Fires* 11-21 (2000), available at [http://www.nist.gov/manuscript-publication-search.cfm?pub\\_id=909967](http://www.nist.gov/manuscript-publication-search.cfm?pub_id=909967).

<sup>18</sup> See, e.g., P.J. Rew et al., U.K. Health and Safety Executive, HSE Contract Research Report No. 94/1996: Review of Flash Fire Modeling 4 (1996), available at [http://www.hse.gov.uk/research/crr\\_pdf/1996/crr96094.pdf](http://www.hse.gov.uk/research/crr_pdf/1996/crr96094.pdf).

unloading/loading installation within such close proximity, and therefore fails to address a major safety risk posed by the Project.

Another safety issue that the EA ignores is the potential for a leak of LNG within the tunnel between the LNG liquefaction and storage site and the marine loading terminal located on the offshore pier. The LNG piping in the tunnel has expansion joints that can be the source of leaks. If such a leak were to occur, damaging levels of overpressure could be produced at either end of the tunnel, where the ships are loaded with LNG or onshore. Leaks of LNG could produce vapor clouds, which, if confined within a rigid structure like the Project's tunnel, have the potential to produce high levels of overpressure leading to explosions.<sup>19</sup> The EA does not discuss the risk of a potential explosion involving the tunnel linking the Project to the pier, the likelihood of which would significantly increase as Dominion's facility goes from being virtually idle to providing LNG to up to 200 ships per year for export. The EA summarily states only that Dominion should take measures to mitigate vapor dispersion into confined areas such as buildings, EA at 129, but that suggestion disregards the intensity of the foreseeable impacts from an LNG vapor cloud explosion involving the tunnel.

The unanalyzed safety impacts identified above are potentially devastating and require the preparation of an EIS. Unfortunately, there may well be additional flaws in FERC's analysis of the safety impacts of the Project that cannot be ascertained from materials in the public docket. The vast majority of the documents bearing on safety have been filed by Dominion as either Critical Energy Infrastructure Information ("CEII") or Privileged under FERC's regulations. See 18 C.F.R. §§ 388.112, 388.113. Although the regulations allow individuals with a need for the information to sign a confidentiality agreement and obtain access to materials filed as CEII, *id.* § 388.113,<sup>20</sup> Earthjustice attorneys seeking the materials under those regulations were unable to obtain most of the requested CEII prior to the comment deadline on the EA.<sup>21</sup>

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<sup>19</sup> See Comm. for the Prevention of Disasters by Hazardous Materials, *Methods for the Calculation of Physical Effects Due to Releases of Hazardous Materials (Liquids and Gases)* 5.13-20 (C.J.H. van den Bosch and R.A.P.M. Weterings eds., 2nd ed. 2005), available at <http://www.bib.uh.edu/fileadmin/fdocs/PGS2-1997.pdf>.

<sup>20</sup> The regulations provide: "If any other requester has a particular need for information designated as CEII, the requester may request the information using the following procedures: (i) File a signed, written request with the Commission's CEII Coordinator. The request must contain the following: Requester's name (including any other name(s) which the requester has used and the dates the requester used such name(s)), title, address, and telephone number; the name, address, and telephone number of the person or entity on whose behalf the information is requested; a detailed statement explaining the particular need for and intended use of the information; and a statement as to the requester's willingness to adhere to limitations on the use and disclosure of the information requested. A requester shall provide his or her date and place of birth upon request, if it is determined by the CEII Coordinator that this information is necessary to process the request. Unless otherwise provided in Section 113(d)(3), a requester must also file an executed non-disclosure agreement." 18 C.F.R. § 388.113(d)(4).

<sup>21</sup> Although FERC's regulations allow the agency to "balance the requester's need for the information against the sensitivity of the information" and to deny the request if "CEII requester has not demonstrated a valid or legitimate need for the CEII" or "for other reasons," *id.*, Dominion has objected to disclosure of significant amounts of CEII materials by appeal to exemptions under the Freedom of Information Act ("FOIA"). As Earthjustice attorneys have explained in multiple submissions, CEII is by definition exempt from disclosure under FOIA. See *id.* § 388.113(c) (the definition of CEII includes the requirement that the material is "exempt from mandatory disclosure under [FOIA]"); see also Letter from Jocelyn D'Ambrosio, Earthjustice to David Morenoff, FERC (Apr. 21, 2014), submitted herewith. By accepting Dominion's argument, the Commission has barred disclosure of CEII materials, even though the requester has demonstrated a need for the information and signed a confidentiality agreement.

On the afternoon of June 13, 2014, only one business day before the comment deadline, FERC ordered Dominion to release 14 separate documents to the requesting Intervenor. FERC, Order Requiring Production of Material Pursuant to a Protective Agreement (June 13, 2014) Docket CP13-113, Accession No. 20140613-3034. Some of these materials were the subject of requests to FERC dating back as far as August 2013. FERC has provided limited additional time after close of the comment period to review the documents and to submit additional comments.

As signatories to a confidentiality agreement, Intervenors should not have been forced to expend such extraordinary time and effort securing documents filed as CEII. Ordinary members of the public are more seriously disadvantaged, however, because they are forced to accept on faith that the safety impacts of the Project have been analyzed and mitigated adequately to present an insignificant threat to the surrounding community. Eliminating all opportunity for scrutiny of the material allegedly supporting FERC's analysis makes it impossible for the public to meaningfully evaluate and comment on the full range of potentially significant safety issues. Nevertheless, it is clear from the setting of the Project, the intensity of the potential safety impacts on the surrounding community, and the range of severe risks that FERC has failed to address adequately that the safety impacts of the Project are significant, have not been evaluated sufficiently, and necessitate the preparation of an EIS.

**B. FERC Improperly Discounts Potentially Significant Air Quality Impacts of Constructing and Operating the Facility.**

Construction and operation of the Project will cause the emission of large volumes of air pollution. Because FERC does not take a hard look at emissions from either source, the EA fails to support its conclusion that air quality impacts will be insignificant.

As to construction emissions, the EA improperly discounts the significance of non-particulate emissions, such as nitrogen dioxide ("NO<sub>2</sub>") and carbon monoxide ("CO"). The EA confusingly states that "[t]he majority of air emissions produced during construction activities would be [particulate matter ("PM<sub>10</sub> and PM<sub>2.5</sub>") in the form of fugitive dust." EA at 109. Yet tables in the EA indicate that in each of the four years of construction, emissions of nitrogen oxides ("NO<sub>x</sub>") and CO will, on a mass basis, greatly exceed emissions of PM<sub>10</sub> and PM<sub>2.5</sub>. *Id.* (Table 2.7.1-5); *accord id.* at 106 (Table 2.7.1-4). In discussing "Construction Impacts and Mitigation," the EA is completely silent as to what impact, if any, these non-particulate emissions will have, or whether they are significant. *Id.* at 108-110. There is a substantial question, at least, as to whether non-particulate construction emissions will have significant adverse impacts, including causing or contributing to a violation of the 1-hour National Ambient Air Quality Standard ("NAAQS") for NO<sub>2</sub>. The EA predicts that operational emissions of NO<sub>2</sub> will cause regional air quality to worsen to the level identified in the NAAQS.<sup>22</sup> *Id.* at 115 (Table 2.7.1-9). In year two of construction, construction will emit 325.12 tons of NO<sub>x</sub>, whereas

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<sup>22</sup> As discussed below, the EA understates this impact.

the EA estimates only 279.3 tons per year of NO<sub>2</sub> during full project operation.<sup>23</sup> *Id.* Although the construction NO<sub>x</sub> emissions are not speciated into NO<sub>2</sub> and NO, FERC's NO<sub>x</sub> estimate raises at least the "substantial question" as to whether construction emissions would cause a violation of the 1-hour NO<sub>2</sub> standard. The EA states that Dominion "has committed to fully offsetting the project construction NO<sub>x</sub> emissions through the purchase of emission reduction credits from within the Washington, DC AQCR," *id.* at 106, however these emission credits are not required to be purchased locally. While the EA asserts that offsets purchased elsewhere in the Air Quality Control Region can offset impacts on ozone, *id.* at 114, the EA provides no basis for concluding that offsets from elsewhere in the region will avoid harmful local 1-hour NO<sub>2</sub> levels.

Even as to the PM<sub>10</sub> and PM<sub>2.5</sub> that the EA concludes will constitute the "majority" of emissions produced during construction, the EA fails to support the conclusion that the Project will not have a significant impact. Indeed, the EA explicitly acknowledges that Dominion *has not* provided a mitigation plan that demonstrates that these emissions can or will be mitigated to insignificance. *Id.* at 109. The EA explains "we do not believe the Fugitive Dust Control Plan sufficiently describes how DCP would implement these measures to ensure adequate mitigation of fugitive dust emissions that would occur in the same area over a multi-year period (e.g., identification of speed limits, usage of speed limit signage, use of gravel at construction entrances to reduce track-out)." *Id.* The EA recommends requiring Dominion to file a revised plan to address fugitive dust, *id.* at 109-110, where a FONSI is predicated on mitigation of impacts, the mitigation plan and measures must be "clearly described" and must be "enforceable."<sup>24</sup> An EIS may be avoided only where mitigation measures "completely compensate for any possible adverse environmental impacts stemming from the original proposal." *Cabinet Mountains Wilderness/Scotchman's Peak Grizzly Bears v. Peterson*, 685 F.2d 678, 682-83 (D.C. Cir. 1982). The EA must provide analytic data showing that the specific mitigation measures selected will, in fact, fully mitigate the potential impacts. *Id.*; *Northwest Indian Cemetery Protective Assoc. v. Peterson*, 795 F.2d 688, 697 (9th Cir. 1986) ("A mere listing of mitigation measures is insufficient to qualify as the reasoned discussion required by the NEPA."), *rev'd on other grounds*, *Lyng v. Northwest Indian Cemetery Protective Assoc.*, 485 U.S. 439 (1988). In keeping with NEPA's purpose of informing the public and allowing for public comment, *Citizens Against Rails-to-Trails v. Surface Transp. Bd.*, 267 F.3d 1144, 1151 (D.C. Cir. 2001), any mitigation should be presented to the public during environmental review. Here, where the EA acknowledges that the proposed mitigation plan does not ensure that impacts related to fugitive dust will be fully mitigated, the EA does not support a FONSI.

Turning to operation emissions, the EA concludes that the Project will not have significant environmental effects because it will comply with the Clean Air Act and will not cause a violation of the NAAQS. The EA's analysis fails to take a hard look at potential health

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<sup>23</sup> The majority of NO<sub>x</sub> emissions from air emissions sources are nitric oxide, but EPA has established a NAAQS for NO<sub>2</sub>. There is extensive guidance for modelers on how to calculate NO<sub>2</sub> concentrations based on dispersion model predictions of NO<sub>x</sub> concentrations. See, e.g., RTP Environmental Associates, *Ambient Ratio Method Version 2 (ARM2) for use with AERMOD for 1-hr NO<sub>2</sub> Modeling* (Sept. 20, 2013) available at [http://www.epa.gov/scram001/models/aermod/ARM2\\_Development\\_and\\_Evaluation\\_Report-September\\_20\\_2013.pdf](http://www.epa.gov/scram001/models/aermod/ARM2_Development_and_Evaluation_Report-September_20_2013.pdf).

<sup>24</sup> CEQ, Memorandum For Heads of Federal Agencies, *Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact 7* (2011), available at [http://ceq.hss.doe.gov/current\\_developments/docs/Mitigation\\_and\\_Monitoring\\_Guidance\\_14Jan2011.pdf](http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf).

impacts relating to sulfur dioxide (“SO<sub>2</sub>”) and NO<sub>2</sub> emissions. The “FERC modeling” of the Project’s emissions predicts that the Project will cause 1-hour SO<sub>2</sub> levels to reach 195.997 µg/m<sup>3</sup>, whereas the NAAQS is 196 micrograms per cubic meter (“µg/m<sup>3</sup>”), and that 1-hour NO<sub>2</sub> will reach 187.9, with a NAAQS of 188.<sup>25</sup> The EA concludes that this “demonstrates compliance with the NAAQS” and “secondary NAAQS,” and that impacts would therefore be insignificant. EA at 114, 116. This conclusion is unsupported by the analysis in the EA.

As a threshold issue, the values for SO<sub>2</sub> and NO<sub>x</sub> operations contained in the EA are understated and the EA therefore fails to show that the Project will not cause a violation of the NAAQS. EPA guidance regarding the Clean Air Act notes that, unless otherwise specified, air emissions standards include only two or three significant digits, and should be rounded accordingly.<sup>26</sup> The level of SO<sub>2</sub> emissions from Project operations therefore is 196 µg/m<sup>3</sup>, and the level of NO<sub>x</sub> emissions is 188 µg/m<sup>3</sup>, both exactly at the levels of the NAAQS. The FERC modeling also fails to include all emissions from the Project. Although the FERC modeling includes emissions from one dockside vessel, it does not account for emissions from vessel transits or address whether vessels in transit but near the site will have emissions greater than during docking. FERC’s modeling also does not consider the permitted scenario in which two vessels are docked or the situation where one is docked and another is in transit. In addition, the FERC modeling does not include any emissions from induced gas production, as is discussed below. Although these emissions may occur farther from the Project site, they are likely to be of sufficient magnitude to affect nearby air quality.<sup>27</sup> Thus, while the EA concludes that the Project will not have significant impacts on air quality because the Project emissions (including emissions covered by New Source Review permitting, FERC’s conformity determination, and any other emissions that are “effects” of the project for purposes of NEPA analysis) will not cause or contribute to a violation of the NAAQS, the record does not support this conclusion. In fact, the rounding errors and missing operations emissions from the Project would suggest strongly that the Project’s operations will result in an exceedance of the NAAQS levels for SO<sub>2</sub> and NO<sub>2</sub>.

Moreover, FERC cannot assume that a project that does not cause a violation of the primary or secondary NAAQS, or otherwise violate the Clean Air Act, necessarily has insignificant effects on air quality. Available evidence indicates, for example, that the Project’s NO<sub>2</sub> emissions will contribute to NO<sub>2</sub> levels that are harmful to sensitive groups. EPA has recognized that pollution at the level of the NAAQS—i.e., one-hour exposures at 100 ppb—can adversely affect asthmatics.<sup>28</sup> EPA recognized in its Integrated Science Assessment<sup>29</sup> for one-

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<sup>25</sup> The EA describes the NO<sub>2</sub> and SO<sub>2</sub> NAAQS in terms of, whereas EPA defines the standards in terms of parts per billion (ppb). The one-hour NO<sub>2</sub> and SO<sub>2</sub> standards are 100 and 75 ppb, respectively. EPA, *National Ambient Air Quality Standards (NAAQS)*, <http://www.epa.gov/air/criteria.html> (last visited June 16, 2014).

<sup>26</sup> EPA, Performance Test Calculation Guidelines (June 6, 1990), *available at* <http://www.epa.gov/ttnemc01/rounding.pdf>.

<sup>27</sup> As the EA recognizes, ozone is a regional pollutant, and ozone precursor emissions can affect air quality over a broad area. One recent source illustrating this impact is Alamo Area Council of Governments, *Development of the Extended June 2006 Photochemical Modeling Episode*, (Oct. 2013), *available at* <https://www.aacog.com/DocumentCenter/View/19262>. Compare *id.* at 1-2 (monitor locations), 2-15 (location of Eagle Ford Shale), 6-29 (modeled impacts of different Eagle Ford development scenarios on individual monitors).

<sup>28</sup> Primary NAAQS for NO<sub>2</sub>, 74 Fed. Reg. 34,404, 34,422 (proposed July 15, 2009).

hour NO<sub>2</sub> NAAQS “that NO<sub>2</sub> epidemiologic studies provide ‘little evidence of any effect threshold.’”<sup>30</sup> In other words, there is no NO<sub>2</sub> level below which health effects did not occur. Other research studies found negative health impacts from exposure to 1-hour daily maximum NO<sub>2</sub> concentrations at half the current NAAQS.<sup>31</sup> Congress recognized that an “adverse effect” on public health may occur “*notwithstanding attainment and maintenance of all national ambient air quality standards.*” 42 U.S.C. § 7470 (emphasis added); *see also Hawaiian Elec. Co. v. U.S. Env’tl. Prot. Agency*, 723 F.2d 1440, 1447 (9th Cir. 1984) (“[The NAAQS] do not adequately protect against genetic mutations, birth defects, cancer, or diseases caused by long-term chronic exposures or periodic short-term peak concentrations, and hazards due to derivative pollutants and to cumulative or synergistic impacts of various pollutants.”). EPA currently is considering whether to revise the one-hour NO<sub>2</sub> NAAQS, and has concluded that studies released since the 2010 standard was adopted further confirm the connection between NO<sub>2</sub> and harmful health effects.<sup>32</sup> FERC therefore has not demonstrated that emissions at or very slightly below the NAAQS levels will not cause a significant impact to air quality and public health.

The Project also will emit greenhouse gas (“GHG”) pollution with a potential to significantly affect the environment. The EA concludes that the project will directly emit more than two million tons per year of carbon dioxide equivalent (“CO<sub>2</sub>e”).<sup>33</sup> The EA nonetheless concludes that “[b]ecause we cannot determine the Project’s incremental physical impacts due to climate change on the environment, we cannot determine whether or not the Project’s contribution to cumulative impacts on climate change would be significant.” EA at 171. NEPA however requires agencies to prepare an EIS for proposed actions unless the agency has “made a convincing case that the impact was insignificant.” *Cabinet Mountains Wilderness/Scotchman’s Peak Grizzly Bears*, 685 F.2d at 682; *see Ocean Advocates*, 402 F.3d at 864 (holding that, to avoid preparing an EIS, the agency bears the burden of “put[ting] forth a ‘convincing statement of reasons’ that explain why the project will impact the environment no more than insignificantly”). FERC’s refusal to evaluate the direct climate change impacts of the Project’s significant GHG emissions falls far short of making a “convincing case” that this impact will be insignificant.

Furthermore, the facts in the EA demonstrate clearly that the record does not support a determination of insignificance. By any reasonable measure, two million tons per year of CO<sub>2</sub>e is significant. The Project’s emissions are an order of magnitude greater than the emissions that

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<sup>29</sup> Integrated Science Assessments are reports that represent a concise evaluation and synthesis of the most policy-relevant science for reviewing the NAAQS. These Assessments are required under the Clean Air Act and must reflect “the latest scientific knowledge useful in indicating the kind and extent of identifiable effects on public health which may be expected from the presence of [a] pollutant in ambient air.” *See* 42 U.S.C. § 7408; *see also* EPA, *Air Quality: EPA’s Integrated Science Assessments (ISAs)* (Nov. 22, 2013), available at <http://www.epa.gov/ncea/isa/basicinfo.htm>.

<sup>30</sup> 75 Fed. Reg. 6474, 6880 (Feb. 9, 2010).

<sup>31</sup> J.S. Schildcrout et al., *Ambient Air Pollution and Asthma Exacerbations in Children: An Eight-City Analysis*, 164 *Am. J. Epidemiology* 505, 505-17 (2006), available at <http://aje.oxfordjournals.org/content/164/6/505.full.pdf+html>.

<sup>32</sup> *See* EPA, *Integrated Science Assessment for Oxides of Nitrogen – Health Criteria (First External Review Draft)*, available at <http://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=259167#Download>.

<sup>33</sup> Commenters assume that the tonnage of “GHGs” included in Tables 2.7.1-6 and 2.7.1-7, EA at 112, are in CO<sub>2</sub>e, given that Table 2.7.1-5 specifies that emission totals are given in CO<sub>2</sub>e. Thus, operation of the liquefaction project and Pleasant Valley Compressor Station will increase CO<sub>2</sub>e emissions by 2,033,309 tons per year.

render a source “major” for GHGs under the Clean Air Act.<sup>34</sup> They also are nearly two orders of magnitude greater than the threshold the CEQ has set, in draft guidance, beyond which NEPA discussion of GHG emissions is recommended.<sup>35</sup> Using the current federal estimate of the social cost of carbon,<sup>36</sup> each year of the Project’s GHG emissions will cause monetized damages in excess of \$95 million, or nearly \$2 billion over the 20-year life of the Project.<sup>37</sup> Accordingly, there is no basis for concluding that the direct GHG emissions of the Project are insignificant.

The EA further understates the Project’s direct GHG emissions, by understating the impact of methane emissions. As we discuss in Section IV.C., the primary component of natural gas is methane, and methane is also a potent GHG. The EA does not identify the Project’s methane emissions. Instead, it reports GHG emissions in terms of CO<sub>2</sub>e. To calculate CO<sub>2</sub>e, emissions of non-CO<sub>2</sub> GHGs are multiplied by a pollutant-specific “global warming potential” (“GWP”), which reflects the ratio between the amount of warming a ton of that pollutant causes and the amount of warming that would be caused by a ton of CO<sub>2</sub>.<sup>38</sup> While methane is a much more potent GHG than carbon dioxide, methane is much shorter-lived in the atmosphere.<sup>39</sup> Thus, in converting methane to CO<sub>2</sub>e, different values must be used for different timescales.

The EA’s use of a methane GWP of 25 is flawed for two reasons. *See* EA at 99. First, FERC must explain the basis for its decision to use the 100-year, rather than 20-year, assessment of methane’s impacts. Authorities including the EPA, the Obama Administration, and the Intergovernmental Panel on Climate Change (“IPCC”) have emphasized the importance of acting quickly on climate change and the danger of reaching “tipping points” triggering cascading releases of GHGs within the coming decades.<sup>40</sup> A century-long assessment therefore is an inappropriate period to use to evaluate the impacts of the Project’s methane emissions.

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<sup>34</sup> EA at 100 (summarizing EPA’s “Tailoring Rule,” Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010)).

<sup>35</sup> CEQ, Draft Guidance for Greenhouse Gas Emissions and Climate Change Impacts (Feb. 18, 2010), *available at* <http://www.whitehouse.gov/administration/eop/ceq/initiatives/nepa/ghg-guidance>.

<sup>36</sup> Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, 3 (Nov. 2013), *available at* <http://www.whitehouse.gov/sites/default/files/omb/assets/inforg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf>. This figure is carbon dioxide specific, whereas the EA describes the Project’s greenhouse gas emissions in terms of CO<sub>2</sub>e, aggregating CO<sub>2</sub> with other greenhouse gases. Although EPA has cautioned that there are limits to the ability to apply the social cost of carbon dioxide to other greenhouse gases on the basis of their global warming potentials (see following paragraph), this comparison provides a best available estimate of the social cost of the project’s aggregate greenhouse gas emissions.

<sup>37</sup> 2,033,309 short tons = 1,844,587 metric tons. The estimate for the social cost of a metric ton of carbon in 2030, roughly the middle of the proposed operational span of the export project, is \$52, using the middle 3% discount rate. 1,844,587 metric tons \* \$52/metric ton = \$95,918,524.

<sup>38</sup> *See* EPA, *Glossary of Climate Change Terms - Carbon Dioxide Equivalent*, <http://www.epa.gov/climatechange/glossary.html#C> (last visited June 16, 2014).

<sup>39</sup> IPCC, *Climate Change 2013: The Physical Science Basis, Carbon and Other Biogeochemical Cycles* 473 (2013), *available at* [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter06\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter06_FINAL.pdf).

<sup>40</sup> IPCC, *Climate Change 2013: The Physical Science Basis, Long-term Climate Change: Projections, Commitments, and Irreversibility* 1029-1119 (2013), *available at* [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter12\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter12_FINAL.pdf) (discussing irreversible effects of climate change and tipping points); *see also* U.S. Env’tl. Prot. Agency, Proposed Rule, Carbon Pollution: Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, <http://www2.epa.gov/sites/production/files/2014-05/documents/20140602proposal->

Second, even on the 100-year timeframe, the 100-year methane GWP used in the EA does not represent the best available science. *See* EA at 25. Although the EA does not explain its basis for this figure, it presumably comes from the IPCC Fourth Assessment Report (either directly or indirectly, by relying on the EPA’s GHG reporting rule that adopted this report’s conclusion).<sup>41</sup> Yet as the U.S. Department of Energy (“DOE”) recently acknowledged in its report titled “Life Cycle Greenhouse Gas Perspective On Exporting Liquefied Natural Gas From The United States,” the IPCC’s superseding Fifth Assessment Report represents the best available science regarding methane’s GWP.<sup>42</sup> The most recent IPCC report estimates that fossil methane has 36 times the GWP of carbon dioxide over a 100-year time frame and at least 86 times the GWP of carbon dioxide over a 20-year time frame.<sup>43</sup> Thus, the available evidence overwhelmingly indicates that the methane GWP FERC used in the EA is too low. Because the Fifth Assessment Report represents the best available science, FERC should use the GWPs identified therein. Use of the GWP for methane that reflects the best available science is also crucial for a reasoned assessment of the impacts of the increases in gas production that would be an indirect effect of the Project, as is discussed in part IV.A below.

Thus, construction and operation emissions of the Project have the potential to significantly impact the environment by creating unhealthy levels of NO<sub>x</sub> and SO<sub>2</sub> pollution, by having incompletely mitigated PM emissions, and by causing billions of dollars of climate change damage. The EA has not shown that any, much less all, of these impacts will be insignificant.

### **C. FERC Improperly Discounts the Potentially Significant Impacts of Increasing Industrial Shipping in the Chesapeake Bay.**

The EA fails to take a hard look at the impacts associated with substantially increasing industrial shipping to Cove Point, a rural, non-industrialized port location located in a nationally important estuary, and thus fails to support its conclusion that these impacts are insignificant. In particular, the EA fails to properly account for the significant risk that shipping will introduce invasive species through ballast water discharges or as biofouling organisms attached to the exterior of the vessels.

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cleanpowerplan.pdf (“[r]ecognizing the urgent need for actions to reduce GHG emissions”); *see also* U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment 657 (Jerry M. Melillo et al. eds 2014) (“delay by any of the major emitters makes meeting any such target even more difficult and may rule out some of the more ambitious goals”); *see also id.* at 5, 28, 592 (discussing tipping points and thresholds in climate system).

<sup>41</sup> EPA, 2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements; 78 Fed. Reg. 19,802, 19,808-10 (proposed Apr. 2, 2013), EPA, 2013 Revisions to the Greenhouse Gas Reporting Rule and Final Confidentiality Determinations for New or Substantially Revised Data Elements, 78 Fed. Reg. 71,904, 71,909 (Nov. 29, 2013).

<sup>42</sup> DOE, Nat’l Energy Technology Lab., Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States (May 29, 2014), *available at* <http://www.energy.gov/sites/prod/files/2014/05/f16/Life%20Cycle%20GHG%20Perspective%20Report.pdf> (“DOE Life Cycle GHG Perspective”); *see also* IPCC, Climate Change 2013: The Physical Science Basis, Anthropogenic and Natural Radiative Forcing 714, Table 8.7 (2013), *available at* [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter08\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf).

<sup>43</sup> *Id.* These figures represent the global warming potential of methane when climate feedbacks are included in the analysis. Although DOE used the estimates without climate feedbacks, that decision was unsupported; FERC must use the more comprehensive estimates.

Throughout the proceeding, Dominion has claimed that it has been authorized to receive up to 200 ships at its existing LNG import pier. *See* EA at 89. In the EA, FERC noted Dominion’s recent claim that it expects to receive only 85 LNG tankers per year at the proposed export terminal once operational, *id.* at 53, but FERC fails to mention that receiving even 85 ships would represent a nearly 20-fold increase over the count in 2011<sup>44</sup> (the last officially reported period) and even more since last year. Each of these tankers, which can be over 1,000 feet long<sup>45</sup>—the equivalent of 15 average-sized blue whales, almost four football fields, and only slightly smaller than the Empire State Building—will be loaded with 16 to 25 million gallons (60,000 to 94,000 cubic meters) of ballast water, likely drawn from coastal waters of India and Japan, to be discharged into the Chesapeake Bay. As is noted in the expert submissions of Dr. Mario Tamburri, Research Professor with the University of Maryland and Director of the Maritime Environmental Resource Center, this ballast water could be loaded with invasive species, pathogens, including infectious bacteria such as cholera, and even radioactive material.<sup>46</sup> Invasive species also can be introduced into the Bay as biofouling organisms attached to the exterior of the vessels. Together, the ballast discharges and shipping itself threaten the health of the Chesapeake Bay; operations at the nearby nuclear power plant, which relies on Bay water for its cooling system; and commercial and recreational fishing industries centered on the Bay.<sup>47</sup>

Although the EA briefly discusses the risk from ballast water discharges and increased shipping, it dismisses any concerns as adequately addressed by existing regulations. *Id.* at 53-55. FERC has made no effort, however, to examine those regulations or to consider their shortcomings. In the absence of that critical analysis, the EA fails the hard look standard, and FERC’s finding that the increased industrial shipping from the largely defunct Cove Point facility will not have a significant impact on the Chesapeake Bay is unsupported. Because introducing invasive species into the sensitive Chesapeake Bay estuary could have significant impacts on the environment, human health, and the economy, FERC should have undertaken a more robust review in an EIS.

### **1. FERC Improperly Disregards the Potentially Significant Impacts Associated with Ballast Discharges.**

The EA fails to take a hard look at the potentially significant impacts of discharging 1.36-2.125 billion gallons of ballast water every year for the 20-year life of the Project into the Chesapeake Bay. FERC dismissed any impacts, given the laws and United States Coast Guard (“USCG”) regulations regulating ballast water, but the EA has failed to critically examine those regulations and acknowledge their shortcomings. In particular, the EA (1) fails to account for

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<sup>44</sup> *See* U.S. Dep’t of Transportation, Maritime Administration, Vessel Calls at U.S. Ports by Vessel Type (Nov. 06, 2013), *available at* [http://www.marad.dot.gov/documents/US\\_Port\\_Calls\\_by\\_Vessel\\_Type.xls](http://www.marad.dot.gov/documents/US_Port_Calls_by_Vessel_Type.xls).

<sup>45</sup> Environmental Assessment for the Cove Point Reinforcement Project at 3, Docket CP09-60-000. Accession No. 20090508-4000 (May 2009). *See also* Qatargas, Fact Sheet: A New Generation of LNG Ships, <https://www.qatargas.com/English/MediaCenter/Publications/folder/A%20new%20generation%20of%20LNG%20ships.pdf> (last visited June 12, 2014) (Q-Max, the largest LNG carrier in the world, is over 1,100 feet long).

<sup>46</sup> *See* Letter from Mario Tamburri, University of Maryland, Center for Environmental Science, Chesapeake Biological Laboratory, to Kimberley Bose, Federal Energy Regulatory Commission (June 2, 2014), Accession No. 20140602-5111 (“Tamburri June 2014 Letter”); Letter from Mario Tamburri, University of Maryland, Center for Environmental Science, Chesapeake Biological Laboratory, to Kimberley Bose, Federal Energy Regulatory Commission (Nov. 11, 2013), Accession No. 20131112-5030 (“Tamburri Nov. 2013 Letter”).

<sup>47</sup> *See generally* Tamburri June 2014 Letter; Tamburri Nov. 2013 Letter.

the laxity of interim regulations in effect while the USCG works to certify new shipboard ballast water treatment equipment, which is still being developed and tested; and (2) does not address the seriousness of the threat of invasive species that will remain even once the approved ballast water treatment systems are installed and in operation.

Ballast water discharge is governed by overlapping frameworks of USCG regulations and EPA's General Permit for vessel discharges. The USCG regulations are promulgated under the aegis of an interagency task force created by the Nonindigenous Aquatic Nuisance Prevention Act. 16 U.S.C §§ 4701 *et seq.* The most recent regulations were promulgated by the USCG in 2012.<sup>48</sup>

The General Permit fits within the Clean Water Act framework for regulating discharges into the waters of the United States. *See* Vessel General Permit for Discharges Incidental to Normal Operation of Vessels (effective Dec. 19, 2013), *available at* [http://www.epa.gov/npdes/pubs/vgp\\_permit2013.pdf](http://www.epa.gov/npdes/pubs/vgp_permit2013.pdf) ("VGP"). It is a permit under the National Pollution Discharge Elimination System that applies to all non-military and non-recreational vessels over 79 feet long (a category that includes all LNG tankers), and it regulates 27 categories of discharge from such vessels, including ballast water. *See* VGP §§ 1.1-1.2. The EPA issued the most recent VGP in 2013.

The USCG regulations and the VGP ballast water provisions create a complementary scheme regulating ballast water discharges. Both regulatory mechanisms set limits on the number of particular types of organisms that may be present per volume in ballast water intended for discharge into United States waters, 33 C.F.R. § 151.2030; VGP § 2.2.3.5, and both give ship owners and operators a choice of procedures that they may undertake to meet those standards. Owners and operators can choose between any of the following options to reduce the risk of invasive species:

- Install and operate on-ship a USCG-approved Ballast Water Management System ("BWMS");
- Fill ballast tanks only with water drawn from a U.S. municipal water system;
- Discharge ballast water to an on-shore facility or another vessel for treatment; or
- Retain ballast water within ballast tanks while in U.S. waters.

*See* 33 C.F.R. § 151.2025(a); VGP § 2.2.3.5.1.1-2.2.3.5.1.4.

The USCG regulations require that vessels constructed after December 1, 2013 have the BWMS installed on delivery, and other large vessels must employ a BWMS by their first scheduled dry-docking after January 1, 2016. 33 C.F.R. § 151.2035(b). However, the USCG has extended these deadlines because it has not yet approved *any* BWMS for use on ships.<sup>49</sup>

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<sup>48</sup> Standards for Living Organisms in Ships' Ballast Water Discharged in U.S. Waters, 77 Fed. Reg. 17,254 (Mar. 23, 2012).

<sup>49</sup> *Enforcement Response Policy for EPA's 2013 Vessel General Permit: Ballast Water Discharges and U.S. Coast Guard Extensions under 33 C.F.R. Part 151* (December 27, 2013), *available at* <http://www2.epa.gov/sites/production/files/2013-12/documents/vesselgeneralpermit-erp.pdf>.

Until these systems are approved and installed, ships have the additional option of engaging in ballast water exchange at least 200 nautical miles from shore.<sup>50</sup>

Indeed, one of the critical deficiencies of the EA is that it fails to take a hard look at the risk of introducing invasive species before the transition to the new ballast water regulations is complete. As is noted in the comments filed by Professor Tamburri:

it is widely accepted that the current management practice of offshore ballast water exchange (as described on page 54 of the EA) is limited in its ability to reduce the risk of ballast water invasive species... and should only be an interim approach until shipboard treatments are developed and certified as meeting [International Maritime Organization] and USCG discharge regulations.<sup>51</sup>

Although the EA cites the USCG timetable for the required use of BWMS, FERC does not acknowledge the delays in the USCG's certification of BWMS, which has further extended the use of the flawed ballast water exchange practice.<sup>52</sup> Furthermore, the EA does not acknowledge the risks associated with continuing this outdated practice for several years, nor does it propose methods to reduce that risk.

Perhaps the most serious flaw in the EA's analysis of ballast water discharge is its failure to consider the risk of invasive species introduction that remains even with full compliance with the most current regulations. As Professor Tamburri explains in his expert comments, the National Research Council considers the USCG's 2012 regulations a mere "first step" that would reduce but not eliminate this risk.<sup>53</sup> The regular influx of LNG tankers from India and Japan will create the "perfect scenario" for the introduction of invasive species.<sup>54</sup> Finally, the Cove Point facility's location in an area heavily reliant on fisheries, tourism, and recreational use of the Chesapeake Bay makes it particularly vulnerable to the adverse consequences of introducing invasive species.<sup>55</sup>

As Professor Tamburri notes, FERC could substantially lessen the risk that ballast water discharges will introduce invasive species into the Bay by requiring Dominion to provide a system for on-shore treatment of ballast water. As Professor Tamburri notes, shore-based systems are best used to mitigate the risk from ballast discharges when there are dedicated vessels, traveling consistent set routes, and with ballast discharge at one specific dock location—

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<sup>50</sup> The interim ballast water management regime is outlined in a joint USCG and EPA enforcement response policy outlined in a December 2013 letter. *Id.* The USCG has granted extensions to vessels not compliant with the current ballast water discharge standards conditional upon their use of ballast water exchange in the interim, and the EPA has made violations of the VGP discharge standards by ships that have been granted such extensions a "low enforcement priority." *Id.*; see also Extension of Implementation Schedule for Vessels Subject to Ballast Water Management (BWM) Standards (Sept. 25 2013), available at [http://www1.veristar.com/veristar/Dps\\_Info.nsf/1cc36b1a9995d368c1256f81002d8740/02cb86a73ef38a04c1257c0c002dae5b/\\$FILE/CG-OESPolicyLetter13-01.pdf](http://www1.veristar.com/veristar/Dps_Info.nsf/1cc36b1a9995d368c1256f81002d8740/02cb86a73ef38a04c1257c0c002dae5b/$FILE/CG-OESPolicyLetter13-01.pdf).

<sup>51</sup> Tamburri June 2014 Letter at 2.

<sup>52</sup> *Id.*

<sup>53</sup> *Id.* at 3.

<sup>54</sup> *Id.* at 2.

<sup>55</sup> *Id.* at 4.

all of which would be the case for LNG carriers calling on Cove Point. FERC should have prepared an EIS to analyze the potentially significant impacts of ballast water discharges, in light of the shortcomings of the regulatory regime, and it should have required measures to mitigate the significant adverse effects.

## **2. FERC Improperly Disregarded the Potentially Significant Impacts from Fouling Organisms.**

The EA acknowledged the potential for invasive species introduction via fouling organisms attached to the hulls of LNG tankers visiting the Cove Point facility, yet, as with ballast water discharge, FERC disregarded the significance of the threat by referring to USCG regulations. Specifically, the EA cited the following requirements, found in 33 C.F.R. § 151.2050:

(e) Rinse anchors and anchor chains when the anchor is retrieved to remove organisms and sediments at their places of origin.

(f) Remove fouling organisms from the vessel's hull, piping, and tanks on a regular basis and dispose of any removed substances in accordance with local, State and Federal regulations.

The USCG does not provide more detailed guidance on specific procedures for rinsing anchors or the frequency at which vessels must be cleaned of fouling organisms. As Professor Tamburri explained, in failing to specify procedures to reduce the risk of fouling organisms, the regulations give ship owners and operators the discretion to choose their own procedures, which may not be effective.<sup>56</sup> FERC cannot simply assume that, in the absence of specified procedures for removing fouling organisms, the regulations will eliminate the substantial risk of introducing invasive species into the Chesapeake Bay. Because fouling organisms can spread rapidly and unpredictably from ships, and are an equal or greater source of invasive species than ballast water, the risk to the Bay and Bay-dependent activities is significant. FERC should have prepared an EIS to analyze the potential biofouling invasive species impacts from shipping.

## **D. FERC Improperly Discounts the Potentially Significant Impacts on the Highly Endangered North Atlantic Right Whale.**

The EA does not provide a sufficient analysis under NEPA or the Endangered Species Act (“ESA”) of the potentially significant impacts of the Project on the federally endangered North Atlantic right whale, which breeds and migrates in the Chesapeake Bay region. Instead of taking an independent hard look at those potential impacts, the EA relied on out-of-date data, Dominion’s self-serving estimate of the number of ships that will visit its facility, and insufficient mitigation plans. *See* EA at 69-72. This analysis does not support FERC’s finding under NEPA that impacts on the critically endangered species will be insignificant and cannot sustain the conclusion under ESA that the Project is not likely to jeopardize the endangered North Atlantic right whale.

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<sup>56</sup> *Id.* at 3.

It is well established that the “North Atlantic right whales are the world’s most critically endangered large whale species and one of the world’s most endangered mammals.” (Dec. 9, 2013). Best estimates are that only 444 North Atlantic right whales remain. *Id.* The National Oceanic and Atmospheric Administration (“NOAA”) has further found that:

A population size of several hundred individuals is precariously small for any large whale or large mammal population, particularly given that this population is frequently exposed to anthropogenic threats that result primarily from entanglement in commercial fishing gear and collisions with vessels.

*Id.* Mortality caused by ship strikes poses a serious threat to the North Atlantic right whale because of its small population and slow growth rate. *Id.* at 73,727. The dangerously low number of survivors means that the loss of even one individual could be “devastating to the right whale population.”<sup>57</sup>

The Project would induce increased ship traffic as LNG tankers travel from India or Japan to Cove Point, Maryland, likely through the Panama Canal and up the east coast of the United States and into the Chesapeake Bay, and then back again to Asia. This route puts the ships directly into the North Atlantic right whale’s migratory path. Currently, Dominion’s import facility is virtually idle, with only five ship arrivals in 2011.<sup>58</sup> Although the EA emphasized Dominion’s estimate that only 85 ships would call on the Project annually, Dominion would be authorized to receive 200 ships at its facility every year for at least 20 years. *See EA* at 89. The impacts of that 40-fold yearly increase in shipping traffic over the status quo is therefore what FERC must analyze under the ESA and NEPA.<sup>59</sup>

The ESA requires that agencies engage in consultation with the appropriate expert wildlife service—the Fish and Wildlife Service or the National Marine Fisheries Service (“NMFS”)—to insure that any federally authorized action “is not likely to jeopardize the continued existence of any endangered or threatened species.” 16 U.S.C. § 1536(a)(2). In carrying out that duty, the statute states that agencies “shall use the best scientific and commercial data available.” *Id.*; *see also Pub. Emps. for Env’tl. Responsibility v. Beaudreu*, 2014 WL 985394, \* 3 (D.D.C. Mar. 14, 2014); *see also Native Village of Chickaloon v. Nat’l Marine Fisheries Serv.*, 947 F. Supp. 2d 1031, 1062 (D. Alaska 2013).

The required consultation may be formal or informal, depending on the likely impact on listed species. If the action may affect a listed species, a formal consultation is required and must culminate in the completion of a “biological opinion” that determines if the action is likely to jeopardize the species. 40 C.F.R. § 402.14. The ESA consultation may remain “informal” if the consulting agencies conclude that the action is “not likely to adversely affect listed species or critical habitat.” *Id.* § 402.13. Before terminating an informal consultation, the relevant wildlife service must provide a written concurrence with that conclusion. *Id.* A consultation must be

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<sup>57</sup> NOAA, *Three vessels charged with violating right whale ship strike reduction rule pay penalties* (Jan. 10, 2012), available at [http://www.noaanews.noaa.gov/stories2012/20120110\\_rightwhalepenalties.html](http://www.noaanews.noaa.gov/stories2012/20120110_rightwhalepenalties.html).

<sup>58</sup> *See* U.S. Dep’t of Transportation, Maritime Administration, *Vessel Calls at U.S. Ports by Vessel Type* (Nov. 06, 2013), available at [http://www.marad.dot.gov/documents/US\\_Port\\_Calls\\_by\\_Vessel\\_Type.xls](http://www.marad.dot.gov/documents/US_Port_Calls_by_Vessel_Type.xls).

<sup>59</sup> Even if Dominion’s ships increase to 85, the potential impacts to the North Atlantic right whale from an increase of 5 to 85 ships still is significant.

reinitiated under four circumstances, including when “new information reveals effects of the action that may affect listed species or critical habitat in a manner or to an extent not previously considered.” *Id.* § 402.16; *see also Forest Guardians v. Johanns*, 450 F. 3d 455, 458 (9th Cir. 2006) (finding the duty to reinitiate consultation also applies to informal consultations).

NMFS and FERC previously engaged in informal consultations on the impact of Dominion’s import facility on the North Atlantic right whale in 2007 and 2009.<sup>60</sup> The 2007 informal consultation resulted in the development of a Vessel Strike Avoidance Measures and Injured or Dead Protected Species Reporting Plan (the “Plan”) for the vessels calling on Dominion’s import facility. Based on Dominion’s agreement to incorporate the Plan into the operational conditions governing Cove Point, NMFS concluded in November 2007 that Dominion’s expanded import operations were not likely to adversely affect the North Atlantic right whale.<sup>61</sup> That finding in turn was incorporated into a 2008 EA conducted by NOAA.<sup>62</sup> The 2009 informal consultation was triggered by Dominion’s proposal to reinforce the pier, so that larger ships could call at the facility, but NMFS concluded this expansion did not change vessel traffic and did not require further informal consultation regarding impacts to the North Atlantic right whale.<sup>63</sup>

In a letter dated April 8, 2014, NMFS offered “clarification” of its prior determinations regarding the impacts of the Project on endangered species, including its September 2013 conclusion that the Project did not require the reinitiation of consultation under the ESA.<sup>64</sup> The reinitiation option does not apply to agency actions that are complete, however, as opposed to ongoing actions that still require some “affirmative action.” *Salix v. U.S. Forest Serv.*, 944 F. Supp. 2d 984, 998 (D. Mont. 2013) (finding that a “forest plan is an ongoing agency action because the plan ‘continues to apply to new projects’ and thus has an ‘ongoing and long-lasting effect even after adoption.’”) (internal quotations omitted); *cf. Forest Guardians*, 450 F.3d at 458 (where the Forest Service was engaged in a comprehensive management and monitoring of lands). FERC’s action approving the Dominion’s pier reinforcement was complete in 2009, and therefore consultation with NMFS could not have been reinitiated in 2013.

Instead, NOAA should have opened new consultations with FERC, using the best scientific and commercial data available to determine whether the Project may adversely impact the North Atlantic right whale. *See* 16 U.S.C. § 1536(a)(2). “Compliance with this requirement requires a ‘first class effort’ on the part of the agency, including the performance of ‘any ... tests and studies which are suggested by the best available science and technology.’” *Conserv. Law Found. v. Watt*, 560 F. Supp. 561, 571-72 (D. Mass. 1983) (citing *Roosevelt Campobello Int’l Park Comm’n v. United States EPA*, 684 F.2d 1041, 1052 n. 9 (1st Cir.1982)). The ESA therefore requires that the consulting agencies examine the increase in shipping traffic in the

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<sup>60</sup> The consultation that occurred in 2005 did not address the effects of the expansion of the import facility on listed species of whales. Letter from Patricia Kurkul, NOAA to Kimberley Bose, FERC 4 (Sept. 30, 2009), Accession No. 20091002-0097.

<sup>61</sup> Letter from Patricia Kurkul, NOAA to Alisa Lykens, FERC (Nov. 19, 2007) Accession No. 20091002-0097.

<sup>62</sup> NOAA, Supplemental EA for the Dominion Cove Point LNG Terminal Expansion Project: LNG Ship Transit in United States Waters 30-31 (May 2008)

<sup>63</sup> *See* Sept. 30, 2009 letter from Kurkul *supra* note 60 at 1.

<sup>64</sup> Letter from John Bullard, NOAA to Kimberley Bose, FERC dated Apr. 8, 2014, Accession No. 20140609-0036 (stating all previous consultations “were completed informally”). This letter is referenced in the EA but was not made available to the public until less than a week remained until the close of the comment period on the EA.

Mid-Atlantic Seasonal Management Area,<sup>65</sup> whether the species is being subjected to any additional new threats, including from climate change, and whether Dominion's proposed mitigation measures are sufficiently protective. As discussed below, there are numerous critical developments that have occurred since 2007 and 2009 that together strongly suggest that the Project is likely to adversely effect the North Atlantic right whale, necessitating formal consultation. *See* 50 C.F.R. § 402.14.

Even if Dominion's import facility and the Project are considered the same ongoing "agency action" under the ESA, and a new consultation is not required, NMFS had no basis for declining to reinitiate consultation in 2013. Reinitiation of consultation is *required* when "new information reveals effects of the action that may affect listed species or critical habitat in a manner or to an extent not previously considered." *Id.* § 402.16; *see Defenders of Wildlife v. Bureau of Ocean Energy Mgmt. Regulation, Enforcement*, 871 F. Supp. 2d 1312, 1324 (S.D. Al. 2012) (information that reasonably called into question the assumptions and models on which previous conclusions were based constituted "new information" warranting reinitiation of consultation"). Contrary to NOAA's assertions, substantial new information has emerged since NOAA's assessments in 2007 and 2009 that significantly changes the potential impacts of the Project on the North Atlantic right whale. Consultation therefore should have been reinitiated.

The context in which the Project is taking place has changed significantly since 2007 and 2009. The most up-to-date information reveals that there is and will be significantly more ship traffic in the North Atlantic right whale's habitat than there was 5-7 years ago. Between 2008 and 2011, shipping traffic through the Port of Baltimore increased by 15 percent, from 1,870 to 2,158 ships annually.<sup>66</sup> The Port also is investing millions of dollars to expand its facilities to accommodate larger container ships.<sup>67</sup> It therefore is extremely likely that the number and size of ships traveling to and from Baltimore, through the mouth of the Chesapeake Bay, will continue to increase. The expansion of the Panama Canal also will open access to the East Coast shipping corridor for greater numbers of very large vessels.<sup>68</sup> When the loss of even a single whale would be a critical blow to the survival of the species,<sup>69</sup> the failure of FERC and NMFS to undertake an updated review of increased shipping impacts on the North Atlantic right whale contravenes NEPA and the ESA.

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<sup>65</sup> The Mid-Atlantic Seasonal Management Area is an area used by North Atlantic right whales, particularly pregnant females and females with calves, that are migrating to and from calving/nursery areas in the southeast U.S. and feeding grounds off the coasts of the northeast U.S. coast and eastern Canada. 73 Fed. Reg. 60173-01, 60179.

<sup>66</sup> U.S. Dep't of Transportation, Maritime Administration, Vessel Calls at U.S. Ports by Vessel Type (Nov. 06, 2013), *available at* [http://www.marad.dot.gov/documents/US\\_Port\\_Calls\\_by\\_Vessel\\_Type.xls](http://www.marad.dot.gov/documents/US_Port_Calls_by_Vessel_Type.xls).

<sup>67</sup> *See, e.g.,* The Baltimore Sun, *\$10 million grant to expand port of Baltimore* (Sept. 01, 2013), *available at* [http://articles.baltimoresun.com/2013-09-01/news/bs-md-port-of-baltimore-expansion-20130831\\_1\\_masonville-marine-terminal-ships-state-grant](http://articles.baltimoresun.com/2013-09-01/news/bs-md-port-of-baltimore-expansion-20130831_1_masonville-marine-terminal-ships-state-grant).

<sup>68</sup> *See* Katie Johnson, *Panama Canal expansion to have major impact on Boston*, The Boston Globe (Mar. 16, 2014) ("The stakes are high for both the Panama Canal, which is rapidly losing shipping traffic to the larger Suez Canal in Egypt, and the eastern ports of the United States, which, along with Asia, have the most ships using the passage connecting the Atlantic and Pacific through the Isthmus of Panama...On the East Coast, Baltimore and Norfolk, Va., are ready for the bigger 'post-Panamax' ships; Miami and New York/New Jersey are making billions of dollars worth of improvements."), *available at* <http://www.bostonglobe.com/business/2014/03/15/panama-canal-expansion-have-major-impact-boston-worldwide-shipping/lqz3iiehcfpHWdTMS9ePDKO/story.html>.

<sup>69</sup> *See* 78 Fed. Reg. 34,025 (June 6, 2013).

Second, new information casts doubts on whether current regulations provide adequate protection for the whales. Reports have highlighted a series of ship strikes in recent months that are part of a “higher-than-usual rate of strikes along the eastern seaboard for this time of year.”<sup>70</sup> Indeed, there are three known deaths of whales on the East Coast of the United States this year alone.<sup>71</sup> Although these deaths were not among the North Atlantic right whale population, they indicate an increasing problem of greater ship traffic leading to increasing ship strikes and marine mammal fatalities.

The ship strikes may be related to extremely low compliance with speed restrictions adopted in 2008 to protect the North Atlantic right whale. Scientists at NOAA have shown that, during the first two years after promulgation of the speed restrictions, vessels complied with the rules on only approximately four percent of trips.<sup>72</sup> Although compliance has improved, it remained at about 20 percent for the fourth and fifth seasons.<sup>73</sup> Moreover, 64 percent of vessel-strike deaths occurred in zones that are not subject to speed limits.<sup>74</sup> Approximately 32 percent of right whale deaths occurred outside the protected zones, including in unregulated migration routes.<sup>75</sup> The speed restrictions imposed by NOAA therefore offer limited protection to the North Atlantic right whale and cannot form the basis of FERC’s conclusion that increased shipping impacts will be insignificant.

A third development since the 2007 and 2009 reviews is the huge advance in climate science. NOAA’s Recovery Plan for the North Atlantic Right Whale recognizes climate change as a potential threat to the survival of the species,<sup>76</sup> but there is nothing in the Project’s docket indicating that either FERC or NOAA considered how climate change could exacerbate the impacts of the increased shipping traffic on the North Atlantic right whale. Moreover, the Recovery Plan was last updated in 2004 and is based on climate studies conducted in the 1990s and early 2000s.<sup>77</sup> By contrast, the latest report from the IPCC has predicted a range of climate change impacts that will affect the ocean habitat and likely will affect the habitat of the North Atlantic right whale, all potentially within the time frame when the Project will be operating. These include:

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<sup>70</sup> Associated Press, *Whale killed by cruise ship near New York amid upsurge in cetacean strikes*, The Guardian (May 24, 2014), available at <http://www.theguardian.com/environment/2014/may/24/whale-strike-killed-ship-new-york>.

<sup>71</sup> *Id.*

<sup>72</sup> Gregory Silber, et al., *Compliance with Vessel Speed Restrictions to Protect North Atlantic Right Whales*, National Marine Fisheries Service, NOAA (June 3, 2014), available at <http://www.noaaneews.noaa.gov/stories2014/images/Silber%20et%20al.%20Regulatory%20Compliance.pdf>.

<sup>73</sup> *Id.* at 32.

<sup>74</sup> Julie van der Hoop, et al., *Vessel strikes to large whales before and after 2008 Ship Strike Rule*, Conservation Letters (May 2014), submitted herewith.

<sup>75</sup> *Id.*

<sup>76</sup> NOAA, *Recovery Plan for the North Atlantic Right Whale – Revision* (Aug. 2004) available at [http://www.nmfs.noaa.gov/pr/pdfs/recovery/whale\\_right\\_northatlantic.pdf](http://www.nmfs.noaa.gov/pr/pdfs/recovery/whale_right_northatlantic.pdf).

<sup>77</sup> *Id.* at IG-4 (citing to studies from 1995, 1996, 1998, and 2001).

- Ocean warming of 0.6 °C to 2.0°C in the top 100 meters and 0.3°C to 0.6°C warming at a depth of approximately 1000 meters by the end of the 21<sup>st</sup> century.<sup>78</sup>
- The very likely weakening of the Atlantic Meridional Overturning Circulation, including some decline by 2050.<sup>79</sup>
- Increasing ocean acidification from higher levels of carbon dioxide being absorbed by oceans, including a higher rate of acidification in the North Atlantic.<sup>80</sup>

The above changes from increased concentrations of GHGs in the atmosphere could affect the whales' prey or increase competition for available resources.<sup>81</sup> The effect of such additional stressors on an already critically endangered species could be disastrous, especially when coupled with the increased potential for fatal ship strikes.

NEPA also does not permit FERC to rely on an outdated analysis of potential impacts on endangered species, such as the 2007 and 2009 correspondence with NMFS for the expansions to Dominion's import facility.<sup>82</sup> To the contrary, NEPA specifically requires that a significance determination take into consideration the context, or "the setting in which the agency's action takes place." 40 C.F.R. § 1508.27; see *Barnes v. U.S. Dep't of Transp.*, 655 F.3d 1124, 1139 (9th Cir. 2011) (internal quotations omitted) (citing *Nat'l Parks & Conservation Ass'n v. Babbitt*, 241 F.3d 722, 731 (9th Cir.2001)); see also *Burkholder v. Wykle*, 268 F. Supp. 2d 835, 848 (N.D. Ohio 2002) ("[I]n preparing and/or reviewing the EA, the agency took a 'hard look' at all the relevant foreseeable consequences of a proposed action, in light of their *context* and intensity, and determined that no 'significant impact' to the environment would result.") (emphasis added). The additional shipping, impacts of climate change, and routine violation of speed restrictions materially change the context in which the Project will operate, with potentially significant impacts on the North Atlantic right whale.

The mitigation measures proposed in the EA also do not adequately address the impacts of the Project. As is discussed above, NOAA regulations designed to protect the North Atlantic right whale do not fully protect migration routes and suffer from low compliance rates, where they do apply. The Plan that was adopted pursuant to the 2007 informal consultation under the

<sup>78</sup> IPCC, *Climate Change 2013: The Physical Science Basis, Summary for Policymakers*, 24 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_SPM\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_SPM_FINAL.pdf).

<sup>79</sup> *Id.*

<sup>80</sup> IPCC, *Climate Change 2014: Impacts, Adaptation, and Vulnerability, Global and Sectoral Aspects, Ocean Systems*, 8 (2014), available at [http://ipcc-wg2.gov/AR5/images/uploads/WGIAR5-Chap6\\_FGDall.pdf](http://ipcc-wg2.gov/AR5/images/uploads/WGIAR5-Chap6_FGDall.pdf).

<sup>81</sup> See Russell Leaper et al., *Global climate drives southern right whale (*Eubalaena australis*) population dynamics*, 2 *Biology Ltrs.* 289 (2006) (showing linkages between global climate signals and right whale calving output and population dynamics), available at <http://rsbl.royalsocietypublishing.org/content/2/2/289.full.pdf+html>; see also Stephanie L. Hinder et al., *Multi-Decadal Range Changes vs. Thermal Adaptation for North East Atlantic Oceanic Copepods in the Face of Climate Change*, 20 *Global Change Biology* 140 (2014), available at <http://onlinelibrary.wiley.com/doi/10.1111/gcb.12387/pdf> (showing "unabated range contraction" and limited thermal adaptation for *Calanus finmarchicus*, the North Atlantic right whale's main prey, and suggesting "continued dramatic climate induced changes in the biology of the oceans.").

<sup>82</sup> NOAA, *Supplemental Environmental Assessment for the Dominion Cove Point Liquefied Natural Gas (LNG) Terminal Expansion Project: LNG Ship Transit in United States Waters* (May 2008), Docket USCG-2008-0035.

ESA also contains significantly weaker protections for North Atlantic right whales than those contained in strike avoidance plans for similar facilities. These deficiencies include the following:

- (1) For most of the provisions of the Plan, Dominion is required merely to “request” that vessels calling on its facility comply with requirements to protect species from ship strike.<sup>83</sup> Ship operators therefore are not obligated to adhere to the protective measures contained in the Plan, as they would be if the vessel strike avoidance provisions were incorporated as mandatory conditions in contracts with Dominion. By contrast, the terms of the Marine Mammal Detection, Monitoring, and Response Plan (“MMDMR”) for the Northeast Gateway Deepwater Port and Pipeline Lateral require that all ships calling on this facility “shall” comply with the protective measures of the MMDMR.<sup>84</sup>
- (2) The Plan also excuses ships from complying with its provisions if doing so would be inconsistent with “safe navigation” but provides no guidance on what circumstances would be sufficiently unsafe to permit ships to stray from the Plan.<sup>85</sup> The MMDMR, by contrast, allows deviation from the plan’s procedures only in “emergency situations” that are narrowly and clearly defined.<sup>86</sup> The vague standard in the Plan fails to adequately protect North Atlantic right whales.
- (3) The Plan suggests that, to avoid ship strikes, “vessel operations and crew” will keep watch for marine mammals.<sup>87</sup> Given the significant threat to the species from hitting even one individual North Atlantic right whale, an adequate strike avoidance plan also should require, as does the MMDMR, that, upon entering into an area where the species is known to occur, including the Mid-Atlantic Seasonal Management Area, the ship shall assign a trained look-out to visually monitor for the presence of North Atlantic right whales and other marine mammals.<sup>88</sup>
- (4) The Plan instructs Dominion to distribute the most recent NOAA materials on avoiding ship strikes to any vessel prior to its calling on Cove Point but, unlike the MMDMR, the Plan does not require that the ship’s crew receive avoidance training. Instead, the Plan merely states that Dominion will *ask* the ship master to view the training materials and “to ensure that lookouts are aware of relevant information.”<sup>89</sup> Protection will be

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<sup>83</sup> *Id.* at Appendix N.

<sup>84</sup> Marine Mammal Detection, Monitoring, and Response Plan for Operation of the Northeast Gateway Deepwater Port and Pipeline Lateral, 2 (June 2010) (requiring that the ships “shall” adhere to the Marine Mammal Detection, Monitoring, and Response Plan) (hereinafter, NE Gateway Plan), *available at* [http://www.nmfs.noaa.gov/pr/pdfs/permits/neg\\_ing\\_monitoring.pdf](http://www.nmfs.noaa.gov/pr/pdfs/permits/neg_ing_monitoring.pdf).

<sup>85</sup> *See* Plan at N-2.

<sup>86</sup> NE Gateway Plan at 2 (defining “emergency situations” as instances involving “the risk to life, property and the environment, and failure to respond appropriately could potentially worsen the consequences. Such emergency situations would include, but would not be limited to, maintaining vessel maneuverability, avoiding severe weather conditions, collision/grounding avoidance, vessel safety and security, rendering assistance (i.e., first response) to vessels and aircraft in distress, search and rescue, medical emergencies, fire/explosion, port security/piracy threats and spill prevention/response to the NEG Port itself or other vessels in the area..”

<sup>87</sup> Plan at N-1.

<sup>88</sup> NE Gateway Plan at 6.

<sup>89</sup> Plan at N-2.

inadequate unless all individuals assigned to monitor for marine mammals *are required to receive training on marine mammal sighting and reporting and on vessel strike avoidance measures.*<sup>90</sup>

- (5) Unlike the Northern Gateway Export Project's plan, the Plan does not require but only *suggests* that LNG vessel operators check with various communication media for general information on avoiding ship strikes.<sup>91</sup> Before entering the Mid-Atlantic Seasonal Management Area, a ship calling on Cove Point should be required to consult with the NOAA Weather Radio; the U.S. Coast Guard NAVTEX broadcasts; the Sighting Advisory System website, fax and email distribution list; Notices to Mariners; or obtain an automatic reply with the latest right whale sighting through the email address [ne.rw.sightings@noaa.gov](mailto:ne.rw.sightings@noaa.gov) to ensure that it obtains the most recent information on North Atlantic right whale sightings.<sup>92</sup>
- (6) The Plan does not reflect NOAA's extension of the mandatory seasonal speed restrictions contained at 78 Fed. Reg. 73,726.

Particularly when considered in light of the latest information about Project context, the above deficiencies illustrate that the Vessel Strike Avoidance Plan adopted by Dominion is insufficient to protect the critically endangered North Atlantic right whale. The Plan therefore cannot adequately mitigate the potentially significant impact of the Project on this species and cannot support FERC's finding that likely adverse impacts will be insignificant.

#### **E. FERC Ignores the Reality of Climate Change, a Factor that Contributes to the Significance of the Project's Impacts.**

In light of the location and lifespan of the Project, FERC cannot provide the requisite convincing case that the Project's impacts are insignificant, unless the agency first undertakes a more in-depth consideration of the potentially significant impacts of climate change on the Project. The analysis in the EA is insufficient to sustain the conclusion that climate change does not have the potential to heighten the impacts of the Project and cause significant environmental effects. On the contrary, climate change impacts could significantly affect the LNG facility, the pier, and the ships traveling to and from the Project. Although the EA briefly discusses and dismisses the potential for rising sea levels and storm surge to cause flooding at the LNG facility, it does not address any of the following: (1) the impacts of storm surge on the pier and associated infrastructure; (2) the impacts of more significant storms and hurricanes on the LNG facility; and (3) the impacts of more significant storms and hurricanes on the ships traveling up and down the Chesapeake Bay to Dominion's facility. These impacts from climate change have the potential to augment the environmental risks posed by the Project, resulting in significant environmental impacts that must be analyzed in an EIS as part of FERC's "hard look" under NEPA.

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<sup>90</sup> See, e.g., NE Gateway Plan at 7.

<sup>91</sup> Plan at N-2.

<sup>92</sup> See, e.g., NE Gateway Plan at 14.

There is a recognized “pressing need” for agencies to account for climate change in performing their duties under NEPA. *See Conservation Nw. v. Rey*, 674 F. Supp. 2d 1232, 1253 (W.D. Wash. 2009). The draft guidance by the CEQ highlights the risks posed by climate change and suggests ways in which climate change can increase the environmental impacts associated with a proposed project:

[C]limate change can affect the integrity of a development or structure by exposing it to a greater risk of floods, storm surges, or higher temperatures. Climate change can increase the vulnerability of a resource, ecosystem, or human community, causing a proposed action to result in consequences that are more damaging than prior experience with environmental impacts analysis might indicate.<sup>93</sup>

Other federal agencies also have recognized the significant ways in which climate change can heighten the environmental impacts of a project.<sup>94</sup> In particular, the Nuclear Regulatory Commission noted the importance of assessing the effects of climate change at coastal locations:

Implications of global climate change—including implications for severe weather and storm intensity—are important to coastal communities and to critical infrastructure. . . . Based on findings to date, . . . potential impacts from warming of the climate system include expansion of sea water volume; decreases in mountain glaciers and snow cover resulting in sea level rise; changes in arctic temperatures and ice; changes in precipitation, ocean salinity, and wind patterns; and changes in extreme weather.<sup>95</sup>

There also is clear scientific consensus that increased anthropogenic concentrations of GHGs in the atmosphere are causing a rise in average global temperatures and that the effects of climate change are being felt in the present day. The most recent report by the IPCC unequivocally concludes that since the 1950s, “[t]he atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of GHGs have increased.”<sup>96</sup>

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<sup>93</sup> Memorandum from Nancy H. Sutley to Heads of Federal Departments and Agencies Regarding “Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions” 6 (Feb. 18, 2010), available at <http://www.whitehouse.gov/sites/default/files/microsites/ceq/20100218-nepa-consideration-effects-ghg-draft-guidance.pdf>.

<sup>94</sup> *See, e.g.*, Bureau of Ocean Energy Mgmt., U.S. Dep’t of the Interior, Outer Continental Shelf Oil and Gas Leasing Program: 2012-2017, Final Programmatic Environmental Impact Statement 3-18 to 3-27 (July 2012), available at [http://www.boem.gov/uploadedFiles/BOEM/Oil\\_and\\_Gas\\_Energy\\_Program/Leasing/Five\\_Year\\_Program/2012-2017\\_Five\\_Year\\_Program/2012-2017\\_Final\\_PEIS.pdf](http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/2012-2017_Final_PEIS.pdf); U.S. Army Corps of Eng’rs, Mississippi River Gulf Outlet (MRGO) Ecosystem Restoration Plan, Final Environmental Impact Statement 2-96, 2-128, 2-139, 3-53 to 3-54 (June 2012), available at <http://www.mvn.usace.army.mil/Portals/56/docs/environmental/MRGO/MRGOEcosystemRestorationFinalEnvironmentalImpactStatementJune2012compressed.pdf>.

<sup>95</sup> U.S. Nuclear Regulatory Comm’n, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 46, Regarding Seabrook Station, Draft Report for Comment 2-20 (2011), available at <http://pbadupws.nrc.gov/docs/ML1121/ML11213A024.pdf>

<sup>96</sup> IPCC, Climate Change 2013: The Physical Science Basis, Summary for Policymakers, 4 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_SPM\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_SPM_FINAL.pdf).

The impacts of climate change on the Project area could be significant. The IPCC Report concludes that the northeastern North American coast is “vulnerable to some of the fastest and largest sea level rises during this century.”<sup>97</sup> The IPCC further reports that it is very likely that “human-induced increase in GHGs has contributed to the increase in [sea surface temperatures] in the hurricane formation regions and that over the past 50 years there has been a strong statistical connection between tropical Atlantic [sea surface temperatures] and Atlantic hurricane activity.”<sup>98</sup> In addition, “there is evidence that there has been a poleward shift in the storm tracks,”<sup>99</sup> and studies “continue to support a northward and eastward shift in the Atlantic cyclone activity during the last 60 years with . . . more frequent and more intense wintertime cyclones in the high-latitude Atlantic.”<sup>100</sup> Studies also project that storm activity in the Atlantic likely will increase and grow in intensity, including the doubling of Katrina-magnitude events over the next century.<sup>101</sup>

As a result, the North Atlantic and the East Coast of North America may see increased numbers of hurricanes.<sup>102</sup> The evidence further suggests that there will be a “greatly increased Atlantic hurricane surge threat.”<sup>103</sup> The Chesapeake Bay may be particularly impacted by this change in storm activity, because major storms have been known to have “dramatic and long-lasting effects” on the area.<sup>104</sup> For example, 50 percent of the sediment deposited in the northern Chesapeake Bay between 1900 and the mid-1970s originated with Tropical Storm Agnes in 1972 and an extratropical cyclone in 1936.<sup>105</sup>

Moreover, since the publication of the most recent IPCC report, more evidence has surfaced suggesting that climate change impacts might be more imminent and significant than predicted by the IPCC. For example, a recently published study found that the Thwaites Glacier in West Antarctic is beginning to collapse and that the entire ice sheet is doomed.<sup>106</sup> The complete collapse of the ice sheet would release enough meltwater into the ocean to cause more

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<sup>97</sup> IPCC, *Climate Change 2013: The Physical Science Basis*, Sea Level Change 1194 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter13\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter13_FINAL.pdf).

<sup>98</sup> IPCC, *Climate Change 2013: The Physical Science Basis*, Detection and Attribution of Climate Change: from Regional to Global 913 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter10\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter10_FINAL.pdf).

<sup>99</sup> *Id.*

<sup>100</sup> IPCC, *Climate Change 2013: The Physical Science Basis*, Observations: Atmosphere and Surface 217 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter02\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter02_FINAL.pdf).

<sup>101</sup> Aslak Grinsted et al., *Projected Atlantic Hurricane Surge Threat from Rising Temperatures*, 110 *Proc. Nat'l Acad. Sci.* 5369 (Apr. 2, 2013), available at <http://www.pnas.org/content/110/14/5369.full.pdf>.

<sup>102</sup> Stanley B. Goldenberg et al., *The Recent Increase in Atlantic Hurricane Activity: Causes and Implications*, 293 *Science* 474, 477 (2001), available at <http://www.sciencemag.org/content/293/5529/474.full.pdf>; see also Morris A. Bender et al., *Modeled Impact of Anthropogenic Warming on the Frequency of Intense Atlantic Hurricanes*, 327 *Science* 454 (Jan. 22, 2010), submitted herewith.

<sup>103</sup> Najjar et al., *supra* note 11, at 5.

<sup>104</sup> *Id.*

<sup>105</sup> *Id.*

<sup>106</sup> Ian Joughin, et al, *Marine Ice Sheet Collapse Potentially Under Way for the Thwaites Glacier Basin, West Antarctica*, 344 *Science* 735 (May 16, 2014), available at <http://sciences.blogs.liberation.fr/files/glacier-thwaites.pdf>.

than three meters of sea level rise, the timing of which would depend on the rate of future warming.<sup>107</sup>

FERC itself has recognized the increased potential impacts that coastal LNG facilities may experience from the more intense storms and winds caused by climate change. In the draft EIS for the proposed Cameron LNG export terminal in Louisiana, FERC noted that in the “general area of the Proposed Project . . . , the destructive potential of Atlantic hurricanes increased since 1970 and the intensity (with higher peak wind speeds, rainfall intensity, and storm surge height and strength) is likely to increase during this century.”<sup>108</sup> The EA for the Cove Point facility fails, however, to consider seriously the impacts of climate change on the Project. Indeed, the text of the EA suggests that FERC has failed to grasp the basic science behind climate change. In noting commentators’ concerns regarding the impacts of climate change and increased storm surge on the Project, FERC states that “[c]limate change in the northeast region could have two effects that may cause increased storm surges: temperature increase of the Chesapeake Bay waters, which would increase storm intensity; and a rising sea level.” EA at 171. As discussed above, future increased storm activity, particularly hurricanes, will result from increased average sea surface temperatures in the Atlantic Ocean where hurricanes form.<sup>109</sup> The increase in the temperature of a smaller body of the water such as the Chesapeake Bay may have other negative environmental impacts—for example it could harm aquatic species or create an environment that allows for the proliferation of invasive species—but it will not cause increased storm intensity. This basic factual error is indicative of FERC’s failure to take seriously the potentially significant impacts of climate change on this facility.

FERC’s failure to evaluate the potentially damaging and significant impacts of the Project in light of climate change is reflected throughout its EA. The EA examines only the risk of storm surge on “the Fenced Area in which the Liquefaction Facilities would be located” and notes that “majority of the existing and proposed facilities [are] located at an elevation of more than 110 feet above mean sea level.” EA at 40. The EA does not examine the potential impacts to the pier and the pier’s associated infrastructure. In particular, storm surge could threaten the pier’s infrastructure and any ship moored to the pier, either of which could cause a release of LNG into the Chesapeake Bay.

The increased threat of intense hurricanes could pose a substantial risk to the up to 200 ships traveling up the Bay to the Project and then back to the Atlantic full of large volumes of LNG. More frequent Katrina-magnitude storms could make shipping accidents and spills more likely and increase the risk that LNG carriers will run aground in the shallow Bay waters. Such an event would be devastating to the Chesapeake Bay environment and ecosystem and could cripple the regional economic activities that are sustained by the Bay. The EA fails entirely to discuss this risk or the associated potentially significant environmental impacts.

In light of the increased likelihood of severe storms and hurricanes impacting the Chesapeake Bay area, FERC also should have evaluated the potential for high winds associated with the most severe storms to impact the LNG facility and the offshore pier. The LNG facility

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<sup>107</sup> *Id.*

<sup>108</sup> Cameron DEIS, *supra* note 10, at 4-219.

<sup>109</sup> *See, e.g.*, Goldenberg, *supra* note 102.

is designed to withstand winds of only up to 150 miles per hour (“mph”), with gusts of 183.3 mph for a three-second duration. *See* EA at 132-33. Category 5 hurricanes have sustained winds of 157 mph or higher.<sup>110</sup> Even Category 4 hurricanes have sustained winds of 130-156 mph.<sup>111</sup> Given the projections for the future increase of hurricane strength and the greater likelihood of Atlantic storms taking more northward paths towards the Project area, FERC must consider the potentially significant impacts that intense storms with high winds could have on the LNG facility and the pier. FERC’s analysis also must review the risks posed by more intense hurricanes and storms on the existing infrastructure at the site, particularly the older single-walled LNG storage tanks, which could be susceptible to penetration by high-velocity flying debris. In light of the limited number of evacuation routes away from the Project and the close proximity of residential dwellings, a major storm affecting the LNG facility could have catastrophic consequences for public safety, which also must be analyzed as part of FERC’s “hard look” under NEPA.

The infrastructure Dominion is proposing to construct and operate will last at least through the 20-year service contract terms for the Project and likely for many years after that. *See* EA at 18. Climate change has the potential to significantly augment the risks and environmental impacts associated with the Project. FERC’s failure to address these potential impacts adequately in the EA renders it incapable of supporting a FONSI. Rather, the potentially catastrophic impacts that could result from climate change’s effects on the LNG facility, the pier, or the LNG ships are potentially significant and require preparation of an EIS.

#### **IV. FERC Completely Fails to Take a Hard Look at Potentially Significant Indirect Impacts.**

Not only does FERC fail to provide a convincing case that the Project’s direct impacts are insignificant, but FERC also entirely fails to take a hard look at many of the Project’s indirect impacts. For example, FERC refuses to consider the impacts associated with increasing natural gas production in the Marcellus shale, even though Dominion “presumes that the Project customers selected DCP’s facility as their location for export due to its proximity to natural gas supplied in the northeastern United States.”<sup>112</sup> In addition, FERC disclaims any responsibility for considering the Project’s contribution to climate change, and the attendant environmental effects.

The impacts of induced gas production and climate change are indirect effects of the Project. *See* 40 C.F.R. § 1508.8(a). Indirect impacts may include “growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems.” *Id.*

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<sup>110</sup> National Hurricane Center, Saffir Simpson Hurricane Wind Scale, *available at* <http://www.nhc.noaa.gov/aboutsshws.php>.

<sup>111</sup> *Id.*

<sup>112</sup> For example, in its discussion of alternatives to the Project, FERC noted the following about the attractiveness of the Cove Point location: “[Dominion] states that existing interconnects with the Cove Point Pipeline would allow feed gas from the Project to be sourced from a wide variety of regions in the United States, depending on market forces and circumstances at any given time, but *presumes that the Project customers selected [Dominion’s] facility as their location for export due to its proximity to natural gas supplied in the northeastern United States.*” EA at 176 (emphasis added).

FERC has an obligation to consider all reasonably foreseeable indirect effects of the Project, including the fact that the Project will induce additional natural gas production and contribute to climate change. Failure to consider the significant impacts associated with natural gas development and from climate change renders the EA deficient. Moreover, because the impacts are significant, they should be considered as part of an EIS.

**A. FERC Fails to Take a Hard Look at the Potentially Significant Impacts from Upstream Gas Development.**

The EA is deficient because it fails to consider critical indirect effects associated with the Project, including the environmental consequences of increasing natural gas production to meet Dominion's customers' demand. New development to meet demand is fairly understood as indirectly caused by the Project, and thus the environmental effects of that development must be considered in the EA. See *Natural Res. Def. Council, Inc. v. Fed. Aviation Admin.*, 564 F.3d 549, 559-60 (2d Cir. 2009) (agency properly considered indirect and cumulative impacts of induced growth caused by construction of new airport); *City of Davis v. Coleman*, 521 F.2d 661, 674-77 (9th Cir. 1975) (environmental review for highway project needed to analyze impact of induced development despite uncertainty about pace and direction of development); *Border Power Plant Working Group v. Dept. of Energy*, 260 F. Supp. 2d 997, 1028-29 (S.D. Cal. 2003) (requiring consideration of environmental impacts, such as increased carbon dioxide and ammonia emissions, from additional electricity generation spurred by construction of energy transmission lines subject to federal approval). According to FERC, however, the agency need not consider indirect effects of induced development because any natural gas development allegedly is speculative. EA at 25 (disclaiming responsibility to evaluate induced production because "specific details, including the timing, location, and number of additional production wells that may or may not be drilled, are speculative"). The EA may not so easily dismiss these indirect effects.

As is demonstrated below, recent economic studies conclude that the demand for natural gas exports will largely be met with new production. In addition, real-world responses to the Project, including announcements about where one of Dominion's customers will obtain the gas, strongly suggest that the demand will be met with new production. Dominion itself "presumes that the Project customers selected [its] facility as their location for export due to its proximity to natural gas supplies in the northeastern United States," EA at 176, and has candidly stated that the Project will "support ongoing supply development" (that is, stimulate production in gas fields).<sup>113</sup> Dominion has even claimed credit for creating upstream production jobs as part of production that would not occur but for the Project.<sup>114</sup> Thus, it is reasonably foreseeable, as opposed to speculative, that the Project, and the demand it creates for natural gas, will induce natural gas production. The effects of this induced production must be considered in the EA, and in fact, necessitate a more robust review under an EIS. See, e.g., *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1081-82 (9th Cir. 2011) (finding that NEPA review must consider induced coal production at mines, which was a reasonably foreseeable effect of a project to expand a railway line that would carry coal, especially where company proposing the

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<sup>113</sup> Dominion Cove Point LNG, LP, Application for Long-Term Authorization to Export LNG to Non-Free Trade Agreement Countries, FE Docket No. 11-128-LNG at 15 (Oct. 3, 2011).

<sup>114</sup> *Id.* at 16.

railway line anticipated induced coal production in justifying its proposal); *Mid States Coal. for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549-50 (8th Cir. 2003) (environmental effects of increased coal consumption due to construction of a new rail line to reach coal mines was reasonably foreseeable and required evaluation under NEPA); *Native Village of Point Hope v. Salazar*, 730 F. Supp. 2d 1009, 1017 (D. Alaska 2010) (requiring consideration of induced development of natural gas drilling in EIS for offshore oil and gas lease sale that caused the gas development); *see also Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992) (a future impact is reasonably foreseeable if it is “sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision”).

Moreover, FERC is wrong to suggest that it needs to know the exact location of the various wells that will be drilled before it can consider the impact that induced development will have on the environment. EA at 25. First, knowledge of the exact extent of induced development or the precise location of future wells is not necessary to conduct an analysis of indirect effects. *Mid States*, 345 F.3d at 549-50. FERC need only understand the scope of the induced development to assess most of the potential harms. Moreover, analytic tools, such as the National Energy Modeling System (“NEMS”) developed by the Energy Information Administration (“EIA”), allow FERC to predict the location of newly producing wells. Cabot’s announcement also confirms that at least some of the development will occur in the Marcellus shale, and both the proximity and the size of the play increase the likelihood that it will serve as the source of all of the exported gas.

The environmental consequences of drilling, fracturing, and production likewise are knowable. Natural gas development brings with it increased air, groundwater, and surface water pollution, as well as landscape and community impacts. Many of these consequences are noted in the addendum the Department of Energy recently issued to its environmental review of natural gas export projects.<sup>115</sup> Intervenors do not concede that the Department of Energy’s study sufficiently addresses the impacts; however, the availability of the analysis defeats FERC’s claim that it cannot evaluate the impacts of natural gas production. Thus, the unavoidable environmental effects of new natural gas production are precisely the type of indirect effects that FERC must take into account in its environmental review.

Finally, FERC claims that it need not consider these indirect impacts of natural gas development because “[its] authority under the NGA and NEPA review requirements relate only to natural gas facilities that are involved in interstate commerce.” EA at 25. The fact that FERC does not regulate gas production wells, or smaller pipelines, does not mean that FERC does not have to consider the environmental effects of this development under NEPA. NEPA requires consideration of effects that are outside the scope of the reviewing federal agency’s regulatory authority. For example, the Ninth Circuit has explicitly held that NEPA requires agencies to analyze the effects of their actions even when the agency does not have permitting authority over those effects, explaining that “while it is the development’s impact on jurisdictional waters that determines the scope of the [Army Corps of Engineers’] *permitting authority*, it is the impact of

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<sup>115</sup> DOE, Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (May 29, 2014), *available at* <http://energy.gov/fe/downloads/addendum-environmental-review-documents-concerning-exports-natural-gas-us> (“DOE Addendum”). In citing this study, Intervenors do not endorse the Department of Energy’s analysis of the impacts of natural gas exploration and production, or its conclusions about whether and how the impacts can be mitigated.

the permit on the environment at large that determines the Corps' NEPA responsibility.” *Save Our Sonoran v. Flowers*, 408 F.3d 1113, 1122 (9th Cir. 2005) (emphasis added). Similarly, the Surface Transportation Board has been required to consider impacts railroad construction would have on coal combustion and coal mining without regard for the Board's lack of authority to regulate these issues. *Mid States*, 345 F.3d at 545-51; *see also N. Plains Res. Council*, 668 F.3d at 1081-82. Still other cases have required NEPA analyses of proposed casino projects to include impacts of increases in vehicle traffic the projects would induce. *See Mich. Gambling Opposition v. Kempthorne*, 525 F.3d 23, 29-30 (D.C. Cir. 2008). Thus, FERC's lack of authority to regulate gas production under the Natural Gas Act does not excuse it from its obligation under NEPA to evaluate the impacts of Project-induced production. To the contrary, FERC's failure to consider these indirect effects is a violation of NEPA. FERC must take a hard look at these significant impacts in an EIS.

### **1. Additional Natural Gas Production and Pipeline Development Is a Reasonably Foreseeable Indirect Effect of the Project.**

It is reasonably likely that the Project will lead to additional natural gas production. EIA and industry consulting firms agree that “about 60 to 70 percent” of the demand for export projects will be met with new natural gas development.<sup>116</sup> Note that where facilities, such as the Dominion proposal, use natural gas to power liquefaction equipment, the demand created by the export project is greater than the volume of gas exported. The EIA generally assumes that operating liquefaction equipment increases demand by 10% of the export volume.<sup>117</sup> In particular, the EIA estimates that 63 percent of the demand will be met with newly producing wells,<sup>118</sup> with “about three-quarters of this increased production [coming] from shale sources.”<sup>119</sup> Accordingly, Dominion's proposal to export 0.77 billion cubic feet (“bcf”) per day of gas can be expected to create 0.85 bcf/d of additional demand, which in turn will induce an additional 0.53 bcf/day of new natural gas production, at least 0.39 bcf/day of which will come from shale formations, most likely the nearby Marcellus shale.<sup>120</sup>

EIA derived these estimates from the NEMS, which models the economy's energy use through a series of interlocking modules representing different energy sectors on geographic levels.<sup>121</sup> The “Natural Gas Transmission and Distribution” module looks at the relationship between United States and Canadian gas production, consumption, and trade.<sup>122</sup> At present, the

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<sup>116</sup> EIA, *Effect of Increased Natural Gas Exports on Domestic Energy Markets* 6, 10 (2012), available at [http://www.eia.gov/analysis/requests/fe/pdf/fe\\_ing.pdf](http://www.eia.gov/analysis/requests/fe/pdf/fe_ing.pdf) (“EIA Export Study”); *see also, e.g.,* Deloitte MarketPoint, *Analysis of Economic Impact of LNG Exports from the United States* 16, available at [http://www.fossil.energy.gov/programs/gasregulation/authorizations/2013\\_applications/sc\\_exhibts\\_13\\_116\\_118/Ex\\_08\\_-\\_Deloitte\\_Analysis\\_for\\_Excelerat.pdf](http://www.fossil.energy.gov/programs/gasregulation/authorizations/2013_applications/sc_exhibts_13_116_118/Ex_08_-_Deloitte_Analysis_for_Excelerat.pdf) (“Deloitte Study”); DOE Addendum, *supra* note 115, at 4-5.

<sup>117</sup> EIA Export Study, *supra* note 116, at 2.

<sup>118</sup> *Id.* at 10.

<sup>119</sup> *Id.* at 6. In particular, EIA projected that 93 percent of the increased domestic production would come from unconventional sources, including 72 percent from shale gas, 13 percent from tight gas, and 8 percent from coalbed methane. *Id.* at 11; *see also* DOE Addendum, *supra* note 115, at 4.

<sup>120</sup> This calculation does not account for gas burned to power the liquefaction process. The EIA Study found that liquefaction generally consumed an additional 10 percent of the gas liquefied. EIA Export Study, *supra* note 116, at 2. FERC's NEPA analysis must consider the effects of this energy usage.

<sup>121</sup> EIA, *The National Energy Modeling System: An Overview* 1-2 (2009), available at [http://www.eia.gov/oiaf/aeo/overview/pdf/0581\(2009\).pdf](http://www.eia.gov/oiaf/aeo/overview/pdf/0581(2009).pdf).

<sup>122</sup> *Id.* at 59.

Transmission and Distribution module focuses largely on LNG imports, reflecting prior trends. However, the Transmission and Distribution module is capable of predicting the effects of exports on production. For example, it takes account of trade across North America, estimating United States imports in view of imports from and exports to Mexico, among other factors.<sup>123</sup> Moreover, it is linked to an existing Alaskan *export* terminal and projects how exports from that site will affect production.<sup>124</sup>

In addition to predicting, on a broad scale, whether exports will encourage additional production in the United States, EIA's "Oil and Gas Supply" module can be used to highlight the particular region where the development will occur. The Supply Module takes into account demand for natural gas, and other factors, including operative laws and regulations, to forecast where additional development will take place. It is built on detailed state-by-state reports of gas production curves across the country,<sup>125</sup> and distinguishes between coalbed methane, shale gas, and tight gas from other resources.<sup>126</sup> Thus, the module can predict whether production will come from conventional or unconventional sources. The Supply Module further projects the number of wells drilled each year, and their likely output—important figures for estimating environmental impacts.<sup>127</sup> In short, with the Supply Module, for each play in the continental United States, the EIA is able to predict the location of future production based on economic and policy considerations.<sup>128</sup>

In addition to EIA's tools to estimate production, Deloitte Marketpoint has developed a model that can predict how exports will induce domestic production.<sup>129</sup> According to Deloitte, its "World Gas Model" includes detailed global gas resources, modeling "575 plays in the US alone."<sup>130</sup> "Within each major region," the model provides "very detailed representations of many market elements: production, liquefaction, transportation, market hubs, regasification and demand by country or sub area," as well as "producers, pipelines, refineries, ships, distributors, and consumers."<sup>131</sup> Deloitte has applied its model to predict production increases in five distinct shale gas plays associated with another LNG export proposal.<sup>132</sup>

Without commenting on the strengths or weaknesses of the various models, their availability demonstrates that multiple tools exist that would allow FERC to predict how and where production will respond to exports. Thus, FERC's statement that the "specific details, including the timing, location, and number of additional production wells that may or may not be

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<sup>123</sup> EIA, *Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System*, 22-32 (2012), available at [http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders\\_Issued\\_2010/Exhibit\\_C.pdf](http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2010/Exhibit_C.pdf).

<sup>124</sup> *Id.* at 30-31.

<sup>125</sup> EIA, *Documentation of the Oil and Gas Supply Module*, 2-2 to 2-3 (2011), available at [http://www.fossil.energy.gov/programs/gasregulation/authorizations/2013\\_applications/sc\\_exhibts\\_13\\_116\\_118/Ex\\_28\\_-\\_EIA\\_Documentation\\_of\\_Oil\\_and\\_Ga.pdf](http://www.fossil.energy.gov/programs/gasregulation/authorizations/2013_applications/sc_exhibts_13_116_118/Ex_28_-_EIA_Documentation_of_Oil_and_Ga.pdf).

<sup>126</sup> *Id.* at 2-7.

<sup>127</sup> *Id.* at 2-25 to 2-26.

<sup>128</sup> *Id.*

<sup>129</sup> Deloitte Study, *supra* note 118, at 14.

<sup>130</sup> *Id.* at 25.

<sup>131</sup> *Id.* at 24.

<sup>132</sup> *Id.* at 14 (predicting the effect of exporting LNG from Lavaca Bay on production from various shale plays). Although the report aggregates the estimates for other shale plays and for non-shale sources, it appears that Deloitte's model is capable of specifying where, geographically, this aggregated production will occur.

drilled, are speculative,” EA at 25, is not persuasive. The “specific details” are not necessary for the legally required analysis, and tools are available that would allow FERC to obtain the information necessary to assess the environmental impacts of induced production, in compliance with its obligations under NEPA.

## **2. Recent Announcements Confirm that the Project Will Spur Additional Natural Gas Production in the Marcellus Shale.**

In addition to the studies and models noted above, which demonstrate that the Project will induce additional production, recent announcements about where one of Dominion’s customers will obtain its natural gas provide concrete evidence that the Project will induce new natural gas production within the Marcellus shale.

In December 2013, Cabot reported that it had executed a definitive gas sale and purchase agreement with one of Dominion’s customers, Pacific Summit Energy, a subsidiary of the Japanese company Sumitomo Corporation.<sup>133</sup> Under the contract, Cabot reportedly has agreed to sell Pacific Summit Energy 350,000 million British thermal units (“MMBtu”) per day of natural gas from its Marcellus shale position for a term of 20 years, commencing on the in-service date of Dominion’s export terminal.<sup>134</sup> With this announcement, FERC cannot plausibly claim not to know where the additional gas development induced by the Project will take place. Indeed, as shown in the map below, Cabot’s drilled wells and permitted but not yet drilled wells are clustered in and near Susquehanna County, Pennsylvania. It is virtually certain that Cabot’s gas for the Project will come from its holdings in this area.<sup>135</sup>

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<sup>133</sup> Press Release, Cabot Oil & Gas Corporation Provides Corporate Update, Announces Agreement to Provide Natural Gas to the Dominion Cove Point LNG Terminal (Dec. 19, 2013), *reprinted in* Wall Street J., *available at* <http://online.wsj.com/article/PR-CO-20131219-905979.html>.

<sup>134</sup> *Id.*

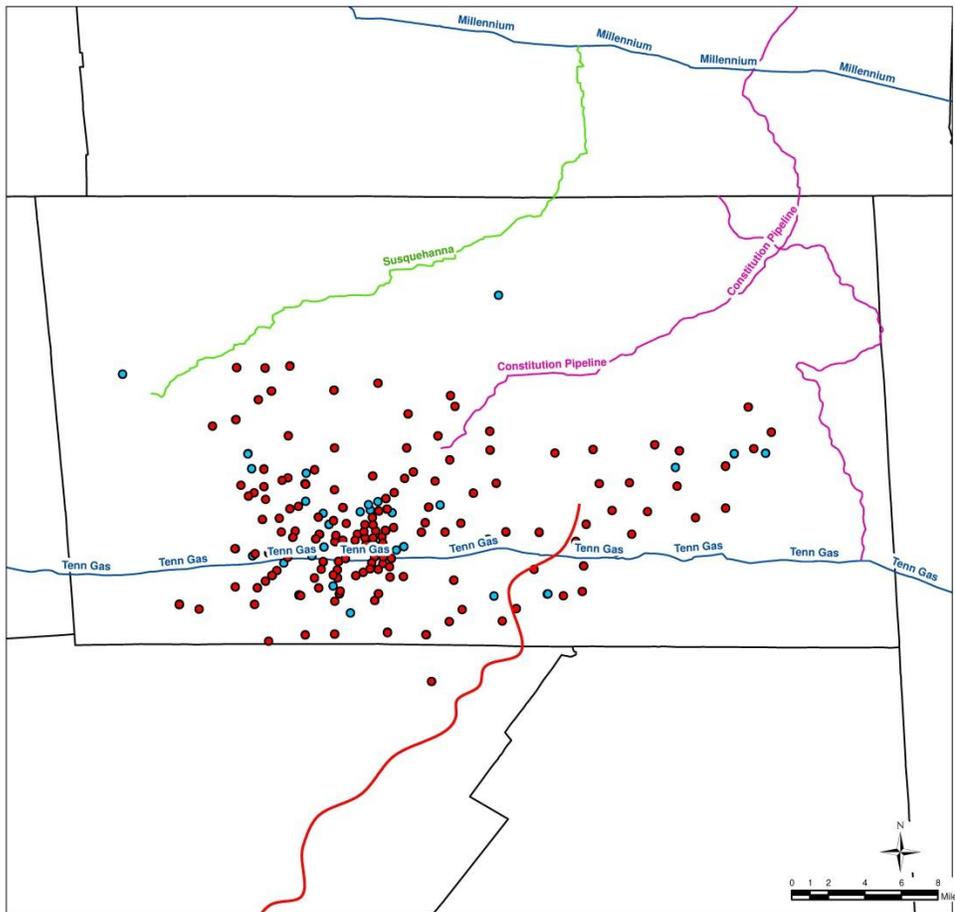
<sup>135</sup> Indeed, according to an article published in November 2013, Cabot has leased 200,000 acres of land in Susquehanna County. *See* Brendan Gibbons, *Cabot’s NEPA Wells “Still Howling” a Year Later*, Scranton Times-Tribune, Nov. 18, 2013, <http://thetimes-tribune.com/news/cabot-s-nepa-wells-still-howling-a-year-later-1.1587463>, submitted herewith.



**Dominion Cove Point  
LNG Terminal and Cabot  
Marcellus Wells**

- Atlantic Sunrise Pipeline
- Cabot Drilled Wells
- Cabot Permitted Wells, Not Drilled
- Natural Gas Pipeline Under Construction
- Active Natural Gas Pipelines >20" Diameter
- Proposed Natural Gas Pipeline

Source: Wells and production data from PADEP, downloaded June 6, 2014.  
Natural gas infrastructure data from MAPSearch.



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Cabot's contract with Pacific Summit Energy is a significant commitment above its current commitments and, as a result, it is reasonably foreseeable that Cabot will need to drill additional wells to meet the contract with Pacific Summit Energy. Cabot has committed to provide Pacific Summit Energy approximately 127.8 bcf of natural gas per year, for a period of 20 years, beginning on the Project's expected in-service date in 2017.<sup>136</sup> Cabot also has several other customer commitments likely to be active by the Project's expected 2017 in-service date. For example, Cabot has entered into a contract for the transport of 500,000 dekatherms ("dth") per day, the equivalent of 500,000 MMBtu per day<sup>137</sup> or approximately 182.5 bcf a year,<sup>138</sup> via the Constitution Pipeline, beginning on the pipeline's planned in-service date of March 2015.<sup>139</sup> Though the specific length of Cabot's contract with the Constitution Pipeline is not public information, Constitution's application to FERC to construct and operate the pipeline characterizes the contract as a "long-term firm transportation service agreement[]," likely to continue through 2017 and beyond, when Cabot has committed to ship gas to Cove Point.<sup>140</sup> Cabot also has agreed to supply "a meaningful portion" of Piedmont Natural Gas's supply commitments via Transco-Williams's proposed Leidy Southeast project, beginning in December 2015 and lasting for fifteen years.<sup>141</sup> Recently, Cabot confirmed "new long-term firm sales" of 125 million cubic feet per day, or 45.6 bcf per year to be transported via the Leidy Southeast

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<sup>136</sup> Calculation as follows: 365 days/year \* 350,000 MMBtu/day = 127.8 million MMBtu per year. Assuming 1,000 Btu in each cubic foot, per CenterPoint Energy, Energy Conversion Factors, <http://www.centerpointenergy.com/services/energymarketing/learningcenter/energyconversionfactors/> (last visited June 13, 2014), 127.8 million MMBtu is equivalent to 127.8 bcf of natural gas.

<sup>137</sup> CenterPoint Energy, Energy Conversion Factors, <http://www.centerpointenergy.com/services/energymarketing/learningcenter/energyconversionfactors/> (1 MMBtu is equivalent to 1 dth).

<sup>138</sup> Calculation as follows: 365 days/year \* 500,000 MMBtu/day = 182.5 million MMBtu per year. Assuming 1,000 Btu in each cubic foot, 182.5 million MMBtu translates to 182.5 bcf of natural gas.

<sup>139</sup> See Application of Constitution Pipeline Company, LLC for a Certificate of Public Convenience and Necessity, CP13-499, at 5, 8, Accession No. 20130613-5078 (Jun. 13, 2013). Cabot owns a 25% equity interest in the proposed Constitution Pipeline. *Id.* at 2-3.

<sup>140</sup> *Id.* at 5.

<sup>141</sup> Piedmont Natural Gas supplies natural gas to residential and business customers in North Carolina, South Carolina, and Tennessee. Piedmont Natural Gas, About Piedmont, <http://www.piedmontng.com/about/aboutpng/home.aspx> (last visited June 13, 2014). On Piedmont's January 2013 investors' conference call on 2012 earnings, Piedmont CEO Tom Skains announced the company had entered a supply agreement with Cabot. Under the agreement, Cabot will provide natural gas to Piedmont's customers in the Carolinas via the proposed Williams-Transco Leidy Southeast Project. Delivery is expected to begin in December 2015 and last for 15 years. Given confidentiality provisions in the agreement, Skains did not disclose specific amounts of gas or energy, but did state Cabot would provide "a meaningful portion of our annual gas supply commitments." See generally Thomson Reuters Streetevents, Edited Transcript, PNY-Q4 2012 Piedmont Natural Gas Earnings Conference Call at 5, 11, (Jan. 3, 2013), available at <http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MTY4NTE0fENoaWxkSUQ9LTF8VHlwZT0z&t=1>.

Project, likely fulfilling their commitment to Piedmont.<sup>142</sup> A July 2013 presentation from Cabot suggests that the Constitution and Piedmont commitments are long term. In the presentation, Cabot noted that by 2015, it plans to fulfill 615 million cubic feet per day in long-term sales contracts of 8-15 years duration, the approximate amount of these two commitments.<sup>143</sup> Finally, Cabot has agreed to sell WGL Midstream 500,000 MMBtus per day, or 182.5 bcf per year, via Transco's proposed Atlantic Sunrise Project, commencing on Atlantic Sunrise's in-service date in late 2017 and lasting through 2032 (Cabot owns 850,000 MMBtu per day of firm capacity on Atlantic Sunrise, allowing it to ship gas both to Cove Point for export and to WGL Midstream).<sup>144</sup> When factoring in these other existing customer commitments,<sup>145</sup> it is reasonably foreseeable that Cabot will need to drill additional wells to fulfill its commitment to Pacific Summit Energy.

In addition to the commitments discussed above, which are relatively clear, Cabot has made additional statements that strongly imply that it has entered into additional long term contracts that will be active through 2017 and beyond. For example, on an April 2014 conference call, Cabot CEO Dan Dinges announced that Cabot had acquired 70 million cubic feet per day of capacity on the Millennium Pipeline, and would add an additional 150 million cubic feet per day to Millennium by September 2014.<sup>146</sup> Dinges also stated that Cabot would begin providing 200 million cubic feet per day, or 73.0 bcf per year, to a local gas distribution company adjacent to its Marcellus infrastructure in late 2014.<sup>147</sup> A May 2014 investor presentation characterized these commitments as stimulating additional production through at least the end of 2015.<sup>148</sup> Dinges also stated that Cabot would provide 50 million cubic feet per

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<sup>142</sup> SA Transcripts, *Cabot Oil & Gas' CEO Discusses Q1 2014 Results - Earnings Call Transcript*, Seeking Alpha (Apr. 24, 2014, 2:10 PM), <http://seekingalpha.com/article/2162053-cabot-oil-and-gas-ceo-discusses-q1-2014-results-earnings-call-transcript>, submitted herewith ("Cabot Q1 2014 Results"). According to a recent Piedmont 10-K Report, Piedmont delivered 387.6 million dth of natural gas, or approximately 387.6 bcf of natural gas to customers in the fiscal year ending October 2013. Piedmont Natural Gas Company, Inc., Annual Report (Form 10-K) at 7 (Dec. 23, 2013), available at <http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MjE1OTQ1fENoaWxkSUQ9LTF8VHlwZT0z&t=1>. 387.6 million dth is equivalent to 387.6 million MMBtu, which is equivalent to 387.6 bcf (using a value of 1,000 Btu per cubic feet of gas). Cabot's commitment to supply 45.6 bcf via the Leidy Southeast project could be a "meaningful portion" of Piedmont's annual sales. If Piedmont is not the intended customer of the 45.6 bcf per year of sales via the Southeast Leidy project announced by Dinges in the April 2014 conference call, then Cabot's agreement with Piedmont could represent another significant customer commitment, lasting for 15 years from 2015 through 2030.

<sup>143</sup> Cabot Oil & Gas Corp., Marcellus Marketing Supplementary Materials, Jul. 24, 2013, <http://www.cabotog.com/pdfs/Marcellus-Marketing-Supplementary-Materials.pdf>. 615 million cubic feet per day is roughly equivalent to 224.5 bcf per year, close to the sum of the Constitution commitment and the Leidy Southeast commitment (182.5 bcf + 45.6 bcf = 228.1 bcf).

<sup>144</sup> News Release, Cabot Oil & Gas Corporation Announces New Agreements for Long-Term Sales and Pipeline Takeaway (Feb. 20, 2014), available at <http://phx.corporate-ir.net/phoenix.zhtml?c=116492&p=irol-newsArticle&ID=1902094&highlight=>. Bcf calculated assuming 1,000 Btu per cubic foot.

<sup>145</sup> Cabot has not provided detailed customer information in its investor relations materials or filings with the Securities and Exchange Commission. However, in early 2014 Cabot disclosed that it has natural gas and liquids transportation agreements with many pipelines for the next four to twenty-three years. These agreements are worth \$1,812,785. Cabot Oil & Gas Corp., Annual Report (Form 10-K) 84 (Feb. 28, 2014).

<sup>146</sup> Cabot Q1 2014 Results, *supra* note 142.

<sup>147</sup> *Id.*

<sup>148</sup> Cabot Oil & Gas Corp., Investor Presentation, 15 (May 12-13, 2014), available at <http://phx.corporate-ir.net/External.File?t=1&item=VHlwZT0yfFBhcmVudEIEPTUxNDQ0ODN8Q2hpbGRJRDR01NDM2NjE=>. This slide's vertical axis appears to be mislabelled as MMBtu/day instead of Million MMBtu/day.

year, or 18.3 bcf yearly, to Columbia's East Side Expansion Project in late 2015.<sup>149</sup> Though there is not enough public information to determine whether these commitments will still be in place in 2017 or whether they constitute commitments of separate volumes of gas from those described in the previous paragraph, they could represent even more customer commitments that Cabot will be required to fulfill in 2017 and beyond, the same time when Cabot will be shipping gas to Cove Point for export. Furthermore, complete information on Cabot's current and future short-term and long-term customers is not publically available. Ostensibly, Cabot is providing recently produced gas to customers under short- and long-term arrangements, and many of those arrangements could remain in place by 2017 and beyond. Thus, the above summary of Cabot's customer commitments is probably an underestimate of its actual commitment volumes in 2017. FERC's position as a federal agency and its access to confidential information puts it in a superior position to assess the scope of Cabot's supply commitments, yet FERC has refused to undertake this critical analysis.

The need to drill new wells for the Project to meet future commitments is confirmed by Cabot's production data. Between January and March of this year (the most recent period Cabot reported to the Securities and Exchange Commission), Cabot produced 115.8 bcf of natural gas, largely from its Pennsylvania wells.<sup>150</sup> Assuming consistent production across all months, Cabot will likely produce 463.2 bcf of gas this year, which, as shown in the chart below, falls short of the firm commitments discussed above. Thus, Cabot will need to increase production to meet the commitment to Dominion's customer. Cabot has already increased its production levels in recent years. For example, Cabot increased its production from 125.5 bcf in 2010<sup>151</sup> to 394.2 bcf in 2013,<sup>152</sup> and, as is noted above, will likely produce at least 463.2 bcf in 2014.<sup>153</sup> Cabot projects that its 2015 production levels could exceed 600 bcf.<sup>154</sup> Cabot's production increases have been matched by increased drilling of unconventional wells in Pennsylvania. For example, Cabot operated 207 active unconventional wells during the July 2009 through June 2010 reporting period, yet during the most recent reporting period, July through December 2013, Cabot reported 384 active unconventional wells.<sup>155</sup> Cabot has indicated that it plans to continue drilling new wells to increase production levels, and has estimated that it will drill approximately 110 net wells in their Marcellus holdings in 2014.<sup>156</sup> FERC must consider the environmental impact of this additional development in its review of Dominion's Cove Point project.

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<sup>149</sup> Cabot Q1 2014 Results, *supra* note 142.

<sup>150</sup> Cabot Oil & Gas Corp., Quarterly Report (Form 10-Q) at 19 (Apr. 25, 2014).

<sup>151</sup> Cabot Oil & Gas Corp., Annual Report (Form 10-K) at 12 (Feb. 28, 2013).

<sup>152</sup> Cabot Oil & Gas Corp., Annual Report (Form 10-K) at 14 (Feb. 28, 2014).

<sup>153</sup> Cabot Oil & Gas Corp., Investor Presentation, *supra* note 148, at 4 (predicting that 2014 production levels could exceed 500 bcf)

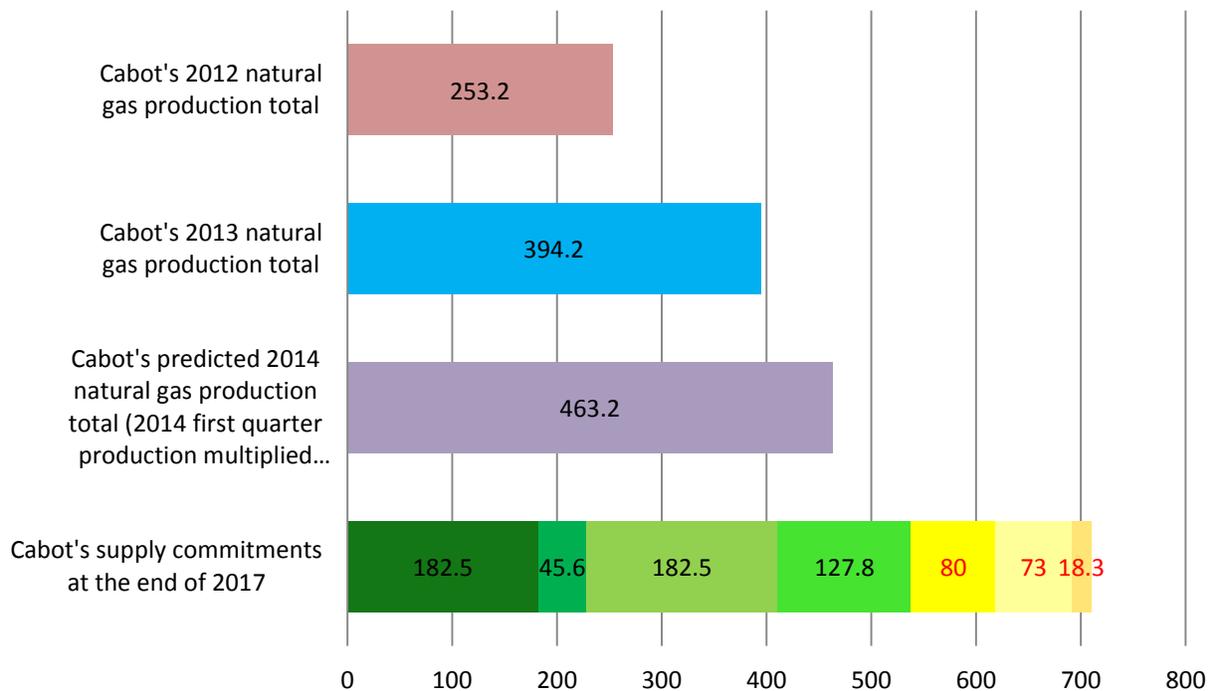
<sup>154</sup> *Id.*

<sup>155</sup> Pa. Dep't. of Env'tl. Prot., Oil & Gas Reporting Website,

<https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx> (last accessed June 13, 2014) (To find the number of Cabot's unconventional well sites, click on "Production Reports" and narrow "By Operator." Check the boxes for "Unconventional Only" and "Include Non-Producing Wells," enter "CABOT OIL & GAS CORP" under Operator Name. Providing the operator name will allow you to search for the "Jul 2009 – Jun 2010 (Marcellus Only, 12 months)" and "Jul – Dec 2013 (Unconventional Wells)" reporting periods.).

<sup>156</sup> Cabot Oil & Gas Corp., Investor Presentation, *supra* note 148 at 3.

## Cabot's Annual Production Levels and 2017 Supply Commitments



- Agreed yearly supply via Constitution Pipeline (500,000 MMBtu per day for 365 days, commencing on Constitution's in-service date in late 2015)\*
- Agreed yearly supply to the Transco Leidy Southeast Expansion Project (125 million cubic feet/day for 365 days, commencing December 2015)
- Agreed yearly supply to WGL Midstream via the Atlantic Sunrise Project (500,000 MMBtu per day for 365 days, commencing late 2017)\*
- Agreed yearly supply to Dominion Cove Point LNG liquefaction project (350,000 MMBtu per day for 365 days, commencing 2017)\*
- Agreed yearly supply to Millenium Pipeline (220 million cubic feet/day for 365 days, commencing 2014)<sup>i</sup>
- Recently announced yearly supply to Local Distribution Company. (200 million cubic feet/day for 365 days, commencing fourth quarter of 2014)<sup>i</sup>
- Agreed yearly supply to Columbia East Side Expansion Project (50 million cubic feet/day for 365 days, commencing December 2015)<sup>i</sup>

\* Calculated using a natural gas approximate heat value of 1,000 Btu per cubic foot.

<sup>i</sup> Some of the volumes indicated in the yellow commitments could overlap with volumes provided in the first four green definitive commitments. We do not know the specific durations of these contracts and some could expire before December 2017. Cabot's May 2014 investor presentation posits that additional capacity on the Millennium pipeline and new supplies to the marked Local Distribution Company will consistently stimulate additional production at least until December 2015 (see note 148). However, even if all marked commitments expired by late 2017 and/or overlapped with the four described definitive commitments, Cabot's customer commitments would still exceed their predicted 2014 production total.

Even if Cabot could meet its future commitments at its current annual production capacity, Cabot is likely to have to drill additional wells or refracture existing wells, with all of the environmental impacts those processes entail. Recent reports suggest that output from unconventional natural gas wells sharply declines after the first few years of production. One report documented a 60 to 80 percent decline at unconventional wells in shale formations after a single year.<sup>157</sup> Referred as the “Red Queen” effect, the decline in production at unconventional wells means that companies typically are forced to drill more and more wells to maintain the same levels of natural gas production.<sup>158</sup> One source predicts that “more than 6,000 U.S. wells would be needed each year to offset declines, at an annual cost of \$35 billion.”<sup>159</sup> FERC cannot simply ignore the extent to which Cabot will need to develop additional production capacity, with its attendant environmental effects.

### **3. Induced Natural Gas Production Is Likely to Impose Significant Environmental Harms.**

Because it is reasonably foreseeable that the Project will induce new natural gas production, FERC’s environmental review is deficient for failing to consider, let alone take a hard look at, the well-documented, significant adverse environmental effects of natural gas production. Much of the induced production resulting from exports is likely to come from shale gas and other unconventional sources. For example, the contract with Cabot suggests that at least half of the gas to be exported will be extracted from Cabot’s holdings in the Marcellus shale, where gas production requires the controversial practice of hydraulic fracturing to release the gas from the drilled wells.<sup>160</sup> Moreover, the EIA has concluded that domestic shale production will increase by over 70 percent in response to demand from exports.<sup>161</sup> Continued expansion of shale gas production poses “a real risk of serious environmental consequences.”<sup>162</sup> As is explained below, natural gas production in general, and from unconventional sources that rely on fracturing in particular, imposes significant environmental harms that should have been considered in the EIS.<sup>163</sup>

#### **a. Natural Gas Production Is a Major Source of Air Pollution.**

Natural gas production is a significant source of GHGs and other air pollutants, including methane, volatile organic compounds (“VOCs”), NO<sub>x</sub>, SO<sub>2</sub>, hydrogen sulfide (“H<sub>2</sub>S”), and PM<sub>10</sub>

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<sup>157</sup> Jennifer Hiller, *Red Queen Effect Can Make Production Slow Down in a Hurry*, FuelFix, Oct. 30, 2013, <http://fuelfix.com/blog/2013/10/30/red-queen-effect-can-make-production-slow-down-in-a-hurry/>.

<sup>158</sup> *Id.*

<sup>159</sup> *Id.*

<sup>160</sup> Hydraulic fracturing is the process of injecting a base fluid, sand, or other proppant and chemicals into gas-bearing formations at high pressures to fracture the rock and release the trapped gas.

<sup>161</sup> EIA Export Study, *supra* note 116, at 11 (explaining that “[o]n average, across all cases and export scenarios, the shares of the increase in total domestic production coming from shale gas, tight gas, [and] coalbed . . . sources are 72 percent, 13 percent, [and] 8 percent,” respectively).

<sup>162</sup> DOE, Sec’y of Energy’s Advisory Bd., Shale Gas Production Subcommittee Second 90-Day Report 10 (2011), available at <http://energy.gov/downloads/90-day-second-report-shale-gas-production-secretary-energy-advisory-board>. See also DOE, Sec’y of Energy’s Advisory Bd., Shale Gas Production Subcommittee 90-Day Report (2011), available at [http://www.shalegas.energy.gov/resources/081811\\_90\\_day\\_report\\_final.pdf](http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf) (“DOE, First 90-Day Report”).

<sup>163</sup> See generally DOE Addendum, *supra* note 115 (looking at the impact of additional gas development on water resources, air quality, climate, seismicity, and land).

and PM<sub>2.5</sub>. The equipment used to drill the gas, the wells themselves, the pipelines and compressor stations that transport the gas all emit pollutants that contribute to air pollution.<sup>164</sup>

As is noted in Section IV.C. below, natural gas production, processing, and transmission is a significant source of GHGs, particularly methane. Methane is the primary component of natural gas. Methane can be directly vented into the atmosphere or can escape from the wells, the gathering pipelines at the well pads and the larger pipelines in the distribution system, and the compressor stations that shuttle the gas through the distribution system.<sup>165</sup> Methane leakage rates from gas production differ, with studies projecting rates between 1.5 percent and 9 percent.<sup>166</sup> EPA has identified natural gas systems as the “single largest contributor to United States anthropogenic methane emissions,” with emissions from the oil and gas industry amounting to over 40 percent of total methane emissions.<sup>167</sup> Even when using an estimate of total methane emissions that many recent studies have criticized as too low, and a GWP that has been superseded by recent higher estimates, EPA concluded that methane emissions from the oil and gas industry constituted five percent of all CO<sub>2</sub>e emissions in the country.<sup>168</sup>

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<sup>164</sup> EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules, at 2-1 to 2-4 (July 2011), available at <http://nepis.epa.gov/Exe/ZyPDF.cgi/P100CHTC.PDF?Dockey=P100CHTC.PDF> (“2011 TSD”) (showing major sources of air pollution across associated with natural gas production, transmission, and distribution, including the wells, compressors, pipelines, pneumatic devices, dehydrators, storage tanks, pits and ponds, natural gas processing plants, and trucks and construction equipment).

<sup>165</sup> Dana R. Caulton et al., *Toward a better understanding and quantification of methane emissions from shale gas development*, Proc. Nat’l Acad. Sci. (Apr. 14, 2014), submitted herewith (evaluating methane emissions from fractured wells in the Southwestern Pennsylvania Marcellus shale region during drilling prior to gas flow stimulation and finding that “overall sites leak rates can be higher than current inventory estimates”); see also Anna Karion et al., *Methane emissions estimates from airborne measurements over a western United States natural gas field*, 40 Geophysical Res. Letters 4393-97 (2013), submitted herewith (measuring methane emissions from a producing oil and gas field in Utah, and finding emissions were five times the US EPA nationwide average estimate of leakage from the production and processing of natural gas).

<sup>166</sup> EPA’s Inventory of Greenhouse Gas Emissions and Sinks uses a “bottom-up” method based on engineering estimates of emissions from particular pieces of equipment or events multiplied by estimate of the census of such events. Many of these studies have estimated total lifecycle leak rates around 1.4 percent. See, e.g., Jeffrey Logan et al., Joint Inst. for Strategic Analysis, *Natural Gas and the Transformation of the U.S. Energy Sector 5* (2012), available at <http://www.nrel.gov/docs/fy13osti/55538.pdf>. Recently, many atmospheric measurements of methane have concluded that these bottom-up estimates are drastically too low. S. Miller et al., *Anthropogenic Emissions of Methane in the United States*, Proc. Nat’l Acad. Sci. (Dec. 10, 2013), available at <http://calgem.lbl.gov/Miller-2013-PNAS-US-CH4-Emissions-9J5D3GH72.pdf> (nationwide gas leak rate estimate of 3.6 percent); A.R. Brandt, et al., *Methane Leaks from North American Natural Gas Systems*, 343 Science 733-735 (Feb. 14, 2014) (a nationwide survey concluding that bottom-up estimates are generally 50% to low, and setting an upper bound for leak rates at 3.6 to 7.1 percent), available at <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>. Studies of individual gas plays have estimated leak rates from the production segment alone at 4 to 9 percent. Petron, G., et al., *A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin*, J. Geophys. Res. Atmospheres (2014) (production leak rate in the Colorado Denver-Julesburg Basin estimated at 4 percent) submitted herewith; Karion et al., *Methane Emissions Estimate from Airborne Measurements over a Western United States Natural Gas Field* 40 Geophysical Research Letters 4393 (Aug. 2013) (production leak rate in Utah’s Uinta basin estimated at 9 percent), submitted herewith.

<sup>167</sup> EPA, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738, 52,792 (Aug. 23, 2011).

<sup>168</sup> *Id.* at 52,791–92.

The natural gas system also is a major source of VOCs and NO<sub>x</sub>, both of which are precursors to ozone.<sup>169</sup> VOCs are emitted from well drilling and completions, compressors, pneumatic devices, storage tanks, processing plants, and as fugitives from production and transmission.<sup>170</sup> The primary sources of NO<sub>x</sub> are compressor engines, turbines, and other engines used in drilling and hydraulic fracturing.<sup>171</sup> NO<sub>x</sub> also is produced when gas is flared or used for heating.<sup>172</sup>

As a result of significant VOC and NO<sub>x</sub> emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems.<sup>173</sup> For example, on July 20, 2012, EPA newly designated Wyoming's Upper Green River Basin as a marginal nonattainment area for ozone.<sup>174</sup> In an extended assessment, the Wyoming Department of Environmental Quality found that ozone pollution was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."<sup>175</sup>

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<sup>169</sup> See, e.g., Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), available at [http://www.edf.org/documents/9235\\_Barnett\\_Shale\\_Report.pdf](http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf) (hereinafter "Barnett Shale Report") at 24; see also DOE Addendum, *supra* note 115, at 20 ("The oil and natural gas industry is the largest industrial source of [VOC] emissions according to the [EPA] and contributes to the formation of ground-level ozone.").

<sup>170</sup> See, e.g., 2011 TSD, *supra* note 164, at 4-7, 5-6, 6-5, 7-9, 8-1; see also Barnett Shale Report, *supra* note 169, at 24.

<sup>171</sup> See, e.g., 2011 TSD, *supra* note 164, at 3-6; Barnett Shale Report, *supra* note 169, at 24; Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project at 11 (Table 2.1) (Dec. 2007), submitted herewith.

<sup>172</sup> 2011 TSD, *supra* note 164, at 3-6; Colo. Dep't of Pub. Health & Env't, Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado, Appendix D at 1 (2011), available at [http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011\\_applications/exhibits\\_11-162-LNG/14.\\_Colorado\\_Haze\\_Plan.pdf](http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/exhibits_11-162-LNG/14._Colorado_Haze_Plan.pdf).

<sup>173</sup> See DOE Addendum, *supra* note 115, at 27-28 (documenting ozone nonattainment areas near major natural gas development activities and metropolitan areas, including in counties near Dallas-Fort Worth, Texas (near the Fort Worth Basin/Barnett Shale); Denver, Colorado (near the Denver Basin, Niobrara shale); and Pittsburg, Pennsylvania (near the Appalachian Basin/Marcellus shale), as well as ozone nonattainment areas near rural drilling operations); see also Comment of Sierra Club, *supra* note 1, at 48-50. The oil and gas industry also has contributed to ozone issues in the area surrounding Northeastern Utah's Uintah Basin. See, e.g., Utah Dept. of Env'tl. Quality, *Uinta Basin: Ozone in the Uinta Basin* (updated May 9, 2014), available at <http://www.deq.utah.gov/locations/uintahbasin/ozone.htm>; BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact Statement* ("GASCO DEIS"), at 3-13, available at [http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa/\\_gasco\\_energy\\_eis.html](http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa/_gasco_energy_eis.html). In addition, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone NAAQS. See Kembell-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale*, 44 Environ. Sci. Technol. 9357, 9362 (2010), submitted herewith.

<sup>174</sup> EPA, Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standards, 77 Fed. Reg. 30,088, 30,157 (May 21, 2012).

<sup>175</sup> Wyoming Dep't of Env'tl. Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin vii (Mar. 26, 2009), submitted herewith; see also Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, available at <http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1>.

VOCs also are co-emitted with a stew of “hazardous air pollutants,” including benzene, which are toxic and in some cases carcinogenic. Recent risk assessments from Colorado document elevated health risks for residents living near gas wells. Indeed, levels of benzene and other toxics near wells in rural Colorado were “higher than levels measured at 27 out of 37 EPA air toxics monitoring sites . . . including urban sites” in major industrial areas.<sup>176</sup>

Oil and gas production also emits SO<sub>2</sub>, primarily from natural gas processing plants.<sup>177</sup> SO<sub>2</sub> is released as part of the sweetening process, which removes hydrogen sulfide from the gas.<sup>178</sup>

The oil and gas industry also is a major source of PM pollution. This pollution is generated by heavy equipment used to move and level earth during well pad and road construction. Vehicles also generate fugitive dust by traveling on access roads during drilling, completion, and production activities.<sup>179</sup> Diesel engines used in drilling rigs and at compressor stations are also large sources of fine PM/diesel soot emissions. VOCs are also a precursor to formation of PM<sub>2.5</sub>.<sup>180</sup>

PM emissions from the oil and gas industry are leading to significant pollution problems. For example, monitors in Uintah County and Duchesne County, Utah have repeatedly measured wintertime PM<sub>2.5</sub> concentrations above federal standards.<sup>181</sup> These elevated levels of PM<sub>2.5</sub> have been linked to oil and gas activities in the Uinta Basin.<sup>182</sup> Modeling also shows that road traffic associated with energy development is pushing PM<sub>10</sub> levels very close to violating NAAQS standards.<sup>183</sup>

In summary, gas production emits numerous harmful air pollutants—from NO<sub>x</sub> and VOCs to SO<sub>2</sub>, H<sub>2</sub>S, and PM. The EA for the Project is deficient because it fails to address the air quality and health impacts of the induced natural gas production. Moreover, because these impacts are likely significant, FERC should have reviewed these impacts in an EIS.

#### **b. Natural Gas Production Disrupts Landscapes and Habitats.**

Increased oil and gas production is likely to transform the landscape of regions overlying shale gas plays, bringing industrialization to previously rural landscapes and significantly affecting ecosystems, plants, and animals.<sup>184</sup> In failing to consider induced natural gas

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<sup>176</sup> L. McKenzie et al., Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources, 424 *Sci. Total Env't* 79, 83 (2012), *available at* <https://www.bouldercounty.org/doc/landuse/mckenzie2012study.pdf>.

<sup>177</sup> 76 Fed. Reg. at 52,756, *supra* note 167.

<sup>178</sup> 2011 TSD, *supra* note 164, at 3-3 to 3-5.

<sup>179</sup> See GASCO DEIS, *supra* note 173, at App. J at 2.

<sup>180</sup> EPA, Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry: Regulatory Impact Analysis 4-18 (July 2011) (“O&G NSPS RIA”), *available at* <http://www.epa.gov/ttnecas1/regdata/RIAs/oilnaturalgasfinalria.pdf>.

<sup>181</sup> GASCO DEIS, *supra* note 173, at 3-12.

<sup>182</sup> BLM, West Tavaputs Plateau Natural Gas Full Field Development Plan Final Environmental Impact Statement (July 2010), at 3-20, *available at* [http://www.blm.gov/ut/st/en/fo/price/energy/Oil\\_Gas/wtp\\_final\\_eis.html](http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html).

<sup>183</sup> See GASCO DEIS, *supra* note 173, at 4-27.

<sup>184</sup> See *generally* DOE Addendum, *supra* note 115, at 55-66 (summarizing the land use impacts of natural gas development).

development, the EA illegally ignores these foreseeable impacts. Because these impacts are likely significant, FERC was under an obligation to consider them in a more robust EIS.

Natural gas development requires physically clearing and grading land to build well pads and associated infrastructure. Land and habitat is lost through development of well pads, roads, pipeline corridors, corridors for seismic testing, and other infrastructure. The Nature Conservancy (“TNC”) estimated that, in Pennsylvania, “[w]ell pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad.”<sup>185</sup> New York State’s Department of Environmental Conservation reached similar estimates about the scope of land disturbance.<sup>186</sup> After initial drilling is completed, well pads can be partially restored, but one to three acres of the well pad will remain disturbed through the 20- to 40-year life of the wells.<sup>187</sup> Associated infrastructure such as roads and corridors likewise will remain disturbed. Because these disturbances involve clearing and grading of the land, disturbed land is no longer suitable as wildlife habitat, and it increases the risk of invasion by non-native and ecologically destructive plant and animal species.<sup>188</sup>

Land loss also occurs when, although the area is not directly disturbed, its character is irreparably changed because of adjacent development. Adjacent land disturbance is “most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on ‘interior’ forest conditions.”<sup>189</sup> “Research has shown measureable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge.”<sup>190</sup>

Land disturbances can have a significant effect on the environment, species, and the economy. Since additional natural gas production is foreseeable, FERC has an obligation under NEPA to take a hard look at these impacts and, because the impacts are likely to be significant, FERC has an obligation to take that hard look in an EIS.

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<sup>185</sup> TNC, Pennsylvania Energy Impacts Assessment, Report 1: Marcellus Shale Natural Gas and Wind 10 (2010), available at [http://www.nature.org/media/pa/pa\\_energy\\_assessment\\_report.pdf](http://www.nature.org/media/pa/pa_energy_assessment_report.pdf).

<sup>186</sup> N.Y. Dep’t of Env’tl. Conservation, Revised Draft Supplemental General Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, 5-5 (2011) (“NY RDSGEIS”), available at <http://www.dec.ny.gov/energy/75370.html>.

<sup>187</sup> *Id.* at 6-67

<sup>188</sup> *Id.* at 6-68; see also E.T. Slonecker et al., U.S. Geological Survey, *Landscape Consequences of Natural Gas Extraction in Allegheny and Susquehanna Counties, Pennsylvania, 2004-2010* 7 (2013), available at [http://pubs.usgs.gov/of/2013/1025/OFR2013\\_1025.pdf](http://pubs.usgs.gov/of/2013/1025/OFR2013_1025.pdf) (“When natural or anthropogenic disturbance occurs in natural systems, it generally alters abiotic and biotic conditions that favor the success of different species, such as opportunistic invasive species over pre-disturbance organisms.”); P.J. Drohan et al., *Early Trends in Landcover Change and Forest Fragmentation Due to Shale-Gas Development in Pennsylvania: A Potential Outcome for the Northcentral Appalachians*, 49 *Env’tl. Mgmt.* 1061 (2012), available at <http://link.springer.com/article/10.1007/s00267-012-9841-6> (noting the extent of landscape disturbance on agricultural and forest land in Pennsylvania and the intensity of core forest disturbance impacting streams).

<sup>189</sup> Pennsylvania Energy Impacts Assessment, *supra* note 185, at 10.

<sup>190</sup> NY RDSGEIS, *supra* note 186, at 6-75.

**c. Natural Gas Production Poses Risks to Ground and Surface Water.**

Most of the production induced by the Project will likely be from shale gas reserves, and producing gas from these sources requires hydraulic fracturing.<sup>191</sup> Hydraulic fracturing involves injecting a base fluid (typically water),<sup>192</sup> sand or other proppant, and various fracturing chemicals into the gas-bearing formation at high pressures to fracture the rock and release trapped gas. Each step of the fracturing process presents a risk to water resources. Withdrawal of the water may overtax the water source. Fracturing itself may contaminate groundwater with either chemicals added to the fracturing fluid or with naturally occurring chemicals mobilized by fracturing. After the well is fractured, some water composed of both fracturing fluid and naturally occurring “formation” water will return to the surface. This water, together with drilling muds and drill cuttings, must be disposed of without further endangering surface water resources. Often the chemicals and water used in fracturing are stored on site, and wastes may be stored in open air pits, for a period of time. There is a significant risk of spills or leaks that threaten ground or surface water, or both. An adequate EA must consider the water impacts of Project-induced natural gas production. Moreover, because these effects are likely to be significant, FERC should have evaluated them in an EIS.

**i. Water Withdrawals**

Fracturing requires large quantities of water. The precise amount of water is dependent on the shale formation and the total length of each well. Estimates of water needed to fracture wells in the Marcellus shale region, where production induced by the Project is likely to occur, range from 4.2 to over 7.2 million gallons.<sup>193</sup> Approximately 80- 90 percent of the total water used to fracture a well generally comes from fresh water sources, even in instances where operators recycle “flowback” water from the fracturing of previous wells.<sup>194</sup> Many wells are fractured multiple times over their productive life.

Water withdrawals can negatively impact aquatic ecosystems and human communities. Reductions in instream flow negatively affect aquatic species by changing flow depth and velocity, raising water temperature, changing oxygen content, and altering streambed

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<sup>191</sup> See DOE, Shale Gas Production Subcommittee First 90-Day Report, *supra* note 162, at 8.

<sup>192</sup> The majority of hydraulic fracturing operations are conducted with a water-based fracturing fluid. Fracturing may also be conducted with oil or synthetic-oil based fluid, with foam, or with gas.

<sup>193</sup> See TNC, Pennsylvania Energy Impacts Assessment, *supra* note 185, at 8; *accord* NY RDSGEIS, *supra* note 186, at 6-10 (“Between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 4.2 million gallons per well, based on data for 553 wells.”). Other estimates suggest that as much as 7.2 million gallons of fracturing fluid may be used in a 4000 foot well bore. NRDC, et al., *Comment on NY RDSGEIS on the Oil, Gas and Solution Mining Regulatory Program* (Jan. 11, 2012) (Attachment 2, Report of Tom Myers at 9), *available at* [http://docs.nrdc.org/energy/files/ene\\_12011201c.pdf](http://docs.nrdc.org/energy/files/ene_12011201c.pdf) (“Comment on NY RDSGEIS”).

<sup>194</sup> NY RDSGEIS, *supra* note 186, at 6-10; Jean-Philippe Nicot, et al., *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report 54* (Sept. 2012), *available at* [http://www.twdb.state.tx.us/publications/reports/contracted\\_reports/doc/0904830939\\_2012Update\\_MiningWaterUse.pdf](http://www.twdb.state.tx.us/publications/reports/contracted_reports/doc/0904830939_2012Update_MiningWaterUse.pdf).

morphology.<sup>195</sup> Moreover, the intake structures can harm aquatic organisms.<sup>196</sup> Where water is withdrawn from aquifers, rather than surface sources, withdrawal may cause permanent depletion of the source. The risk of aquifer depletion is higher with withdrawals for fracturing than it is for other withdrawals, because fracturing is a consumptive use. Some of the fluid injected during the fracking process remains underground and (barring accident) is deposited below freshwater aquifers and into sealed formations.<sup>197</sup> What returns to the surface is heavily contaminated and cannot be disposed of safely on land or in waterways, without expensive and energy intensive treatment to remove pollutants. As a result, the wastewater typically is recycled for use in new wells or re-injected into sealed formations for permanent disposal. Thus, the water withdrawn from the aquifer will be used in a way that provides little or no opportunity to percolate back down to the aquifer and recharge it.

FERC's EA completely fails to evaluate these foreseeable effects of inducing natural gas production and thus is deficient. Because the impacts from water withdrawals could be significant, FERC should have prepared an EIS.

## ii. Groundwater Contamination

Fracturing also poses a serious risk of groundwater contamination. Contamination may have several causes, such as improper well siting, poor well design and construction, including problems with casing and cementing;<sup>198</sup> blow-outs and other catastrophic accidents; leaks in wells, pipes, and waste pits; spills of hydraulic fracturing chemicals and waste that percolate to groundwater; fracturing operations that were inappropriately conducted near an improperly plugged well or near a conduit in the rock,<sup>199</sup> fractures that grew out of zone, or a combination of these causes.<sup>200</sup>

Potential contaminants include the chemicals added to the drilling mud and fracturing fluid,<sup>201</sup> including diesel, which is so potentially harmful that a DOE Subcommittee recommended it be banned from use as a fracturing fluid additive.<sup>202</sup> Contamination may also result from chemicals naturally occurring in the formation. Flowback and produced water “may

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<sup>195</sup> NY RDSGEIS, *supra* note 186, at 6-3 to 6-4, *see also* Maya Weltman-Fahs, Jason M. Taylor, *Hydraulic Fracturing and Brook Trout Habitat in the Marcellus Shale Region: Potential Impacts and Research Needs*, 38 Fisheries 4, 6-7 (Jan. 2013), submitted herewith.

<sup>196</sup> NY RDSGEIS, *supra* note 186, at 6-4.

<sup>197</sup> *Id.* at 6-5; DOE, First 90-Day Report, *supra* note 162, at 19 (“[I]n some regions and localities there are significant concerns about consumptive water use for shale gas development.”).

<sup>198</sup> DOE, First 90-Day Report, *supra* note 162, at 19-20.

<sup>199</sup> Comment on NY RDSGEIS, *supra* note 193, attachment 2, Report of Tom Myers, at 12-15.

<sup>200</sup> *See generally* DOE Addendum, *supra* note 115, at 14, 18-19.

<sup>201</sup> NY RDSGEIS, *supra* note 186, at 5-40 to 5-41. These chemicals include petroleum distillates; aromatic hydrocarbons; glycols; glycol ethers; alcohols and aldehydes; amides; amines; organic acids, salts, esters and related chemicals; and microbicides, many of which present health risks. *Id.* at 5-75 to 5-78.

<sup>202</sup> DOE, First 90-Day Report, *supra* note 162, at 25. Despite the risks of fracturing with diesel, in 2011, the minority staff of the House Committee on Energy and Commerce noted that between 2005 and 2009 “oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states.” Natural Resources Defense Council, Earthjustice, and Sierra Club, Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels 2 (June 29, 2011) (quoting Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson 1), *available at* [http://docs.nrdc.org/energy/files/ene\\_11120901a.pdf](http://docs.nrdc.org/energy/files/ene_11120901a.pdf) (“Comment on Diesel Guidance”).

include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium), and organic compounds.<sup>203</sup> For example, in the Marcellus region, mercury that naturally occurs in shale formation can mix with water-based drilling muds, resulting in up to 5 pounds of mercury in the mud per well drilled.<sup>204</sup>

Scientific studies and real world experience confirms that fracturing operations threaten groundwater resources.<sup>205</sup> For example, regulatory investigations have found that groundwater contamination in Wyoming,<sup>206</sup> Pennsylvania,<sup>207</sup> and Texas<sup>208</sup> may have been attributable to fracturing. The EA is deficient for ignoring the groundwater impacts associated with induced production, including fracturing operations. Because such groundwater contamination is potentially significant, FERC should have completed an EIS to evaluate and mitigate these impacts.

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<sup>203</sup> DOE, First 90-Day Report, *supra* note 162, at 21; *see also* Comment on NY RDSGEIS, *supra* note 193, attachment 3, Report of Glen Miller, at 2-3.

<sup>204</sup> Comment on NY RDSGEIS, *supra* note 193, at attachment 1; Report of Susan Harvey, at 92.

<sup>205</sup> *See, e.g.*, DOE, First 90-Day Report, *supra* note 162, at 20 (citing Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, *Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing*, 108 Proc. Nat'l Acad. Sci. 8172 (2011), available at <http://nicholas.duke.edu/cgc/pnas2011.pdf> (documenting “the higher concentration of methane originating in shale gas deposits . . . into wells surrounding a producing shale production site in northern Pennsylvania.”); Comment on NY RDSGEIS, *supra* note 193, attachment 2, Report of Tom Myers, at 13; Geoffrey Thyne, *Review of Phase II Hydrogeologic Study* (2008), prepared for Garfield County, Colorado, available at [http://cogcc.state.co.us/Library/Presentations/Glenwood\\_Spgs\\_HearingJuly\\_2009/\(1\\_A\)\\_ReviewofPhase-II-HydrogeologicStudy.pdf](http://cogcc.state.co.us/Library/Presentations/Glenwood_Spgs_HearingJuly_2009/(1_A)_ReviewofPhase-II-HydrogeologicStudy.pdf) (finding methane and chloride in wells 100s of feet above the fracked zone); Environmental Protection Agency, *1 Report to Congress, Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy IV-22* (1987), available at [nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20012D4P.txt](http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20012D4P.txt) (documenting fracturing fluid moving into a 416-foot deep water well in West Virginia).

<sup>206</sup> EPA, Draft Investigation of Ground Water Contamination near Pavillion, Wyoming xiii (2011), available at [http://www2.epa.gov/sites/production/files/documents/EPA\\_ReportOnPavillion\\_Dec-8-2011.pdf](http://www2.epa.gov/sites/production/files/documents/EPA_ReportOnPavillion_Dec-8-2011.pdf) (concluding that “when considered together with other lines of evidence, the data indicates likely impact to ground water that can be explained by hydraulic fracturing”). Although EPA determined not to finalize this draft and instead turned its research over to the state, EPA “stands behind its work and data” in the draft report. EPA Region 8, Pavilion, <http://www2.epa.gov/region8/pavillion> (last visited June 16, 2014).

<sup>207</sup> *See, e.g.*, EPA Region III, Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site (Jan. 19, 2012), available at <http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%20001-19-12.PDF>.

<sup>208</sup> In 2010, EPA Region 6 concluded that groundwater in Parker County, Texas had elevated levels of methane and benzene, and they also found that methane from a “gas production well owned by Range Resources caused or contributed to the contamination in the groundwater.” Office of Inspector Gen., EPA, Response to Congressional Inquiry Regarding the EPA’s Emergency Order to the Range Resources Gas Drilling Company 4-5, available at <http://www.epa.gov/oig/reports/2014/20131220-14-P-0044.pdf> (2013). Independent scientists have concluded that water wells near drilling operations is more likely to contain contaminants than other waters. Brian E. Fontenot et al., *An Evaluation of Water Quality in Private Drinking Water Wells Near Natural Gas Extraction Sites in the Barnett Shale Formation*, 47 *Env'tl. Science and Tech.* 10032, 10032 (2013) (showing that water wells located within 3 km of active natural gas wells are more likely to contain contaminants (e.g., arsenic, selenium, strontium and total dissolved solids) than water wells further away), submitted herewith; Brett Shipp, Scientists: Tests Prove Fracking to blame for flaming Texas wells, WFAA.com, June 6, 2014, available at <http://www.khou.com/news/texas-news/Scientists-Tests-prove-fracking-to-blame-for-flaming-Texas-wells-262115241.html> (linking well water contamination to the Barnett shale).

### iii. Waste Management and the Potential for Water Contamination

Fracturing also generates large amounts of waste that, if not disposed of carefully, can pollute surface and ground waters, another indirect effect of the additional natural gas development that the EA unlawfully fails to consider. Again, because this effect is likely to be significant, FERC should have considered it in an EIS.

The potentially polluting waste includes drilling muds used to lubricate the drilling process, the drill cuttings removed from the well bore, the “flowback” of fracturing fluid that returns to the surface in the days after well stimulation, and the water naturally occurring in the shale formation that mixes with lingering fracturing fluid and comes to the surface during production, known as “produced water.” Drilling mud, drill cuttings, flowback, and produced water are often stored in pits on site, in tanks, or in offsite impoundments, which, if breached or otherwise compromised, can spill contaminated fluids into surface water, or can leach into shallow groundwater. Pipes and hoses connecting tanks to the well can fail, threatening surface water.<sup>209</sup>

Flowback and produced water must ultimately be processed and disposed of offsite. Some of these fluids may be recycled and used in further fracturing operations, but the recycling process does not solve the disposal problem, because treatment of the waste for recycling strips out contaminants, which also must be managed. The most common means of disposal are either processing the waste at a treatment facility for discharge into surface waters, or injecting the waste underground. Water treatment plants need to be, but rarely are, designed to remove constituents found in fracturing waste, including the bromides, radioactive material, and salts and other chemicals that can significantly affect water quality.<sup>210</sup> Underground injection wells present risks of groundwater contamination similar to those identified above for the fracturing itself.<sup>211</sup> Gas production wastes are not categorized as hazardous under the Safe Drinking Water

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<sup>209</sup> For more information on how improper waste management can lead to surface water contamination, please see the comments submitted on behalf of EarthReports, Inc. (dba Patuxent Riverkeeper); Potomac Riverkeeper, Inc.; Shenandoah Riverkeeper; Sierra Club; and Stewards of the Lower Susquehanna, Inc. on May 3, 2013. *See* Comments on Dominion Cove Point LNG, LP, Docket No. CP13-113-000, Doc. No. 20130503-5215, at 60-62.

<sup>210</sup> *See* Comment on NY RDSGEIS, *supra* note 193, Report of Glen Miller, at 13.

<sup>211</sup> For example, underground injection of fracturing wastes may have induced earthquakes in Ohio. *See* Columbia University, Lamont-Doherty Earth Observatory, Ohio Quakes Probably Triggered by Waste Disposal Well, *Say Seismologists* (Jan. 6, 2012), *available at* <http://www.ldeo.columbia.edu/news-events/seismologists-link-ohio-earthquakes-waste-disposal-wells>; *see also* Ellsworth, W. L., et al., Are Seismicity Rate Changes in the Midcontinent Natural or Manmade?, *Seismological Society of America*, (April 2012), *available at* [http://www2.seismosoc.org/FMPro?-db=Abstract\\_Submission\\_12&-recid=224&-format=%2Fmeetings%2F2012%2Fabstracts%2Fsessionabstractdetail.html&-lay=MtgList&-find](http://www2.seismosoc.org/FMPro?-db=Abstract_Submission_12&-recid=224&-format=%2Fmeetings%2F2012%2Fabstracts%2Fsessionabstractdetail.html&-lay=MtgList&-find) (confirming the connection between disposal wells and earthquakes); Alexis Flynn, Study Ties Fracking to Quakes in England, *Wall Street J.* (Nov. 3, 2011), *available at* <http://online.wsj.com/news/articles/SB10001424052970203804204577013771109580352>.

Act, 42 U.S.C. § 300f *et seq.*, and may be disposed of in Class II injection wells, which were not designed with safeguards to protect against the contaminants found in fracturing waste.<sup>212</sup>

The EA violates NEPA by failing to evaluate the waste management and disposal risks of Project-induced gas development in a robust EIS.

**d. Impacts of Additional Development at Cabot's Wells Are Potentially Significant.**

While these negative environmental effects of natural gas production can be expected at even the “best” operations, Cabot has a record of violations, which suggests that heightened scrutiny of environmental effects is warranted. For example, Cabot wells have contributed to the widely documented groundwater pollution in Dimock Township, Pennsylvania.<sup>213</sup> Failures of pipes and hoses at Cabot's well sites have also been found to contribute to surface water pollution.<sup>214</sup> More generally, data collected by the Pennsylvania Department of Environmental Protection shows that Cabot has been cited for more violations of Pennsylvania law than it has wells. From January 2008 until May 2014, Cabot drilled 425 wells in Pennsylvania,<sup>215</sup> while accruing 594 violations of Pennsylvania environmental, health, and safety laws.<sup>216</sup> In the most recent production reporting period, Cabot's violation rate at unconventional wells (the rate of

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<sup>212</sup> See NRDC et al., Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy 25 (Sept. 8, 2010), available at [http://docs.nrdc.org/energy/files/ene\\_10091301a.pdf](http://docs.nrdc.org/energy/files/ene_10091301a.pdf).

<sup>213</sup> Consent Order and Agreement at 2, *Cabot Oil and Gas Corp., Susquehanna County* (Pa. Dept. of Env'tl. Protection Nov. 4, 2009), available at <http://scrantontimestribune.com/waterproject/699.pdf>.

<sup>214</sup> In October 2009, the Pennsylvania Department of Environmental Protection (“PADEP”) fined Cabot when equipment failures at Cabot's Heitsman Well in Dimock Township spilled approximately 8,000 gallons of water and fracking gel mixture, polluting a nearby wetland and Stevens Creek. Cabot was found to have violated the Clean Streams Law, the Solid Waste Management Act, and the Oil and Gas Act. Press Release, Pennsylvania Department of Environmental Protection (“PADEP”), *DEP Fines Cabot Oil and Gas Corp. \$56,650 for Susquehanna County Spills* (Oct. 22, 2009), available at <http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2399&typeid=1>; see also PADEP Orders Cabot Oil and Gas To Cease All Gas Well Fracking In Susquehanna County, PA Env't. Digest, Sep. 28, 2009, <http://www.paenvironmentdigest.com/newsletter/default.asp?NewsletterArticleID=13621> (relaying that Cabot informed PADEP that failed pipe connections caused the spills).

<sup>215</sup> Cabot began their horizontal drilling program in Pennsylvania in 2008. See Cabot Oil & Gas Corp., Marcellus Shale, <http://www.cabotog.com/operations/marcellus/> (last visited June 16, 2014).

<sup>216</sup> PADEP, Oil & Gas Reports, [http://www.portal.state.pa.us/portal/server.pt/community/oil\\_and\\_gas\\_reports/20297](http://www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297) (last visited June 16, 2014). The number of Cabot's unconventional wells drilled can be viewed by visiting the Oil & Gas Reports Website, clicking on “Wells Drilled by Operator,” entering the reporting period between 1/1/2008 and 05/31/2014, setting “WELL STATUS” to “(Select All),” setting “REGION” to “All,” and clicking “View Report.” This will generate a report showing all of the conventional and unconventional wells in the state, by operator, including Cabot Oil and Gas Corporation. The number of violations at Cabot's conventional and unconventional wells can be calculated by visiting the Oil & Gas Reports Website, clicking on “Oil and Gas Compliance Report,” entering the inspection period between 1/1/2008 and 5/31/2014, setting “OPERATOR” to “CABOT OIL & GAS CORP (43513),” and setting “UNCONVENTIONAL ONLY (PF INSPECTIONS)” to read “No.” County, Region, Inspection Category, and Municipality should all be set to “All,” “RESOLVED VIOLATIONS ONLY” should be set to “No,” and “INSPECTIONS WITH VIOLATIONS ONLY” should be set to “Yes.” Upon clicking “View Report,” Cabot's violation total at their facilities for this time period will display on the first page of the report. Violations at unconventional facilities only can be seen by setting “UNCONVENTIONAL ONLY (PF INSPECTIONS)” to read “Yes.” Reports executed Jun. 16, 2014.

violations compared to active unconventional well sites) was over 25% higher than times the statewide average of all other unconventional well operators.<sup>217</sup> Given Cabot's history, FERC's failure to take a hard look at the environmental effects of additional Cabot development induced by the Project violates NEPA. Moreover, given the potential significance of the impacts, FERC should have prepared an EIS.

**B. FERC Fails to Take a Hard Look at the Potentially Significant Impacts of Natural Gas Transmission to Cove Point.**

In addition to failing to consider induced natural gas production, FERC's environmental review unlawfully fails to consider the environmental effects of gas transmission to Cove Point. Most notably, the EA fails to take account of the evidence that additional pipelines, including the Central Penn Line, and compressor stations, including the Myersville Compressor station, are being developed to move gas to Cove Point for export. As is described in more detail below, the Central Penn Line is new pipeline proposed as part of the Atlantic Sunrise Project. Once constructed, it will connect Cabot's natural gas production fields in Susquehanna County, Pennsylvania to the Transcontinental Pipeline Company's pipeline that leads to Cove Point.<sup>218</sup> The Myersville Compressor station was proposed as part of a project designed by Dominion Transmission, Inc. to increase natural gas storage capacity. The Myersville Compressor station is located on the Dominion Transmission's PL-1 pipeline, which also connects to Cove Point.<sup>219</sup>

The additional pipeline and compressor station projects were undertaken in response to the Project. Thus, the environmental consequences of this development must be, but are not, considered as indirect effects of the Project, i.e., those reasonably foreseeable induced impacts that are caused by the action, but occur later in time or farther away in distance. 40 C.F.R. § 1508.8. At a minimum, even if FERC refuses to acknowledge that the additional pipeline and the compressor station were completed to respond to the new market created by the Project, qualifying their effects as induced "indirect effects" of the Project, the environmental

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<sup>217</sup> From July 2013 - December 2013, Cabot reported custody of 383 active unconventional well sites, most of them producing gas, completing drilling, or temporarily closed. PADEP, Oil & Gas Reporting Website, <https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx> (To find the number of Cabot's unconventional well sites, click on "Production Reports" and narrow "By Operator." Check the boxes for "Unconventional Only" and "Include Non-Producing Wells," enter "CABOT OIL & GAS CORP" under Operator Name. Providing the operator name will allow you to search for the "Jul - Dec 2013 (Unconventional Wells)" reporting period.). In that period Cabot received 20 violations at unconventional well facilities, while the state issued 231 violations to the 6,266 active unconventional well sites run by other operators. As noted in the preceding footnote, well violations data is available on the Pennsylvania Department of Environmental Protection website, [http://www.portal.state.pa.us/portal/server.pt/community/oil\\_and\\_gas\\_reports/20297](http://www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297) (click "Oil and Gas Compliance Report"). Enter "07/01/2013" and "12/31/2013" as the range, and make sure "Unconventional Only" reads "Yes." Click the "Export" icon to download the data as a spreadsheet. For the statewide active well data, click on "Statewide Data Downloads" from the "Oil and Gas Reporting Website," then download the data for the Jul 2013 - Dec 2013 reporting period for unconventional wells. Filtering Column D generates a count of the total number of active wells. To exclude Cabot from the total statewide figure, we subtract Cabot's 383 active wells from the counted number. Reports executed June 16, 2014

<sup>218</sup> Transcontinental Gas Pipe Line Company, LLC, Request for Pre-filing Review, Docket No. PF14-8, Accession No.. 20140331-5484 (Mar. 31, 2014).

<sup>219</sup> See generally Allegheny Storage Project CP12-72; FERC, Allegheny Storage Project, Environmental Assessment, Docket No. CP12-72, Accession No. 20120614-4001, at 17-18 (June 2012); FERC, Order Issuing Certificate, 141 FERC ¶ 61,240 at 2-3 (Dec. 20, 2012).

consequences of building the proposed pipeline and compressor station should be considered in an analysis of the cumulative impacts of the Project. *See id.* § 1508.7. Cumulative impacts are those impacts on the environment resulting from “the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency . . . or person undertakes such other actions.” *Id.* By all accounts, the impacts from constructing the additional pipeline are cumulative with the impacts from constructing the export facility. *Thomas v. Peterson*, 753 F.2d 754, 759 (9th Cir. 1985) (reasoning that effects of proposed road and of timber sales that road was designed to facilitate were cumulative actions for which comprehensive analysis was required).

## 1. Additional Pipeline Development

FERC unlawfully is refusing to evaluate the effects of the construction and operation of the Central Penn Line. As is noted in the EA, “[Dominion] . . . presumes that the Project customers selected DCP’s facility as their location for export due to its proximity to natural gas supplies in the northeastern United States.” EA at 176. However, FERC is refusing to consider not only the environmental consequences of induced natural gas production, but also the environmental consequences of constructing and operating a new gas transmission system specifically designed to ship the newly produced Marcellus gas to Cove Point. According to FERC, “[w]hereas the Project could export natural gas derived from shale formations,” EA at 24, FERC need not consider the impacts of shipping the gas to Cove Point both because Dominion’s customers bear responsibility for shipment, and because details about the additional transmission are not reasonably foreseeable. EA at 25.

FERC’s refusal to consider the impacts from additional gas transmission is grounded neither in fact nor law. As is noted above, FERC has before it information confirming that half of the natural gas to be exported from Cove Point will originate at Cabot’s wells in Susquehanna County. Further industry announcements confirm that gas produced from Cabot’s wells will travel to Cove Point via a new, greenfield pipeline, the Central Penn Line. Thus, FERC has sufficient details to inform its environmental review. Moreover, when FERC does not have sufficient information for an analysis—for example, information about how Dominion’s other customer will obtain gas to be exported from Cove Point—it should ask Dominion to fill in the gaps so that it can evaluate all of the likely impacts of the Project. Indeed, under NEPA, FERC has an obligation to consider effects of the new pipeline development as reasonably foreseeable indirect effects of the Project, or as cumulative impacts of the Project. 40 C.F.R. §§ 1508.7, 1508.8.

On March 31, 2014, Transcontinental Gas Pipe Line Company, LLC (“Transco”) began the process to secure approval from FERC to construct and operate a new pipeline system, referred to as the Atlantic Sunrise Project.<sup>220</sup> As part of that project, Transco intends to build the Central Penn Line, 180 miles of new, greenfield pipeline, which will connect natural gas wells in

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<sup>220</sup> Transcontinental Gas Pipe Line Company, LLC, Request for Pre-filing Review, PF14-8, e-Library No. 20140331-5484 (Mar. 31, 2014).

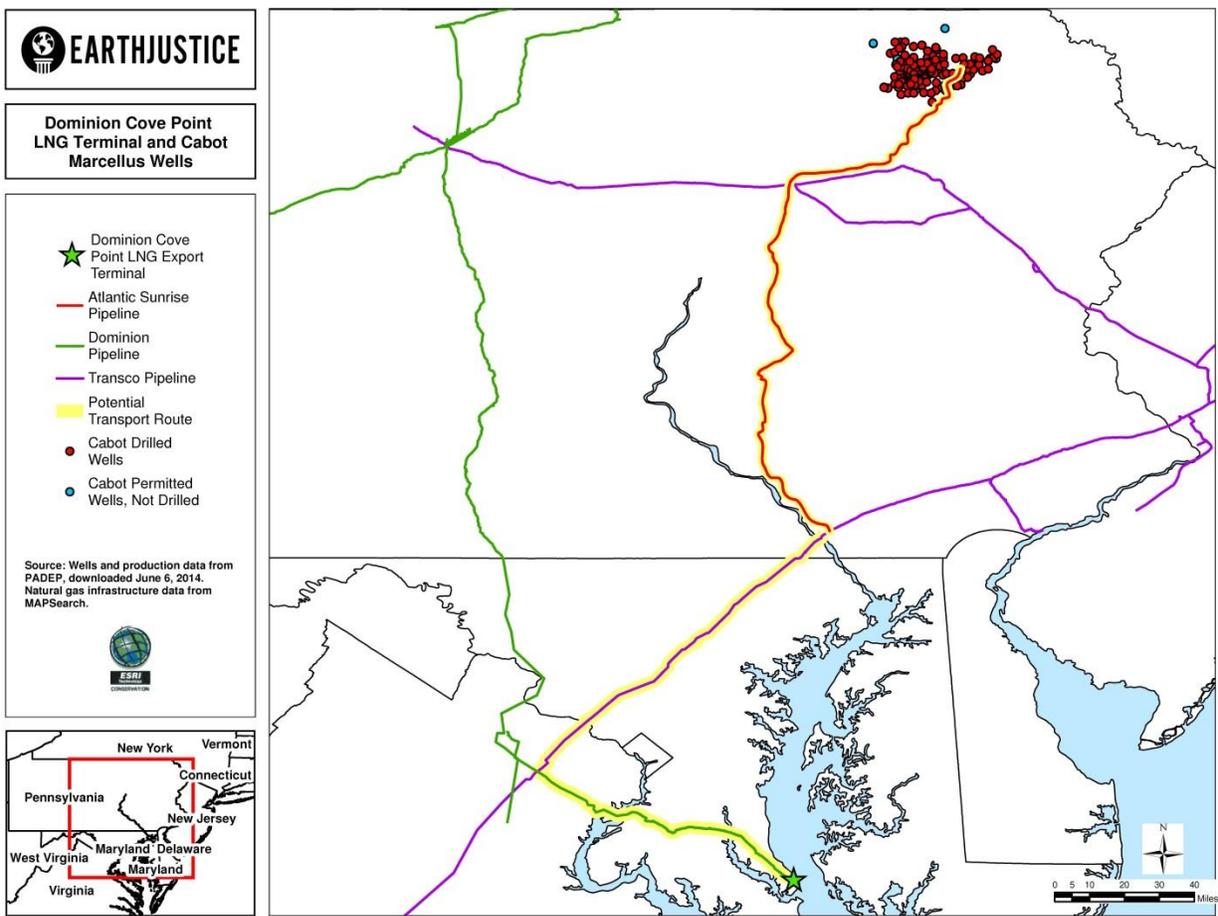
Susquehanna County, Pennsylvania, to Transco's mainline in Lancaster County, Pennsylvania.<sup>221</sup> In Lancaster County, the pipeline will plug into the Pleasant Valley Interconnection, which links Transco's mainline and Dominion Transmission's pipeline.<sup>222</sup> As is shown in the map below, the proposed Central Penn Line provides the only apparent route for the natural gas to travel from Cabot Oil & Gas Co.'s wells in Susquehanna County to Cove Point. Indeed, an oil and gas industry report about the project touted that the Central Penn Line "pave[s] the way for Cabot's shipment of 350 MMcfd to Dominion Cove Point LNG to fulfill a 20-year supply agreement with Pacific Summit Energy."<sup>223</sup> Thus, FERC must consider the Central Penn Line, and all of its attendant environmental effects, in assessing the impacts of the Cove Point Project. The Pipeline is designed to facilitate Cabot's shipment of natural gas to Cove Point, and thus is a reasonably foreseeable induced, indirect effect of the project. Moreover, because the pipeline will be constructed in the northeast region that the Project encompasses, the environmental effects are cumulative with the direct Project effects, and should be part of the larger environmental review. FERC's failure to consider the effect of pipeline development renders the EA deficient.

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<sup>221</sup> The first segment, the Central Penn Line North, will consist of 56.4 miles of 30-inch greenfield pipeline connecting wells in Susquehanna County with Transco's Leidy Line in Columbia County. Pre-filing Request at 4. The second segment, the Central Penn Line South, will consist of 122.2 miles of 42-inch greenfield pipeline connecting the Leidy Line to Transco's mainline in Lancaster County. *Id.*

<sup>222</sup> *Id.*; see also *id.* at 1-2 (explaining that "[a]s a result of significant interest expressed by shippers," the Project will be designed to provide firm transportation capacity from a proposed interconnection in Susquehanna County, Pennsylvania to the interconnection between Transco's mainline and Dominion Transmission's pipeline in Fairfax County, Virginia).

<sup>223</sup> Christopher E. Smith, *Cabot Secures Transco Natural Gas Pipeline Space, Sales to WGL*, Oil & Gas J., Feb. 21, 2014, <http://www.ogj.com/articles/2014/02/cabot-secures-transco-natural-gas-pipeline-space-sales-to-wgl.html>.



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Moreover, because the effects of this development are likely to be significant, as FERC’s own EA suggests, FERC should have prepared an EIS. In its analysis of alternatives, FERC dismisses the potential to use other LNG export terminals that have been proposed in the Gulf Coast as an alternative to the Project because, according to the Agency, use of those projects “would be unlikely to offer an environmental advantage over the Project as the facilities would require construction and operation of similar, if not greater, pipeline,” among other development. EA at 176. FERC later explains that pipeline development could impact resources, including “vegetation, soil, water, and air quality.” *Id.* at 177. FERC refused to consider other proposed LNG export facilities as alternatives to the Project because, according to the Agency, developing pipelines to transport the gas from the wells in the Northeast to other proposed facilities in the Gulf would impact the environment, undercutting any benefits of relocation. FERC cannot on the one hand, recognize that LNG export facilities induce pipeline development, and that pipeline development carries with it significant environmental impacts, to support its decision to dismiss Project alternatives, and on the other refuse to consider reasonably foreseeable pipeline development in its environmental review. Pipeline development does carry with it significant—and quantifiable—environmental impacts, including impacts on “vegetation, soil, water, and air quality.” EA at 177. These significant effects must be discussed in an EIS for the Project.

## 2. Additional Compressor Station

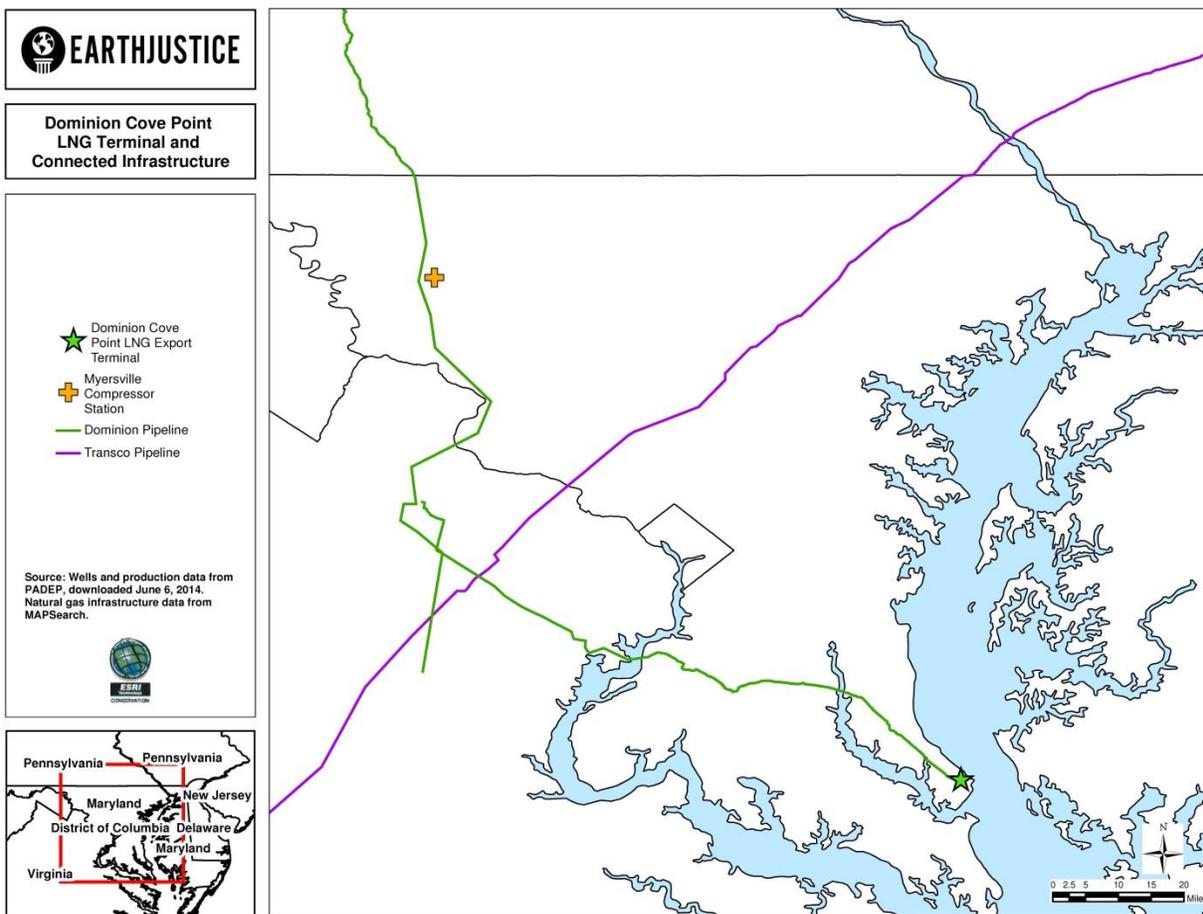
FERC's EA for the Project is deficient because it fails to consider the impacts from another related project, the Myersville Compressor station. The Myersville Compressor station was proposed as part of the Allegheny Storage Project operated by Dominion Transmission, Inc. ("DTI").<sup>224</sup> From an expert review of the materials supporting the Allegheny Storage Project and the Project, including the flow chart documents, it is likely that the Myersville Compressor station was designed to push gas through the pipeline system to Cove Point for export. As such, FERC should consider the effects of constructing and operating the compressor station in its review of the Project. At a minimum, the impacts of the compressor station are cumulative with the impacts of the export terminal. 40 C.F.R. § 1508.7.

The Myersville Compressor station is a 16,000 horsepower compressor station to be located in the town of Myersville, along DTI's PL-1 pipeline.<sup>225</sup> As is shown in the map below, the DTI pipeline ultimately connects to Cove Point via Dominion's Cove Point pipeline. An expert in pipeline systems, Richard B. Kuprewicz, reviewed the two projects and was able to conclude, preliminarily, that the projects appear connected.

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<sup>224</sup> Allegheny Storage Project CP12-72.

<sup>225</sup> FERC, Allegheny Storage Project, Environmental Assessment, Docket No. CP12-72, Accession No. 20120614-4001, at 17-18 (June 2012); FERC, Order Issuing Certificate, 141 FERC ¶ 61,240 at 2-3 (Dec. 20, 2012).



Redacted—relies on material filed as Critical Energy Infrastructure Information.

While the pipeline expert is reasonably confident in his conclusion that the DTI added additional compression capacity at Myersville to help ship gas to Cove Point, he requires additional information that has been filed as Critical Energy Infrastructure Information (“CEII”) to verify this conclusion, and to assess whether the compressor station was needed to support the Allegheny Storage Project at all. For example, information is needed about delivery pressures along the pertinent segments of pipeline, the parameters that set those pressures, information on pipe grade and thickness, and information about the interconnection between the PL-1 pipeline and the Cove Point pipeline.

On March 5, 2014, the undersigned submitted a request to FERC seeking answers to specific questions about the pipeline systems.<sup>226</sup> Ultimately, FERC provided a partial response to the request on May 5, 2014.<sup>227</sup> As Jacqueline Holmes of FERC explained to Earthjustice in a telephone conversation on April 28th, documents filed with FERC purportedly contain answers

<sup>226</sup> See Letter from Jocelyn D’Ambrosio, Earthjustice, to Kimberley Bose, FERC, dated Mar. 5, 2014, Accession No. 20140305-5085.

<sup>227</sup> See Letter from Michael J. McGehee, FERC, to Jocelyn D’Ambrosio, Earthjustice, dated May 5, 2014, Accession No. 20140505-3005.

to Questions 1, 3, and 5 in the March 5, 2014 letter. The responsive documents, which were filed as CEII, are listed in FERC's letter of May 5, 2014. As directed in the May 5, 2014 letter, the undersigned submitted a request for documents filed as CEII with FERC on May 7, 2014. FERC did not provide guidance as to where one would be able to obtain answers to Questions 2 and 4 in the March 5, 2014 request. In a telephone on May 12, 2014, Ms. Holmes directed Earthjustice to ask Dominion directly for answers to the outstanding questions. On May 20, 2014, the undersigned emailed counsel for Dominion seeking answers to Questions 2 and 4. In response, Dominion offered to provide counsel the CEII documents listed in FERC's May 5, 2014 letter, under the terms of a non-disclosure agreement. The parties have negotiated an agreement, and Earthjustice received the documents on Monday, June 9th, a week before the deadline to comment on the EA for the Project. Mr. Kuprewicz is unable to review the documents within the short timeframe, and the undersigned intend to submit supplemental comments as necessary once we have had a chance to review the material. It is unclear whether the documents provide answers to the outstanding questions and will allow the expert to complete his analysis. Regardless, FERC itself is under an obligation to assess the potential connection between the two projects, and, if they are in fact connected, as current evidence suggests, FERC must analyze the impacts of the Myersville Compressor station in the EA. Compressor stations are known to increase air pollution, disturb land, and impact species. These impacts, among others, must be considered in the EA.

**C. FERC Fails to Take a Hard Look at the Fact that the Project Will Contribute to Climate Change.**

There is a "pressing need" for agencies to account for climate change in performing their duties under NEPA. *See Conservation Nw. v. Rey*, 674 F. Supp. 2d 1232, 1253 (W.D. Wash. 2009). As a result, it has become relatively routine practice to account for indirect GHG emissions from proposed federal actions.<sup>228</sup> The EA fails to do so, however, and thus ignores Project impacts on climate change from both the upstream natural gas development discussed in the preceding section and the downstream transportation, regasification, and end use of the natural gas liquefied at Dominion's export facility. The EA therefore fails to take a hard look at the Project's climate change impacts or to support its conclusion that these impacts will be insignificant.

The EA quantifies only the direct GHG emissions from the Project, *see* EA at 169-71, although those effects likely have been underestimated. *See supra* Section III.B. Even accepting FERC's values for the Project's direct emissions, the Project alone would be the fourth-biggest climate polluter in Maryland. *See id.* The EA's discussion of direct GHG emissions from the liquefaction facility serves ought to appear, however, as only one part of a much larger natural gas lifecycle analysis. Using conservative assumptions, the full lifecycle GHG emissions of the LNG that would be exported from Project are in excess of 26,100,000 tons of CO<sub>2</sub>e per year.

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<sup>228</sup> *See, e.g.*, BLM, Final EIS for South Gillette Area Coal Lease Applications (Aug. 2009) *available at* [http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/hpdo/south\\_gillette/feis.Par.57426.File.tmp/vol1.pdf](http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/hpdo/south_gillette/feis.Par.57426.File.tmp/vol1.pdf) (BLM accounted for the emissions from coal mining and the combustion of coal in its NEPA review of mine leases. BLM did not evaluate GHG emissions from the transportation of the coal because it claimed that data was unavailable); *see also WildEarth Guardians v. U.S. Forest Serv.*, 828 F. Supp. 2d 1223, 1231 (D. Colo. 2011) (discussing final EIS by Forest Service that included an evaluation of GHG emissions from mining a coal seam and from combustion of the recovered coal).

The Project therefore would cause more GHG emissions than the combined lifecycle emissions of Maryland's entire fleet of coal-fired power plants.<sup>229</sup> This massive amount of GHG emissions unquestionably is a significant environmental impact that FERC must evaluate in an EIS.

As discussed above in Section VIII.B, significant emissions of GHGs, particularly methane, are associated with domestic natural gas production. Emissions occur as the result of intentional venting or unintentional leaks during drilling, production, processing, transmission and storage, and distribution. The rate at which methane leaks during the domestic production process has been hotly debated, with more conservative estimates ranging around 1.5 percent.<sup>230</sup> The climate change impacts of methane are of particular concern because methane has 86 times the GWP of CO<sub>2</sub> over 20 years, when considering the potential for positive climate carbon feedbacks.<sup>231</sup> The latest IPCC Report also found that methane has 70 times the global temperature change potential, the change in global mean surface temperature resulting from emissions, of CO<sub>2</sub>.<sup>232</sup> Emissions of methane therefore will have a greater and more immediate effect on the climate than emissions of CO<sub>2</sub>.

The Project also will cause additional indirect GHG emissions from the transportation of the LNG from the East Coast of the United States to Japan and India. *See* EA at 18. The typical mid-size LNG carrier can transport 138,000 m<sup>3</sup> of LNG cargo capacity or about 3.1 billion cubic feet ("bcf") of LNG.<sup>233</sup> These tankers emit GHGs by burning fuel on their more 8,657 to 9,712-nautical mile journey to India or Japan.<sup>234</sup> Once the tankers arrive at their foreign destination, the LNG must be regasified, often through the use of heat generated by the burning of yet more natural gas. Studies have estimated that these operations drastically increase the lifecycle GHG emissions of LNG relative to traditionally delivered natural gas, adding between 13.85 and 51.7

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<sup>229</sup>See Exhibit 1: II Methodology for Calculating Lifecycle GHG for Maryland's Coal Fleet.

<sup>230</sup> James McGarry, CCAN, *Dominion Study Confirms Climate Risks of "Lifecycle" Methane Leakage from Exporting Liquefied Natural Gas: Policy and Infrastructure Uncertainty Calls into Question the Pollution Status of Cove Point* (Apr. 25, 2014), available at [http://chesapeakeclimate.org/wp/wp-content/uploads/2014/03/Summary-of-methane-leakage-studies\\_061214.pdf](http://chesapeakeclimate.org/wp/wp-content/uploads/2014/03/Summary-of-methane-leakage-studies_061214.pdf).

<sup>231</sup> IPCC, *Climate Change 2013: Physical Science Basis, Anthropogenic and Natural Radiative Forcing*, 714 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_Chapter08\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf). A climate carbon feedback involving changes in the properties of the land and ocean carbon cycle in response to climate change. For example, changes to ocean temperature and circulation could affect the CO<sub>2</sub> balance between the oceans and the atmosphere. IPCC, *Climate Change 2013: Physical Science Basis, Annex III: Glossary*, 1450 (2013), available at [http://www.climatechange2013.org/images/report/WG1AR5\\_AnnexIII\\_FINAL.pdf](http://www.climatechange2013.org/images/report/WG1AR5_AnnexIII_FINAL.pdf).

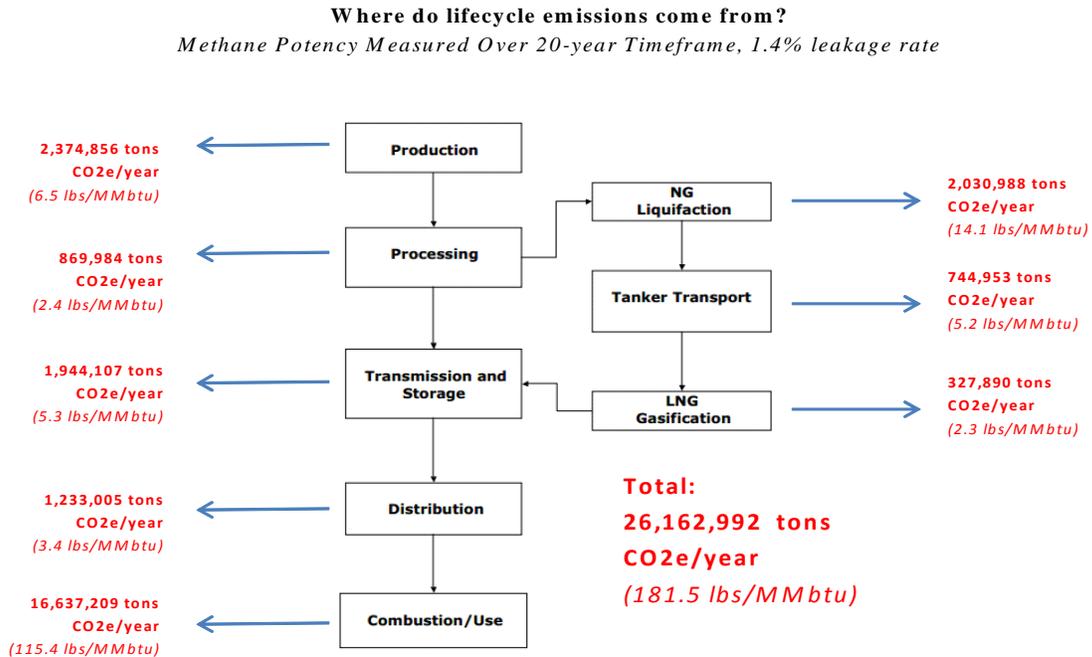
<sup>232</sup> *Id.*

<sup>233</sup> The 2008 EA prepared by the U.S. Coast Guard notes that the LNG tankers calling on Dominion's facility may not exceed 148,000 m<sup>3</sup>. NOAA, *Supplemental EA for the Dominion Cove Point LNG Terminal Expansion Project: LNG Ship Transit in United States Waters 5* (May 2008).

<sup>234</sup> See *Port Distance Calculator* (last visited June 13, 2014), available at <http://www.portworld.com/map/> (the approximate nautical distances from Cove Point to India and Japan were calculated by taking the average distances from Baltimore to the ports associated with the companies that have signed contracts with Dominion - GAIL (India), a state owned natural gas processing and distribution company, and Sumitomo Corporation (Japan), a trading company).

pounds of CO<sub>2</sub>e per MMBtu.<sup>235</sup> The regasified product then must be delivered to customers, which may involve delivery systems with much higher leakage rates than those used in U.S.<sup>236</sup> Lastly, approximately 120 pounds of CO<sub>2</sub>e per MMBtu is emitted when the gas is combusted.

The following graphic illustrates the total lifecycle emissions from the Project:

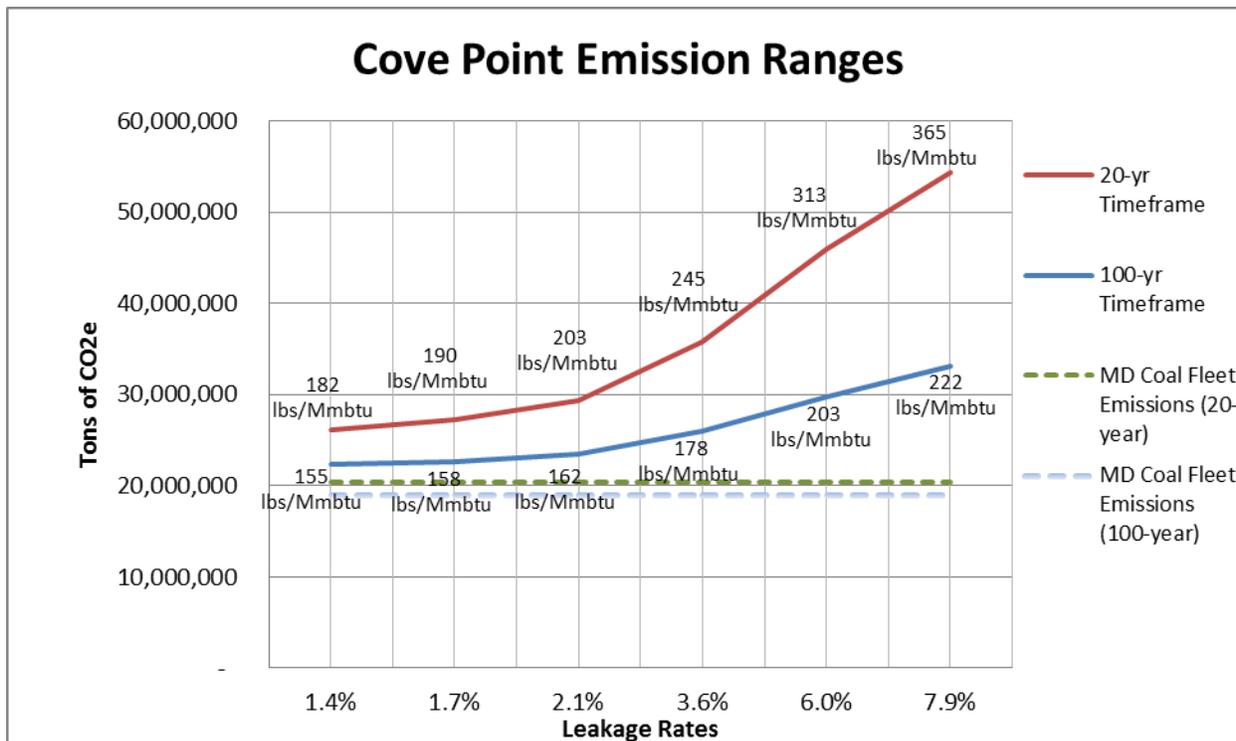


The methodology used in the above calculations can be found at Exhibit 1 to these comments.

<sup>235</sup> Paulina Jaramillo, W. Michael Griffin & H. Scott Matthews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, 41 *Envt. Sci. Technol.* 6,290 (2007) (“Jaramillo 2007”), available at [http://www.ce.cmu.edu/~gdrgr/readings/2007/09/13/Jaramillo\\_ComparativeLCACoalNG.pdf](http://www.ce.cmu.edu/~gdrgr/readings/2007/09/13/Jaramillo_ComparativeLCACoalNG.pdf). The cited estimate for the GHG emissions of liquefaction, transport, and regasification are derived by adding figures for these phases recorded in Figure 6S, p. 9, of the supporting information for this article, which is available at [http://pubs.acs.org/doi/suppl/10.1021/es063031o/suppl\\_file/es063031osi20070516\\_042542.pdf](http://pubs.acs.org/doi/suppl/10.1021/es063031o/suppl_file/es063031osi20070516_042542.pdf) (“Jaramillo Supporting Information”). An earlier, related report with some additional information is Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews, *Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation* (2005), available at [http://www.ce.cmu.edu/~gdrgr/readings/2005/10/12/Jaramillo\\_LifeCycleCarbonEmissionsFromLNG.pdf](http://www.ce.cmu.edu/~gdrgr/readings/2005/10/12/Jaramillo_LifeCycleCarbonEmissionsFromLNG.pdf). A more recent study reached a similar conclusion, suggesting that U.S. LNG may be about 15 percent more carbon-intensive than ordinary gas. Testimony of James Bradbury, World Resources Institute, Before the U.S. House of Representatives, Energy and Commerce Subcommittee on Energy and Power (May 7, 2013) at 15 (drawing on data from recent life cycle assessments), available at <http://docs.house.gov/meetings/IF/IF03/20130507/100793/HHRG-113-IF03-Wstate-BradburyJ-20130507.pdf>.

<sup>236</sup> See IPCC, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 4: Fugitive Emissions, 4.46 (2006), available at [http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\\_Volume2/V2\\_4\\_Ch4\\_Fugitive\\_Emissions.pdf](http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_4_Ch4_Fugitive_Emissions.pdf) (noting that “developing countries and countries with economies in transition have much greater amounts of fugitive emissions per unit of activity (often by an order of magnitude or more)” compared with their North American and Western European counterparts).

The above calculations assume a conservative leakage rate of 1.4 percent, which is far below recent atmospheric estimates, and is the “expected” leak rate for Marcellus production given in DOE’s recent “Life Cycle GHG Perspective on Exporting LNG from the U.S.” report. The following graph illustrates the significantly greater lifecycle GHG emissions for the Project that would result from the use of higher leakage rates and varying time frames:



The total GHG emissions, both direct and indirect, that will result from the Project therefore are between 26,162,992 tons and 365,000,000 tons per year over a 20-year timeframe. As direct GHG emissions are conservatively estimated at 2,030,988 tons per year, the indirect GHG emissions alone from the Project exceed at least 24,000,000 tons per year. As the above chart demonstrates, these indirect GHG emissions clearly are significant; in fact, they are well in excess of the GHG emissions from the entire Maryland coal-fired power plant fleet.<sup>237</sup>

The above calculations demonstrate that the lifecycle GHG emissions of the Project are quantifiable, as does DOE’s recent preliminary environmental report on the lifecycle GHG emissions resulting from LNG exports, generally.<sup>238</sup> The DOE report seriously underestimates the climate change impacts from LNG exports because it uses a low GWP for methane that does not adequately account for climate-carbon feedbacks and it underestimates leakage rates, both in the U.S. and abroad.<sup>239</sup> The report also misleadingly compares only U.S. LNG to other sources

<sup>237</sup> See Exhibit 1: II. Methodology for Calculating Lifecycle GHG for Maryland’s Coal Fleet.

<sup>238</sup> See DOE Life Cycle GHG Perspective, *supra* note 42.

<sup>239</sup> See *id.* There were several limitations in the DOE lifecycle analysis that resulted in underestimating the GHG impact of U.S. LNG exports. In addition to those described above, these include DOE’s failure to consider a range of higher leakage rates despite recent evidence from academic and government bodies suggesting that official leakage estimates may be substantially underestimating fugitive methane emissions from natural gas systems.

of natural gas or coal, ignoring the fact that U.S. LNG exports are likely to displace renewable energy in these countries.<sup>240</sup> Notwithstanding these deficiencies, the study proves that a lifecycle GHG analysis is possible and that FERC could have conducted an analysis of the Project's indirect GHG emissions. Having refused to do so, FERC cannot support its claim that the impacts of the Project's lifecycle GHG emissions on climate change will be insignificant.

## V. FERC's Analysis of Project Alternatives Is Deficient.

It is well established that consideration of alternatives is the heart of an environmental review under NEPA. *See, e.g., Young v. Gen. Servs. Admin.*, 99 F. Supp. 2d 59, 69 (D.D.C. 2000). The alternatives analysis must include consideration of the "no action" alternative to provide a baseline against which the Project is evaluated. *See Ctr. for Biological Diversity v. U.S. Dep't of the Interior*, 623 F.3d 633, 642 (9th Cir. 2010); *see also* 40 C.F.R. §§ 1502.14(d), 1508.9. As is discussed above, the potential environmental impacts of the Project are significant and require FERC to prepare an EIS. Even in an EA, however, FERC is required to provide a no action alternative analysis that "allows policymakers and the public to compare the environmental consequences of the status quo to the consequences of the proposed action." *Ctr. for Biological Diversity*, 623 F.3d at 642; *Pac. Coast Fed'n of Fishermen's Ass'ns. v. U.S. Dep't of the Interior*, 929 F. Supp. 2d 1039, 1048 (E.D. Cal. 2013) ("A no action alternative in an [EA or] EIS allows policymakers and the public to compare the environmental consequences of the status quo to the consequences of the proposed action."). NEPA also requires that the deciding agency "explore and objectively evaluate all reasonable alternatives," as well as discuss the reasons for rejecting alternatives. 40 C.F.R. § 1502.14; *Ctr. for Envtl. Law & Policy v. U.S. Bureau of Reclamation*, 655 F.3d 1000, 1012 (9th Cir. 2011) (noting that an EA must include a "'full and meaningful consideration' of the alternatives by the agency"); *N. Idaho Cmty. Action Network v. U.S. Dep't of Transp.*, 545 F.3d 1147, 1153 (9th Cir. 2008) (holding that the requirement to assess alternatives "applies whether an agency is preparing an [EIS] or an [EA], and requires the agency to give full and meaningful consideration to all reasonable alternatives"). The alternatives analysis in the EA is wholly inadequate because it (1) fails to account for the real environmental benefits of the no action alternative and engages in unsupported speculation regarding the alleged environmental benefits of the Project, and (2) fails to consider all reasonable alternatives because of the impermissibly narrow stated purpose and need for the Project.

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<sup>240</sup> *Id.* at 1. Even within this inappropriately narrow frame, DOE's comparison is flawed. As explained in the previous footnote, the report understates lifecycle emissions from US LNG exports. The report also potentially overstates emissions from coal: DOE's high-range efficiency for coal-fired power plants displaced abroad (36.7%) is lower than the average efficiency of Japan's coal-fired power plant fleet (40.8%). Thermal Efficiency of Electricity Generation in Japan, provided to CCAN by Shigeru Kimura, Senior Research Fellow at the Energy Data and Modelling [sic] Center within The Institute of Energy Economics, Japan (Mar. 25, 2014), submitted herewith. Despite these flaws, the Report concluded that over a 20-year period, the lifecycle greenhouse gas emissions per kilowatt hour of electricity generated using U.S. LNG exported to Asia will potentially exceed lifecycle emissions from coal-fired electricity generation in those countries.

**A. The Description of the No Action Alternative Fails to Meet NEPA's Requirements.**

The no action alternative analysis contained in the EA fails to weigh appropriately the environmental benefits of the status quo against the adverse environmental impacts of the Project. Although FERC admits that, under the no action alternative, “the environmental impacts identified in this EA would not occur,” EA at 173, the EA does not adequately address the full range and extent of the adverse environmental impacts from the Project (as is explained above) and thereby grossly underestimates the environmental benefits that would result from the no action alternative. Even in an EA, FERC must fully and meaningfully consider the alternative of maintaining the status quo and refusing to allow the Project to move forward. *See, e.g., N. Idaho Cmty. Action Network*, 545 F.3d at 1153.

The status quo that must be analyzed as part of the no action alternative includes the facts that only five ships called at Dominion’s facility in 2011 and that there is no prospect of increased shipping without the Project.<sup>241</sup> Continuing the minimal annual activity at Cove Point would have an array of environmental benefits—significantly reducing the threat of ship strike deaths of the endangered North Atlantic right whale, the potential for accidents from LNG ships and the associated environmental impacts, the air emissions (including GHGs) from these vessels, and the discharge of ballast water into the Chesapeake Bay. Because none of these very substantial environmental benefits is mentioned in FERC’s consideration of the no action alternative, the EA does not allow “policymakers and the public to compare the environmental consequences of the status quo to the consequences of the proposed action.” *See Pac. Coast Fed’n of Fishermen’s Ass’ns.*, 929 F. Supp. 2d at 1048.

The EA also grossly inflates the purported benefits of the Project by engaging in rampant and wholly unsupported speculation about the claimed benefits of exporting natural gas. In the “No Action Alternative” section, FERC claims that “[i]t is speculative and beyond the scope of this analysis to predict what action might be taken by policy makers or end users in response to the No Action Alternative.” EA at 173. FERC also characterized potentially significant induced upstream development in the Marcellus shale as too speculative for consideration in the EA, “because *the exact location, scale, and timing of future facilities are unknown.*” *Id.* at 163 (emphasis added). Nevertheless, in the section entitled “Alternative Energy,” FERC admittedly speculates, without any evidentiary support, that the failure to export natural gas to from the Project could lead to increased use of coal abroad. *Id.* at 173-75.<sup>242</sup> FERC cannot have it both ways. It cannot characterize foreseeably *adverse* impacts as too speculative for consideration and then blithely speculate about ostensibly beneficial effects of the Project.

FERC’s speculation that LNG exports will offset the use of coal or other higher GHG-emitting fuels in importing countries also is not supported by available evidence. Within the electricity sector, use of renewables in Asia is rising, with wind and solar at or approaching price

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<sup>241</sup> *See* U.S. Dep’t of Transp., Maritime Admin., Vessel Calls at U.S. Ports by Vessel Type (Nov. 06, 2013), available at [http://www.marad.dot.gov/documents/US\\_Port\\_Calls\\_by\\_Vessel\\_Type.xls](http://www.marad.dot.gov/documents/US_Port_Calls_by_Vessel_Type.xls).

<sup>242</sup> FERC cites a study by the EIA, reporting that coal exports from the U.S. are increasing and discussing why other forms of energy generation face hurdles. EA at 173-75. Nothing in that study shows that an increase in domestic natural gas exports will offset the use of coal overseas or result in net environmental benefits. FERC cites nothing else in support of its claim.

parity with fossil fuel generated electricity, and installations of wind and solar expected to boom in coming years.<sup>243</sup> Thus, it is likely that U.S. LNG exports will compete against clean renewable energy in addition to, or instead of, competing against other fossil fuels. Recognizing that increased gas use would displace renewables as well as other fossil fuels, the International Energy Agency has concluded that global scenarios of increased gas use are unlikely to decrease global GHG emissions.<sup>244</sup>

In addition, FERC's assessment of the purported climate and air quality benefits of the Project in its no action alternative analysis ignores important adverse environmental impacts of exporting natural gas, including GHG emissions. FERC also neglects to factor in the EIA's clear findings that exporting natural gas likely will result in increased use of coal domestically to generate energy.<sup>245</sup> The EA therefore is insufficient for failing to include a full and meaningful consideration of the costs and benefits of the no action alternative.

### **B. The EA Impermissibly Limits the Scope of FERC's Alternatives Analysis.**

The EA unlawfully fails to consider other reasonable alternatives to the Project because FERC has adopted an impermissibly narrow construction of the Project's purpose and need. *See* EA at 18. FERC is not permitted to "define[] the objectives of the project so narrowly that the proposed project [is] the only alternative that would serve those objectives." *Envtl. Prot. Info. Ctr. v. U.S. Forest Serv.*, 234 F. App'x 440, 443 (9th Cir. 2007). In the "Project Purpose and Need" section, the EA states that the purpose of the Project is "to liquefy for export domestically produced natural gas." EA at 18. The section then reports Dominion's claim that the Project is "ideally located to provide access to abundant and diverse domestic supply sources through the Cove Point pipeline" and states that Dominion has "fully contracted the proposed bi-directional service at the LNG Terminal to two customers," each of which has a 20-year agreement. *Id.* On that basis, FERC rejected the following alternatives: (1) any LNG terminals not located on the East Coast; (2) all East Coast LNG terminals with fully contracted capacity; (3) any LNG terminal that would not connect into Dominion's pipeline system; and (4) any LNG terminal that did not meet the timeframe of the Project. EA at 173, 176.

In rejecting those alternatives, FERC effectively has narrowed the broadly stated Project purpose—"to liquefy for export domestically produced natural gas"—to include liquefaction of gas for export only from a terminal located on the East Coast, only for use by Dominion's two pre-identified customers, and only within the same timeframe anticipated for the Project. *See id.* at 18, 173, 176. Limiting the Project purpose and need to exporting natural gas from one location to two customers in a specified window of time is impermissible under NEPA. *See Nat'l Parks & Cons. Ass'n v. Bureau of Land Mgmt.*, 606 F.3d 1058, 1072 (9th Cir. 2009)

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<sup>243</sup> Sophie Vorrath, *Wind at Parity with New Coal in India, Solar To Join by 2018: HSBC*, RenewEconomy (Jul. 11, 2013), available at <http://reneweconomy.com.au/2013/wind-at-parity-with-new-coal-in-india-solar-to-join-by-2018-hsbc-14836>; KPMG, *The Rising Sun: Grid Parity Gets Closer* (Sept. 2012), available at <https://www.kpmg.com/Global/en/IssuesAndInsights/ArticlesPublications/Documents/the-rising-sun-grid.pdf>.

<sup>244</sup> Int'l Energy Agency, *Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas 91* (Nov. 12, 2012), available at [http://www.worldenergyoutlook.org/media/weowebiste/2012/goldenrules/weo2012\\_goldenrulesreport.pdf](http://www.worldenergyoutlook.org/media/weowebiste/2012/goldenrules/weo2012_goldenrulesreport.pdf).

<sup>245</sup> EIA, *Effect of Increased Natural Gas Exports on Domestic Energy Markets 6-10, 12* (Jan. 2012), available at [http://www.eia.gov/analysis/requests/fe/pdf/fe\\_lng.pdf](http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf).

(finding a purpose and need statement that included one agency goal and three private party goals was too narrowly drawn and constrained the possible range of alternatives in violation of NEPA). FERC cannot interpret the Project's purpose and need so narrowly that every conceivable alternative is ruled out by definition. See *Envtl. Prot. Info. Ctr.*, 234 F. App'x at 443.

The analysis of purpose and need in the EA allows the needs and goals of Dominion and Dominion's customers to overwhelm the interests of the constituency FERC is supposed to serve. Although FERC is permitted to take into account the needs and goals of the parties involved in the application, the "overriding purpose of the NGA is to protect consumers against exploitation at the hands of natural gas companies." *United Distrib. Co. v. FERC*, 88 F.3d 1105, 1122 (D.C. Cir. 1996) (citation omitted). Nothing in the EA's statement of purpose and need or its alternatives analysis gives any consideration to the interests of domestic natural gas customers, and the NGA does not allow FERC to reject all alternatives except the Project in order to promote the pecuniary interests of three private corporations. FERC's alternatives analysis therefore is deficient under NEPA and cannot sustain the ultimate conclusions reached in the EA.

## **VI. The Draft EA Is Based on Incomplete Information.**

Although Dominion has been seeking authorization for the Project since June 2012, and has been submitting information relating to the environmental and human health impacts of the Project since that time, it has yet to file a number of expressly requested studies, analyses, and other plans that are essential to public review of this significant project and to governmental decision-making required under NEPA. Until Dominion provides FERC with complete information about the full suite of environmental impacts associated with the Project, and final plans designed to mitigate those impacts, FERC is in no position to reach any conclusion about whether the impacts are significant, and its mitigated FONSI is unsupported.

The EA indicates that FERC intends to proceed without even collecting much needed data supporting Dominion's plans to "mitigate" the environmental effects of the Project. At the very least, the Commission must insist that Dominion file the following admittedly missing information as soon as possible, and hold off on determining whether the impacts are insignificant under the finalized mitigation. As is noted above, where a FONSI is predicated on mitigation of impacts, the mitigation plan and measures must be "clearly described" and must be "enforceable."<sup>246</sup> Plans that have not been submitted are not clearly described, and cannot support a FONSI. Moreover, to fulfill NEPA's goal of informing the public about the environmental consequences of actions requiring federal approval, the following information, along with other yet-to-be-disclosed information described in the comments above, must be presented to the public during environmental review.

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<sup>246</sup> CEQ, *supra* note 24, at 7 & n. 18 ("Mitigation commitments needed to lower the level of impacts so that they are not significant should be clearly described in the mitigated FONSI document and in any other relevant decision documents related to the proposed action. Agencies must provide for appropriate public involvement during the development of the EA and FONSI.").

- An Implementation Plan describing how Dominion will comply with environmental permits and regulations, including plans to train its workers and Environmental Inspectors, EA at 30-31, 187-88;
- Final structure and foundation design drawings and calculations for the Liquefaction Facilities, as well as final calculations about vibratory equipment, *id.* at 42, 190;
- The results of a geotechnical investigation and final project design for planned work at the Pleasant Valley Compressor Station, *id.* at 43, 190;
- The final Oyster Bar Mitigation Plan and Artificial Reef Development Plan for Offsite Area B, and approval of these materials by the Maryland Department of Natural Resources (“MDNR”), *id.* at 57, 190;
- The final Forest Preservation Plan for Offsite Area A, and approval of these materials by MDNR; *id.* at 64, 190;
- Documentation of concurrence from Maryland Department of the Environment (“MDE”) that the Project is consistent with the Maryland Coastal Zone Management Program, *id.* at 83, 190;
- The final landscaping plan for the LNG terminal sound barrier, and documentation of MDNR’s approval of the plan, *id.* at 84, 191;
- Information required for the issuance of a final General Conformity Determination, including an updated estimate of Project emissions for each calendar year of construction and initial start-up, a record of the NOX offsets and documentation that MDE and Virginia Department of Environmental Quality concur that the offset requirements for the project have been met, *id.* at 107, 191;
- A revised Fugitive Dust Control Plan specifying the precautions Dominion will take to minimize construction-related dust emissions and identifying additional mitigation measures, *id.* at 109-110, 191;
- Specific measures to mitigate noise from ground flares, and a noise analysis demonstrating that operations would not exceed FERC’s noise criteria, along with a full load noise survey, *id.* at 119, 121, 191;
- Certification that the final design has been modified to be consistent with federal wind speed requirements in C.F.R. §193.2067 or that the U.S. Department of Transportation has approved the use of a lower wind speed, *id.* at 133, 193;
- A technical review of the facility design, with attention to safety procedures, *id.* at 134-39, 192-96;
- Details of vapor fences (including procedures for maintaining and inspecting barriers), *id.* at 150, 196; and
- An updated emergency response plan that covers the Liquefaction Facilities and includes instructions on handling on-site refrigerant and natural gas liquid-related emergencies, *id.* at 158, 193.

NEPA does not permit agencies to “act first and study later.” *Nat’l Parks & Conservation Ass’n v. Babbitt*, 241 F.3d 722, 734 (9th Cir. 2001). The missing information listed above “is precisely the information and understanding that is required *before* a decision

that may have a significant adverse impact on the environment is made.” *Id.* at 733 (emphasis in original). Granting Dominion’s application, even with conditions requiring submission of the missing information before construction begins, defeats NEPA’s purpose. Instead, FERC must revise its environmental review to provide accurate, consistent and complete data and analyses by which the public, FERC, and other agencies relying on FERC’s review can take a hard look at the potential impacts of the proposed Project.

## **VII. The Project Is Not in the Public Interest and Is Not Required by the Public Convenience and Necessity.**

The NGA, and subsequent DOE delegation orders and regulations, charge FERC with determining whether or not the construction and operation of a particular gas export facility is in the public interest. *See, e.g.*, 15 U.S.C. § 717b(a). Likewise, FERC must decide whether the Section 7 facilities Dominion wishes to build are required by the public convenience and necessity. *See id.* § 717f(c). In assessing whether the Project will be in the public convenience and necessity, FERC balances the stated public benefits from the Project against its adverse impacts. *See Certificate Policy*, 88 FERC ¶ 61,227, 61,748 (Sept. 15, 1999). “Vague assertions of public benefits will not be sufficient,” and the stated interests must outweigh the adverse effects caused by the Project for FERC to grant a Certificate. *See id.* at 61,748, 61,750; *see also Millennium Pipeline Co.*, 141 FERC ¶ 61,198, 2012 WL 6067320, at \*4 (2012). “[T]he more interests adversely affected or the more adverse impact a project would have on a particular economic interest, the greater the showing of public benefits from the project required to balance the adverse impact.” *Id.* at \*5. Simply stated, FERC cannot approve a project unless it concludes that the project’s benefits outweigh its adverse impacts.

As discussed above, the Project is likely to have significant adverse environmental impacts on human health and safety, air quality (including GHG emissions), the Chesapeake Bay, and the endangered North Atlantic right whale. The Project also is likely to induce additional drilling for natural gas in the nearby Marcellus shale, with foreseeable negative consequences for air, water, land, and communities. The Project, both directly and indirectly, will contribute to climate change, with monetized damages of \$2 billion dollars as a result of just the direct GHG emissions over the life of the Project. These impacts not only necessitate an EIS but also strongly suggest that the Project is not in the public interest.

Moreover, the Project will require clear-cutting of nearly of 100 acres of forest at Offsite Area A, to the detriment of species dependent on interior of forest habitat. EA at 13. Dominion plans to transform Offsite Area A, a currently forested tract of land next to Maryland Route 2/4, into a parking lot for 17,000 vehicles and a storage ground for the heavy materials needed to construct the power plant. *Id.* Dominion also is planning on building a temporary pier that will jut out into the Patuxent River, near a popular boat ramp, potentially obstructing recreational use. *Id.* Dominion will barge in the heavy construction materials and equipment to the Patuxent pier, truck those materials from historic Solomons, past the bustling Thomas Johnson Bridge (the only bridge connecting Calvert County to St. Mary’s County) to Offsite Area A and then on to the proposed export facility. The traffic—both from workers travelling to Calvert County, and from the trucks moving the heavy construction materials—will disturb quiet Calvert County and threatens to undermine tourism in the tranquil town of Solomons.

Dominion and FERC both have argued that the impacts during construction are temporary. However, construction will last up to three years, and repeated summers of inescapable noise and direct from industrial activity could have a permanent adverse impact on the region's seasonal tourism industry. Moreover, clear-cutting nearly 100 acres of forest may not easily be undone. The impacts from construction, then also raise significant questions about whether the Project's benefits outweigh its negative impacts. FERC has not taken a hard look at the Project's many impacts, and has failed to justify its conclusion that the impacts will be insignificant. This scant analysis cannot support a conclusion that the Project's negative impacts are outweighed by its benefits.

Moreover, as to the benefits, FERC has not addressed substantial questions about whether and where the alleged economic benefits will occur. On May 23, 2014, Dr. James Nicholas, Professor Emeritus of the University of Florida, submitted comments that identified substantial errors with Dominion's economic impact model that led to improbable estimates of the Project's economic benefits.<sup>247</sup> In particular, Dominion's analysis suggested that specialized construction jobs would be filled with Calvert County residents, when all available evidence points to the contrary conclusion.

Based on Dominion's analysis, the EA estimates that construction of the liquefaction facility and use of the offsite areas will generate approximately \$11.6 million in Calvert County income taxes during the construction period, 2014 to 2017, an estimate that other economists have questioned. EA at 92. In a letter filed on June 13, 2014, Dr. Dennis King concluded that to achieve this tax revenue, Dominion would have to assume that "thousands of construction jobs will be filled by Calvert County workers who do not exist" and that Dominion "will be purchasing literally billions of dollars' worth of construction materials and services in Calvert County that have never been produced and will never be produced in Calvert County."<sup>248</sup>

Dr. Nicholas and Dr. King raise substantial questions about whether FERC should rely on Dominion's account of the purported benefits of the Project. Without redoing this analysis, FERC is not in a position to determine whether the Project benefits outweigh the serious adverse impacts, and thus is in the public interest. In fact, the analyses of Dr. King and Dr. Nicholas suggest that the Project may not have sufficient benefits to outweigh the substantial adverse effects outlined throughout these comments. *Millennium Pipeline Co.*, 141 FERC ¶ 61,198, 2012 WL 60607320, at \*5 (explaining that "the more interests adversely affected or the more adverse impact a project would have on a particular economic interest, the greater the showing of public benefits from the project required to balance the adverse impact").

## VIII. Conclusion

For the reasons set forth above, the EA fails to take a hard look at significant environmental impacts, and therefore cannot provide a convincing case for its conclusion that the Project will not have a significant impact on the environment. Because the impacts ignored or

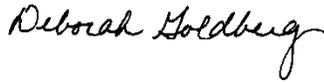
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<sup>247</sup> Letter from James C. Nicholas, Professor Emeritus, University of Florida, to Kimberley Bose, FERC, dated May 15, 2014, Accession No. 20140523-5110.

<sup>248</sup> Letter from Dennis M. King, University of Maryland, to Kimberley Bose, FERC, dated June 13, 2014, at 2-3, Accession No. 20140613-5157.

inadequately addressed are likely to be significant, FERC is under an obligation to prepare an EIS. We therefore urge FERC to revise its analysis, and release a draft EIS for public review and comment prior to proceeding with a decision on Dominion's application for a Certificate of Public Convenience and Necessity.

Respectfully submitted,



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*On behalf of EarthReports, Inc. (dba Patuxent Riverkeeper); Potomac Riverkeeper, Inc.; Shenandoah Riverkeeper; Sierra Club; Stewards of the Lower Susquehanna, Inc.; and the Chesapeake Climate Action Network.*

# **EXHIBIT 1**

## **Methodology for Calculation of Project Lifecycle GHG Emissions**

- A 1.4% natural gas leakage rate from the combination of natural gas production, processing, transmission & storage, and distribution. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011* (Apr. 12, 2013), available at <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf>.
  - This assumes that foreign pipelines, storage facilities, and compressor stations leak at the same rate as in the U.S.
  - Potentially a conservative estimate given that some of the gas is destined for developing countries and countries with economies in transition. See IPCC, 2006 *IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 4: Fugitive Emissions*, 4.46 (Simon Eggleston et al. eds., 2006), available at [http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\\_Volume2/V2\\_4\\_Ch4\\_Fugitive\\_Emissions.pdf](http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_4_Ch4_Fugitive_Emissions.pdf) (“developing countries and countries with economies in transition [have] much greater amounts of fugitive emissions per unit of activity (often by an order of magnitude or more)” compared to North American and Western European counterparts).
  - The leakage rate breaks down as follows (based on total natural gas systems fugitive emissions found in EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011*. (Apr. 12, 2013), available at <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf> (last visited June 16, 2014)):
    - **Production:** 0.5%
    - **Processing:** 0.2%
    - **Transmission & Storage:** 0.4%
    - **Distribution:** 0.3%
- Export-related emissions:
  - **Liquefaction:**
    - Emissions from liquefaction were taken from table 2.7.1-6 of the EA.
  - **Tanker transport**
    - Typical mid-size 138,000 m<sup>3</sup> LNG carriers transporting about 65,115 tons of LNG, or 3.1 bcf of natural gas per voyage. Vivek Chandra, *Fundamentals of Natural Gas: An International Perspective* 60 (Stephen Hill ed., PennWell Corp.) (2006), [http://www.worldwatch.org/system/files/pdf/Natural\\_Gas\\_LCA\\_Update\\_082511.pdf](http://www.worldwatch.org/system/files/pdf/Natural_Gas_LCA_Update_082511.pdf).

- Emissions from these tankers were calculated using the methodology described in equation 1 in Paulina Jaramillo et al., *Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation*, (2006) (“Jaramillo 2006”), available at [http://www.ce.cmu.edu/~gdrgr/readings/2005/10/12/Jaramillo\\_LifeCycleCarbonEmissionsFromLNG.pdf](http://www.ce.cmu.edu/~gdrgr/readings/2005/10/12/Jaramillo_LifeCycleCarbonEmissionsFromLNG.pdf).
- **Re-gasification**
  - Emissions from re-gasification were calculated assuming that the process emits 2.275 lbs of CO<sub>2</sub>e per MMBtu, which comes from the average of the emissions ranges ascribed to re-gasification. See Jaramillo 2006.
  - Emissions from combustion of natural gas in foreign nations assumes that natural gas emits 117.0 lbs of CO<sub>2</sub>/MMBtu. EIA, Carbon Dioxide Emissions Coefficients by Fuel (Feb. 14, 2013), available at [http://www.eia.gov/environment/emissions/co2\\_vol\\_mass.cfm](http://www.eia.gov/environment/emissions/co2_vol_mass.cfm).

### **Methodology for Calculating Lifecycle GHG for Maryland’s Coal Fleet:**

- Maryland’s combined coal plant emissions at the point-of-combustion in 2013 were 17,910,648 tons of CO<sub>2</sub>.
  - Maryland 2013 Power Plant Emissions calculated using Regional Greenhouse Gas Initiative (“RGGI”) CO<sub>2</sub> Allowance Trading System annual report data. RGGI CO<sub>2</sub> Allowance Tracking System, Reports: Annual Emissions (last visited June 16, 2014), [https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=reportsv2.annual\\_emissions\\_rpt&clearfuseattribs=true](https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=reportsv2.annual_emissions_rpt&clearfuseattribs=true). (2013 Maryland power plant emissions were compiled by following these steps: Enter this filter criteria: Beginning Year: 2013; End Year: 2013; State: Maryland. Click filter; Check the box marked “select all”. Click “Get Facility Level Report.” This lays out a list of Maryland’s 2013 power plant emissions.).
  - Coal plants include: Brandon Shores, Morgantown, Chalk Point, AES Warrior Run, Herbert A Wagner, Dickerson, and C P Crane.
- The 2011 Worldwatch Institute study *Comparing Lifecycle Greenhouse Gas Emissions From Natural Gas and Coal* found that the lifecycle emissions factor for coal is 99.9 kg CO<sub>2</sub>e/MMBtu. Mark Fulton et al., Worldwatch Institute, *Comparing Life-Cycle Greenhouse Gas Emissions From Natural Gas and Coal* 17 (2011), [http://www.worldwatch.org/system/files/pdf/Natural\\_Gas\\_LCA\\_Update\\_082511.pdf](http://www.worldwatch.org/system/files/pdf/Natural_Gas_LCA_Update_082511.pdf). Of that, upstream methane emissions account for 3.3 kg CO<sub>2</sub>e/MMBtu, which increases lifecycle emissions of coal-fired electricity by 3.3% over combustion emissions. *Id.* at 26.

- In combination with upstream CO<sub>2</sub> and N<sub>2</sub>O emissions, total upstream emissions account for 4.8 kg CO<sub>2</sub>e/MMBtu, which increases lifecycle emissions by 5.0% over combustion emissions. *Id.*
  - Notably, this finding is based on a 100-year timeframe using a methane GWP of 25, which comes from the IPCC's 4th Assessment Report ("AR4"). *Id.* at 2.
    - In order to account for upstream emissions when calculating the lifecycle emissions of coal-fired electricity (over 100 years using the GWP from AR4), increase the point of combustion emissions by 5.0%.

*Note: The following analysis is based on CCAN's interpretation of the Worldwatch Institute Report, not on findings from the report itself.*

- In order to account for upstream emissions when calculating the lifecycle emissions of coal-fired electricity (over 100 years using the GWP from the IPCC's 5th Assessment Report ("AR5")), first scale up methane's contribution to lifecycle coal emissions from the Worldwatch Institute report by 1.36. That is because 34 (methane's 100-year GWP from AR5) is 36% higher than 25 (methane's 100-year GWP from AR4). After scaling up the potency of methane, upstream methane emissions account for 4.5 kg CO<sub>2</sub>e/MMBtu, which increases lifecycle emissions of coal-fired electricity by 4.7% over combustion emissions. In combination with upstream CO<sub>2</sub> and N<sub>2</sub>O emission, total upstream emissions account for 5.9 kg CO<sub>2</sub>e/MMBtu, which increases lifecycle emissions by 6.2% over combustion emissions.
  - **A 6.2% increase in the point-of-combustion emissions from Maryland's coal fleet (17,910,648 tons of CO<sub>2</sub>e) would result in lifecycle emissions of 19,021,108 tons of CO<sub>2</sub>e from Maryland coal plants when methane is measured over a 100-year lifecycle.**
- In order to account for upstream emissions when calculating the lifecycle emissions of coal-fired electricity (over 20 years using the GWP from AR5), first scale up methane's contribution to lifecycle coal emissions from the Worldwatch Institute report by 3.44. That is because 86 (methane's 20-year GWP from AR5) is 244% higher than 25 (methane's 100-year GWP from AR4). After scaling up the potency of methane, upstream methane emissions account for 11.4 kg CO<sub>2</sub>e/MMBtu, which increases lifecycle emissions of coal-fired electricity by 12.0% over combustion emissions. In combination with upstream CO<sub>2</sub> and N<sub>2</sub>O emission, total upstream emissions account for 12.8 kg CO<sub>2</sub>e/MMBtu, which increases lifecycle emissions by 13.5% over combustion emissions.
  - **A 13.5% increase in the point-of-combustion emissions from Maryland's coal fleet (17,910,648 tons of CO<sub>2</sub>e) would result in lifecycle emissions of 20,328,586 tons of CO<sub>2</sub>e from Maryland coal plants when methane is measured over a 20-year lifecycle.**