IN THE UNITED STATES COURT OF APPEALS
FOR DISTRICT OF COLUMBIA CIRCUIT

EARTHREPORTS, INC. (DBA PATUXENT RIVERKEEPER), SIERRA CLUB, AND CHESAPEAKE CLIMATE ACTION NETWORK,	
Petitioners,	No. 15-1127
v.	
FEDERAL ENERGY REGULATORY COMMISSION,	
Respondent.	

ORIGINAL

PETITION FOR REVIEW

Pursuant to Section 19(b) of the Natural Gas Act, 15 U.S.C. § 717r(b), Federal Rule of Appellate Procedure 15, and Circuit Rule 15, EarthReports, Inc. (dba Patuxent Riverkeeper), Sierra Club, and Chesapeake Climate Action Network hereby petition the United States Court of Appeals for the District of Columbia Circuit for review of the following orders of the Federal Energy Regulatory Commission (the "Commission"):

1. The September 29, 2014 "Order Granting Section 3 and Section 7 Authorizations," 148 FERC ¶ 61,244, entered in Commission Docket Dominion Cove Point LNG, LP, No. CP13-113-000; and

2. The May 4, 2015 "Order Denying Rehearing and Stay," 151 FERC ¶ 61,095, entered in Commission Docket Dominion Cove Point LNG, LP, No. CP13-113-001.

Copies of the challenged orders are attached hereto.

Dated: May 6, 2015

Respectfully submitted,

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PETITIONERS' RULE 26.1 STATEMENT

Pursuant to Federal Rule of Appellate Procedure 26.1 and Circuit Rule 26.1, Petitioners make the following disclosures:

EarthReports, Inc. (dba Patuxent Riverkeeper): EarthReports, Inc. has no parent companies, and there are no publicly held companies that have a 10 percent or greater ownership interest in EarthReports, Inc.

EarthReports, Inc., a corporation organized and existing under the laws of the State of Maryland, is a nonprofit organization dedicated to conserving, protecting, and replenishing the Patuxent River.

Sierra Club: Sierra Club has no parent companies, and there are no publicly held companies that have a 10 percent or greater ownership interest in Sierra Club.

Sierra Club, a corporation organized and existing under the laws of the State of California, is a national nonprofit organization dedicated to the protection and enjoyment of the environment.

Chesapeake Climate Action Network: Chesapeake Climate Action Network has no parent companies, and there are no publicly held companies that have a 10 percent or greater ownership interest in Chesapeake Climate Action Network.

Chesapeake Climate Action Network, a corporation organized and existing under the laws of the State of Maryland, is a nonprofit organization dedicated to fighting global warming and moving our country towards cleaner energy.

Dated: May 6, 2015

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CERTIFICATE OF SERVICE

I, Jocelyn D'Ambrosio, hereby certify under penalty of perjury that on May 6, 2015, I served a copy of the foregoing Petition for Review and Corporate Disclosure Statement by United States mail on all of the following individuals, including all members of the service list in FERC Docket No. CP13-113:

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148 FERC ¶ 61,244
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
and Norman C. Bay.

Dominion Cove Point LNG, LP — Docket No. CP13-113-000

ORDER GRANTING SECTION 3 AND SECTION 7 AUTHORIZATIONS

(Issued September 29, 2014)

Paragraph Numbers

1. On April 1, 2013, Dominion Cove Point LNG, LP (Dominion)[1] filed an application for authority under section 3 of the Natural Gas Act (NGA)[2] and Part 153 of the Commission's regulations[3] to site, construct, and operate facilities for the liquefaction and export of domestically-produced natural gas (Cove Point Liquefaction Project) at Dominion's existing liquefied natural gas (LNG) import terminal in Calvert County, Maryland.[4] Dominion also seeks authority under section 7(c) of the NGA[5] and Part 157 of the Commission's regulations,[6] to construct and operate facilities at its existing compressor station and metering and regulating (M&R) site in Fairfax County, Virginia, and at its M&R site in Loudoun County, Virginia (collectively, Virginia Facilities).

2. For the reasons discussed below, we will authorize Dominion's proposal under section 3 to construct and operate the Cove Point Liquefaction Project. We will also authorize Dominion's proposal under section 7(c) to construct and operate the Virginia Facilities. The authorizations issued to Dominion are subject to the conditions discussed below.

I. <u>Background</u>

3. Dominion, a limited partnership organized and existing under the laws of Delaware, is a natural gas company as defined by section 2(6) of the NGA engaged in the business of transporting natural gas in interstate commerce.[7] Dominion owns the existing Cove Point LNG Terminal (Cove Point Terminal) near Lusby, in Calvert County, Maryland, as well as an 88-mile-long gas pipeline (Cove Point Pipeline) that extends west from the terminal to connections with interstate pipelines in Loudoun and Fairfax Counties, Virginia. The Cove Point Terminal and Cove Point Pipeline were initially

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[1] Dominion Cove Point LNG, LP is a subsidiary of Dominion Resources, Inc.

[2] 15 U.S.C. § 717b (2012).

[3] 18 C.F.R. Part 153 (2014).

[4] The Cove Point LNG Terminal was initially authorized by the Commission in 1972 and commenced service in 1978. *See infra* note 8.

[5] 15 U.S.C. § 717f (2012).

[6] 18 C.F.R. Part 157 (2014).

[7] 15 U.S.C. § 717a(6) (2012).

authorized in 1972 to receive LNG imports and transport natural gas to U.S. markets.[8] The original terminal had four LNG storage tanks with 5.0 billion cubic feet (Bcf) of capacity and the certificated capacity of the Cove Point Pipeline was 1.0 Bcf per day. An underwater tunnel connects the onshore facilities with an offshore pier used to receive LNG offloaded from arriving ships.

4. Shipments of LNG to the terminal commenced in the spring of 1978 but were suspended in 1980 due to market forces. In 1994, the Commission authorized Dominion's predecessor to construct a liquefaction unit to liquefy domestic natural gas in order to provide LNG peaking and storage services.[9] In 2001, the Commission authorized Dominion's predecessor to construct new facilities, including an additional LNG storage tank that increased the total facility capacity to 7.8 Bcf, and to reactivate existing facilities to resume imports and provide terminal services for shippers.[10] The LNG import facilities were placed in service and began to receive LNG shipments in the fall of 2003.

5. In 2006, the Commission approved the Cove Point Expansion Project involving the expansion of the Cove Point Terminal and the Cove Point Pipeline, as well as the construction of related downstream pipeline and storage facilities.[11] The sole expansion

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[8] On June 28, 1972, the Commission authorized Columbia LNG Corporation and Consolidated System LNG Company to construct and operate the Cove Point Terminal and the Cove Point Pipeline. Opinion No. 622, 47 FPC 1624 (1972), *aff'd and modified*, Opinion No. 622-A, 48 FPC 723 (1972). Subsequently, the Commission authorized (1) Consolidated System LNG Company to abandon its undivided one-half interest in the LNG facilities in *Consolidated System LNG Co.*, 42 FERC ¶ 61,078 (1988); and (2) Columbia LNG Corporation to abandon all of its jurisdictional facilities by transfer to Cove Point LNG Limited Partnership in *Cove Point LNG Limited Partnership*, 68 FERC ¶ 61,128 (1994). In 2002, Dominion Resources, Inc. acquired the equity shares of the two companies comprising Cove Point LNG Limited Partnership, and later that year, Cove Point LNG Limited Partnership became Dominion Cove Point LNG, LP. *See* Dominion March 10, 2014 Data Response.

[9] *Cove Point LNG Limited Partnership*, 68 FERC ¶ 61,377 (1994).

[10] *Cove Point LNG Limited Partnership*, 97 FERC ¶ 61,043 (2001).

[11] *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,337 (2006), *order on reh'g*, 118 FERC ¶ 61,007 (2007), *vacated and remanded sub nom. Washington Gas Light Co. v. FERC*, 532 F.3d 928 (D.C. Cir. 2008), *order on remand*, 125 FERC ¶ 61,018 (2008), *order on reh'g and clarification*, 126 FERC ¶ 61,036 (2009), *petition for review denied sub nom. Washington Gas Light Co. v. FERC*, 603 F.3d 55 (D.C. Cir. 2010).

customer, Statoil Natural Gas LLC (Statoil), entered into a non-open access service agreement for all of the expanded capacity. The expanded facilities were placed into service in January 2009, and included two new LNG storage tanks and additional vaporization facilities that increased the combined storage capacity at the terminal to seven tanks with a total capacity of 14.6 Bcf and a peak send-out rate of 1.8 million dekatherms (Dth) per day.

6. In 2009, the Commission approved the Pier Reinforcement Project,[12] which authorized Dominion to upgrade, modify, and expand the existing offshore pier at the Cove Point LNG terminal. The Pier Reinforcement Project allowed the offshore pier to accommodate more modern ships with cargo capacities of up to 267,000 cubic meters of LNG.

II. Proposal

A. Dominion's Cove Point Liquefaction Project

7. Dominion's proposed Cove Point Liquefaction Project, combined with its existing facilities, would enable it to either receive and vaporize imported LNG or liquefy domestically-produced natural gas for loading onto LNG vessels for export.[13] Dominion states that it will use its facilities initially to provide liquefaction and export service, and will likely continue to do so barring significant changes to worldwide gas markets. Nevertheless, Dominion states that to maintain flexibility, the liquefaction project will allow for bi-directional import or export service. Dominion explains that it cannot provide both export and import services at the same time for Pacific Summit Energy, LLC (Pacific Summit)[14] and a U.S. subsidiary of GAIL (India) Limited,[15] (collectively, Export Customers) that have initially contracted for export service, but rather, the Export Customers may make a joint election once a year whether to receive import and regasification service, or liquefaction and export service.

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[12] *Dominion Cove Point LNG, LP*, 128 FERC ¶ 61,037 (2009), *petition for review denied sub nom. Washington Gas Light Co. v. FERC,* 603 F.3d 55.

[13] The LNG vessels will be owned and operated by third parties.

[14] Pacific Summit is a United States (U.S.) subsidiary of Sumitomo Corporation, a Japanese trading company.

[15] GAIL Limited is the largest natural gas processing and distribution company in India. In an October 30, 2013 filing, Dominion requested that GAIL Global (USA) LNG, LLC (GAIL Global) be used as the identified export customer.

8. Dominion proposes under section 3 of the NGA to construct and operate one liquefaction train that is expected to have a nameplate capacity of up to 5.75 million metric tons per annum (MTPA) of LNG.[16] The liquefaction train contains gas turbine-driven refrigerant compressors, draft air coolers, process vessels, pumps, and heat exchangers for liquefying natural gas. Other equipment within the liquefaction train battery includes waste heat recovery systems, fire and gas detection and safety systems, control systems and electrical infrastructure, utility connections and distribution systems, piping, pipe racks, foundations, and structures. In addition, gas treatment equipment will be installed to remove impurities from the gas supply stream that have no heating value, have corrosive potential, or will crystallize during the liquefaction process.

9. The Cove Point Liquefaction Project will use two new natural gas-fired turbines[17] to drive the main refrigerant compressors.[18] The waste heat from the gas-fired turbines will be used to generate electric power on-site to meet the power demands of the liquefaction facilities.[19]

10. Dominion proposes to use its existing storage tanks at the LNG terminal to store LNG produced by the liquefaction unit. LNG will be pumped from the storage tanks through the existing underwater tunnel to the offshore pier for loading onto LNG vessels for export. Dominion states that no additional marine facilities are required for the liquefaction project, and that only limited modifications to the existing marine gas

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[16] Dominion's front end engineering design (FEED) study that established design parameters and production estimates determined that the facilities will have a base LNG production capacity of 5.25 million MTPA. Dominion states that its review of production capability for global liquefaction plants supports its projection that during operation, the actual capacity will exceed 5.25 million MTPA by as much as ten percent. For this reason, Dominion requests authorization to construct and operate liquefaction facilities with an LNG production capacity of up to 5.75 million MTPA.

[17] Dominion will use General Electric Frame 7EA gas turbines.

[18] Dominion will employ the Air Products C3/split MR process as its liquefaction technology. This process uses a propane pre-cooled, mixed-refrigerant refrigeration system with a proprietary main cryogenic heat exchanger to cool the natural gas feed stream and produce LNG.

[19] Dominion's load calculations indicate that approximately 80 megawatts (MW) of power will be needed for the Cove Point Liquefaction Project. This power will be provided by two 65 MW steam turbine generators using the waste heat from the gas turbines to produce steam and generate power.

processing systems will be necessary.[20] Specifically, to enable the existing offshore pier to serve both offloading and loading function, existing suction drums will be removed to make room for two new vapor return blowers that will be installed on each of two pier platforms.[21]

11. Dominion states that it will construct the liquefaction facilities on its existing property at the Cove Point Terminal and will use approximately 190.1 acres of additional offsite property in Calvert County (Offsite Areas A and B)[22] for temporary construction laydown, parking areas, and an area for offloading material from barges.

B. Virginia Facilities

12. Dominion also requests authority under section 7(c) of the NGA to add compression at its existing Pleasant Valley Compressor Station and to modify the existing Pleasant Valley and Loudoun M&R sites. Dominion states that the additional proposed compression and modifications, together with the use of capacity from a terminated contract, will enable it to transport up to 860,000 Dth per day of natural gas on a firm basis from existing pipeline interconnects near the west end of the Cove Point Pipeline to the Cove Point Terminal for the Export Customers.[23]

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[20] Dominion states that check valves in some existing piping will be modified to enable bi-directional flow, depending on whether the ships are loading or offloading. Additionally, Dominion states that it will modify the LNG transfer piping in the tunnel to meet the LNG flow rates required for the export service. Dominion states that this work will require replacement of the existing 100 expansion joints in the liquid lines.

[21] Dominion states that the suction drums, originally used to facilitate transfer of LNG from the delivery vessels, have not been used for approximately 25 years and serve no function because ships now use their own pumps to offload the LNG without the assistance of pumps and suction drums on the platform. Dominion states that the vapor return blowers help manage vapor displacement during the loading of LNG ships.

[22] Offsite Area A would consist of approximately 179.1 acres near Lusby, Maryland used for terminal construction-related activities. Offsite Area B would consist of approximately 11 acres adjacent to the Patuxent River and is the site of a temporary barge unloading facility.

[23] The Cove Point Pipeline interconnects with three interstate natural gas pipeline systems owned by Transcontinental Gas Pipe Line Company, LLC; Dominion Transmission Inc.; and Columbia Gas Transmission Corporation. Dominion contends that the proposed facility design will allow for as much as 720,000 Dth per day to be

(continued ...)

13. The existing Pleasant Valley Compressor Station is located on a 37-acre parcel of land in an existing industrial site in Centreville, Fairfax County, Virginia, approximately seven miles southwest of Dulles International Airport. Dominion asserts that 3.9 acres will be permanently developed due to the additional compression. Dominion states that an additional 3.3 acres of land will be temporarily disturbed to allow for a pipeline right-of-way and to connect additional compression units to the Pleasant Valley M&R site.

14. Dominion states that there are currently two, 3,000 horsepower (hp) electric compressor units at the compressor station. Dominion proposes to install four additional electric-driven compressor units at the compressor station for a total increase of 62,500 hp. Two 20,000 hp units and one 15,000 hp unit will be housed in a new building within the existing site boundary. Additionally, an existing building will be extended to accommodate one 7,500 hp unit.

15. To support the operation of the compressor station, Dominion also proposes to replace (lift and lay) the existing 1,200 feet of 16-inch-diameter discharge pipeline (TL-531) with a 36-inch-diameter pipeline, extending from the Pleasant Valley Compressor Station to the existing Pleasant Valley M&R site. Additionally, at the compressor station, Dominion will install approximately 1,200 feet of 36-inch-diameter suction pipeline extending from the compressor station to the existing Pleasant Valley M&R site.[24] In addition, Dominion proposes miscellaneous piping and measurement upgrades, including additional meter runs and/or pipe, fittings, and valves.

16. The Loudoun M&R site is located on a 2.4-acre parcel of land in an existing industrial site on the east side of Virginia State Route 860 (Watson Road) in Leesburg, Loudoun County, Virginia, approximately eight miles northwest of Dulles International Airport. The Loudoun M&R site is adjacent to the Loudoun Compressor Station.

17. Dominion states that miscellaneous piping and measurement upgrades will be required, including additional meter runs and/or pipe and fittings. Dominion explains

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received at its Loudoun Compressor Station without the addition of any incremental compression, with the remaining 140,000 Dth per day being received at Pleasant Valley. Alternatively, Dominion states that it can also meet its firm transportation obligations if the Export Customers designate all of their gas for receipt at Pleasant Valley, or other combinations in between. Dominion states that the flexibility of the project's design is critical to the Export Customers' primary receipt point selection and will improve secondary receipt point flexibility for all of Dominion's transportation customers.

[24] The new suction pipeline will be located between the existing TL-530 and TL-531 pipelines within the existing right-of-way.

that gas received at the Loudoun M&R site will flow directly to the Pleasant Valley site, where the gas will be compressed at the Pleasant Valley Compressor Station for further downstream transportation to the Cove Point Terminal.

C. Services

18. The Export Customers have fully contracted the service to be provided by the proposed project. Each customer is entitled to 50 percent of the available capacity. Dominion asserts that the Export Customers have entered into 20-year service agreements at the Cove Point Terminal, as well as accompanying 20-year service agreements for firm transportation on the existing Cove Point Pipeline. Dominion states that the Export Customers will be responsible for procuring their own supplies and transporting the supplies to or from the Cove Point Terminal.

19. Dominion conducted an open season, as well as a reverse open season, for transportation capacity on the Cove Point Pipeline in the spring of 2012. While no entities signed up for service or turned back their existing service during the open season, Dominion and Statoil agreed to terminate Statoil's Cove Point Expansion service agreement.

III. Public Notice

20. Notice of Dominion's application was published in the *Federal Register* on April 19, 2013, with interventions and protests due on or before May 3, 2013.[25] Timely, unopposed motions to intervene were filed by the parties listed in Appendix A of this order.[26]

21. Allegheny Defense Project, Chesapeake Climate Action Network (Chesapeake Climate), Clean Air Council, Cove of Calvert Homeowners Association, Keys Energy Center, LLC, PSEG Energy Resources & Trade LLC, and Wild Virginia filed untimely motions to intervene. These movants have demonstrated an interest in this proceeding and granting those parties intervention status at this stage of the proceeding will not cause

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[25] 78 Fed. Reg. 23,552 (April 19, 2013).

[26] Timely, unopposed motions to intervene are automatically granted pursuant to Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214 (2014).

undue delay or disruption or otherwise prejudice the applicant or other parties.[27] Thus, we will grant the late motions to intervene.

22. As indicated in Appendix A, certain parties filed comments with their motions to intervene. Statoil's motion to intervene included a request for a technical conference. EarthReports, Inc. (dba Patuxent Riverkeeper); Potomac Riverkeeper, Inc.; Shenandoah Riverkeeper; Sierra Club; and Stewards of the Lower Susquehanna, Inc. (collectively, EarthReports) included a request for a hearing in its motion to intervene. In addition, numerous other entities filed comments on Dominion's proposal.

23. BP Energy Company (BP), Shell NA LNG LLC (Shell LNG), and Washington Gas Light Company's (Washington Gas)[28] motions to intervene included protests. Shell LNG's protest also included a request for a technical conference. Dominion filed an answer to the comments and protests. Statoil filed an answer to BP's protest. BP filed an answer to Dominion and Statoil, which was followed by another round of answers from Dominion and Statoil and then an additional answer from BP. Although the Commission's Rules of Practice and Procedure do not permit answers to protests or answers to answers,[29] we find good cause to waive its rules and admit these pleadings because they provide information that assisted our decision making.

24. The protestors raise concerns regarding the opportunity for existing customers to turnback service, the impact of Dominion's proposals on existing pipeline service, and the adequacy of Dominion's proposed tariff provisions.

25. On June 13, 2014, the Commission issued an order requiring Dominion to provide Earthjustice[30] with certain previously undisclosed Critical Energy Infrastructure Information (CEII) and privileged materials pursuant to a protective agreement.[31] The order allowed Earthjustice to file additional comments based on the CEII and privileged

[27] 18 C.F.R. § 385.214(d) (2014).

[28] Washington Gas filed a limited protest asking Dominion to better explain its statements that the addition of export facilities will not degrade current west-to-east services on the Cove Point Pipeline.

[29] 18 C.F.R. § 385.213(a)(2) (2014).

[30] Earthjustice represents EarthReports, Inc., doing business as Patuxent Riverkeeper, an intervenor in this proceeding.

[31] *Dominion Cove Point LNG, LP*, 147 FERC ¶ 61,202 (2014).

material within 21 days after receipt of the information. On July 11, 2014, Earthjustice filed a request asking that it be given until August 1, 2014 to file additional comments and on July 14, 2014, we granted an extension of time until August 1, 2014. On August 1, 2014, Earthjustice requested an additional extension to August 4, 2014. On August 4, 2014, Earthjustice filed comments based on its review of the CEII and privileged material.

IV. <u>Discussion</u>

A. <u>Dominion's Cove Point Liquefaction Project</u>

26. Because the proposed LNG liquefaction facilities will be used to export natural gas to foreign countries, the construction and operation of the proposed facilities and site of their location require approval by the Commission under section 3 of the NGA.[32] While section 3 provides that an application for the exportation or importation of natural gas shall be approved if the proposal "will not be inconsistent with the public interest," section 3 also provides that an application may be approved "in whole or in part, with such modification and upon such terms and conditions as the Commission may find necessary or appropriate."[33]

27. Section 311(c) of the Energy Policy Act of 2005 (EPAct 2005)[34] added a new NGA section 3(e)(3) providing that, before January 1, 2015, the Commission shall not condition an order approving an application to site, construct, expand, or operate an LNG terminal on: (1) a requirement that the LNG terminal offer service to customers other

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[32] The regulatory functions of section 3 were transferred to the Secretary of Energy in 1977 pursuant to section 301(b) of the Department of Energy Organization Act, Pub. L. No. 95-91, 42 U.S.C. § 7101 *et seq.* In reference to regulating the imports or exports of natural gas, the Secretary subsequently delegated to the Commission the authority to approve or disapprove the construction and operation of natural gas import and export facilities and the site at which such facilities shall be located. The most recent delegation is in DOE Delegation Order No. 00-044.00A, effective May 16, 2006. Applications for authorization to import or export natural gas must be submitted to DOE. The Commission does not authorize importation or exportation of the commodity itself.

[33] For a discussion of the Commission's authority to condition its approvals of facilities under section 3 of the NGA, *see, e.g., Distrigas Corp. v. FPC*, 495 F.2d 1057, 1063-64 (D.C. Cir. 1974), *cert. denied*, 419 U.S. 834 (1974), and *Dynegy LNG Production Terminal, L.P.*, 97 FERC ¶ 61,231 (2001).

[34] Energy Policy Act of 2005, Pub. L. No. 109-58, § 311, 119 Stat. 594 (2005).

than the applicant, or any affiliate of the applicant securing the order; (2) any regulation of the rates, charges, terms, or conditions of service of the LNG terminal; or (3) a requirement to file schedules or contracts related to the rates, charges, terms, or conditions of service of the LNG terminal.

28. Earthjustice[35] and Chesapeake Climate[36] contend that the Cove Point Liquefaction Project would cause significant increases in natural gas prices either individually or in concert with exports from other facilities and would have negative impacts on the U.S. economy. In addition, West Virginia State Building and Construction Trades Council, AFL-CIO and its division the Affiliated Construction Trades Foundation (Trades Council) filed comments expressing its concerns with export of domestically-sourced natural gas as LNG.

29. Section 3 of the NGA provides, in part, that "no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so." In 1977, the Department of Energy Organization Act transferred the regulatory functions of section 3 of the NGA to the Secretary of Energy. Subsequently, the Secretary delegated to the Commission authority to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports…."[37] However, the Secretary has not delegated to the Commission any authority to approve or disapprove the import or export of the commodity itself.[38]

30. In 2011, the Department of Energy (DOE) authorized Dominion to export up to the equivalent of 1.0 Bcf per day of domestically-produced natural gas by vessel to Free

[35] Earthjustice filed comments on behalf of EarthReports.

[36] Chesapeake Climate is an organization dedicated to fighting global warming in Maryland, Virginia, and Washington, D.C.

[37] DOE Delegation Order No. 00-004.00A (effective May 16, 2006).

[38] *See supra* note 31. *See also National Steel Corp.*, 45 FERC ¶ 61,100, at 61,332-33 (1988) (observing that DOE, "pursuant to its exclusive jurisdiction, has approved the importation with respect to every aspect of it except the point of importation" and that the "Commission's authority in this matter is limited to consideration of the place of importation, which necessarily includes the technical and environmental aspects of any related facilities").

Trade Agreement (FTA) Nations.[39] DOE subsequently authorized Dominion to export up to 0.77 Bcf per day of natural gas to non-FTA nations, finding the potential export of such volumes to be not inconsistent with the public interest.[40]

31. In conditionally granting Dominion long-term authorization to export LNG, DOE recognized substantial evidence of economic and other public benefits concluding that the authorization was not inconsistent with the public interest. We recognize DOE's public interest findings in issuing our order. Among other things, DOE found that exporting natural gas will lead to net benefits to the U.S. economy and can counteract concentration within global LNG markets, thereby diversifying international supply options and improving energy security for U.S. allies and trading partners.

32. The proposed Cove Point Liquefaction Project is located on, and adjacent to, the footprint of the previously-approved Cove Point Terminal. Much of the land in the area was previously disturbed during construction of the LNG terminal and, as a result, the proposed project's environmental impacts are expected to be relatively small in number and well-defined.

33. We conclude that, with the conditions required herein, the Cove Point Liquefaction Project results in minimal environmental impacts and can be constructed and operated safely. Accordingly, we find that, subject to the conditions imposed in this order, Dominion's proposals are not inconsistent with the public interest.

B. Virginia Facilities

34. Since Dominion's proposed Virginia Facilities will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA.[41]

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[39] DOE/FE Order No. 3019 (2011).

[40] DOE/FE Order No. 3331 (2013). The export volume authorized in both the FTA Order and the non-FTA Order mirror the liquefaction capacity of the Cove Point Liquefaction Project estimated at the time each application was submitted, and thus are not additive. The lesser level approved in the non-FTA Order reflects the level found in Dominion's FEED study that was submitted after the non-FTA export application.

[41] 15 U.S.C. §§ 717f(c) and 717f(e) (2012).

35. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new construction.[42] The Certificate Policy Statement established criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explained that in deciding whether to authorize the construction of major new natural gas facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

36. Under this policy, the threshold requirement for existing pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from the existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, or landowners and communities affected by construction. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered.

1. <u>Subsidization</u>

37. We find that existing customers will not subsidize the expansion of the Cove Point Pipeline. The Certificate Policy Statement presumes an incremental rate for firm service is appropriate when the incremental rate would be in excess of the maximum system rate.[43] Dominion's proposed $5.5260 per Dth incremental recourse reservation rate is higher than the current Rate Schedule FTS recourse rate of $0.4388 per Dth. Thus, since

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[42] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

[43] Certificate Policy Statement, 88 FERC ¶ 61,227 at 61,744 ("[w]hen a pipeline proposes to charge a cost-based incremental rate (establishing separate costs-of-service and separate rates for the existing and expansion facilities) higher than its existing generally applicable rates, the Commission usually approves the proposal.").

Dominion proposes an incremental FTS recourse rate as an initial rate for the incremental service, and since other sources of potential subsidization such as fuel retainage and power requirements will be appropriately addressed in a section 4 proceeding prior to the in-service date of the expansion, we find there will be no subsidization of the proposed Cove Point Pipeline facilities by existing customers.

2. Existing Customers

a. Turnback of Service Opportunity

38. In 2001, the Commission authorized Dominion's predecessor to construct new facilities and reactivate the existing LNG terminal to recommence LNG imports. BP was one of three customers that contracted for NGA section 7 LNG terminal service under rate schedule LTD-1.[44]

39. In 2006, the Commission authorized the Cove Point Expansion Project, with Statoil as the sole expansion customer.[45] Dominion requested, and was granted, market-based rate treatment, under *Hackberry LNG Terminal, L.L.C.*,[46] for the expansion capacity and entered into a non-open access service agreement with Statoil for section 3 LNG terminal service using the expanded capacity. In addition, Statoil subscribed to jurisdictional service through rate schedule FTS for service on the expanded Cove Point Pipeline. Dominion and Statoil agreed to include tariff provisions to ensure that existing and expansion customers are treated in a not unduly discriminatory manner.

40. To support the Cove Point Liquefaction Project, Dominion held an open season and a reverse open season for transportation capacity on the Cove Point Pipeline in the spring of 2012 and received no requests under either open season.[47]

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[44] *Cove Point LNG Limited Partnership*, 68 FERC ¶ 61,377.

[45] *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,337.

[46] *Hackberry LNG Terminal, L.L.C.*, 101 FERC ¶ 61,294 (2002).

[47] Washington Gas contends that Dominion provided inadequate notice of the open season. Dominion states that the notice cited by Washington Gas as having been provided too late to allow for adequate consideration simply corrected a formatting error in the original notice, which was posted at the outset of the open season.

41. Dominion and Statoil agreed to an early termination of the non-open access Cove Point Expansion service agreement for Statoil's section 3 terminal service and section 7 Cove Point Pipeline capacity.

42. In its protest, BP contends that Dominion acted in an unduly discriminatory manner by allowing Statoil to relinquish both its section 3 terminal service and its section 7 pipeline capacity, while Dominion offered BP the opportunity to relinquish only its section 7 pipeline capacity. BP asserts that it is a similarly situated customer[48] with firm entitlements utilizing pre-expansion storage and regasification capacity authorized under section 7 of the NGA, but that it was given no opportunity to relinquish its import capacity at the LNG terminal.[49] BP asks that the Commission require Dominion to offer BP an opportunity to turnback its terminal service.

43. In its answer, Dominion asserts that Statoil, as the Expansion Customer with non-open access terminal service, and BP with open-access LTD-1 terminal service are not similarly situated. Dominion contends that while Statoil and BP are both customers of Dominion, they receive service under completely different regulatory regimes and therefore cannot be similarly situated.

44. Likewise, Statoil states that Dominion was under no obligation to provide BP with the same opportunity to turn back terminal capacity because BP is not a similarly situated shipper.[50] Statoil states that its early termination of Cove Point Expansion Project service was negotiated pursuant to its section 3, non-open access expansion service contract, which is exempt from section 7 regulation.[51] Statoil contends that Dominion is not required to give BP, an open access, section 7 shipper, the same opportunities.[52]

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[48] BP asserts that Dominion stated that the 2005 expansion facilities would be operated on an integrated basis with the then-existing import facilities and pledged that wherever the expansion services "interact" with existing services, both existing and expansion customers would be treated in a not unduly discriminatory manner. BP Protest at 2, footnotes 2, 3.

[49] BP May 3, 2013 Protest at 1-2.

[50] Statoil May 20, 2013 Answer at 5 (citing *Columbia Gas Transmission Corp.*, 103 FERC ¶ 61,388, *order on reh'g*, 105 FERC ¶ 61,373 (2003) (finding that a section 7 pipeline may provide early termination rights to one group of shippers and not to others because the two shipper groups are not similarly situated on account of different risks faced)).

[51] Statoil May 20, 2013 Answer at 6. In addition to the Expansion Project service,

(continued ...)

Commission Response

45. EPAct 2005 amended the NGA to prohibit undue preferences and undue discrimination in the context of LNG terminals providing service authorized under both sections 3 and 7 of the NGA, which is the case at Cove Point:

> An order issued for an LNG terminal that also offers service to customers on an open access basis shall not result in subsidization of expansion capacity by existing customers, degradation of service to existing customers, or undue discrimination against existing customers as to their terms or conditions of service at the facility, as all of those terms are defined by the Commission.[53]

46. BP contends that it has suffered undue discrimination as to the terms or conditions of its service. As described in more detail below, Dominion has not proposed to change the terms and conditions of service for BP in this proceeding. The operational requirements contained in section 30 of Dominion's tariff will continue to ensure no discriminatory treatment of service.

47. Further, it is well-established that not all discrimination is undue, and only similarly situated customers need to be treated similarly.[54] BP is a LTD-1 shipper, receiving open access terminal services provided under section 7 of the NGA, while Statoil is an expansion customer receiving non-open access service under NGA section 3. The section 7 and section 3 terminal services are distinguishable, thus BP and Statoil are not similarly situated. Finally, we are not concerned with the fact that in addition to relinquishing section 3 terminal service Statoil also turned back section 7 service on the Cove Point Pipeline because Dominion held an open season providing all shippers an opportunity to turnback this service.

Statoil also obtains LTD-1 service from Dominion.

[52] Statoil May 20, 2013 Answer at 3.

[53] 15 U.S.C. § 717b(e)(4) (2012).

[54] *See Associated Gas Distributors v. FERC*, 824 F.2d 981, 1009 (D.C. Cir. 1987), *cert. denied sub nom*. *Interstate Natural Gas Ass'n v. FERC*, 485 U.S. 1006 (1988); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1139 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

48. BP's request that we require Dominion to offer a turnback of terminal capacity is denied.

b. Impacts on Existing Pipeline Service

49. Washington Gas,[55] a current west-to-east transportation customer on the Cove Point Pipeline, asserts that Dominion failed to state how current firm west-to-east transportation service would be coordinated with the export service west-to-east transportation. Washington Gas states that an explanation is necessary to demonstrate that the addition of export facilities does not degrade current west-to-east services.

50. Washington Gas contends that historically, secondary access to the Cove Point Pipeline at the Loudoun and Pleasant Valley interconnections has often been physically unavailable and that Dominion has provided no reasons for denial of secondary access. Washington Gas asserts that Dominion has not detailed any plans to mitigate secondary access conditions at its interconnections with the Cove Point Pipeline, even though Dominion claims that the proposals will improve secondary receipt point flexibility for all transportation customers. Washington Gas states it is concerned that such flexibility in the receipt of gas and ability to move it to the delivery points could be illusory unless Dominion is willing to make some contractual receipt point adjustments along with its proposed changes to the operation of compression on its system. Washington Gas proposes that existing west-to-east shippers be permitted to aggregate their firm nominations into Dominion's three receipt points, providing comparable choices for flexibility as are being given to the Export Customers.

51. Washington Gas contends that the peaking service under Rate Schedule FPS, which relies on a single liquefier and storage tanks at the LNG terminal, may have operational changes in the absence of availability of east-to-west transportation. Washington Gas states that Dominion has not described how the peaking service will function after the in-service date of the Cove Point Liquefaction Project, including whether the FPS service will basically become an exchange service.

52. Dominion states that Export Customers are not being permitted to aggregate their nomination into the three different receipt points on the Cove Point Pipeline. Dominion states that the aggregation of points suggested by Washington Gas would be a significant change in Dominion's operations and that if Washington Gas desires to change its current primary receipt point selections, it should request the change and Dominion will allow it to the extent operationally possible.

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[55] Washington Gas is engaged primarily in the retail sale and delivery of natural gas in the District of Columbia and surrounding portions of Maryland and Virginia.

53. Regarding peaking service under Rate Schedule FPS, Dominion states that it currently provides east-to-west transportation service for the FPS service and will continue to do so. In addition, Dominion asserts that given the recent lack of LNG imports, the addition of the proposed new services should create additional flexibility not currently available to the FPS customers. Dominion states that it is not proposing any changes to the existing FPS service and the service will not be transformed into an "exchange service."[56]

Commission Response

54. Washington Gas proposes that existing west-to-east shippers (i.e., Rate Schedule FTS shippers) be permitted to aggregate their firm nominations into Dominion's three receipt points. As noted by Dominion, this right is not being given to the Export Customers. Dominion's tariff currently contains provisions providing all shippers, existing as well as the Export Customers, the option to change a primary receipt point.[57] Thus, we will reject Washington Gas' protest.

55. Dominion asserts that there will be no adverse impacts for existing Rate Schedule FTS and FPS customers, and, at this time, there is not sufficient evidence to conclude that Dominion's proposals will adversely affect existing Rate Schedule FTS and FPS customers. If disputes do arise concerning terminal operations once liquefaction commences, we anticipate that those matters will be resolved pursuant to the terms of the various agreements. Alternatively, if an existing shipper believes that its service has indeed been adversely affected, it can bring the issue to the Commission's attention in the form of a complaint. In addition, Dominion is required to submit proposed tariff records to implement its proposals in a future section 4 proceeding. Should Dominion propose any tariff revisions regarding Rate Schedule FTS or FPS service, parties may address any issues in that proceeding.

56. We conclude that Dominion's proposals, along with conditions imposed herein, will result in no adverse impacts to existing customers.

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[56] Dominion May 2013 Answer at 31.

[57] Dominion Cove Point, LP, FERC NGA Gas Tariff, Dominion_DATABASE; Tariff Record 40.8, GT&C – Flex Prim and Sec Rec and Del Points, 0.0.0.

3. Existing Pipelines

57. No pipelines or their captive customers filed adverse comments regarding Dominion's proposals. Thus, we find that Dominion's proposal will not adversely impact existing pipelines in the market and their captive customers.

4. Landowners

58. We find that Dominion's Virginia Facilities have been designed to minimize impacts on landowners and the environment, since the proposed facilities associated with the enhancements to the Cove Point Pipeline would be located within existing Dominion-owned land and/or right-of-ways. Thus, there would be minimal adverse impacts to landowners.

5. Conclusion

59. The proposed Virginia Facilities, together with the use of turnback capacity, will enable Dominion to transport up to 860,000 Dth per day of natural gas on a firm basis from existing pipeline interconnects near the west end of the Cove Point Pipeline to the Cove Point Terminal for the Export Customers. Dominion has entered into 20-year agreements for transportation with the Export Customers. Based on the benefits the project will provide and the minimal adverse impacts on existing customers, other pipelines and their customers, and landowners and surrounding communities, we find, consistent with the Certificate Policy Statement and section 7(c) of the NGA, that Dominion's proposal, as conditioned below, is required by the public convenience and necessity.

C. Rates

1. Virginia Facilities

60. Dominion explains that it will provide firm transportation services for the Export Customers using the turnback capacity it negotiated with Statoil and the capacity created by the proposed increase in compression. Dominion states that the Export Customers will have firm entitlements for transportation from west-to-east on the Cove Point Pipeline to the Cove Point Terminal. Dominion asserts that in the event of a change to import/regasification service, the Export Customers will be entitled to switch their primary receipt and delivery points to provide for transportation flowing east-to-west away from the Cove Point Terminal. Dominion asserts that no customer or potential

customer is harmed because the capacity only becomes available upon the import election.[58]

61. Dominion proposes to establish an incremental firm transportation recourse rate to recover the cost of the transmission facilities utilized for service provided to the Export Customers. Consistent with Commission policy, Dominion states that the service is priced incrementally because the rate required to recover the incremental costs exceeds the existing system rates for firm service under Rate Schedule FTS.[59]

a. <u>Recourse Rates</u>

62. Dominion proposes to charge a firm incremental transportation rate of $5.5260 per Dth and a commodity charge equal to the currently-effective commodity charge rate under Rate Schedule FTS to recover the cost of the proposed facilities. The proposed recourse rates are designed using straight-fixed variable rate design with annual billing determinants of 10,320,000 Dth per day. Dominion proposes a first year cost of service of $57,028,578. The cost of service is based on: (1) Operation and Maintenance expense of $34,074,164; (2) depreciation expense of $3,561,449; (3) other taxes of $2,033,310; and (4) a pretax return of $17,359,655. This cost of service is based upon Dominion's last approved pre-tax rate of return of 14.00 percent and a depreciation rate of 2.82 percent, as agreed to as part of its rate case settlement in Docket No. RP11-2137-000.[60] Dominion states that the cost of service reflects the costs of the new transmission facilities and the annual costs associated with the turned-back Cove Point Expansion transportation capacity that will be dedicated to the project.[61] Firm transportation service will be provided under the terms and conditions of Dominion's existing Rate Schedule FTS. Dominion proposes to use the generally-applicable Rate Schedule ITS rate, currently $0.0144 per Dth, as the rate for interruptible service.[62]

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[58] During import/regasification service, the Export Customers' firm receipt point rights at the LNG Terminal will be limited to 330,000 Dth per day, to match the terminal's send-out capacity.

[59] The currently applicable Rate Schedule FTS rate is $0.4388 per Dth.

[60] *Dominion Cove Point LNG, LP*, 140 FERC ¶ 61,013 (2012).

[61] Dominion valued the Cove Point Expansion transmission capacity at the currently applicable Rate Schedule FTS incremental recourse rate of $3.8367 per Dth.

[62] Dominion October 16, 2013 Data Response.

63. The Certificate Policy Statement presumes an incremental rate for firm service is appropriate when the incremental rate would be in excess of the maximum system rate.[63] Dominion's proposed $5.5260 per Dth incremental recourse reservation rate is higher than the current Rate Schedule FTS recourse rate of $0.4388 per Dth. Thus, we will approve Dominion's proposed incremental FTS recourse rate as an initial rate for the incremental service.

b. <u>Negotiated Rate</u>

64. Dominion states that the Export Customers will pay a negotiated rate for the firm transportation service. The agreed-upon negotiated rate is a fixed rate, which will not vary over the term of the service agreement, of $0.1930 per Dth. Dominion indicates that in accordance with General Terms and Conditions (GT&C) section 29, it will file prior to the commencement of negotiated rate transportation service either the service agreement or numbered tariff records stating the name of any shipper paying a negotiated rate, the negotiated rate or rate formula, the applicable rate schedule, the applicable receipt and delivery points, contract quantities, contract duration and an affirmation that the agreement does not deviate in any material respect from the Form of Service Agreement. Dominion will be required to keep separate and identifiable accounts for any quantities transported, billing determinants, rate components, surcharges and revenue associated with its negotiated rates in sufficient detail so that they can be separately identified in future rate cases.

2. <u>Fuel and Other Surcharges</u>

65. Noting that the Export Customers will have responsibility for the fuel used to provide their Cove Point Liquefaction Project service, Dominion states that fuel consumption will be tracked to ensure that no existing customer will be responsible for costs associated with the fuel used to provide the liquefaction services to Export Customers. Dominion asserts that additional modifications to its tariff will be required to accommodate the addition of the new services for the Export Customers. Specifically, Dominion states that it expects changes will be required in the tariff provisions concerning "cooling quantities" and the allocation of fuel retainage, electric costs, and boil-off. Dominion contends that because these proposed tariff revisions affect not only the Export Customers, but other Dominion customers as well, they will be filed in a NGA section 4 proceeding, rather than this proceeding.[64] Dominion states that it plans to

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[63] *See supra* note 42.

[64] In addition, Dominion states these issues will be part of the agenda in upcoming Dominion customer meetings. Dominion May 20, 2013 Answer at 23.

submit a NGA section 4 tariff filing 30 to 60 days before the in-service date of the project.

66. Shell LNG[65] and Statoil state that Dominion has not explained adequately the impact of the project on fuel retainage, power requirements, and LNG boil-off at the terminal. In addition, Shell LNG notes that Dominion has not explained the impact of the project on the fuel and electric costs associated with Dominion's proposal to use the compression at Pleasant Valley as its primary source for transportation, or the anticipated allocation of lost and unaccounted for gas on the Cove Point Pipeline. Further, Washington Gas states that Dominion should be required to provide current shippers with the substance of the planned or anticipated tariff or service changes at this time, so that the Commission and shippers can review them as part of this proceeding.

67. The Commission has previously permitted a pipeline to submit tariff records concerning a certificate proceeding in a section 4 proceeding, rather than the section 7 proceeding, when the proposed tariff revisions would affect not only project customers, but other customers as well.[66] We find that reasoning applies here. Thus, we will require Dominion to submit additional tariff provisions in a future section 4 NGA filing 30 to 60 days before the in-service date of the project. We note that requiring Dominion to submit proposed tariff records in a future filing is without prejudice and customers may voice any concerns in that proceeding.

68. Dominion also proposes to assess the currently-effective applicable surcharges (including electric power costs) and fuel retainage percentage for Rate Schedule FTS service contracted by the Export Customers. We will approve this proposal.

3. **Tariff Proposals**

69. NGA section 3(e)(3) provides that agreements between customers and an LNG terminal operator under section 3 of the NGA need not be filed with the Commission. Nevertheless, Dominion and the Export Customers have agreed to incorporate key operational provisions of the non-open access agreements into Rate Schedule LTD-1 (Regasification Services) and the GT&C by reference to define the Export Customers' regasification and import service. Dominion contends that this approach will ensure that the Export Customers, when electing import services, and the existing LTD-1 shippers are treated in a not unduly discriminatory manner. Dominion states that this approach is consistent with that taken for Statoil, the existing Cove Point Expansion customer.

[65] Shell LNG is an LNG import customer at the Cove Point LNG Terminal.

[66] *Dominion Transmission, Inc.*, 135 FERC ¶ 61,239, at P 34 (2011).

70. Dominion proposes to revise GT&C section 30, "Notice of Incremental Services," to reflect certain operational terms of the import and regasification service for the Export Customers. Existing GT&C section 30 provides that the firm services offered by Dominion under NGA section 3 are generally defined by and performed under separate contracts between Dominion and its customers. Existing GT&C section 30 applies to Statoil and outlines the sections of the GT&C and Rate Schedule LTD-1 that apply to Statoil. Dominion's proposed GT&C section 30(a)(1) provides that section 3 service shall be treated as equivalent to service under Rate Schedule LTD-1, except for certain provisions. GT&C section 30(a)(2) provides that certain provisions of the GT&C are not incorporated and are not part of the section 3 firm service. In addition, GT&C section 30 provides that the Export Customers may utilize the "Coordinating Buyer" provisions of section 2.5 of Rate Schedule LTD-1.[67]

71. In addition, Dominion expects minor changes will be needed to incorporate the Export Customers into the existing ship scheduling provisions. Dominion asserts that changes in these tariff provisions required to accommodate the new service will not degrade service to its existing customers.

a. <u>GT&C Section 30</u>

72. Statoil and Shell LNG contend that Dominion has not explained why changes to GT&C section 30 are necessary. Statoil questions why the changes are necessary, if the section 3 import service contracted for by the Export Customers is the same as or substantially similar to its section 3 import service.

73. BP asserts that the open season process, discussed above, "fatally infect[ed]" the currently-effective GT&C section 30, which is designed to address the interaction between different classes of customers, and any proposed modification to it. BP requests that the Commission require Dominion to file a new GT&C section 30 to govern the interaction among the various classes of customers on Dominion's facilities.

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[67] Section 2.5 of Rate Schedule LTD-1 provides that, "In the event more than one Buyer is receiving firm LNG tanker discharging service under this Rate Schedule LTD-1, any or all of such Buyers may elect to coordinate among themselves their operations at Operator's facilities, including the joint scheduling of LNG arrivals, injections into storage, scheduling of vaporization and other activities required for the use of Operator's facilities." Dominion Cove Point, LP, FERC NGA Gas Tariff, Dominion_DATABASE; <u>Tariff Record 20.1.2, LTD-1 Rate Schedule - Applicability and Character of Service, 0.0.0</u>.

74. Dominion states that section 30 needs to be revised because existing section 30 concerns only the Cove Point Expansion Project service, which will terminate by the time the proposed section 30 will become effective.[68] Dominion contends that proposed section 30 will serve a similar purpose as the existing version, but for the service to the new Export Customers. Dominion states that proposed sections 30(a)(1), 30(a)(2) and 30(a)(3) concern import service for the Export Customers, if and when they elect to take it.[69] Further, Dominion asserts that proposed section 30 assumes that the new import service for the Export Customers will be treated as equivalent to Rate Schedule LTD-1 service, and lists only the exceptions to Rate Schedule LTD-1 and the GT&C. In contrast, Dominion states that existing section 30 lists the provisions of Rate Schedule LTD-1 and the GT&C that apply to the Cove Point Expansion service.

75. Dominion states that proposed section 30(a)(4) provides that the Export Customers may participate as part of the "Coordinating Buyer," as provided in section 2.5 of Rate Schedule LTD-1, if they and the LTD-1 customers so desire, and section 30(a)(5) provides that Export Customers may engage in inventory transfers with existing shippers pursuant to existing tariff provisions. Dominion contends that these provisions will not harm existing shippers and could potentially provide benefits to them. In addition Dominion states that proposed section 30(a)(6) simply acknowledges that the Export Customers may fully participate in Dominion tariff proceedings.[70]

Commission Response

76. As noted above, we found that Dominion did not act in an unduly discriminatory manner in allowing Statoil to turn-back its terminal capacity. Thus, we will reject BP's request to require Dominion to file a new GT&C section 30.

77. Dominion's proposed revised section 30 is different than existing section 30 because it lists the exceptions to the tariff for the Export Customers' service, rather than listing the provisions of its tariff that apply to Statoil. We find that Dominion's proposed GT&C section 30 is reasonable and agree that it is appropriate that Dominion revise section 30 with the termination of the service for Statoil and the commencement of service for the Export Customers.

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[68] Dominion May 20, 2013 Answer at 20.

[69] *Id*.

[70] *Id.* at 21.

78. In accepting Dominion's existing section 30, we found that "while section 30 does allow for some differences in Dominion's services to Statoil and the LTD-1 customers, we are satisfied that there will be no undue discrimination against existing LTD-1 customers as to their terms and conditions of service in the critical tariff areas, such as nominations, scheduling and operating conditions."[71] We continue to be satisfied that there will be no undue discrimination against existing LTD-1 customers regarding proposed section 30.

b. Tariff Provisions and Existing Import Customers

79. Dominion states that there will be no changes to the existing LNG shipping arrangements and that LTD-1 customers will not be adversely affected in their shipping scheduling rights as a result of its proposal. Shell LNG notes that Dominion plans to use the approach previously agreed upon with the existing import shippers to resolve scheduling conflicts between Statoil and the LTD-1 customers. Shell LNG argues that it is unclear whether LTD-1 customers will be adversely affected by Dominion's shipping proposal. Likewise, Statoil states that details regarding the procedures for scheduling import and export vessels must be examined further to ensure that service to existing LTD-1 shippers is not degraded.

80. Shell LNG states that Dominion has not explained whether LTD-1 customers will be able to import LNG while the Export Customers are in export mode. Statoil argues that Dominion has not explained how granting import and export service equal priority does not degrade current LTD-1 service.

81. Shell LNG requests additional information about potential outages at the LNG terminal while Dominion integrates the Cove Point Liquefaction Project. In addition, Shell LNG contends that Dominion has not identified how it plans to resolve any gas quality issues that may arise from simultaneous LNG imports and exports.

82. Dominion contends that the Export Customers will have the same priority as the existing import shippers and that the total authorized marine traffic will not be increased. Dominion states that the difference in time to offload or load a ship is immaterial and that, consistent with historical practice, it will schedule only one ship for loading or offloading on any one day. In addition, Cove Point asserts that two berths are available at the LNG terminal pier to facilitate back-to-back operations as quickly as possible.

83. Dominion contends that the only possible shipping conflict is if two shippers seek to schedule an arrival at the pier on the same day. In the event this happens, Dominion

[71] *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,337 at P 150.

states that it will use the current approach (agreed upon with the existing import shippers), which provides that the first time two shippers request an arrival on the same day, the first shipper will be awarded the desired date and the second shipper will be given the closest available date and that the next time those two shippers request the same day, the second shipper will be awarded the preferred date, and so on with alternating winners. Dominion maintains that there have never been any scheduling conflicts at the Cove Point Terminal among the LTD-1 shippers (including Statoil in its role as the Expansion Shipper).[72]

84. Dominion states that LTD-1 customers will be able to import LNG when the Export Customers are in export mode; that it will be able to load LNG onto a ship one day and offload LNG from another ship the next, and vice versa; and liquefy gas for the Export Customers at the same time that it re-gasifies LNG for the LTD-1 customers.[73] Dominion states that it does not anticipate any gas quality issues resulting from the Cove Point Liquefaction Project and that it is not proposing any changes in the gas quality specifications applicable to transportation on the Cove Point Pipeline or in the LNG specifications applicable to LTD-1 service.[74]

Commission Response

85. Dominion has not projected that its liquefaction project will result in an increase in the number of vessels permitted to dock at the LNG terminal in a given year. Moreover, there is no indication that Dominion's existing vessel scheduling system will not continue to be adequate when the proposed Export Service commences.[75] During its review of the waterway for the Cove Point Expansion Project, the Coast Guard determined that the Chesapeake Bay, from Cape Henry, Virginia, to Cove Point, Maryland, can accommodate 200 LNG ships per year.

86. Dominion will continue to provide import, regasification, and storage services to customers under existing LTD Agreements. In its pleadings, Dominion emphasizes that there is no physical limitation to simultaneous operation of the existing regasification and

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[72] Dominion May 20, 2013 Answer at 14.

[73] *Id.* at 13.

[74] *Id.* at 17.

[75] The number of ships received in the last several years is as follows: 2009 – 25 ships, 2010 – 15 ships, 2011 – 5 ships, 2012 – 1 ship, 2013 – 2 ships, and 2014 through June – 1 ship.

proposed liquefaction capabilities. Thus, at this time, there is not sufficient evidence demonstrating that the rights of existing terminal customers would be jeopardized by construction and operation of the liquefaction project. If disputes arise concerning terminal operations once liquefaction commences, we anticipate that those matters will be resolved pursuant to the terms of the various agreements or that allegations of undue discrimination or anticompetitive behavior can be brought to the Commission's attention in the form of a complaint.[76]

c. Non-Conforming Provisions

87. Dominion notes that the Rate Schedule FTS Service Agreements contain the following provisions that deviate from the Rate Schedule FTS *pro forma* service agreement: (1) contract extension and termination rights, which reflect specific characteristics relating to the Project, including the right to terminate the service agreement if Dominion is no longer providing terminal service for reasons other than a default by the Export Customer; (2) the right to reverse its primary receipt and delivery points to correspond to the export/import elections, and under certain circumstances, an election to revise the primary receipt points after the Commission issues an order regarding the project;[77] and (3) credit-worthiness provisions that reflect higher risks, and significant financial commitments, associated with the Project. Dominion requests that the Commission rule on these non-conforming provisions in this proceeding.

88. As required by the Commission's regulations, Dominion states it intends to file the firm transportation agreements and negotiated rate agreements and identify any material deviations or non-conforming provisions in each agreement. However, Dominion requests the Commission address the potentially non-conforming provisions in this proceeding.

d. Receipt and Delivery Points

89. Shell LNG states that Dominion has not sufficiently explained the impact of its proposal to allow the Export Customers to switch their primary receipt points and delivery points on the Cove Point Pipeline. Shell LNG contends that it requires more information about the contract extension and termination rights Dominion proposes for the Export Customers.

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[76] *Sabine Pass Liquefaction, LLC*, 139 FERC ¶ 61,039, at P 24, *order on reh'g*, 140 FERC ¶ 61,076 (2012).

[77] Dominion notes that the Export Customers have yet to finalize their primary receipt point selections.

90. Dominion states that offering the Export Customers the option to switch their primary receipt points and delivery points corresponds with the bi-directional service that is proposed to be offered at the LNG terminal.[78] Dominion asserts that no existing customer will be harmed in the event that an Export Customer elects to switch its receipt and delivery points as the revised points can only be made available on a primary basis due to the fact that such points will not be used in the reverse flow during the same period.[79]

91. Dominion states that the contract extension provisions of the Export Customers' FTS service agreements reflect specific characteristics relating to the proposals herein and certain extension rights based on the individual customer's needs. Dominion asserts this is consistent with GT&C section 5(b)(1) of its tariff, which allows the period of time covered by the service agreement to be "determined by agreement between the parties."[80] In addition, Dominion states that the termination rights proposed in the Export Customers' FTS service agreements are consistent with GT&C section 5(b)(2) of the tariff, which allows it to agree to the termination of an existing service agreement prior to its expiration date contingent upon negotiated conditions.[81]

Commission Response

92. Although we have made upfront determinations regarding non-conforming provisions in service agreements in certificate proceedings in the past under similar circumstances,[82] we have more recently indicated that it is only appropriate to do so when the pipeline files redline/strikeout versions of the service agreements. On October 16, 2013, in response to a data request, Dominion submitted redline/strikeout versions of the service agreements with the Export Customers.[83]

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[78] Dominion October 16, 2013 Data Response.

[79] *Id.*

[80] *Id.*

[81] *Id.*

[82] *Tennessee Gas Pipeline Co., L.L.C.*, 144 FERC ¶ 61,219 (2013).

[83] Dominion requested that the service agreements be accorded privileged and confidential treatment and included a Form of Protective Agreement in its filing as required by section 388.112 of the Commission's Rules of Practice and Procedure.

93. We find that the incorporation of the non-conforming provisions described above in the Export Customers' service agreements constitutes a material deviation from Dominion's *pro forma* service agreement. However, we have found in the past that non-conforming provisions may be necessary to reflect the unique circumstances involved with the construction of new infrastructure and to provide the security needed to ensure the viability of a project. We find the non-conforming provisions identified by Dominion are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service. Regarding the Export Customers' right to reverse primary receipt and delivery points to correspond with export/import elections, we find that there is no substantial risk of undue discrimination in this situation where the reversal of primary receipt and delivery points involves shippers with export/import capacity at the LNG terminal. As Dominion explains, the Export Customers' reversal of their primary receipt and delivery points on the Cove Point Pipeline would be done only in concert with their switching between export and import service at the terminal. Thus, existing customers' service would not be impacted.[84] We note that any future customers with export/import service should receive similar terms. As discussed further below, when Dominion files its service agreements, we will require Dominion to identify and disclose all non-conforming provisions or agreements affecting the substantive rights of the parties under the tariff or service agreement. This required disclosure includes any such transportation provision or agreement detailed in a precedent agreement that survives the execution of the service agreement.

94. Dominion must file not less than 30 days, or more than 60 days, before the in-service date of the proposed facilities, an executed copy of each non-conforming agreement reflecting all non-conforming language and a tariff record identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations. In addition, we emphasize that the above determinations relate only to those items as described by Dominion in section VII of its application and not to the entirety of the precedent agreements or the language contained in the precedent agreements.

D. Accounting

95. Dominion requests that the Commission clarify whether generally applicable cost reporting and accounting requirements apply to its proposed LNG export service and, if so, waive those requirements. Dominion states that the Commission previously denied such a waiver for its existing LNG import service on the basis that it had both cost of

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[84] Dominion Application at 31.

service and market-based rates.[85] However, Dominion asserts that its new LNG export service will only be provided on a non-open access basis.

96. In denying Dominion's waiver request for its expansion project to serve Statoil,[86] we explained that our accounting and reporting rules require the maintenance of books and records and the preparation and filing of financial statements for the entire jurisdictional entity. Accounting and reporting rules, for example, do not allow the preparation of an Income Statement, which excludes revenues and costs related to part of an entity's operations. Additionally, many of the assets, liabilities, and capital of a reporting entity are applicable on a joint and non-severable basis to all the business activities of an entity. Consequently, it is not possible to waive reporting requirements for only part of the operations of a natural gas company that has both cost-of-service and market-based rate activities, as to do so would render its financial statements incomplete and misleading. It is irrelevant that part of an entity's operations are related to non-economically regulated services, as all activities are performed by the same entity.

97. Finally, Dominion refers to two orders in which the Commission granted waivers.[87] In neither of the two cases, however, did the respective entities have cost based rates, which Dominion does. We have consistently denied waiver of our accounting and reporting requirements in cases where the reporting entity has both cost and market based operations within the same reporting entity. We will continue to do so here.[88]

E. <u>Environmental Analysis</u>

1. <u>Pre-Filing Review</u>

98. On June 26, 2012, Commission staff granted Dominion's request to use the prefiling process in Docket No. PF12-16-000. On September 24, 2012, the Commission issued a *Notice of Intent to Prepare an Environmental Assessment* (NOI). This notice

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[85] Dominion Application at 55.

[86] *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,337.

[87] *D'Lo Gas Storage, LLC*, 140 FERC ¶ 61,182, at P 43 (2012); *Broadwater Energy LLC*, 122 FERC ¶ 61,255, at P 42 (2008).

[88] *Hackberry LNG Terminal, L.L.C.*, 101 FERC ¶ 61,294 at PP 67-68; *PECO Energy Co.*, 88 FERC ¶ 61,330, at 62,020 (1999); *Transok, L.L.C.*, 97 FERC ¶ 61,362, at 62,683 (2001).

was published in the Federal Register on September 28, 2012 and mailed to over 720 interested parties on the environmental mailing list including federal, state, and local officials; agency representatives; environmental and public interest groups; Native American tribes; local libraries and newspapers in the project areas; and property owners in the vicinity of proposed project facilities.[89]

99. On July 16, July 17, and July 18, 2012, Commission staff participated in public open houses sponsored by Dominion in the project area to explain our environmental review process to interested stakeholders. On October 9, and October 10, 2012, Commission staff conducted public scoping meetings in Lusby, Maryland and Ashburn, Virginia to provide an opportunity for agencies and the general public to learn more about the project and to participate in the environmental analysis by identifying issues to be addressed in the environmental analysis (EA). A total of 40 speakers presented comments at the scoping meetings. A transcript of the scoping meetings and all written scoping comments were placed into the public record for the proceeding.

100. We received comments in response to the NOI from landowners in proximity to the project; the U.S. Environmental Protection Agency (EPA); the U.S. Army Corps of Engineers; the U.S. Department of Defense; the U.S. Chamber of Commerce; the Maryland Department of Planning; the Maryland Environmental Service; the Virginia Department of Health; the Virginia Department of Conservation and Recreation; the Virginia Department of Environmental Quality; Montgomery County, Maryland; Prince George's County, Maryland; Loudoun County, Virginia; and Fairfax County, Virginia. The primary issues raised during the public scoping process concerned: the need for the project; preparation of an environmental impact statement (EIS) rather than an EA; erosion and sedimentation; geological hazards; impacts on groundwater wells and surface water quality; impacts on wetlands, fish, wildlife, vegetation, and ecosystems; ballast water impacts; forest fragmentation and invasive species; impacts on state and federally listed threatened and endangered species; impacts on the Chesapeake Bay, Elklick Woodlands State Natural Area Preserve, and Calvert Cliffs State Park; socioeconomic impacts including, property values, shipping impacts, and traffic; noise impacts; air impacts; greenhouse gas emissions; safety during construction and operation, including evacuation routes; need for a quantitative risk assessment; cumulative impacts; and alternatives.

2. Application Review

101. After the application for the Cove Point Liquefaction project and Virginia Facilities was filed, Commission staff evaluated the potential environmental impacts of

[89] 77 Fed. Reg. 59,601 (Sept. 28, 2012).

the proposed facilities in the EA in accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA).[90] The U.S. Department of Energy, Office of Fossil Energy (DOE-FE), U.S. Army Corps of Engineers (Army Corps), U.S. Department of Transportation, U.S. Coast Guard (Coast Guard), and Maryland Department of Natural Resources (Maryland DNR) participated as cooperating agencies in the preparation of the EA.

102. On May 15, 2014, Commission staff placed the EA into the public record.[91] The analysis in the EA addresses geology, soils, water resources, wetlands, vegetation, fisheries, wildlife, threatened and endangered species, land use, recreation, visual resources, cultural resources, air quality, noise, safety, socioeconomics, cumulative impacts, and alternatives. All substantive comments received in response to the NOI and during the public scoping process were addressed in the EA.

103. A 30-day public comment period followed the issuance of the EA. Commission staff held a public comment meeting on May 31, 2014, in Lusby, Maryland, and Commission staff placed a transcript of the public comment meeting into the public record. A total of 106 speakers provided comments at the meeting, and over 650 additional stakeholders submitted written comments in response to the EA.

104. The Commission received comments on the EA from Dominion; the EPA; National Marine Fisheries Service (NMFS); Maryland Department of the Environment; Virginia Department of Environmental Quality; Virginia Department of Conservation and Recreation; Sierra Club; Calvert County, Maryland; Fairfax County, Virginia; the City of Virginia Beach, Virginia; and approximately 640 individuals and organizations during the comment period. In addition, approximately 125,000 copies of various form letters were submitted as written comments in response to the EA. The majority of the comments on the EA revisited matters previously raised in scoping comments that were fully addressed in the EA.[92] Substantive comments that required clarification to issues

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[90] 42 U.S.C. §§ 4321 *et seq.* (2012). *See* 18 C.F.R. pt 380 (2014) for the Commission's NEPA-implementing regulations.

[91] The Commission published notice of the EA in the *Federal Register* on May 22, 2014. 79 Fed. Reg. 29,435 (May 22, 2014).

[92] These issues include: general opposition or support of the project; the need for the project; a request for the extension of the comment period; preparation of an EIS rather than an EA; erosion and sedimentation; geological hazards and land subsidence; impacts on groundwater wells and aquifers; surface water quality impacts from construction and ship transits; ballast water impacts, including invasive species; impacts on wetlands, fish, wildlife, vegetation, and ecosystems; forest fragmentation and invasive

(continued ...)

addressed in the EA are addressed in this order. These issues include concerns associated with the following topics: earthquakes and the Moran Landing Fault Zone; foundations soil conditions; subsidence and sinkholes; groundwater/aquifers; ballast water; aquatic resources/Offsite Area B; terrestrial wildlife, vegetation, and protected species; light emissions/visual resources; property values; environmental justice; future gas prices; socioeconomic impacts; shipping impacts; population estimates; traffic; air emissions and modeling; noise; public safety, and alternatives.

105. On June 16, 2014, Dominion provided comments and updates to information in the EA and responded to several comments filed on the EA by others. Among these issues are site locations and mapping updates, specifics on facility design, updated permit data regarding stream impacts, work force numbers, topsoil restoration, and timing of non-jurisdictional facility construction. Our review finds that none of these comments and update changes are significant, nor do they alter our conclusions with respect to the environmental impacts resulting from the project. Clarifications regarding various mitigation plan requirements (Forest Preservation Plan, Nighttime Noise Mitigation Plan, final landscaping plan, final lighting distribution plan, Oyster Mitigation Plan, and Artificial Reef Plan), vegetative buffers, and hydrostatic test water volumes are further discussed in this order.

106. On July 24, 2014, the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation (DOT) communicated to Commission staff that it had reviewed Dominion's methodology and data for establishing the wind speeds to be used in the facility design.[93] The PHMSA found that the approach taken by Dominion complied with its regulatory requirements under 49 C.F.R. § 193.2067(b). Therefore, Recommended Condition 35 from the EA, which required

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species; impacts on state and federally listed threatened and endangered species; impacts on the Chesapeake Bay; socioeconomic impacts including, property values, future gas prices, shipping impacts, population estimates, and traffic; light emissions; noise impacts; air impacts; greenhouse gas emissions; safety during construction and operation, including evacuation routes and proximity to the Calvert Cliffs Nuclear Power Plant; national security concerns; need for a quantitative risk assessment; cumulative impacts, especially regarding shale gas extraction; and alternatives, including Atlantic Sunrise Pipeline, alternatives to Offsite Area B, desalination as an alternative water source, and onshore ballast water collection alternatives.

[93] PHMSA has the authority to establish and enforce safety standards for onshore LNG facilities. PHMSA's regulations specify the wind forces that LNG facilities must be designed to withstand.

further consultation with the DOT regarding design wind speed requirements under Part 193, is no longer needed and has not been included as a condition of this order.[94]

107. On August 8, 2014, Dominion filed supplemental information regarding Recommended Conditions 10, 16, 17, and 19 from the EA. Dominion filed documentation of compliance with Recommended Condition 10 from the EA (requiring that Dominion receive all applicable authorizations under federal law), and Recommended Condition 19 from the EA (requiring concurrence from the Maryland Department of the Environment that the project is consistent with the Maryland Coastal Zone Management Program). Therefore, Recommended Conditions 10 and 19 from the EA are no longer needed and have not been included as conditions of this order. Recommended Conditions 16 and 17 from the EA are discussed in greater detail below under aquatic resources/Offsite Area B and terrestrial wildlife, vegetation, and protected species, respectively.

3. <u>Major Environmental Issues Addressed in the EA</u>

a. <u>Earthquakes and the Moran Landing Fault Zone</u>

108. Commenters question whether the Moran Landing Fault and other faults have been adequately considered in the determination of seismic design ground motions for the LNG terminal,[95] and hypothesize that vibration from the steam generators and liquefaction equipment would trigger an "LNG-induced" earthquake. June Sevilla indicates that she provided a report to the Commission on April 9, 2014, regarding the 2010 Nuclear Regulatory Commission hearings on the Moran Landing Fault and recommends including an evaluation of the report in Commission staff's environmental assessment.

109. Section 2.1.1 of the EA addresses the Moran Landing Fault and the existing natural gas pipeline crossing over the fault. The EA indicates that there is no evidence that this fault is active and states that the existing Dominion gas pipeline is not part of the proposed project. Also section 2.1.1 of the EA recognizes that Central Virginia had a magnitude 5.8 earthquake that occurred 100 miles from the Cove Point LNG facility and 70 miles from the existing compressor station locations in Virginia. The source of the Central Virginia earthquake was well known to the U.S. Geological Survey (USGS) and

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[94] Appendix B sets forth the environmental conditions that are part of the authorizations.

[95] Seismic design ground motions are the specified level of earthquake ground shaking at a site that are used to determine the seismic forces for design.

its epicenter occurred at the location of previous earthquakes. On July 15, 2014, the USGS released the 2014 United States National Seismic Hazard Maps. The resulting mapped values for the 2 percent probability of exceedance in 50 year earthquake are about the same as in previous versions of the maps and are similar to those Dominion considered as the seismic design ground motions for the LNG Facility, and as such, does not alter the conclusions in the EA.

110. Section 2.1.2 of the EA concludes that the project is located in an area that presents several potential challenges related to geology, foundation conditions, and natural hazards; however, these conditions can be effectively managed through proper engineering design or may be shown to be minimal through additional evaluation. The EA states that the proposed front-end engineering design has provided feasible seismic design criteria for the project. Information regarding the final design will be reviewed by Commission staff prior to implementation, as required in Environmental Condition 15 included in the appendix to this order. We concur with the conclusions in the EA regarding the appropriateness of Dominion's seismic design for the Liquefaction Facility, including its consideration of the Moran Landing Fault. Further, we find no evidence that the proposed equipment could trigger a "LNG-induced" earthquake.

b. Foundations Soil Conditions

111. Commenters express concerns that the existing foundation soil conditions for the Cove Point Liquefaction project would be unsuitable for support foundations at the site. June Sevilla expresses concern that Appendix A of the EA provides no details of soil type or suitability of the soil type for the foundation of the proposed facilities.

112. Section 2.1.2 of the EA states that Dominion would use pile foundations to support the heat recovery steam generator and the gas and steam turbines to ensure settlement and vibration control and thus negate any foundation support issues. Section 2.1.3 of the EA describes the soils affected by the project and references Appendix A for details. Appendix A was not intended for use with foundation design.

113. The EA concludes that proposed seismic design ground motions for the site are sufficiently low; therefore, soil liquefaction[96] would not occur when subjected to ground shaking. Further, the proposed foundation criteria and concepts for the project are

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[96] Soil liquefaction occurs when all of the following conditions exist: (1) moderate or strong ground shaking at a site; (2) loose to medium dense sands and silts exist within the top 60 feet of the subsurface; and (3) shallow ground water is present. Soil liquefaction results in a loss of bearing capacity, settlement, and lateral movement of near surface soils.

sufficient to support the equipment as intended for operation and were designed based on the potential natural hazard design conditions.[97] We concur with the EA determination.

c. Subsidence and Sinkholes

114. June Sevilla expresses concern that gas turbine vibrations at the Liquefaction Facility will cause the area surrounding the Liquefaction Facility to subside faster. Commenters also express concern that sinkholes could be caused by pumping groundwater to supply the project with water. Miriam West states concern about the effect of land subsidence on the pipeline and questions whether operating conditions could cause sinkholes.

115. Section 2.1.1 of the EA addresses subsidence and sinkholes and indicates that the Liquefaction Facility is not underlain by near-surface carbonate bedrock units and that no karst terrain is in proximity to the proposed facilities.[98] The EA concludes that subsidence due to liquefaction, karst terrain, or mine collapse is not likely to cause significant impacts on the Liquefaction Project.[99] Additionally, the EA indicates that the Maryland Public Service Commission's (Maryland PSC) Certificate of Public Convenience and Necessity, requires Dominion to fund a subsidence monitoring program for the project area as further mitigation that will be conducted by the Maryland Geological Survey.[100] The EA concludes that proper foundation design would eliminate the potential for vibration induced subsidence from occurring at the Liquefaction Facility. Therefore, we find no reason to believe that the turbine vibrations will cause the area surrounding the Liquefaction Facility to subside faster.

d. Groundwater/Aquifers

116. Anthony Brescia questions how groundwater use at the project would be metered, monitored, and enforced. He also asks whether the reviewing state agency has any

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[97] Natural hazard design conditions define the specified hazard parameters (i.e. wind speed, seismic ground motion, flood elevation, etc.) that are used to determine the design forces for that hazard.

[98] Near-surface carbonate bedrock and karst terrain may contain solution cavities and its absence makes it unlikely that the site would be subject to subsidence associated with ground collapse.

[99] EA at 40.

[100] *Id.*

metering or monitoring capability. Commenters also raise concerns regarding the volume of groundwater that Dominion would remove from an aquifer on a daily basis, impacts on their personal wells, potential for contamination of their drinking water, saltwater intrusion, drawdown impacts, and drinking water shortages in the future. Mark Giuffrida recommends desalination of Chesapeake Bay water as an alternative water source for the project and June Sevilla questions the source of hydrostatic test water at the LNG Terminal and its impacts on water quality.

117. Maryland Department of the Environment (MDE) Water Management Administration comments that the EA overstates the potential impacts on groundwater and should have presented the actual appropriation amounts of groundwater granted by Maryland. MDE Land Management Administration, Hazardous Waste Program expresses concern that temporary storage of released materials in the LNG Terminal impoundments could cause groundwater contamination issues, but that it could not determine the likelihood of any release from information presented in the EA.

118. Regarding groundwater monitoring and enforcement, we refer to Maryland PSC's condition D-11 of its final Certificate of Public Convenience and Necessity, which requires that Dominion use a flow meter to measure all groundwater withdrawn, and report monthly totals of groundwater use to MDE Water Management Administration. The required reports must be submitted twice a year to allow MDE to verify that groundwater users are operating within their allocated appropriations.

119. Section 2.2.1 of the EA addresses the potential groundwater and aquifer impacts. The actual groundwater appropriation, a daily average of 233,000 gallons of water from the Lower Patapsco Aquifer, was approved by the Maryland PSC on May 30, 2014. The EA, released prior to the Maryland PSC approval, based its analysis on the originally-proposed average of 250,000 gallons of water per day requested by Dominion. The EA acknowledges that because Dominion will limit its water withdrawal to the amounts recommended by the reviewing state agencies, the resulting drawdown in the Lower Patapsco Aquifer from Dominion's pumping well will be less than Dominion's initial estimates.

120. As stated in the EA, the MDE Water Management Administration determined that a daily average withdrawal of 233,000 gallons per day and 275,000 gallons per day maximum monthly withdrawal would not exceed the sustained yield of the Lower Patapsco Aquifer.[101] They also determined that when combined with regional drawdown from other users, these withdrawals would have a minimal impact on the 1,025 feet of available water-level drawdown in the aquifer. This includes the calculated drawdown

[101] *Id.* at 46.

amount to minimize the risk of saltwater intrusion. The MDE Water Management Administration's distance-drawdown analysis also shows that additional water-level drawdown in the Lower Patapsco Aquifer over a 12-year pumping period will be on the order of 5 feet and 4 feet at distances of one-half mile and one-mile, respectively from Dominion's pumping well. As a result, Dominion's proposed water withdrawals will have no discernable effect on water available to the Calvert County Department of Public Works for potable water at a distance of 14 miles.

121. As stated above and as an additional mitigation measure, the EA indicates that the Maryland PSC's Certificate of Public Convenience and Necessity requires Dominion to fund a subsidence monitoring program for the project area that will be conducted by the Maryland Geological Survey.[102] The EA concludes that, based on the predicted water drawdown for construction and operation of the liquefaction facilities and the substantial capacity of the Lower Patapsco Aquifer, Dominion's water withdrawal from the Lower Patapsco Aquifer as recommended by the reviewing state agencies (which includes the MDE and the Maryland DNR, among others) will not significantly impact the aquifer or other groundwater users in the area.[103] We agree.

122. Section 3.5 of the EA analyzes alternative water sources for the Liquefaction Project, including the use of water from the Chesapeake Bay. The EA states that Dominion does not have an existing water intake system in the Chesapeake Bay and environmental covenants on the property preclude installation of such a line.[104] In addition, the EA states that the use of brackish water would require costly treatment, which would generate large volumes of wastewater that would need to be properly managed. The EA concludes that the use of water from the Lower Patapsco Aquifer would not significantly impact the aquifer or other groundwater users and that there are no other viable, environmentally preferable sources of water for the facility. We concur with this determination.

123. The EA states that groundwater contamination from surface spills of hazardous materials during construction will be minimized with the implementation of measures in Dominion's Spill Prevention, Control, and Countermeasures Plan (SPCC Plan).[105] During operation, the spill containment system, which is constructed of concrete, will contain

[102] *Id.* at 40.

[103] *Id.* at 47.

[104] *Id.* at 178-179.

[105] *Id.* at 48.

any process liquid spills (i.e., LNG, refrigerants, condensates, and amines) to prevent migration of these materials offsite, including into groundwater. As stated in the EA, the spill containment system includes trenches that direct liquid releases into appropriately sized impoundments.[106] Any storm water collected within the spill containment system would be analyzed for contamination prior to being sent to the holding pond. Therefore, the EA properly concludes that the project, including the potential for spills, would not significantly impact the aquifer or other groundwater users in the area.

124. Dominion clarifies that the volume of water required for hydrostatic testing over the life of the project could be up to 6,750,000 gallons. We note that Dominion submitted this information to the Power Plant Research Program in the Maryland PSC case regarding the amount of water required for hydrostatic testing. While this represents an increase from the original proposal, we find that Dominion's compliance with its water use permits for hydrostatic testing will minimize impacts on water resources from the withdrawal.

125. Comments were also received regarding sewer system impacts. June Sevilla states that the existing air separation units at the LNG Terminal collect a condensate that requires treatment prior to discharge to a marsh and claims that this is a violation of water discharge regulations that would be allowed to continue. We disagree. Dominion proposes to eliminate these actions associated with the current operation of the facility and proposes to construct a new sewer system at the LNG Terminal that connects to the Calvert County sewer extension. The EA indicates that Dominion has submitted permits for the on-site sewer system to Calvert County and the MDE.[107] The commenter erroneously concludes that the condensate has been disposed of through water discharge into a wetland. However, this is not the case and we see no violation of water discharge regulations.

e. <u>Ballast Water</u>

126. Commenters, including Dr. Mario Tamburri, Mike Tidwell, Earthjustice and others, express concern over the potential introduction of invasive species from ballast water discharge; impacts on water quality and aquatic populations from low dissolved oxygen levels from ballast water releases; potential contamination from ships originating from India and Japan; and surface contamination/biofouling from ships arriving at the LNG Terminal. Commenters also request additional mitigation measures, including explicit means to comply with Coast Guard regulations to remove fouling organisms at

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[106] *Id.* at 145-146.

[107] *Id.* at 17.

the port of origin, and incorporation of onshore ballast water collection and treatment. The EA addresses ballast water impacts in section 2.2.2. Further, Dominion clarifies in its comments on the EA that it will not be implementing a separate ballast water management plan, but rather the LNG ships and barges will be required to comply with U.S. laws, regulations and policies.

127. The MDE Science Services Administration clarifies that the newest Coast Guard rules that phase in more aggressive ballast water management standards will be in effect before the in-service date of the project. The MDE Science Services Administration also states that because the project does not entail increased shipping traffic over and above prior approvals, there is no anticipated increased risk of ballast water introductions from the project. The MDE Science Services Administration opines that the EA sufficiently addresses ballast water issues. We concur with these comments.

128. The EA acknowledges that there are risks of invasive species introduction and water quality impacts even with federal controls.[108] We recognize that potential impacts from ballast water releases and biofouling could include impacts on water quality and aquatic populations from low dissolved oxygen levels from ballast water releases and potential contamination from ships originating from other countries. Dominion does not own the LNG carriers visiting the terminal or control mitigation measures occurring at the port of origin. However, the currently-required measures for all ships entering U.S. waters, including offshore ballast water exchange, provide best management practices to minimize risks from invasive species and contamination from non-U.S. ports. The EA states, as indicated by the MDE Science Services Administration, that new rules and discharge standards approved by the Coast Guard would further minimize the introduction and establishment of nonindigenous species.

129. Dominion will be required to comply with current and future Coast Guard regulations. Given these factors, in addition to the fact that Maryland does not currently require more stringent standards than the federal ballast water program, the Commission has no grounds to presume the established regulations are not satisfactory for maintaining the quality of the environment in the project area. Therefore, the EA properly concludes that ballast water discharges will not have any noticeable, long-term impact on the Chesapeake Bay or aquatic resources beyond those that have already occurred within the Chesapeake Bay.

130. Commenters also request an alternatives analysis for a land-based ballast water treatment facility. This alternative would require adapting the vessels visiting the LNG Terminal with the infrastructure to pump ballast water to shore, and building a land-based

[108] *Id.* at 53-54.

ballast water treatment facility, similar to a municipal waste water plant. As previously stated, Dominion does not own or control the LNG carriers visiting the terminal and will, therefore, not be capable of requiring adaptations to the vessels to allow for pumping ballast water into an onshore system. Additionally, environmental covenants on Dominion's property make the acreage requirements for an onshore facility an unviable alternative. A commenter notes that this option has been considered in other cases, but has been discounted because of port and vessel operations, logistical, and cost constraints. We conclude that an on-site ballast water treatment facility is not a viable, environmentally preferable alternative to the proposed action.

f. **Aquatic Resources/Offsite Area B**

131. Commenters express concern for impacts on essential fish habitat, critical habitats or scenic viewsheds, oysters and other species at Offsite Area B and the Patuxent River, as well as concern with contamination of the Chesapeake Bay. The EPA questions how the project would comply with regulations regarding essential fish habitat, water discharges, and whether dredging would be required during operation of the facility.

132. To address the EPA's questions regarding essential fish habitat, we note that the EA indicates that consultation regarding essential fish habitat was completed with NMFS in February 2013, and concludes that the project would not have a substantial adverse effect on essential fish habitat or managed fish species.[109] Any water discharges associated with the project will comply with all applicable local, state, and federal water quality permits and regulations. In addition, measures to minimize spills, soil erosion, and sedimentation will be employed. Lastly, regarding dredging, the EA clarifies that dredging is not proposed for construction or operation of the project and concludes that no permanent impacts will occur at Offsite Area B.[110]

133. The EA addresses impacts on wetlands, water resources, aquatic species, and protected species, including at Offsite Area B, and concludes that impacts on these resources will be adequately minimized.[111] Concurrent with issuance of the EA, the MDE Water Management Administration issued its Wetlands Report and Recommendations on May 13, 2014, that concludes that the proposed use of Offsite Area B with the required mitigation measures will not cause significant deleterious impacts on marsh vegetation, submerged aquatic vegetation, finfish, shellfish, or navigation. The

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[109] *Id.* at 57.

[110] *Id.* at 53.

[111] *Id.* at 50-59.

Tidal Wetlands License conditions include use of an approved Oyster Mitigation Plan and an Artificial Reef Plan, time of year restrictions, pre- and post-construction erosion surveys and restoration, and Coast Guard-recommended mooring pile marker beacons.[112] Recommended Condition 16 of the EA would require Dominion to file the final Oyster Mitigation Plan and Artificial Reef Plan prior to their implementation. On August 8, 2014, Dominion filed supplemental information, including the final Oyster Mitigation Plan and the July 28, 2014 statement incorporating revisions provided by the Maryland DNR and rendering the plan approved. The Artificial Reef Plan has not yet been finalized with the Maryland DNR. Therefore, we have revised Environmental Condition 16 to this order to require submittal of the final Artificial Reef Plan prior to its implementation. We note that both the Oyster Mitigation Plan and Artificial Reef Plan will be enforceable under Maryland state permits, ensuring proper implementation. As such, we find that the EA properly concludes that construction and use of Offsite Area B will result in temporary impacts on the Patuxent River and aquatic resources and that impacts will be adequately minimized.[113]

134. Commenters also express concerns regarding historically significant areas and scenic viewsheds at Offsite Area B. As the EA states, to further minimize impacts on potential submerged cultural resources adjacent to Offsite Area B, Dominion will maintain avoidance distances from the resources, as established by the Maryland Historical Trust.[114] We agree these measures are adequate to protect submerged cultural resources. Regarding visual impacts, the EA states that temporary impacts on visual resources would occur during construction from the Thomas Johnson Bridge, but that no scenic or unique viewsheds are associated with the site.[115] Therefore, impacts on scenic viewsheds associated with Offsite Area B will be temporary and limited.

135. A commenter states that the EA failed to take a hard look at an alternative for Offsite Area B located at the Calvert Cliffs Nuclear Power Plant. The commenter states that security issues and disruptions of operation at the plant could be controlled and would result in less environmental impact than Offsite Area B. We disagree that addressing security and operational issues at a nuclear facility will be a minor

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[112] The tidal wetland license for the project was issued by the Board of Public Works on July 23, 2014. Dominion indicated that the Draft Artificial Reef Plan was filed with the Maryland DNR on June 6, 2014.

[113] EA at 57.

[114] *Id.* at 94.

[115] *Id.* at 85.

undertaking with minimal impact. Additional mitigation measures may be possible to address the disruptions, with the consent of the operators of the plant, including extensive coordination and reinforcements or improvements to their pier and roadway. However, we do not find that a more detailed review was needed based on the EA conclusion that the proposed location will be environmentally acceptable with the mitigation measures developed. As such, we concur that the project's use and restoration of Offsite Area B will result in temporary impacts on the resources identified and will be adequately minimized.

g. Terrestrial Wildlife, Vegetation, and Protected Species

136. Commenters state concern regarding impacts on forested habitat for wildlife and migratory birds; wetlands and vegetation; invasive species; and protected species, including the Puritan tiger beetle, bald eagles, and the North Atlantic right whale. The Virginia Department of Conservation and Recreation comments regarding concern for natural heritage resources.

137. Dominion notes that condition B-6 of the Maryland DNR's Final Recommended License Conditions for the project requires Dominion to submit for approval a draft Forest Preservation Plan to the Maryland DNR and Calvert County at least sixty days prior to clearing or construction within Offsite Area A.[116] Dominion's draft Forest Mitigation Plan provides mitigation and preservation proposals to offset the temporary and permanent loss of forest land. The Maryland DNR approved the draft Forest Mitigation Plan, item B-6, on July 14, 2014. We have reviewed the Forest Mitigation Plan and conclude that Recommended Condition 17 from the EA, that would require a Forest Preservation Plan for Offsite Area A approved by the Maryland DNR, has been met. Therefore, Recommended Condition 17 from the EA is no longer necessary and is not included as a condition to the order.

138. Dominion clarifies that it will maintain at least a 100-foot buffer of existing vegetative growth around wetlands and waterbodies and other sensitive resources within Offsite Area A. In its comments on the EA, Dominion provides clarification that the seven specimen trees at Offsite Area A will be located within a defined 100-foot protective buffer of the streams, wetlands, and steep slopes; however, an individual specimen tree will not have its own 100-foot buffer. Dominion indicates that it will modify the limits of disturbance to ensure that the critical root zone of each tree will be kept within the protective buffer. We find this acceptable to protect the specimen trees.

[116] Dominion indicated that it submitted its draft plan to the Maryland DNR and Calvert County on March 28, 2014.

139. The EA analyzes impacts on vegetation and wildlife in the project area, including wetlands (section 2.2.4), forested habitat (section 2.3.1), general wildlife (section 2.3.2), and protected species (section 2.3.3). The EA indicates that wetlands impacts would be minor and would be minimized by mitigation measures required by the U.S. Army Corps of Engineers and state agencies.[117] To minimize wildlife and habitat impacts, Dominion will implement its Invasive Species Management Plans. In addition, Environmental Condition 17 of this order requires Dominion to conduct bird nest surveys prior to tree clearing to avoid active nests. The Forest Preservation Plan will further ensure that impacts on forested vegetation will be adequately offset. The EA concludes that the loss of forested habitat would not result in population-level impacts on migratory birds. We find that the EA properly concludes that impacts on vegetation, wetlands, and wildlife will not be significant.

140. The Virginia Department of Conservation and Recreation recommends strict adherence to erosion and sediment control measures at the Loudoun M&R Station in order to protect adjacent aquatic ecosystems containing the green floater.[118] The EA states that Dominion would implement measures to prevent water quality degradation and concludes that these measures would effectively avoid impacts on the green floater. The Virginia Department of Conservation and Recreation also provides data from the Virginia Department of Game and Inland Fisheries identifying the wood turtle as occurring within 2 miles of the Pleasant Valley Compressor Station. The EA concludes that the stream and riparian upland habitat required by this species would not be affected in the project area; therefore, no impacts are anticipated.

141. NMFS provides comments to further clarify its September 11, 2013 determination that there was no need for endangered species consultation under section 7 of the Endangered Species Act. NMFS clarifies that a June 14, 2012 letter from Dominion requested information on listed species, and that its review in June 2012 did not include Offsite Areas A and B, which was addressed in later correspondence. The Commission accepts these clarifications and notes that NMFS' September 11, 2013 determination of effect on listed species remains valid. Thus, consultation with NMFS regarding listed species is complete.

142. The U.S. Fish and Wildlife Service (FWS) did not identify any nesting bald eagles or the Puritan tiger beetle in the project area, and Commission staff concluded its Endangered Species Act consultations with the FWS in August 2013.[119] Commenters

[117] EA at 60.

[118] The green floater is a small, rare, freshwater mussel species.

[119] EA at 70.

question the impacts on the North Atlantic right whale from increased vessel transits. The EA notes that the analyses for LNG vessels were previously assessed for up to 200 vessels, while the currently proposed project will consist of about 42 barges and an estimated 85 LNG vessels per year.[120] In addition, Dominion will be required to comply with the measures established for protected species during the previous review of the LNG Terminal including its Vessel Strike Avoidance Measures and Injured and Dead Protected Species Reporting Plan.[121] The EA determines that the project is not likely to adversely affect the North Atlantic right whale and that consultation is complete for this species. Therefore, the EA properly concludes that the project will have no substantial impact on protected species in the project area.

h. <u>Light Emissions/Visual Resources</u>

143. We received additional comments on the visual impacts of the project, especially concerning the appearance of the sound barrier wall and light emissions at the facility. The EA discusses visual resources and concludes that implementation of a landscaping plan and a lighting distribution plan will serve to reduce the potential visual impacts associated with the sound barrier and project lighting.[122] Pursuant to Environmental Condition 19 to this order, the final lighting distribution plan will be filed with the Secretary of the Commission for the review and written approval by the Director of the Office of Energy Projects (OEP).

144. Dominion's EA comments clarify that the sound barrier at the LNG Terminal will be constructed of concrete (not of sound absorbing panels), that the concrete will be sound attenuating/reflecting rather than sound absorbing, and that, if colored, the color will be blended in the concrete (the sound barrier will not be painted). We find these measures are acceptable to minimize potential visual impacts.

145. Dominion further requests revisions to Recommended Conditions 20 and 21 of the EA (regarding the final landscaping plan and the final lighting distribution plan) to require the submittal of these plans prior to operation, rather than prior to construction, as indicated in the EA. We have determined that the filing of these plans prior to operation will provide responsive mitigation measures reflecting as-built conditions. We note that

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[120] *Id.* at 71.

[121] *See* the Environmental Impact Statement for the Cove Point Expansion Project, April 2006, Docket No. CP05-130-000 *et al.* and EA for the Pier Reinforcement Project, May 2009, Docket No. CP09-60-000.

[122] EA at 84.

this result is consistent with the Maryland PSC's Certificate of Public Convenience and Necessity conditions; therefore, we have revised the recommended environmental conditions from the EA (as Environmental Conditions 18 and 19 to this order) to require submittal of these plans prior to commissioning of the Cove Point Liquefaction Project.

i. Property Values

146. Commenters raise concerns about the potential for the Cove Point Liquefaction Project to affect property values in the vicinity of the facility. A project's impact on land values depends on many factors, including the entire project size, the existence of other energy projects and infrastructure, the current value of the land, and current land use. Each potential purchaser will have varying criteria, considerations, and capabilities for purchasing land and the addition of liquefaction facilities to an existing LNG terminal, especially when not visible to the surrounding community, may be irrelevant to a prospective purchaser.

147. The EA explains that Dominion's proposed liquefaction facilities will be located entirely within the existing Cove Point LNG Terminal, which is an operating industrial facility. Further, the EA explains that 323 of the 377 residential structures within 1 mile of the facility were built after the existing facility commenced operation in 1978. Dominion's proposed sound barrier, which will be installed to mitigate the impacts associated with noise generated by the new facilities, will also result in visual screening of the existing industrial facility from nearby residences.[123] Based on this information, the EA properly concludes that the Cove Point Liquefaction Project should not result in a significant impact on nearby property values.

j. Environmental Justice[124]

148. The EPA comments that the EA does not provide analysis to determine whether there are potentially affected low-income or minority populations. We reviewed additional demographic and income characteristic data from the U.S. Census Bureau for the State of Maryland, Calvert County, and Census Tracts 8609.00 (which covers Offsite Areas A and B), 8610.01 (which includes the LNG Terminal and the area south and east

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[123] *Id.* at 91.

[124] Executive Order 12898: Federal Actions to Address Environmental Justice, applies to agencies other than independent agencies, which are "requested to comply with the provisions of this order." *See, Eagle Crest Energy Co.*, 147 FERC 61,220 (2014); *Idaho Power Co.*, 110 FERC ¶ 61,345 (2005); *Sound Energy Solutions*, 107 FERC ¶61,263, at P 109 (2004).

of the terminal), and 8610.04 (which includes the area south and west of the LNG Terminal).[125]

149. Census Tracts 8609.00 and 8610.04 have somewhat higher minority percentages (25 percent and 21 percent, respectively) than Calvert County as a whole (18 percent). In addition, the per capita income for these census tracts ($37,059 and $26,640, respectively) is also lower than the county as a whole ($37,641), and the percent of the population below the poverty level (7 percent and 9 percent, respectively) is higher than the county as a whole (5 percent). Census tract 8610.01 (which includes the LNG Terminal and the area south and east of the terminal) has a lower minority percentage (11 percent), higher per capita income ($44,076), and lower percentage of population below the poverty level (3 percent) than Calvert County as a whole.

150. As discussed in the EA, the proposed Cove Point Liquefaction Project would be constructed within an existing, industrial facility owned by Dominion, and the use of Offsite Areas A and B will be temporary and short-term, with these areas being restored following construction to their previous use or in accordance with the landowner's request. Further, the project will have some positive socioeconomic effects, including generating new jobs and economic activity in the region.[126] While the census tracts associated with Offsite Areas A and B, and for the area to the south and west of the LNG Terminal can be characterized as having lower incomes and higher minority populations than average, the potential impacts associated with the project will affect all communities surrounding the Cove Point Liquefaction Project and Offsite Areas A and B, and will not disproportionately impact the referenced census tracts. As such, the EA properly concludes that construction and operation of the project will not disproportionately affect any population group, including low-income and minority populations.

k. <u>Socioeconomic Impacts</u>

151. We received comments regarding the potential socioeconomic impacts of the project, including both comments that the project would have beneficial impacts on the local economy, and that the project would negatively affect the local economy, or that the beneficial impacts would be short-term. In addition, commenters (including professors King of the University of Maryland and Nicholas of the University of Florida) claim that

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[125] U.S. Census Bureau: ACS Demographic and Housing Estimates, 2008-2012 American Community Survey 5-Year Estimates (Table DP05); Selected Economic Characteristics, 2008-2012 American Community Survey 5-Year Estimates (Table DP03).

[126] EA at 92.

information filed by Dominion overstates the economic impacts of the project on Calvert County.

152. Section 2.5.6 of the EA addresses the potential that the proposed export of LNG could result in adverse economic impacts, including increased natural gas prices.[127] Section 1.5.2 of the EA addresses the DOE-FE's authority to determine whether the export of natural gas is consistent with the public interest, and describes that the DOE-FE's decision whether to authorize the project considers economic and other factors.[128] The DOE-FE, in its Order No. 3331, concluded that the exports proposed by Dominion "are likely to yield net economic benefits to the United States."[129] Therefore, the EA properly concludes that the project would provide socioeconomic benefits locally and nationwide.

l. Shipping Impacts

153. Numerous comments on the EA state that increased LNG ship traffic would require additional tug boats, affect recreational and commercial fishing activities on the Chesapeake Bay, and increase shoreline erosion from ship wakes. As part of the Pier Reinforcement project and Cove Point Expansion project, the Commission previously analyzed impacts associated with increased vessel transits and support vessels, including impacts on recreational and commercial fishing and shoreline erosion and these analyses were included by reference in the EA.[130] The EA identifies that there would be no increase in ships beyond the maximum of 200 per year previously studied.[131] Based on the Coast Guard's review of Dominion's Waterway Suitability Assessment, the Coast Guard issued a Letter of Recommendation indicating that the waterway was suitable for LNG transit. For the Cove Point Liquefaction Project, the Coast Guard confirmed that construction and operation of the project will not require modification of either the existing Waterway Suitability Assessment or the current Letter of Recommendation.[132]

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[127] *Id.* at 92.

[128] *Id.* at 20.

[129] DOE-FE Order No. 3331 at 6.

[130] EA at 2.

[131] *Id.* at 20.

[132] The Coast Guard's *Supplemental Environmental Assessment for the Dominion Cove Point Liquefied Natural Gas (LNG) Terminal Expansion Project: LNG Ship Transit in United States Waters*, March 5, 2008, indicates that a minimum of three tractor tugs of

(continued ...)

Regarding shoreline erosion, the EA concludes that the waves generated by LNG ships will not erode the Cove Point peninsula shoreline and will be within the normal range of waves due to wind and other ship traffic.[133] Because the project does not result in any increases in shipping traffic from what has been previously evaluated, the EA properly concludes that no additional ship-related impacts will result during operation of the project.

m. Population Estimates

154. We received comments that the population data provided by Dominion in its application and/or in the EA were incorrect and did not accurately reflect the population immediately adjacent to the LNG Terminal that will be affected by the Cove Point Liquefaction Project. Commenters contend that Dominion selectively reported only a portion of the available population data and did not adequately account for the population of Lusby, Maryland.

155. The population and demographic data provided in the EA was based on data filed in the docket, as well as data developed independently by Commission staff to identify the existing demographic and socioeconomic conditions for the counties affected by the project.[134] The EA noted that the U.S. Census Bureau determined the population of Calvert County to be 88,737 in 2010. Because Lusby, Maryland is within Calvert County, its population was accounted for in the census data used in Commission staff's analysis. Accordingly, the EA's conclusions regarding impacts on population are adequate.

n. Traffic

156. We received comments regarding impacts from construction vehicles, including trucks operating at night transporting equipment from Offsite Area B to the Liquefaction Project, blocking the entrances to the Ranch Club community, and the potential closing of the Thomas Johnson Bridge.

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at least 50-ton bollard pull each would be available when the LNG vessel is mooring or getting underway and concluded that the escort tugs would not have a significant impact on the environment.

[133] EA at 52.

[134] *Id.* at 87.

157. Regarding comments that entrances to the Ranch Club community would be blocked, equipment trucks associated with the project will not stand idle at intersections along the route between Offsite Area B and the Liquefaction Project. Thus, no intersections along the route between the offsite area and the facility will be blocked during construction of the project.

158. Regarding the Thomas Johnson Bridge, Dominion will be required to submit a mobile Maintenance of Traffic plan to the Maryland State Highway Administration for approval of the transportation of large loads over state highways. We note that the bridge will not be crossed to deliver materials from Offsite Area B to Offsite Area A and we are unaware of any security requirements in the plan that will necessitate the closing of the Thomas Johnson Bridge.

159. The EA addresses potential impacts on traffic associated with equipment transport between Offsite Area B and the Liquefaction Project. As described in the EA, Dominion completed a traffic impact analysis to address public concerns regarding increased traffic and to satisfy requirements from the Maryland State Highway Administration and Calvert County Department of Public Works to address impacts from construction traffic on public roadways. Based on Dominion's analysis, and as required by the Maryland State Highway Administration and Calvert County, Dominion has begun construction of various road improvements intended to reduce impacts on traffic. In addition, Dominion will continue to consult with the Maryland State Highway Administration and Calvert County to identify any additional modifications that may be required before the start of construction.[135] Accordingly, the EA properly concludes that Dominion's use of local roads during construction to transport equipment and materials from Offsite Area B will result in only a temporary and short-term impact on local traffic.

o. <u>Air Emissions</u>

160. We received several comments concerning the risk of radon exposure associated with natural gas originating from the Marcellus shale region. As discussed below, due to the interconnected nature of the natural gas pipeline systems, the source of natural gas for this project may include gas from any production area in the lower-forty-eight states. However, any gas that is supplied from the Marcellus shale region would not result in significant risk of exposure to radon. Although radon is inert, long-term (chronic) exposure to its decay products can be carcinogenic (causing lung cancer), with increased risk to smokers. The EPA identifies that the average indoor radon level is 1.3 picocuries per liter (pCi/L) and recommends that indoor levels be less than 2 to 4 pCi/L. In addition, Congress passed the Indoor Radon Abatement Act in 1988, establishing the

[135] *Id.* at 16-17.

long-term goal that indoor air radon levels be equal or better than outdoor air radon levels (average of 0.4 pCi/L).

161. In early 2012, an academic paper raised concern regarding radon levels in natural gas from Marcellus shale (Resinkoff 2012). However, this paper used theoretical calculations to estimate Marcellus shale sourced radon concentrations in the home at 0.0187 to 0.482 pCi/L. Subsequent studies by the USGS and natural gas industry, based on natural gas samples measured at the wellhead and in pipelines sourced from the Marcellus shale region, presented measured radon concentrations in natural gas pipelines.[136] In-home concentration levels based on the pipeline measurements were estimated at 0.0042 to 0.0109 pCi/L. These levels are less than the average indoor and outdoor EPA action levels for radon.[137]

162. We also received comments that the 130-MW power plant associated with the Liquefaction Project would emit significant amounts of criteria air pollutants, greenhouse gases (GHG), and hazardous air pollutants, and that the EA did not effectively limit the amount of power plant emissions in accordance with state regulations. The EA states that the 130-MW power plant would be powered by two steam turbines. The steam for these turbines would be created through waste heat recovery units from the liquefaction refrigerant turbine exhaust.[138] Therefore, the operation of the 130-MW power plant would not result in the emission of any pollutants.[139]

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[136] Rowan, E.L. and T.F. Kraemer. 2012. Radon-222 Content of Natural Gas Samples from Upper and Middle Devonian Sandstone and Shale Reservoirs in Pennsylvania: Preliminary Data. U.S. Geological Survey, Reston, Virginia. Available online at http://pubs.usgs.gov/of/2012/1159/ofr2012-1159.pdf.

Anspaugh, L.R. 2012. Scientific Issues Concerning Radon in Natural Gas, Texas Eastern Transmission, LP and Algonquin Gas Transmission, LLC, New Jersey-New York Expansion Project, Docket No. CP11-56. Prepared at Request of Counsel for Applicants, Henderson, Nevada. Available online at http://energyindepth.org/wp-content/uploads/marcellus/2012/07/A-Anspaugh-Report.pdf

[137] Further, while the Commission has no regulatory authority to set, monitor, or respond to indoor radon levels, many local, state, and federal entities (e.g., the EPA) establish and enforce radon exposure standards for indoor air.

[138] EA at 8.

[139] The EA explains that the operation of the Cove Point Liquefaction Project and the Pleasant Valley Compressor Station will result in long-term air emissions. EA at 95.

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163. Commenters believe that the EA is deficient because it fails to address the applicability of the Clean Air Interstate Rule, the Acid Rain Program, and the EPA's June 2, 2014 proposed rulemaking to cut carbon emissions from power plants. The Clean Air Interstate Rule and Acid Rain Program only applies to electric generating units where the electricity produced is sold. The EPA's June 2, 2014 proposed rulemaking was announced after the EA was issued and has not yet been finalized.[140] Similarly, it proposes to apply to electric generating units constructed before January 8, 2014, where the electricity produced is sold. The steam turbines associated with the 130 MW power plant would not produce electricity for sale and would be constructed after the date specified in the EPA proposed rulemaking. Accordingly, the referenced programs are not applicable and the EA appropriately addressed the relevant air programs for the project.

164. Commenters question whether Dominion is required to have a risk management plan under the Chemical Accident Prevention Provisions of 40 C.F.R. Part 68, applicable to stationary sources of air pollution, and requested that the Commission prepare an EIS to address this omission. The EA explains that because the operation of the proposed facilities is subject to the DOT's jurisdiction under 49 C.F.R. Part 193, these facilities would not be required to comply with 40 C.F.R. Part 68.[141] However, the federal regulations for the safety and siting of LNG facilities (49 C.F.R. Part 193) require an applicant to consider any distinct hazard that could affect the safety of the public or personnel. These hazards include flammable and toxic releases, explosions, and fires. When assessing these hazards, Commission staff evaluated endpoints that are similar or exceed those in EPA risk management plan regulations to evaluate the potential impact to the public. We conclude that the EA adequately addressed the hazards associated with the project.

165. The Clean Air Council[142] believes that the EA inappropriately dismisses significant air impacts by relying on permitting performed by other agencies and

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Tables 2.7.1-6, and 2.7.1-7 of the EA include a list of each emission source and the associated emissions. The two electric generating turbines are not on the list of emission sources. EA at 112. The Maryland Department of the Environment is the lead air permitting authority for the Cove Point Liquefaction Project, and the Virginia Department of Environmental Quality administers the federal and state air quality standards for the Virginia Facilities, including the Pleasant Valley Compressor Station.

[140] Indeed, the proposed rule gives states the ability to design their own plan to meet emission rate reductions.

[141] EA at 105 and 144.

[142] The Clean Air Council is a non-profit organization headquartered in

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regulations of other statutes. We disagree. The EA does include an air modeling analysis to identify the impacts of the project.[143] This analysis included marine vessel emissions which are not analyzed through the air permitting process or other statutes. Also, because the project will be subject to permitting by other agencies and to the regulations in other statutes, it is reasonable to assume the project's compliance with these permits and regulations under the NEPA analysis. Therefore, we find that the EA independently assessed impacts of the project and conclude that emissions will be below the National Ambient Air Quality Standards (NAAQS).

166. Commenters believe that the project would illegally emit pollutants in excess of the Nonattainment New Source Review (NNSR) "limits" and question whether the best technology has been evaluated and required to minimize air emissions. The NNSR thresholds are not a limit as commenters indicate, but are an evaluation criteria used to determine whether a specific type of permitting applies to a project. Facilities may exceed the thresholds, as in the case of the proposed project, which prompts further review, emission controls, and permitting requirements by the Maryland PSC. The EA states that as part of the air permitting process performed by the Maryland PSC, it reviewed the Best Available Control Technology (BACT) and Lowest Achievable Emission Rates (LAER) proposed by Dominion.[144]

167. The Power Plant Research Program comments that the EA failed to identify several of the BACT and LAER for some equipment. The EA is a summary document identifying proposed air emissions, mitigation measures, and impacts. The EA identifies that the project is subject to air permitting under the Maryland PSC, which includes compliance with all applicable BACT and LAER measures.[145]

168. The Power Plant Research Program requests clarification that the 625 tons of nitrogen oxides emission reduction credit offsets identified under General Conformity may also be used during operation for Nonattainment New Source Review. The Power Plant Research Program also identifies that the necessary documentation was provided to MDE for the purchase of these offsets, and MDE has approved the transfer of the emission reduction credits. The EA identifies that the emission reduction credits far

Philadelphia, Pennsylvania.

[143] EA at 113-115.

[144] *Id.* at 111.

[145] *Id.* at 100-101.

exceed the projected non-permitted emissions.[146] Dominion may use the offsets for NNSR and General Conformity, such that the total offsets needed simultaneously in the same year does not exceed the amount purchased. Further, Dominion provided documentation demonstrating that 944 tons of emission reduction credits were purchased and MDE and Virginia Department of Environmental Quality have concurred that offset requirements for General Conformity have been met.[147] Therefore, on August 18, 2014, we issued a final General Conformity Determination for the project and Recommended Condition 23 from the EA is not included in this order.

169. Several commenters believe that the analysis of local air impacts is flawed because Dominion's plan to purchase offsets in Frederick County, Maryland, will allow it to pollute locally. Earthjustice states that the EA provides no basis for concluding that offsets obtained elsewhere within the region for ozone would avoid local 1-hour nitrogen dioxide impacts during construction.

170. The EA identifies that the project is located within the Washington, DC ozone nonattainment air quality control region. The Clean Air Act defines nonattainment areas as "any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) that national primary or secondary ambient air quality standard for the pollutant." The EA explains that in order to achieve improved air quality within a nonattainment area, reductions are required throughout the entire air quality control region. The General Conformity Regulations require that offsets be purchased "within the same nonattainment or maintenance area (or a nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violations in the past)." Frederick County is also within the Washington, DC ozone nonattainment air quality control region and Dominion has purchased more than the required amount of offsets for the project, at a rate of 2.9 to 1, which will sufficiently mitigate nitrogen dioxide emissions from the project, both as a precursor to ozone and for direct emissions. Also, the EA includes nitrogen dioxide air modeling for operation of the project, marine vessels, and other offsite sources that concludes impacts will be below the NAAQS. The emissions from these sources exceed those nitrogen dioxide emissions from any individual construction year. For these reasons, we find that the EA appropriately accounted for offsets to mitigate for nitrogen dioxide emissions.

171. Earthjustice comments that an EIS is required because the EA fails to identify how the recommended revised fugitive dust control plan would fully mitigate impacts and it must be enforceable. We disagree. The EA identifies that Dominion prepared a fugitive

[146] *Id.* at 106.

[147] Dominion's August 5, 2014 supplemental filing.

dust control plan that identifies measures to reduce fugitive dust. Many of these measures are proven mitigation recommended by EPA and other state or local agencies to reduce fugitive dust emissions by 50 percent or greater from various sources. The EA states that Dominion's plan lacks specificity in how these measures will be implemented and the individuals with authority and accountability. Therefore, the EA recommends and we have included Environmental Condition 21, requiring Dominion to provide the additional details in their Fugitive Dust Control Plan about how the various mitigation measures will be implemented to ensure awareness and compliance and the individuals responsible for enforcement. We agree with the EA's conclusion that construction will result in short-term impacts on air quality.

p. <u>Air Modeling</u>

172. Commenters also believe that an EIS is warranted because hazardous air pollutant or toxic air pollutant emissions from the project would be significant, citing the number of different hazardous air pollutants, quantities that would be emitted, and health impacts of these pollutants. The EA thoroughly addresses hazardous air pollutant emissions by quantifying the amount of hazardous air pollutants that will be emitted during construction and operation, and discussing the various regulatory programs that minimize hazardous air pollutant emissions. The EA also states that the LNG Terminal would continue to remain a minor source of hazardous air pollutant emissions following construction of the Liquefaction Project.[148] The EA further presents discussion of the toxic air pollutant assessment performed in compliance with Maryland air permitting regulations as part of the Maryland PSC Certificate of Public Convenience and Necessity application. The EA concludes that applicable sources would comply with toxic air pollutant BACT, minimize emissions, and modeled results will be well below Maryland's acceptable ambient levels. Maryland's acceptable ambient levels are concentrations of a toxic air pollutant in the atmosphere that provide a margin of safety to protect the public health from toxic, noncarcinogenic effects that may be caused by the toxic air pollutant.[149] Therefore, hazardous air pollutant or toxic air pollutant emissions resulting from the project will not be significant, and an EIS is not required.

173. Commenters state that the EA fails to address the health impact resulting from air emissions from constructing and operating the project within zip code 20657, surrounding the terminal. Earthjustice believes that any amount of nitrogen dioxide emissions have been linked to significant health impacts. Further, one commenter states that the sulfates and nitrates generated from the project would degrade the environment.

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[148] EA at 103.

[149] COMAR 26.11.15.01.B.1.

174. The EA states that the NAAQS have been developed by EPA to protect human health and public welfare, including the health of sensitive populations, such as children and those with chronic respiratory problems, and economic interests, visibility, vegetation, animal species, and other concerns not related to human life.[150] While the EPA may consider available studies and re-evaluate the need to change the applicable thresholds for each NAAQS in the future, the project was evaluated based on the current standards that were issued by EPA, following a proposed rulemaking and public comment period. The EA presents the amount of emissions that will result from construction each year and recommends a revised Fugitive Dust Control Plan to further reduce particulate matter emissions.[151] We have included this recommendation as Environmental Condition 21 to this order. The EA also includes the results of an air dispersion modeling analysis for operating the project. The modeling analysis included other sources of emissions within 54 kilometers (33.5 miles) of the terminal and presents impacts from the terminal outer fence line to 25 kilometers (15.5 miles) away. This distance adequately covered the entire zip code 20657 and beyond. The modeling demonstrates that impacts from the terminal, marine vessels, and other nearby sources will be below the primary and secondary NAAQS at all locations.[152] Therefore, we find that the EA adequately considered the air impacts from the project, including sulfates and nitrates, and appropriately concluded it will not result in significant impacts on human health or public welfare.

175. Earthjustice believes that the air modeling results presented in the EA understate the sulfur dioxide and nitrogen dioxide impacts because the results were not rounded to two or three significant digits.[153] We disagree. Earthjustice inappropriately cites an EPA guidance memorandum that is applicable to the calculation and reporting of the emission rates for New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, not the modeled impact values. Rather, EPA guidance indicates that modeled values should not be rounded because the thresholds are considered absolute limits.[154] Therefore, the EA correctly concludes that modeled impacts for the project are below the NAAQS for all pollutants.

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[150] EA at 96.

[151] *Id.* at 109-110.

[152] *Id.* at 113-114.

[153] Earthjustice cites the EPA *Performance Test Calculation Guidance* June 6, 1990.

[154] 53 Fed. Reg. 40,657 (Oct. 17, 1988).

176. A few commenters noted that the EA references ambient air quality monitored from three locations, the closest at 46 miles from the project. Commenters believe that we should require a new monitoring station be established near the LNG Terminal (within 5 miles). Under the Clean Air Act, each state is required to establish a network of air monitoring stations. There are currently no monitors within 5 miles of the LNG Terminal. As part of Dominion's air modeling with marine vessels, it provided sufficient justification for the use of monitors located further from the LNG Terminal. The monitors selected are also within the Washington DC air quality control region and represent similar or more conservative ambient conditions. EPA or MDE may establish additional monitors as needed through their monitoring network programs or air permitting requirements. We also note that MDE has an ozone monitor in Calvert County, about 15 miles from the LNG Terminal.

177. Commenters believe the EA did not adequately address air emissions from the associated LNG vessels and Earthjustice states that the air modeling is missing a second possible LNG vessel and the emissions from LNG vessel transits. LNG vessels within state waters entering the Chesapeake Bay in Virginia to the terminal were evaluated in the EA as part of the General Conformity Applicability and Determination. The EA also presented the emissions from other marine vessels, including tugboats and escort vessels.[155] To cumulatively address impacts associated with the project, the EA presents the results of an air modeling analysis that includes marine vessel emissions in addition to the stationary sources at the terminal. The EA addresses modeling for a "worst-case scenario" and two vessels, stating that the LNG Terminal would average less than one vessel per day, resulting in a low likelihood of two vessels docked at one time.[156] To clarify, based on the emission estimates, the LNG Terminal will average between two and three vessels per week, further supporting the reasonable assumption of one vessel modeled at a time. Also, the modeling conservatively assumes that the one vessel would emit continuously 24 hours a day, 7 days a week, 365 days per year. We find that the EA sufficiently addressed emissions from marine activities.

q. <u>Noise</u>

178. Commenters believe that an EIS is warranted to address the health effects of exposure to the constant noise from operating the project. Further, several commenters state that the proposed 60-foot-tall noise wall is an unproven design and therefore, cannot be relied upon to determine that noise would be effectively mitigated. Commenters also

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[155] EA at 106 and Appendix B.

[156] *Id.* at 113.

disagree with the identification of noise sensitive areas (NSA) and request that an additional NSA be considered to the east of the terminal.

179. The EA states that we have adopted a criterion of 55 decibels on the A-weighted scale (dBA) day-night sound level (L_{dn}) to evaluate noise impacts based on EPA's published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety*.[157] The EA includes a reasonable analysis of the noise impacts, including Dominion's commitment to install a 60-foot-tall sound barrier and additional other noise control measures, and concludes noise levels would be below our criterion. However, recognizing actual noise conditions may vary, the EA recommends, and we have included, Environmental Condition 24 to this order requiring Dominion to demonstrate compliance with this criterion by performing a noise survey of the facilities in operation.

180. The residences located to the east of the LNG Terminal are about 0.9 mile from the noise-producing project equipment. Based on this distance and the significant amount of vegetative buffer between the LNG Terminal and these residences, noise levels are unlikely to exceed our noise criterion. However, because the noise wall does not extend to the east side of the terminal, and the residences are within a distance that could experience noise impacts from the project, we agree that the residences located east of the terminal are considered an NSA. Therefore, we have revised Environmental Condition 24 to this order to require Dominion to include a measurement position at Chesapeake Drive in Lusby, Maryland in its operating noise survey, demonstrating noise levels from operations at the terminal at this location do not exceed our noise criterion.

181. Commenters request that an EIS be performed to address noise impacts along the pipeline. The project does not include any modifications to the existing pipeline or any new pipeline facilities. The EA does address the noise impacts associated with the increased compression at the Pleasant Valley Compressor Station which will be well below our 55 dBA L_{dn} criterion.[158] Environmental Condition 25 requires Dominion to demonstrate compliance with our 55 dBA L_{dn} noise criterion after placing the modifications into service.

182. Commenters believe noise during construction would be significant. Based on the information available in Dominion's application, the EA identifies the noise levels of construction equipment and concludes that most construction activities would be limited

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[157] *Id.* at 117. EPA's document indicates that an Ldn of 55 dBA protects the public from indoor and outdoor activity interference.

[158] *Id.* at 121-123.

to daylight hours thereby leaving nighttime noise levels unaffected.[159] Dominion commented on the EA that it will construct at the terminal and Offsite Area A up to 7 days per week, 24 hours per day. Dominion provided a nighttime construction noise analysis and mitigation plan. In general, results of this analysis demonstrate that noise levels will be within the Maryland noise regulations prior to completion of the 60-foot-tall noise wall, and within the Commission's 55 dBA Ldn criterion after completion of the noise wall. Dominion states the wall will be completed by the second quarter of 2016. Further, the projected noise levels prior to completion of the noise wall are less than three decibels above our criterion, and will not be perceptible compared to our criterion level. The Commission also agrees, as identified in Dominion's noise mitigation plan, that implementation of multiple construction shifts and therefore, nighttime construction, will reduce safety risks to workers and maintain the construction schedule, preventing impacts from occurring for a longer duration.

183. However, we find that the overall nighttime construction noise analysis and mitigation plan lacks specificity for implementation (e.g. height and material of moveable barriers, some measures are identified as "may be used" or "if available"), fails to identify all noise sensitive areas and noise impacts within one half mile of Offsite Area A, is unclear in the number of each type of equipment included in the evaluation of impacts at the terminal and whether the sound levels evaluated included back-up alarms, and does not mention the status of noise levels in the notification procedures. Therefore, we have added Environmental Condition 23 to this order to require a revised nighttime noise construction analysis and mitigation plan prior to any nighttime construction. We conclude that the project, as conditioned herein, will not have a significant impact on the environment.

r. <u>Public Safety</u>

184. A number of organizations and individuals, including Earthjustice and Chesapeake Climate, question Dominion's use of the 2001 edition of the National Fire Protection Association (NFPA) 59A, *Standard for the Production, Storage, and Handling of LNG*, as the basis for its siting analysis and suggest that the 2013 edition of NFPA 59A would be more appropriate. Earthjustice comments that it is not appropriate to discard the more current 2013 edition of NFPA 59A without further demonstration. As stated in the EA, Dominion's facility must comply with the DOT's *Federal Safety Standards for Liquefied Natural Gas Facilities* in 49 C.F.R. Part 193.[160] Those regulations incorporate by reference portions of the 2001 and 2006 edition of NFPA 59A. The 2013 edition of

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[159] *Id.* at 118-119.

[160] *Id.* at 142.

NFPA 59A is not currently part of the federal regulations covering LNG. In order to make it so, the DOT would need to initiate a rulemaking and provide for adequate public notification and comment prior to adopting the 2013 edition into 49 C.F.R. Part 193.

185. We received multiple comments that a quantitative risk assessment, as detailed in Chapter 15 of the 2013 edition of NFPA 59A, should be required as part of any public safety analysis due to the sensitive nature of the Chesapeake Bay area. Commenters stated that a quantitative risk assessment would likely show the proposed liquefaction project would exceed the tolerability threshold selected by the Maryland DNR in its 2006 study on the Cove Point LNG terminal expansion.[161] Earthjustice further comments that, rather than conducting a quantitative risk assessment, as required by the 2013 edition of NFPA 59A, Commission staff only indicated that efforts are underway to develop a quantitative risk assessment method for LNG facility siting.

186. As stated in the EA, there are multiple unresolved issues with the NFPA 59A quantitative risk assessment methodology requiring the establishment of specific assumptions, inputs, databases, and models on which to base such an analysis.[162] Earthjustice recognizes that "(e)stablishing specific assumptions/databases/models on which to base the risk methodology that is compliant with both NFPA 59A and 49 C.F.R. Part 193 is critically important to ensuring that results of quantitative risk assessments are consistent and meaningful…." A quantitative risk-based siting methodology must be able to produce consistent results when used by different parties examining the same installation. Until these issues are resolved, the methods provided for conducting a quantitative risk assessment can be manipulated to achieve widely divergent results, which questions their appropriateness as a siting methodology. In addition, there are no quantified acceptance criteria for acceptable or tolerable risks in the U.S. regulatory framework.[163] Even after issues such as equipment failure frequency and selection of appropriate consequence models are settled, there are no established criteria on which to judge the resulting numerical estimates of risk. As a result, the Commission relies on an assessment of whether the proposed facilities would be able to operate safely and

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[161] Maryland Department of Natural Resources Report: DNR 12-7312006-147; PPRP-CPT -01. "Cove Point LNG Terminal Expansion Project Risk Study." Issued June 28, 2006 and Revised January 14, 2010.

[162] EA at 148.

[163] Although the 2013 edition of NFPA 59A presents individual and societal risk acceptability criteria (Tables 15.10.1 and 15.10.2, respectively), these have not been reviewed and incorporated into the federal regulations on LNG facility siting.

securely and minimize potential public safety impacts.[164] This review is based on a technical review of the facility engineering design, as well as a review of the siting analysis that Dominion must perform in order to comply with the DOT's regulations in 49 C.F.R. Part 193.

187. We received numerous comments that the proposed equipment would be located within a small footprint and that any incident would escalate to a major event. In addition, we received comments that reliance on safety measures such as vapor barriers and gas detectors as being 100 percent effective is not credible. Other comments state that several key issues were not addressed in staff's analysis or the EA. Chesapeake Climate states there were four key scenarios left unaddressed: a 41 percent increase in capacity in Dominion's natural gas pipeline system; loss of containment of propane and LNG; spill duration; and release of nitrosamines into the atmosphere or surface waters.

188. Chesapeake Climate adds the export capacity to Dominion's existing import capacity of 1.8 billion standard cubic feet (BSCF) per day and states that the new capacity of the facility and the associated pipeline has increased by 41 percent. Chesapeake Climate estimates this throughput increase to be associated with a 41 percent increase in the length of the pipeline supplying facility and an increased risk to the population surrounding this pipeline.

189. This is incorrect. Dominion is changing the direction of flow, but is not increasing the pipeline capacity or adding additional transmission pipeline. The compressor station modifications included in this project are to allow the pipeline to provide gas to the facility, but it will be at rates less than 1.8 BSCF per day. Discussion of the existing pipeline is outside the scope of our environmental analysis.

190. Chesapeake Climate states that the presence of four propane tanks and the liquefaction train necessitate an analysis of potential safety impacts at offsite locations using the largest spills possible. Chesapeake Climate comments that fire and explosion hazards from the propane and LNG inventory need to be considered, specifically boiling liquid expanding vapor explosions.

191. We find that these issues were adequately addressed in the EA. Failure scenarios to be used in siting calculations, including propane and LNG, are governed by the DOT's regulations for LNG facilities in 49 C.F.R. Part 193. As discussed in the EA, the spills used to set the consequence distances were developed by Dominion in consultation with the DOT.[165] Dominion analyzed over 400 piping segments, including 160 propane

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[164] EA at 125.

[165] *Id.* at 146.

segments, using failure frequency criteria established by the DOT. From these spills, Dominion modeled flammable vapor dispersion, radiant heat, and overpressure effects. While the final determination on whether this facility complies with Part 193 will be made by the DOT, Commission staff reviewed these calculations in order to estimate whether there would be an impact to public safety from these spills. We agree with the EA's finding on this issue. In addition, we note that the EA addresses the potential for boiling liquid expanding vapor explosions of these propane tanks by describing Dominion's plan to protect them by burial and mounding.[166]

192. Chesapeake Climate comments that the record does not support the limitation of release scenarios to a 10-minute period. We disagree. As discussed above, the selection of release scenarios, including duration, is set by criteria established by the DOT. As allowed by the DOT regulations, this duration is "(f)or 10 minutes or for a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction."[167] As discussed in the EA, the DOT provided Commission staff a letter allowing use of Dominion's release scenarios for establishing the Part 193 siting requirements.[168] The 10 minute duration of the spills was included in the information that Dominion provided to the DOT. In addition, Commission staff has reviewed the engineering design, specifications, instrumentation, hazard detection, and shutdown logic and concludes that the design would have the ability to monitor, shutdown, and isolate equipment and piping as needed.

193. Earthjustice states that additional information in the EA or the docket is needed to address navigation hazards, wind damage, heat exchanger operation, facility security measures, and mercury releases. Earthjustice states that the EA safety analysis only focused on the proposed LNG liquefaction train and ignored the on-site power generation equipment, the mixed refrigerant system, new blowers at the offshore pier, the concrete tunnel for LNG piping,[169] the instrument and plant air system, and ground flares.

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[166] *Id.* at 128.

[167] Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001 edition) as incorporated by reference in 49 C.F.R. § 193.2059 (2014).

[168] EA at 147.

[169] As discussed in the EA, Dominion plans to modify the LNG transfer piping within the concrete-lined tunnel to provide bi-directional loading and unloading of LNG to and from ships. The existing leak monitoring instrumentations and hazard detection devices would detect and isolate an LNG release within the tunnel. Changing the LNG flow direction within the tunnel would not have any impact on public safety.

194. The EA's principal focus in summarizing potential hazards is on facilities that may pose a hazard to the public. Staff reviewed the engineering design, specifications, safety instrumented systems, emergency shutdown systems, hazard detection, hazard control, fire protection, and siting requirements for all proposed equipment including the liquefaction facilities, power generation equipment, the mixed refrigeration system, offshore gas blowers, gas flares, and the plant air system. However, the hazards of such equipment were only discussed to the extent staff determined a potential impact to public safety.

195. Commission staff's review focused on the engineering design and safety concepts of the various protection layers, as well as the projected operational reliability of the proposed facilities.[170] These layers would be independent of one another so each could perform its function of preventing an incident or of mitigating the severity of an incident, regardless of the failure of any other protection layer. As discussed in section 2.8.4 of the EA, these protections include a process design capable of handling the operating conditions, instrumentation to control and monitor the process, hazard detection to alert operators of incidents, hazard control equipment to mitigate a release scenario, spill containment systems to ensure any spill is contained on-site, fire protection to enable equipment to withstand a fire, fire suppression systems to extinguish fires, emergency isolation and shutdown systems, and remotely activated firewater monitors. We find that the EA properly concludes that the inclusion of such protection systems or safeguards in a facility design would minimize the potential for an initiating event to develop into an incident that could impact public safety.

196. Commenters were also concerned that fires from the facility may spread beyond the fence line and could start a forest fire. The closest fire source from an impoundment would be located over 200 feet from the fence line. In addition, a 60-foot-tall concrete sound barrier will be constructed along the fence line and will separate the proposed process areas from the adjacent trees. Therefore, any potential fire at the proposed facilities is likely to be confined to the process areas. In addition, the radiant heat from such fires would not reach levels sufficient to cause surrounding trees to ignite.

197. We received comments on toxic chemicals being stored at the proposed facility. In particular, Earthjustice commented that potential releases of mercury were not addressed in staff's review. The toxic chemicals stored on-site would be stabilized condensate and ammonia. As discussed in the EA, the toxic vapor dispersion distances to a non-disabling and reversible exposure level from stabilized condensate and ammonia releases will remain within Dominion's property.[171] We agree with staff's conclusion in

[170] EA at 132.

[171] *Id.* at 153-154.

the EA that releases of stabilized condensate and ammonia would not present a significant impact to the public.

198. Other toxic components present in the feed gas stream include mercury and hydrogen sulfide (H_2S). As described in the EA, mercury would not pose a hazard to the public since it would be removed in the pre-treatment process via chemical reactions in the Mercury Removal Units.[172] The Mercury Removal Units consist of sulfur beds that react with mercury to form a stable mercuric sulfide compound. At the end of its service life, the spent adsorbent will be shipped by truck to an appropriate recycling plant or disposed of in a hazardous waste disposal facility.

199. We received comments that the EA does not address the release of amines or the formation of nitrosamines and any potential impacts to the atmosphere and water bodies. As discussed in the EA, the amine process used for treating the natural gas coming into the plant will include spill containment systems to prevent leaks entering any surrounding water bodies.[173] The pressure relief valves from the natural gas pretreatment process would not discharge directly into the atmosphere. Furthermore, the amine system is not used to control emissions at the facility.[174] Although the Fresh Amine Storage Tank and the Contaminated Amine Storage Tank may vent to atmosphere, they are located approximately 500 feet away from the closest combustion exhaust stack.

200. We received comments that toxic and flammable chemicals would be trucked to and from the facility. The federal requirements for the transportation of hazardous materials are contained within the DOT's regulations in Title 49 of the Code of Federal Regulations. Within the DOT, the PHMSA and the Federal Motor Carrier Safety Administration are charged with administering the safety aspects of hazardous materials transportation. The PHMSA establishes requirements for packaging, labeling, emergency response, and security for the transportation of hazardous material in the United States. The Federal Motor Carrier Safety Administration establishes driver licensing and qualification requirements and standards for routing either by the motor carrier or by a

[172] *Id.* at 125-126.

[173] *Id.* at 146.

[174] Nitrosamines form by reaction of amines with agents such as nitrogen oxides, a product of combustion. During amine regeneration, the acid gas stream containing carbon dioxide would be directed to the Thermal Oxidizer. Amine would not be present in this acid gas stream nor come into direct contact with nitrogen oxide emissions at the Thermal Oxidizer exhaust stack.

state. Any transportation of hazardous materials would have to comply with the DOT regulations.

201. Earthjustice comments that navigation hazards and potential marine LNG releases caused by submerged obstructions were not addressed in staff's analysis. It also believes that the EA should address the impacts of more significant climate change-induced storms and hurricanes on the LNG ships traveling up and down the Chesapeake Bay. We note that the Commission does not have jurisdiction over LNG maritime transportation. Oversight of LNG transport is performed by the U.S. Coast Guard as part of its responsibilities under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Safety and Accountability for Every Port Act. If related to a proposed project, ship transits associated with the onshore facilities under review by the Commission are discussed as a connected action in staff's NEPA document. Impacts from those LNG ship transits are considered by the Commission in deciding whether to authorize those onshore facilities.

202. However, in this case, the project does not involve larger ships or more frequent ship visits than were previously covered by the Commission's analysis in Dockets CP05-130 and CP09-60 for the Cove Point Expansion Project and Pier Reinforcement Project. As stated in the EA, the U.S. Coast Guard determined that its previous analysis related to the size, frequency, and transit route of LNG carriers, performed for the existing import terminal, was adequate for the LNG carrier traffic associated with proposed project.[175]

203. Any navigational hazards arising from submerged obstructions, flooding, or hurricanes would be addressed during the U.S. Coast Guard's day-to-day oversight of vessel traffic and/or facility control measures for ensuring navigational safety and maritime security.

204. Numerous commenters state that the proposed sound barrier walls are untested as vapor barriers and would not be sufficient to handle potential hazards at the facility. Dominion clarified the design of the wall in filings on June 16 and June 27, 2014. The 60-foot-tall sound barrier would be constructed of concrete and would be 6 inches thick. We find it appropriate to accept that the design will act to retain flammable vapors in the way that Dominion's dispersion modeling indicates. Nonetheless, Environmental Condition 66 requires that further information on the design of the vapor barriers, as well as the procedures used to maintain them for the life of the facility, be submitted to the Commission before any construction will be allowed at the project site. Also as discussed in the EA, the consequence analysis, which did not rely on these walls for

[175] EA at 159.

overpressure protection, indicates that overpressures scenarios initiating from a refrigerant or natural gas liquids release would also remain within Dominion's property.[176]

205. Commenters state that the existing single containment LNG storage tanks are outdated and are a safety hazard to nearby homes in the event of a LNG tank rupture. No new LNG storage tanks would be added to the facility with this project. Nonetheless, we note that the existing LNG storage tanks are subject to the DOT inspection and review under 49 C.F.R. Part 193, as well as Commission staff inspection as a condition of previous Commission authorizations. None of staff's inspections have indicated a safety concern with the current LNG storage tanks.

206. We also received comments asserting that the current evacuation zone is insufficient and that the evacuation route is adjacent to the facility. Dominion's Emergency Response Plan relies on existing local response agencies and evacuation plans. The local emergency management agencies identified in Dominion's Emergency Response Plan include the Calvert County Sheriff's Office, Maryland State Police, Maryland Natural Resources Police, Solomons Volunteer Rescue Squad and Fire Department, Saint Leonard Volunteer Fire Company, Maryland State Fire Marshall's Office, and the Calvert County Emergency Management Division. Depending on the type of emergency, the appropriate organization(s) would be notified and the Calvert County Emergency Management Division would determine if an evacuation or shelter-in-place would be required. As noted in Dominion's filing of June 27, 2014, the Calvert County Department of Public Safety has communicated to Dominion that the evacuation route is adequate.

207. Commenters are also concerned with the capabilities of local first responders to respond to an incident at the Liquefaction Project. The commenters state that first responders are not adequately trained, are under-manned, are not prepared to deal with plant related emergencies, and that no specialized emergency response equipment has been developed or identified.

208. For the existing facility, Dominion has routinely conducted drills with the local emergency management agencies and provides training to the local fire companies. These drills and other tabletop exercises further assist in identifying and addressing any resource gaps and ensure familiarization with the plant layout and emergency response equipment installed within the facility. In addition, on May 8, 2014, the Calvert County Sheriff's Office filed a statement that the Special Operations Team routinely trains at the LNG plant, receives firefighting and hazardous materials response training, and acts as a

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[176] *Id.* at 142.

HAZ-MAT team for Calvert County. Furthermore, Environmental Condition 31 to this order requires Dominion to update its existing Emergency Response Plan to include the Liquefaction Project and Environmental Condition 32 to this order requires Dominion to file a Cost Sharing Plan. Once these plans are provided, Commission staff will look for evidence of consultation and coordination with emergency responders and how any identified resource gaps will be addressed by Dominion.

209. Commenters also state that the facility would be a terrorist target due to its close proximity to the Calvert Cliffs Nuclear Power Plant. As discussed in section 2.8.8 of the EA, Dominion will provide security for the LNG facility as detailed in the Facility Security Plan prepared in accordance with the Coast Guard's regulations in 33 C.F.R. Part 105. The Coast Guard's regulations require a Facility Security Assessment to identify site vulnerabilities, possible security threats and consequences from an intentional act, and to identify the facility's protective measures. Dominion has an existing Facility Security Assessment and Plan that would be updated for the proposed facilities and provided to the Coast Guard for review.

210. Furthermore, commenters also state that hazards originating from the LNG facility could impact the Calvert Cliffs Nuclear Power Plant. The facilities are located approximately 3 miles from each other and have agreed to coordinate in the event of an incident. Dominion's Emergency Response Plan includes provisions for this coordination.

211. Earthjustice states that wind damage from hurricanes and tornadoes was not addressed in staff's analysis. However, we note that the EA specifically discusses the design wind speeds required by the DOT for LNG facilities.[177] During its review as a cooperating agency, the DOT notified Commission staff that the wind speeds Dominion proposed for its design may not meet the federal regulatory requirements. As discussed above, Dominion consulted with the DOT on the design wind speeds to be used at the facility. The DOT has notified Commission staff that Dominion's approach for establishing design wind speeds for the facility complies with the regulatory requirements of 49 C.F.R. Part 193.

212. Earthjustice comments that effects of haze, smoke, or other atmospheric pollutants on the safe operation of the liquefaction heat exchangers was not addressed in staff's analysis. Staff's review included the design of the air cooled heat exchangers and associated piping, which includes instrumentation that monitors and isolates equipment, as well as notifies operators of upset conditions. The facility operators would be able to adjust process conditions as needed to address any atmospheric conditions. Therefore,

[177] *Id.* at 132-133.

any potential atmospheric effects on the heat exchangers would not pose a hazard to the public.

213. Earthjustice states that the security measures that would be used to protect the facility, as well as Offsite Areas A and B, and prevent trespassing were not addressed in staff's analysis. As stated in the EA, Dominion proposes to provide security fencing, monitoring systems, and controlled access procedures to prevent unauthorized access into the LNG Terminal.[178] These features must be in compliance with the DOT's 49 C.F.R. Part 193 subpart J requirements.

214. Furthermore, Dominion was required to obtain Coast Guard approval of the Facility Security Plan covering the existing import facility subject to the Maritime Transportation Security Act of 2002. As described in the EA, the Coast Guard has instructed Dominion that the Facility Security Plan would need to be updated to address any changes to the operations associated with the project and that the Facility Security Plan would need to be submitted to the Coast Guard for approval prior to operation as an export facility.[179]

215. Offsite Areas A and B are laydown areas for equipment storage and would not contain LNG or refrigerants. Such areas are typically not required to be fenced unless they are within 25 feet of a residence, at which point residential site-specific plans with safety fencing must be submitted to the Commission. The closest residential areas to Offsite Areas A and B are 150 feet and 160 feet away, respectively.

216. Earthjustice states that the Commission has not addressed the potential for public exposure to cryogenic materials. We note the EA does address this issue.[180] The EA notes that cryogenic liquid spills would be contained within the spill containment systems. Therefore, the cold temperatures from liquid spills would not present a hazard to the public, who would not have access to on-site areas.

217. Earthjustice states that the Commission has not addressed safety impacts of the project to on-site personnel and contractors. The analysis contained in the EA addresses public safety impacts. Other agencies, such as the Occupational Safety and Health Administration and the DOT address on-site personnel safety.

[178] *Id.* at 134.

[179] *Id.* at 159.

[180] *Id.* at 126-127.

s. Consequence Modeling

218. Earthjustice comments that approval of the proposed project, with appropriate mitigating measures, cannot be based on the conceptual nature of the safety analysis included in the EA. Earthjustice claims that the Commission has not ensured that the level of safety of the project is consistent with the standards for "consequence and health hazards administered by the DOT under 49 U.S.C. Part 193, Chapter 601" and that staff's analysis only addresses single accidental releases rather than multiple equipment failures.

219. The Commission is not responsible for ensuring facility compliance with DOT's regulations. If the facility is constructed and operated, compliance with the requirements of 49 C.F.R. Part 193 would be addressed as part of DOT's inspection and enforcement program. We note however that, as discussed in the EA, Dominion consulted with the DOT on the failure probability of over 400 piping segments and process vessels for the purpose of selecting design spills to show compliance with the DOT's regulations.[181]

220. While Earthjustice recognizes that Dominion considered releases from the mixed refrigerant liquid process system, the propane pre-cool system, and the heavy hydrocarbon removal system at the liquefaction process area, it questions why only design spills that produced the highest release rates were discussed in the EA. The design spills with the highest release rate result in the largest vapor cloud with the greatest potential to impact public safety. For this reason, only these spills were used as inputs in the hazard consequence modeling discussed in the EA.

221. Earthjustice comments that, although hazards from overpressures were addressed in section 2.8.6 of the EA, there was no explanation for why the hazard distances calculated with the Process Hazard Analysis Software Tool (PHAST) model, which extended beyond the property boundary, were discarded in lieu of the Flame Acceleration Simulator (FLACS) modeling of the same scenario. These FLACs results showed the overpressure scenario would not leave the property boundary.

222. FLACS is a computational fluid dynamics model that is able to take into account site-specific geometry (i.e., obstructions and congestion from equipment, piping, tanks, buildings, and vapor barriers). However, that ability increases the computational time needed for simulations. PHAST, which cannot account for the effects of obstructions, requires less computing time but will generally over-predict the hazard area. In cases where a large number of simulations need to be performed, a model such as PHAST can be used to identify scenarios that should be subjected to further intensive modeling incorporating site-specific factors.

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[181] *Id.* at 147-148.

223. Earthjustice states that damaging overpressures and detonations due to the ethane and propane concentrations in the feed gas stream proposed for the facility were not evaluated properly. Earthjustice further comments that the analysis provided in the EA is insufficient as it does not address comingled ethane and propane plumes, but only analyzes releases of propane or ethane individually.

224. Staff's assessment in the EA is based on the review of the feed gas compositions and the pre-treatment system design limitations provided by Dominion in Resource Report 13. The expectant feed gas compositions would consist of lower ethane and propane concentrations than specified in the U.S. Coast Guard tests referenced in the EA.[182] Dominion's liquefaction process would consist of a mixed refrigerant stream that would consist of significantly higher concentrations of ethane and propane compared to those in the feed gas stream. A release from a mixed refrigerant piping would result in a comingled vapor cloud consisting of methane, ethane, and propane. The mixed refrigerant related overpressure modeling for this stream was discussed in section 2.8.6 of the EA.

t. <u>Indirect Impacts</u>

225. Commenters state that the EA fails to address potentially significant indirect impacts of the project. Specifically, commenters state that the EA fails to consider the indirect effects of induced natural gas production in the Marcellus shale region in response to demand from Dominion's export customers. Earthjustice contends that increased natural gas production to meet the demand of the Cove Point Liquefaction Project customers "is fairly understood as indirectly caused by the project," and that consequently the environmental effects of that development must be considered in the EA.[183]

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[182] *Id.* at 129 and 154.

[183] Earthjustice June 16, 2014 Comments at 30 (citing *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).

226. The EA notes that commenters on Dominion's application contend that the export of natural gas will spur the development of natural gas derived from shale formations and, therefore, the environmental impacts associated with gas development should be included in the environmental review of the project.[184] The EA explains that the potential impacts of Marcellus shale region drilling activities are not sufficiently causally related to this project to warrant consideration of those impacts.[185] Further, the EA explains that natural gas may be sourced for export from various locations using various methods and that consequently, the impacts associated with production of natural gas are not reasonably foreseeable or quantifiable.[186]

227. The Council on Environmental Quality's (CEQ) NEPA regulations require agencies to consider the indirect impacts of proposed actions. Indirect impacts are "caused by the proposed action" and occur later in time or farther removed in distance than direct project impacts, but are still "reasonably foreseeable."[187] 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.[188] For an agency to include consideration of an impact in its NEPA analysis as an indirect effect, approval of the proposed project and the related secondary effect must be causally related, i.e., the agency action and the effect must be "two links of a single chain."[189]

228. Potential environmental effects associated with Marcellus shale region production are not sufficiently causally related to the Cove Point Liquefaction Project to warrant detailed analysis as indirect impacts.[190] Marcellus shale production is not an essential

[184] EA at 24.

[185] *Id.* at 163.

[186] *Id.* at 25.

[187] 40 C.F.R. § 1508.8(b) (2014).

[188] *Id.*

[189] *Sylvester v. U.S. Army Corps of Engineers*, 884 F.2d 394 (9th Cir. 1980).

[190] The Commission has been upheld in finding that it need not consider the environmental impacts of Marcellus shale region production when authorizing projects that may (or may not) make use of such supplies. *Central NewYork Oil and Gas Co., LLC*, 137 FERC ¶ 61,121, at PP 81-101 (2011), *order on reh'g*, 138 FERC ¶ 61,104, at PP 33-49 (2012), *petition for review dismissed, sub nom., Coalition for Responsible*

(continued ...)

predicate for the Cove Point Liquefaction Project, which can receive natural gas through interconnects with three interstate natural gas pipeline systems. Further, development of the Marcellus shale region will likely continue regardless of whether the Cove Point Liquefaction Project is approved.

229. The cases cited by Earthjustice to support its argument are not applicable here. The environmental impacts at issue in the cases, including impacts of development spurred by a new federal highway project, construction of a new airport, and emissions caused by new electricity generation made possible by a new transmission line, are effects that, unlike here, would not have occurred had the specific federal authorizations not been granted. Natural gas development, including development of the Marcellus shale region, will continue and indeed is continuing, with or without the Cove Point Liquefaction Project, because multiple existing and proposed transportation alternatives for production from the region are available. Thus, there is an insufficient causal link between the proposed project and additional development of the Marcellus shale region for such development to be considered an indirect impact under NEPA and CEQ's regulations.

230. Moreover, even if such a causal relationship were shown, the scope of the impacts from any such induced production is not reasonably foreseeable as contemplated by CEQ's regulations and case law. An 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."[191] Courts have noted the starting point of any NEPA analysis is a "rule of reason," under which NEPA documents "need not address remote and highly speculative consequences."[192] While courts have held that NEPA requires "reasonable forecasting," an agency is not required "to engage in speculative analysis" or "to do the impractical, if not enough information is available to permit meaningful consideration."[193]

231. As the Commission has consistently found under the circumstances presented to date, impacts from additional shale gas development supported by LNG export projects

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Growth, et al. v. FERC, 485 Fed. Appx. 472, 2012 WL 1596341 (2nd Cir., Apr. 17, 2012) (unpublished opinion).

[191] *Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992).

[192] *Hammond v. Norton*, 370 F.Supp.2d 226, 245-46 (D.D.C. 2005).

[193] *N. Plains Res. Council v. Surface Transp. Board.*, 668 F.3d 1067, 1078 (9th Cir. 2011).

are not reasonably foreseeable within the meaning of the CEQ regulations.[194] While it is axiomatic that natural gas exports require natural gas supplies, the source of the gas to be exported via any individual project is speculative and would likely change throughout the operation of the project. The Cove Point Liquefaction Project will receive natural gas through the Cove Point Pipeline, which, as described above, will interconnect with three interstate natural gas pipeline systems. Those interstate pipelines cross multiple shale-gas, as well as conventional-gas, plays and through their interconnections with still other pipeline systems effectively provide access to essentially all of the production areas in the lower-forty-eight states. Thus, assessing where the gas processed by the project will originate, much less where the wells, gathering line locations and the potential associated environmental impacts will occur, would require significant speculation. Accordingly, the level of analysis commenters seek would require the Commission to engage in speculative analysis that would not provide meaningful information to inform our decision here.[195]

232. Earthjustice asserts that a portion of the natural gas used by the project will likely come from the Marcellus shale region. In support, Earthjustice notes that in December 2013, Cabot Oil & Gas Corporation reported it had executed a gas sale and purchase agreement with one of Dominion's export customers, Pacific Summit.[196] Earthjustice states that under the contract, Cabot has agreed to sell Pacific Summit 240,000 million British thermal units per day of natural gas from Marcellus shale region supplies for a term of 20 years, commencing on the in-service date of Dominion's export terminal. Earthjustice asserts that Cabot's wells are clustered in and near Susquehanna County, Pennsylvania and states that it is virtually certain that Cabot's gas for the project will come from its holdings in this area. Earthjustice further asserts that because Cabot's contract with Pacific Summit is a significant commitment above its current customer

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[194] *Sabine Pass Liquefaction, LLC*, 139 FERC ¶ 61,039 at PP 94-99, *order on reh'g*, 140 FERC ¶ 61,076 at PP 8-22; *Cheniere Creole Trail Pipeline, L.P.*, 145 FERC ¶ 61,074, at PP 51-60, *order on reh'g*, 145 FERC ¶ 61,074, at PP 8-19 (2013).

[195] *See Habitat Education Center v. U.S. Forest Service*, 609 F.3d 897 (7th Cir. 2010) (an environmental impact would be considered too speculative for inclusion in the NEPA document if at the time the document is drafted the impact cannot be described with sufficient specificity to make its consideration useful to a reasoned decision maker).

[196] Earthjustice June 16, 2014 Comments at 34 (citing 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 Journal, *available at* http://online.wsj.com/article/PR-CO-20131219-905979.html).

commitments, it is reasonably foreseeable that Cabot will need to drill additional wells to meet the contract with Pacific Summit.

233. We disagree that the information cited by Earthjustice provides a level of certainty sufficient to support a meaningful analysis of any impacts of increased natural gas production. Pacific Summit's purchase and sale agreement with Cabot has not been submitted as part of the record in the proceeding, and therefore nothing in the record indicates where gas will originate over the contract's 20 year period. However, Cabot's press release announcing its agreement with Pacific Summit suggests that it intends to use Marcellus shale region supplies. Assuming *arguendo* that this is so, the record in this case still lacks sufficient specificity for a meaningful analysis of potential impacts from production. The Commission has found the impacts of production to be beyond the scope of our review, even when particular producers were known to be shippers on the proposed pipeline.[197] The tie between Dominion's customers' gas supplier and the project is more attenuated than in those cases where the producer was a customer of a pipeline project. Moreover, knowing the identity of a supplier, and even the area where its existing wells are located, does not alter the fact that the number, location, and impacts associated with any additional production that producer may engage in to supply Dominion's customers are matters of speculation.

234. In further support of its contention that induced production is reasonably foreseeable, Earthjustice points to a U.S. Energy Information Administration (EIA) 2012 report that estimates about 60 to 70 percent of increases in natural gas exports will be satisfied by increased natural gas production with the remaining portion supplied by natural gas that would have been consumed domestically.[198] Earthjustice asserts that the specific details of potential future production are not necessary for the Commission to analyze the impacts of induced production using tools referenced in the EIA report.

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[197] *See*, *Texas Eastern Transmission, LP*, 139 FERC ¶ 61,138, at PP 70-73, *order on reh'g*, 141 FERC ¶ 61,043, at PP 37-41 (2012); *Tennessee Gas Pipeline Co., L.L.C.*, 139 FERC ¶ 61,161, at PP 178-200, *order on reh'g*, 142 FERC ¶ 61,025, at PP 72-87 (2012), *rev'd on other grounds, Delaware River Keepers Network v. FERC*, Case No. 13-1015 (D.C. Cir., June 6, 2014); *Transcontinental Gas Pipe Line Co., LLC*, 141 FERC ¶ 61,091, at P 127-141 (2012), *order on reh'g*, 143 FERC ¶ 61,132, at PP 49-60 (2013).

[198] Earthjustice June 16, 2014 Comments at 32 (citing 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_lng.pdf).

235. The EIA report includes the caveat that projections involving energy markets are highly uncertain and "subject to many events that cannot be foreseen."[199] Accordingly, we find that using the modeling tools referenced in the EIA report, such as the National Energy Modeling System, to predict potential impacts based on a snapshot of market conditions at a particular time is not meaningful for our analysis. Even if the report did not include a disclaimer about the foreseeability of future events impacting the analysis of impacts associated with increased production generally, the report makes no findings with regard to induced production caused by the specific project before us.

236. In addition, some commenters note that the Office of Fossil Energy of the DOE has issued for public comment a "Draft Addendum" related to unconventional gas production for use in its environmental review of LNG exports.[200] While the DOE Draft Addendum provides certain general estimates about the environmental impacts associated with natural gas production, those impacts have no particular relationship to Dominion's proposal. In its notice of the Draft Addendum, DOE itself explained:

> By including this discussion of natural gas production activities, DOE is going beyond what NEPA requires. While DOE has made broad projections about the types of resources from which additional production may come, DOE cannot meaningfully estimate where, when, or by what method any additional natural gas would be produced. Therefore, DOE cannot meaningfully analyze the specific environmental impacts of such production, which are nearly all local or regional in nature.[201]

237. This reasoning, of course, is consistent with the established Commission policy summarized above. The existence of the DOE Draft Addendum, and future comments on it, provide no basis to alter the conclusions of the EA or to delay the Commission's order here.

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[199] EIA Export Study at 3.

[200] *See* "Notice of Availability of Draft Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States," issued May 29, 2014, available on the DOE website at: http://energy.gov/fe/draft-addendum-environmental-review-documents-concerning-exports-natural-gas-united-states.

[201] *Id.* at 4.

u. Cumulative Impacts

238. Earthjustice and others contend that the EA failed to adequately analyze cumulative impacts of projects related to natural gas development and gathering, including Marcellus shale development, natural gas transportation, and natural gas distribution in areas that are outside of the proposed project area.

239. We disagree. Cumulative impacts are defined by CEQ as the "impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions."[202] A cumulative impacts analysis may require an analysis of actions unrelated to the proposed project if they occur *in the project area being analyzed*.[203] CEQ states that "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."[204] An agency is only required to include "such information as appears to be reasonably necessary under the circumstances for evaluation of the project rather than to be so all-encompassing in scope that the task of preparing it would become either fruitless or well nigh impossible."[205]

240. The EA explains that cumulative impacts can result from the construction of other projects in the same vicinity and impacting the same resource areas as the proposed facilities. In such a situation, although the impacts associated with each project might be minor, the cumulative impact resulting from all projects being constructed in the same general area could be greater.[206]

241. Thus, the cumulative impacts analysis in the EA evaluates other projects in the vicinity of the proposed project that affect the same resources in the same approximate time frame. The EA considered several such projects including a proposed addition to the Calvert Cliffs Nuclear Power Plant, road and bridge upgrades and improvements, residential development, and sewer system construction.[207] The EA evaluated the

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[202] 40 C.F.R. § 1508.7 (2014).

[203] CEQ Guidance, *Considering Cumulative Effects Under the National Environmental Policy Act*, (January 1997).

[204] *Id.* at 8.

[205] *New York Natural Res. Def. Council, Inc. v. Kleppe*, 429 U.S. 1307, 1311 (1976) (citing *Natural Res. Def. Council v. Calloway*, 524 F.2d 79, 88 (2d. Cir. 1975)).

[206] EA at 159.

[207] *Id.* at 160-163.

potential cumulative impacts of those projects on geology and soils; waterbodies and wetlands; vegetation and wildlife; land use, recreation, and visual resources; socioeconomics; cultural resources; air quality and noise; climate changes; and safety. The EA concluded that the adverse cumulative impacts that could occur in conjunction with the project would be temporary and minor, and that, overall, the project would not result in significant cumulative impacts.

242. The EA notes that we received comments suggesting that we analyze the cumulative impacts of projects related to natural gas development and gathering, including Marcellus shale development, natural gas transportation, and natural gas distribution in areas that are outside of the proposed project area.[208] The EA explains that a specific analysis of Marcellus shale upstream facilities is outside the scope of this analysis because the exact location, scale, and timing of future facilities are unknown. The EA notes that the specific details, including the timing, location, and number of additional production wells that may or may not be drilled, are speculative.[209] As discussed above, the scope of any impacts associated with upstream production and transportation are not "reasonably foreseeable."[210] Therefore, such impacts are not within the appropriate scope of our cumulative impacts analysis; instead, we find that the EA adequately addressed potential cumulative impacts of the proposed project.

v. Climate Change

243. Commenters state that the EA does not adequately analyze direct, cumulative, and indirect impacts on climate change from GHG emissions. The GHG emissions associated with the construction and operation of the project were identified and quantified in section 2.7.1 of the EA.[211] However, with respect to impacts related to

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[208] *Id.* at 163. The EA noted that the use of process fuel gas would yield substantial GHG emission reductions for a facility of this size and that the use of low carbon containing fuels (natural gas and process fuel gas) would also minimize GHG emissions. *Id.* at 170. The EA states that the total annual potential emissions for the project would increase energy-related carbon dioxide emissions in Maryland by approximately 2.6 percent based on 2010 emissions for Maryland. *Id.*

[209] *Id.* at 25.

[210] *See also Medina Cnty. Envtl. Action Ass'n v. Surface Transp. Bd.*, 602 F.3d 687, 702 (5th Cir. 2010) ("Our case law shows that even the broader 'reasonably foreseeable' standard requires a substantial degree of certainty before a cumulative impacts analysis will be required.").

[211] EA at 95-116.

climate change, the EA explains that there is no standard methodology to determine how a project's incremental contribution to GHG emissions would result in physical effects on the environment, either locally or globally.

244. Several commenters contend that the EA's use of the global warming potential (GWP)[212] in the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report of 25 for methane over a 100-year period in its analysis of GHG emissions associated with the construction and operation of the project is improper because the IPCC has published its Fifth Assessment Report estimating this value to be 36 over a 100-year period and 86 over a 20-year period. Specifically, Earthjustice believes the use of the 100-year period is inappropriate given the importance of timely action with regard to climate change.

245. When the EA was issued, the EPA-accepted GWP value for methane was 25 over a 100-year period. The EA relied on this value over other published GWPs and timeframes because this is the value EPA established on November 29, 2013, for reporting GHG emissions.[213] Similarly, in this final rulemaking, EPA supported the adoption of the published IPCC Fourth Assessment Report GWP values over the Fifth Assessment Report values. We therefore find the EA's use of the EPA-accepted GWP value for methane to be reasonable. We will ensure that Commission staff request the use of any revised EPA GWP values in future NEPA evaluations.

246. The EA explains that there is no standard methodology to determine how a project's incremental contribution to GHGs would result in physical effects on the environment, either locally or globally. We agree with the EA's determination that because we cannot determine the project's incremental physical impacts on climate change, it is not possible to determine whether or not the project's contribution to cumulative impacts on climate change will be significant.[214] We also received comments

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[212] The global warming potential is a ratio relative to carbon dioxide that is based on the properties of the GHG's ability to absorb solar radiation as well as the residence time within the atmosphere. *Id.* at 98.

[213] EPA supported the 100-year time period over the 20-year period in its summary of comments and responses in the final rulemaking, *2013 Revisions to the Greenhouse Gas Reporting Rule and Final Confidentiality Determinations for New or Substantially Revised Data Elements*, establishing the methane GWP at 25. 78 Fed. Reg. 71,904 (November 29, 2013).

[214] Patuxent Riverkeeper asked the Commission to analyze the impact of the proposed project's greenhouse gas emissions using the social cost of carbon protocol citing a recent court decision cautioning that although NEPA does not require an explicit

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that the EA fails to consider upstream and downstream emissions of GHG pollutants and that the Commission should consider the DOE's recent reports on this topic, including the Draft Addendum discussed above.[215] As discussed above, the future development of upstream production is speculative and not reasonably foreseeable. Upstream production is therefore outside the scope of our environmental analysis. The same principle holds true for potential downstream GHG emissions. As described above, the EA considered air emissions, including GHG emissions, attributable to the construction and operation of the project. We had no cause to attempt to assess air emissions, or the climate change impacts of such emissions, from the ultimate consumption of gas exported from the Cove Point LNG Project because the end use is not part of the project before us. We therefore find that the DOE's life cycle reports and comments we received regarding the reports are not informative to our decision making here.

247. The EPA and Earthjustice request that the EA address the measures in place to protect the proposed facilities from future climate change impacts. The EA identifies the potential climate change impacts most likely to affect the facilities would be from increased sea level rise and storm surge. Further, the EA states that the project facilities would be constructed at sufficient elevation to avoid conflict with future projected sea level rise and storm surge.

248. Finally, commenters believe that the project would have significant fugitive emissions of methane due to leaks along the pipeline route and at the LNG Terminal and state that the EA did not quantify these emissions. The emissions associated with leaking components from the Liquefaction Project and Pleasant Valley Compressor Station are provided in tables 2.7.1-6 and 2.7.1-7 of the EA, respectively. As shown in those tables,

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cost-benefit analysis, where such an analysis is included it cannot be misleading. *High Country Conservation Advocates, et al. v. United States Forest Service, et al*. No. 13-cv-01723-RBJ, 2014 WL 2922751 (D. Colo. June 27, 2014). There, the court stated that "[e]ven though NEPA does not require a cost-benefit analysis, it was nonetheless arbitrary and capricious to quantify the benefits of the lease modification and then explain that a similar analysis of the costs was impossible when such an analysis was in fact possible and was included in an earlier draft EIS." Our environmental analysis did not attempt to quantify anticipated benefits of project approval while excluding potential costs from a cost-benefit analysis. We therefore find that an assessment of the social cost of carbon would not be useful for our analysis.

[215] After issuance of the EA, the DOE prepared two documents, *Life Cycle Greenhouse Gas Perspective on Exporting LNG from the U.S* and *Draft Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the U.S*, which were released for comment on May, 29, 2014.

the emissions associated with leakage will be minimal. In addition, the project does not include any modifications or new installation of pipeline that will result in additional fugitive emissions along a pipeline.

w. Segmentation

249. Commenters assert that the EA inappropriately segmented the review of upstream pipeline infrastructure that may be used to transport gas supplies to the Cove Point Liquefaction Project. Improper segmentation of a project occurs when interrelated projects are artificially divided into smaller, less significant components in order to avoid comprehensive environmental review. NEPA and its implementing regulations direct federal agencies to consider whether proposed actions are "[c]onnected actions, which means that they are closely related and therefore should be discussed in the same impact statement."[216] The regulations provide that actions are "connected" if they:

> Automatically trigger other actions which may require environmental impact statements.
>
> Cannot or will not proceed unless other actions are taken previously or simultaneously.
>
> Are interdependent parts of a larger action and depend on the larger action for their justification.[217]

250. The purpose of the connected action requirement is "to prevent agencies from engaging in segmentation . . . by breaking up one project into smaller projects and not studying the overall impacts of the single overall project."[218] Courts typically employ an "independent utility" test when determining whether actions are "connected." This test "asks whether each project would have taken place in the other's absence. If so, they have independent utility and are not considered connected actions."[219]

251. Commenters note that Cabot has entered into a precedent agreement to be an anchor shipper on the proposed "Atlantic Sunrise Project" proposed by Transcontinental

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[216] 40 C.F.R. § 1508.25(a)(1) (2014).

[217] *Id.*

[218] *Webster v. U.S. Dep't of Agric.*, 685 F.3d 411, 426 (4th Cir. 2012).

[219] *See, e.g., id.*; *Wilderness Workshop*, 531 F.3d 1220, 229 (10th Cir. 2008); *Great Basin Mine Watch v. Hankins*, 456 F.3d 955, 969 (9th Cir. 2006).

Gas Pipe Line Co. (Transco) to connect gas supplies in northeastern Pennsylvania to various demand centers on the Atlantic Seaboard.[220] However, we note that Cabot has announced that it will use its Atlantic Sunrise Project capacity not only to deliver the contracted volumes for Pacific Summit to Cove Point, but also to deliver an even larger quantity (500,000 MMBtu per day) to Washington Gas Light, the Washington, DC-area local distribution company.[221] Moreover, Cabot is just one of nine announced shippers for the Atlantic Sunrise Project, which includes facilities to transport gas as far south as Alabama.

252. Regardless of Cabot's participation, neither the Atlantic Sunrise Project nor any other upstream transportation project is a "connected action" here within the meaning of NEPA. The Cove Point Liquefaction Project is in no way connected with, or dependent upon, the Atlantic Sunrise Project, or any other upstream transportation project. The Cove Point Liquefaction Project can go forward regardless of whether the Atlantic Sunrise Project or any other upstream pipeline project is authorized by the Commission. Furthermore, the Atlantic Sunrise Project, which is intended to serve purposes that are independent of Dominion's plans, is not yet fully developed enough for the Commission to consider it in its EA in this case: Transco has yet to file an application for the project. Of course, the Atlantic Sunrise Project would be subject to full Commission scrutiny, including NEPA analysis, and its own Commission order before it could be constructed.

253. Other commenters raise segmentation "connected action" claims with respect to a compressor station to be located in Myersville, Maryland, which was authorized by the Commission as part of the Allegheny Storage Project proposed by Dominion's affiliate Dominion Transmission, Inc. (Dominion Transmission).[222] The Allegheny Storage Project significantly predated the Cove Point Liquefaction Project and is not in any way connected with it. The Allegheny Storage Project consists of compression, pipeline, and storage facilities to be located on the Dominion Transmission system in Frederick

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[220] On April 4, 2014, the Commission granted Transco's request to use the Commission's pre-filing process for its Atlantic Sunrise Project in Docket No. PF14-8.

[221] *See* "Cabot Oil & Gas Corporation Announces New Agreements for Long-Term Sales and Pipeline Takeaway Capacity," Feb. 20, 2014, *available at*: http://www.prnewswire.com/news-releases/cabot-oil--gas- corporation-announces-new-agreements-for-long-term-sales-and-pipeline-takeaway-capacity-246409701.html.

[222] That project was certificated at *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240 (2012), *order on reh'g*, 143 FERC ¶ 61,148 (2013), *petition for review pending* in *Myersville Citizens for Rural Community v. FERC*, D.C. Cir. Docket No. 13-1219. The project is currently under construction.

County, Maryland; Monroe County, Ohio; Lewis County, West Virginia; and Tioga County, Pennsylvania, including the Myersville Compressor Station— a 16,000 horsepower compressor station in Frederick County, Maryland. The compressor station serves to facilitate the transportation of natural gas on Dominion Transmission for deliveries into the Cove Point Pipeline. Those deliveries, however, are for Washington Gas Light, which has a series of gate stations into its distribution system along the Cove Point Pipeline. The Commission properly rejected claims of a connection between the Cove Point Liquefaction Project and the Allegheny Storage Project when it certificated the latter project, and reaches the same conclusion here.

254. In its December 20, 2012 order certificating the Allegheny Storage Project, the Commission rejected arguments by project opponents that the Myersville Compressor Station was being constructed to support Dominion's LNG exports, stating that "[t]here is no indication in the record that any of the customers that have subscribed to the capacity created by the proposed facilities contemplate using that capacity to export natural gas."[223] In its order denying rehearing on this same point, the Commission explained that it was "not convinced that the Myersville Compressor Station reflects overbuild and that the gas transported by the project will ultimately be exported through the Cove Point LNG Terminal."[224] The Commission added, "[i]n addition to the fact that the capacity associated with the Allegheny Storage Project is fully subscribed, the project proposal stems from a 2007 agreement related to natural gas storage and firm transportation services, and is not associated in any way with the Cove Point LNG Terminal or potential export authority at the terminal."[225]

255. The commenting parties raising the same issue here have offered no new information that changes the Commission's prior analysis. Earthjustice presents an analysis by Mr. Richard Kuprewicz that addresses whether Dominion Transmission's Myersville Compressor Station and related existing downstream mainline pipelines (PL-1, PL-2, and TL485) were designed or positioned to help transport gas to the Cove Point Liquefaction Project for export.[226] Mr. Kuprewicz reviewed non-public Critical Energy Infrastructure Information (CEII) material provided by Dominion in this proceeding, including the project Exhibit G flow diagrams, as well as the FERC Form 567 Annual

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[223] *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240 at n.16 (2012).

[224] *Dominion Transmission, Inc.*, 143 FERC ¶ 61,148 at P 32 (2013).

[225] *Id.* at 33.

[226] Earthjustice August 14, 2014 Comments at 1.

Flow Diagram of both Dominion and Dominion Transmission.[227] Based upon his review of this data, Mr. Kuprewicz believes the evidence strongly suggests a connection between the two projects.[228] Mr. Kuprewicz also claims there is a possibility that the Myersville Compressor Station was needed to achieve the capacity proposed in the Allegheny Storage Project. Mr. Kuprewicz relies on his observations of the design pressures from the flow diagrams in order to support his claims; he has not provided a hydraulic analysis of either the Dominion or Dominion Transmission system. Mr. Kuprewicz acknowledges that additional information is needed to verify his conclusions; however, as discussed in more detail below, the records in the pending proceeding as well as in the Allegheny Storage Project do not support Mr. Kuprewicz's claims.

256. Dominion asserts that the two projects are not linked or connected in any way with each other. Dominion explains that the Myersville Compressor Station was designed to allow for the introduction of gas supplies to the Cove Point Pipeline in order to provide the new contractual obligations for Washington Gas Light to be delivered to multiple gate stations along the Cove Point Pipeline to serve customers in Virginia, Maryland, and Washington, DC.[229] Dominion maintains that the Commission properly rejected the arguments by the opponents of the Allegheny Storage Project that the project was not needed in its December 20, 2012 Order certificating the project.[230]

257. Commission staff has reviewed all the information provided by Dominion Transmission in the Allegheny Storage Project and by Dominion in the Cove Point Liquefaction Project, paying particular attention to the design constraints within each hydraulic model used by the companies for each proceeding. Based upon our review of the information, the Commission concludes that, contrary to Earthjustice's claims, Dominion and Dominion Transmission have designed each project as a separate or unlinked project. When evaluating the need for the Myersville Compressor Station in the Allegheny Storage Project, Commission staff paid close attention to the design/operating conditions that each compressor unit would encounter under design Peak Day conditions. For example, the Commission staff reviewed pressure losses and gas velocities along Dominion Transmission's system downstream of the proposed Myersville Compressor

[227] 18 C.F.R. § 260.8 (2014).

[228] Earthjustice August 14, 2014 Comments at 3.

[229] In addition, the Myersville Compressor Station is needed to transport the contractual obligations of Baltimore Gas & Electric Company, the other shipper on the Allegheny Storage Project.

[230] *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240 at P 66.

Station for both the existing and proposed scenarios. In each case, all compressor units were operating within their design constraints and all gas velocities were within Dominion Transmission's design constraints as well. As a result, all design delivery pressures were maintained above their minimum requirement, which is essential to meeting Dominion Transmission's Peak Day market demand to its shippers.

258. In response to Earthjustice's comments, Commission staff has re-confirmed the need for the Allegheny Storage Project's Myersville Compressor Station, independent of Dominion's proposed Cove Point Liquefaction Project. Staff's review of the models shows that without the Myersville Compressor Station, while transporting the Allegheny Storage Project expansion volumes, the inlet pressures to Dominion Transmission's compressor stations (Quantico and Leesburg) located downstream of the proposed Myersville Compressor Station on Dominion Transmission's existing mainline (PL-1, PL-2 and TL485) would be below the minimum operating design requirements. As a result of the minimum design pressures at the downstream compressor stations not being met, the compressor units could potentially shut down and not operate. This would cause the pipeline system to fail to meet both the pre-existing and the proposed Allegheny Storage Project gas transportation requirements simultaneously. Further, without the proposed Myersville Compressor Station, the gas velocities on Dominion Transmission's system would increase and two pipeline segments would approach or exceed Dominion Transmission's upper design limit for gas velocities of 83 feet per second.[231] As a result of this review, the Commission reaffirms its conclusion in the December 20, 2012 Order that the Myersville Compressor Station is required to meet the Allegheny Storage Project obligations to Dominion for further delivery to Washington Gas' multiple gate stations on the Dominion Cove Point Pipeline.

259. The Commission notes that the Myersville Compressor Station will be used to meet peak contractual requirements and will be operated primarily during periods of high demand (operated on an intermittent basis) under a peak day scenario whereby adequate system pressure must be maintained on Dominion Transmission's Line PL-1 mainline system to meet required gas deliveries to customers during the anticipated peak gas demand periods experienced by Dominion Transmission's shippers.[232] It is under these conditions that Dominion Transmission's need and use of the Myersville Compressor Station is required to maintain system operating pressures while providing Washington Gas and Baltimore Gas and Electric their peak day delivery requirements necessary to meet their respective market demand. The Commission is aware that there will be times

[231] Dominion Transmission's response to Question No. 5 of Staff's August 22, 2012 Data Request at 5.

[232] Dominion's Draft EA at 90.

when the horsepower of compression will not be fully utilized. At those times, Dominion Transmission will be able to offer available capacity on its system to provide storage injection service, firm, and interruptible service to different markets. Depending upon the daily nominations, Dominion Transmission may be able to provide additional gas supplies, if nominated, to the Dominion Cove Point Pipeline for liquefaction. This situation is no different than operating conditions on other Commission regulated pipeline facilities.

260. Mr. Kuprewicz also provides comments on the Cove Point Pipeline's ability to reverse flow to allow for the export of LNG. Mr. Kuprewicz makes several observations regarding the design of the compression facilities proposed by Dominion in the Cove Point Liquefaction Project proceeding. Through his examination of the gas flowing pressure labeled on the flow diagrams, Mr. Kuprewicz makes the following observations: (1) the 600 psig pressure in the western portion of the pipeline may be caused by limits from upstream pipelines; and (2) it would appear that Dominion has elected to optimize overall compression at the Pleasant Valley Relay Compressor Station to reduce the required compression requirements within the Cove Point Liquefaction facility. Mr. Kuprewicz states that because the flow diagrams filed by Dominion in this proceeding, the Form 567 Annual Flow Diagrams for both Dominion and Dominion Transmission, and flow diagrams filed by Dominion Transmission in the Allegheny Storage Project were incomplete, there are unanswered questions.

261. The Commission has reviewed the information in the record, such as the Exhibit G Flow Diagrams, and the hydraulic models, of both the Allegheny Storage Project and the Dominion Cove Point Liquefaction Project and concludes that Dominion and Dominion Transmission have provided enough information in both proceedings to allow the Commission to properly evaluate and make an informed and reasoned determination regarding the public convenience and necessity finding for both projects. Although much of the information regarding the proposed projects was incorporated in Dominion's and Dominion Transmission's Exhibit G Flow Diagrams, additional and more specific information was contained in the flow models submitted in both proceedings.[233] This is how the Commission was able to review the operating conditions on the pipeline facilities in order to reach a determination regarding the physical need for facilities.

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[233] Dominion Transmission and Dominion currently use the SynerGEE Gas pipeline simulation software to examine the flow characteristics and pipeline hydraulics. The Commission is currently licensed to use this and another commercially available pipeline simulation software package, Gregg Engineering, in order to review all pipeline related applications before the Commission.

262. Mr. Kuprewicz's concern regarding the receipt pressure of 600 psig is without merit. Although not stated by Dominion, the use of the 600 psig interconnect pressure will provide upstream interconnecting pipelines the ability to effectuate deliveries into the Cove Point Pipeline under widely diverse operating conditions on their respective systems. This will allow the upstream pipelines to maximize deliveries to Dominion's system without the need for additional compression facilities on their respective systems. Based upon Dominion's proposed design, the Pleasant Valley Compressor Station will re-pressurize the gas receipts from multiple pipelines, Dominion Transmission, Columbia Gas Transmission, and Transco, for further transportation on the Cove Point Pipeline with the opportunity to provide peak day gas requirements to Washington Gas and/or the Cove Point plant for liquefaction for export. Thus, we conclude that the 600 psig used as the design inlet pressure into Dominion's facilities is appropriate to allow upstream pipelines greater operational flexibility to transfer gas volumes to Dominion's facilities.

263. Whether the commenting parties' segmentation arguments focus on Dominion Transmission's Myersville Compressor Station, Transco's Atlantic Sunrise Project or any other upstream project, the facts here bear no resemblance to the situation in the recent Tennessee Gas Pipeline case cited by some commenters where multiple pipeline projects were found by the court to be "connected."[234] There, Tennessee proposed, in rapid succession, a series of four projects on a single pipeline facility which the court found, combined, constituted "a complete overhaul and upgrade that was physically, functionally, and financially connected and interdependent."[235] The Court found "a clear physical, functional, and temporal nexus between the projects," where "[t]he end result is a new pipeline that functions as a unified whole thanks to the four interdependent upgrades."[236] That is not the case here. The Cove Point Liquefaction Project is not in any way dependent upon, or physically, functionally, or financially connected with any upstream pipeline project. Therefore, the EA correctly concluded that there was no need to evaluate the effects of any upstream pipeline project.

x. <u>Alternatives</u>

264. Commenters request further review of alternatives, including the no action alternative, and renewable sources of energy such as solar and wind. Commenters also state that building the facility will take focus away from developing renewables and

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[234] *Delaware Riverkeeper Network, et al. v. FERC*, Case No. 13-1015 (D.C. Cir., June 6, 2014).

[235] *Id.*, slip op. at 5.

[236] *Id.* at 6.

transitioning off of fossil fuels. While alternative energy sources could be advanced in the future, it is speculative and beyond the scope of the EA analysis to predict the effect this would have on the use of natural gas for this project. The EA reviews the no action alternative and alternative energy sources and concludes that they will not meet the project objectives.[237] While commenters may disagree with the project purpose, that purpose is to export gas for Dominion's customers; as stated in the EA, the source of the natural gas supply and final uses of the gas are beyond the control of Dominion.[238] As such, we find that the EA properly reviewed available alternatives to the project.

y. Sufficiency of the EA

265. Earthjustice states that the EA does not provide sufficient evidence that the project application included the environmental report information specified by 18 C.F.R. § 380.12. Specifically, Earthjustice requests that the Commission provide the exact location, including the docket accession and page number for several items listed in 18 C.F.R. § 380.12(o)(1)-(5) including: detailed plot plans showing the location of all major components; detailed layouts of the fire protection system; layouts of the hazard detection system; detailed layouts of the spill containment system; and specifications and drawings of the fail-safe shut-off valves for the marine loading area.

266. This information was contained in Resource Report 13 of the application filed on April 1, 2013, as verified by staff prior to the April 12, 2013 Notice of Application issued in accordance with 18 C.F.R. § 157.9. Dominion provided overall plot plans showing the locations of the liquefaction area, pretreatment area, refrigerant and condensate storage area, new LNG loading pump area, marine transfer area, power generation area, and utility area. Resource Report 13 included overall plot plans showing the layout of firewater and foam piping, as well as locations of post indicator valves, hydrants, monitor, deluge valves, and sprinklers. The firewater monitor coverage area plot plan indicated sufficient protection of the major equipment. Dominion also provided the firewater tie-in locations to the existing firewater piping system.

267. The application and Dominion's subsequent filings provided detailed unit plot plans for each area showing fire detectors, flammable gas detectors, low temperature, hydrogen sulfide detector, alarm horn, strobe, and manual fire alarm pull station. Dominion provided a plot plan showing the spill containment system serving potential spills from equipment, as well as the associated impoundment basins, curbing, and trenches. Resource Report 13 also included a list of all shut-off valves and manufacture

[237] EA at 175.

[238] *Id.* at 18.

data and specification. The piping and instrumentation diagrams show locations of fail-safe shut-off valves on the ship loading header and vapor return header.

268. Earthjustice also states that the EA lacks a clear and comprehensive discussion of all the safety and hazard concerns to allow an independent reviewer to confirm staff's conclusion regarding public safety impacts. Earthjustice comments that the Commission should provide clear citations to the record delineating the information used by staff to reach the conclusions contained in the EA. Specifically, Earthjustice states that the Commission must provide a listing of the page numbers and accession numbers for the detailed drawings depicting the proposed equipment, fire protection system, hazard detection system, and spill containment system that staff considered in preparing the EA.

269. We disagree. NEPA documents are intended to be succinct, plain language summaries of the proposed project and associated environmental impacts. The documents are not intended to provide a point-by-point description of staff's review process or to serve as a directory for where information is located in the docket. Staff's conclusions in the EA were based on the engineering information contained in Resource Report 13, as filed in the initial application and supplemented in data responses. This information, which is voluminous and technically complex, spans approximately 11,000 pages, and includes descriptions of the facility equipment, the design basis, process systems, safety instrumentation, security systems, plant layout drawings, piping and instrumentation diagrams, spill containment, fire protection measures, hazard detection equipment, and electrical systems. As is done for all of the Resource Reports required for an application, staff independently reviews and verifies the information provided by the applicant. The EA summarizes staff's review of the material contained in Resource Report 13 but is not intended to provide a detailed roadmap to all of the details in the application.

270. Earthjustice also contends that because many documents regarding facility compliance and operation have yet to be created or provided to the Commission, we cannot make a finding of no significant impact. In support of this argument, Earthjustice provides examples such as the Implementation Plan, the Operations Manual, and the Spill Prevention, Control and Countermeasures Plan (SPCC Plan) as documents necessary prior to any determination of impacts to public safety.

271. The Implementation Plan, as required by Environmental Condition 7, will describe how Dominion will comply with the requirements of this order. It cannot be completed until the Commission has issued a decision on authorizing the facility. The Operations Manual, as required by Environmental Condition 71, will address startup, shutdown, and routine operations of the export facilities. This manual will be based on the final design information Dominion will develop after this order is issued. The SPCC Plan will specify procedures and measures to avoid and minimize potential impacts from fuel and oil spills during project construction. The SPCC Plan is not intended to address process fluids such as LNG and refrigerants during operation of the facility.

272. Notwithstanding the fact that all of this information will need to be provided to the Commission as required by the environmental conditions attached to this order, we find that the information available for use in preparing the EA was sufficient for our analysis of adverse impacts and development of appropriate mitigation measures. Accordingly, we conclude that the record is sufficient to make a "finding of no significant impact" of the project as conditioned.

273. The EA concludes that the project, as mitigated by the measures specified in the EA, does not constitute a major federal action significantly affecting the quality of the human environment.[239] In their comments on the EA, Earthjustice[240] and others contend that the project is a major federal action significantly affecting the quality of the environment for which an environmental impact statement (EIS) is warranted.[241]

274. Though the CEQ regulations do not provide an explicit definition of the term "significant impacts," they do provide that whether a project's impacts on the environment will be considered "significant" depends on both "context" and "intensity."[242] Context means that the "significance of an action must be analyzed in several contexts," including "the affected region, the affected interest, and the locality."[243] With regard to "intensity," the CEQ regulations set forth 10 factors agencies should consider, including: the unique characteristics of the geographic area, the degree to which the effects are highly controversial or highly uncertain or unknown, the degree to which the action may establish a precedent for future actions, whether the action is related to other actions with insignificant but cumulatively significant impacts, and the degree to which the action may adversely affect threatened and endangered species.[244]

275. Commission staff determined that an EA was appropriate in this case because the proposed facilities would be within the footprint of the existing LNG terminal and

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[239] EA at 186.

[240] Commenting on behalf of Chesapeake Climate, EarthReports, Inc. doing business as Patuxent Riverkeeper; Potomac Riverkeeper, Inc.; Shenandoah Riverkeeper; Sierra Club; and Stewards of the Lower Susquehanna, Inc.

[241] Earthjustice June 16, 2014 Comments at 4-29.

[242] 40 C.F.R. § 1508.27 (2014).

[243] *Id.*

[244] 40 C.F.R. § 1508.27(b) (2014).

because the relevant issues that needed to be considered were relatively small in number and well-defined. The impacts listed are discussed in detail above, and we are satisfied that the potential impacts are not significant. The EA concludes, and we agree, that the project would not have a significant impact on the quality of the human environment. Thus, an EIS is not required.

276. As detailed in the EA, the proposed Liquefaction Project will be located on just 59.5 acres within the existing, fenced 131-acre operating industrial area which, in turn, is within the more than 1,000 acres of existing LNG Terminal property. Dominion also will make temporary use of approximately 190 acres of nearby off-site property. The new Virginia Facilities are limited to work at an existing compressor station and two existing metering and regulation sites on Dominion's existing pipeline. The small amount of land involved in the project makes an EA adequate and appropriate to fully consider all environmental issues. Moreover, all previous construction at the LNG Terminal has already been extensively studied for environmental impacts in compliance with NEPA, and previously approved by the Commission.

277. The Commission's reasoning regarding the Sabine Pass LNG export project is on point here. There, the Commission explained: "the staff determined that an EA was appropriate because all the proposed facilities would be within the footprint of the existing LNG terminal, which was previously the subject of an EIS, and the relevant issues that needed to be considered were relatively small in number and well-defined. The EA concludes, and we agree, that the Liquefaction Project would not have a significant impact on the quality of the human environment. Thus, an EIS is not required."[245]

278. The commenters calling for an EIS here emphasize broad national issues of increased gas production and LNG exports. The Commission properly rejected these same general arguments when advanced by the Sierra Club seeking an EIS for the Sabine Pass LNG export project. As the Commission explained there:

> Sierra Club appears to seek a much broader, nationwide review of the costs and benefits of LNG export and its impacts.... This expansive policy proposal is not before the Commission. What is before us is the Liquefaction Project, which will be located entirely within the footprint of the previously approved and currently operating Sabine Pass LNG terminal site. As a result, the project's environmental impacts

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[245] *Sabine Pass Liquefaction, LLC*, 139 FERC ¶ 61,039 at P 46, *order on reh'g*, 140 FERC ¶ 61,076.

> are relatively small in number and well-defined. The fact that Sierra Club disputes the Commission's finding that it cannot, nor is it required to, undertake a comprehensive analysis of LNG exports and their associated potential environmental impacts, does not amount to a 'controversy' requiring the preparation of an EIS.[246]

This holding is equally applicable in the present case.

279. Several individuals reiterated comments received during the environmental scoping and review process indicating that the project is significant because the Cove Point Liquefaction Project would be one of the largest greenhouse gas emitters in Maryland and would contribute to climate change. The EA states that the emissions identified for the project represent the maximum potential to emit with continuous operation, and are not directly comparable to past actual emissions from the LNG Terminal or other regional sources.[247] These other sources report emissions based on their actual operating loads and hours (which may be notably lower than the projected maximum potential to emit). Further, the new Liquefaction Project GHG sources are subject to prevention of significant deterioration permitting and must control the emissions to BACT levels.

280. Finally, some commenters also argue that an EIS is appropriate because the project is "highly controversial," citing 40 C.F.R. § 1508.27(b)(4). As used there, "[t]he term 'controversial' refers to cases where a substantial dispute exists as to the size, nature, or effect of the major federal action rather than to the existence of opposition to a use."[248] There is no such controversy about the Cove Point Liquefaction Project, and the number of individuals or organizations opposing the project cannot create one.

4. <u>Environmental Conclusions</u>

281. We have reviewed the information and analysis contained in the EA regarding the potential environmental effects of the project. Based on our consideration of the analysis

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[246] *Sabine Pass Liquefaction, LLC*, 140 FERC ¶ 61,076 at P 28, *order on reh'g*, 140 FERC ¶ 61,076.

[247] EA at 111.

[248] *Town of Cave Creek v. FAA*, 325 F.3d 320, 331 (D.C. Cir. 2003) (quoting from *Found. For N. Am. Wild Sheep v. U.S. Dep't of Agric.*, 681 F.2d 1172, 1182 (9th Cir. 1982).

in the EA and the discussion above, we conclude that if constructed and operated in accordance with Dominion's application and supplements, and in compliance with the environmental conditions in Appendix A/B to this order, our approval of this proposal would not constitute a major federal action significantly affecting the quality of the human environment.

282. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this authorization. The Commission encourages cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[249]

F. Sufficiency of Evidence on the Record

283. Earthjustice filed a request for a formal hearing to review the environmental impacts and public need for the proposed project. Although our regulations provide for a hearing, neither NGA sections 3, 7, nor our regulations require that such hearings be trial-type evidentiary hearings. When, as is usually the case, the written record provides a sufficient basis for resolving the relevant issues, it is our practice to provide for a "paper hearing."[250] That is the case here. We have reviewed the motions filed by Earthjustice and conclude that all issues of material fact relating to Dominion's proposal are capable of being resolved on the basis of the written record. Therefore, there is no need for a trial-type evidentiary hearing.

[249] *See, e.g., Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988); *National Fuel Gas Supply v. Public Service Commission*, 894 F.2d 571 (2d Cir. 1990); and *Iroquois Gas Transmission System, L.P., et al.*, 52 FERC ¶ 61,091 (1990) and 59 FERC ¶ 61,094 (1992).

[250] *See NE Hub Partners, L.P.*, 83 FERC ¶ 61,043, at 61,192 (1998), *reh'g denied*, 90 FERC ¶ 61,142 (2000); *Pine Needle LNG Co., LLC*, 77 FERC ¶ 61,229, at 61,916 (1996). Moreover, the courts have repeatedly recognized that even where there are disputed issues "[the Commission] need not conduct such a [evidentiary] hearing if they may be adequately resolved on the written record." *Moreau v. FERC*, 982 F.2d 556, 568 (D.C. Cir. 1993). *See also Environmental Action v. FERC*, 996 F.2d 401, 413 (D.C. Cir. 1993); *Alabama Power Co. v. FERC*, 993 F.2d 1557, 1565 (D.C. Cir. 1993).

284. Statoil and Shell LNG requested a technical conference. We conclude that all material facts related to the issues raised by Statoil, Shell LNG, and other parties have been resolved on the basis of the written record, as discussed above. Thus, we find no reason to convene a technical conference in this proceeding.

285. The Commission on its own motion received and made a part of the record in this proceeding all evidence, including the application and exhibits thereto, and all comments submitted, and upon consideration of the record,

The Commission orders:

(A) Dominion's application for authorization under NGA section 3 to construct, modify and operate LNG liquefaction and terminal facilities to export domestically produced natural gas, as detailed in its application, is granted as discussed in the body of this order.

(B) Dominion's application for authorization under NGA section 7 to construct, install, own, operate and maintain facilities associated with the Cove Point Pipeline to transport natural gas to the LNG terminal, as detailed in its application, is granted as discussed in the body of this order.

(C) Dominion shall comply with the environmental conditions contained in Appendix B to this order.

(D) The construction of the proposed facilities shall be completed and made available for service within five years of the date of issuance of this order.

(E) Dominion must file not less than 30 days, or more than 60 days, before the in-service date of the proposed facilities an executed copy of the non-conforming agreements reflecting the non-conforming language and a tariff record identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations.

(F) Dominion must file not less than 30 days, or more than 60 days, before the in-service date of the proposed facilities, all negotiated rate agreements or a tariff record describing the negotiated rate agreements associated with this project.

(G) Dominion's proposed incremental FTS recourse rate is approved.

(H) Dominion must file not less than 30 days, or more than 60 days, before the in-service date of the proposed facilities, actual tariff records implementing the project.

(I) Dominion shall notify the Commission's environmental staff by telephone, e-mail, or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Dominion. Dominion shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

Timely Interventions

Atlanta Gas Light Company and Virginia Natural Gas, Inc. (collectively)
CPV Maryland, LLC
EarthReports, Inc. (dba Patuxent Riverkeeper); Potomac Riverkeeper, Inc.; Shenandoah Riverkeeper; Sierra Club; and Stewards of the Lower Susquehanna, Inc. (collectively) plus request for hearing
Pennsylvania Independent Oil & Gas Association
Independent Oil & Gas Association of West Virginia, Inc.
Myersville Citizens for a Rural Community, Inc.
BP Energy Company++
Public Service Company of North Carolina, Inc.
Shell NA LNG LLC++
Statoil Natural Gas LLC+
Washington Gas Light Company+

\+ Intervention included comments
++ Intervention included protest

Appendix B

Environmental Conditions

1. Dominion shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests) and as identified in the EA, unless modified by this order. Dominion must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);

    b. justify each modification relative to site-specific conditions;

    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

    d. receive approval in writing from the Director of the Office of Energy Projects (OEP) **before using that modification**.

2. For the LNG facilities, the Director of OEP has delegated authority to take all steps necessary to ensure the protection of life, health, property and the environment during construction and operation of the project. This authority shall include:

    a. stop-work authority and authority to cease operation; and

    b. the design and implementation of any additional measures deemed necessary to assure continued compliance with the intent of the conditions of this order.

3. The Director of OEP has delegated authority to take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the project. This authority shall allow:

    a. the modification of conditions of the Order; and

    b. the design and implementation of any additional measures deemed necessary (including stop-work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction

4. **Prior to any construction**, Dominion shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel,

Environmental Inspectors (EI), and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

5. The authorized facility locations shall be as shown in the EA, as supplemented by filed drawings and plans. **As soon as they are available, and before the start of construction**, Dominion shall file with the Secretary any revised detailed drawings or plans at a scale not smaller than 1:6,000 with station positions for all facilities approved by this order. All requests for modifications of environmental conditions of this order or site-specific clearances must be written and must reference locations designated on these drawings or plans.

6. Dominion shall file with the Secretary detailed drawings or plans and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area**.

   This requirement does not apply to extra workspace allowed by our Upland Erosion Control, Revegetation, and Maintenance Plan (Plan) and/or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas such as wetlands.
   Examples of alterations requiring approval include all facility location changes resulting from:

   a. implementation of cultural resources mitigation measures;

   b. implementation of endangered, threatened, or special concern species mitigation measures;

   c. recommendations by state regulatory authorities; and

   d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

7. **Within 60 days of the acceptance of the authorization and before construction begins**, Dominion shall file an Implementation Plan for the review and written approval by the Director of OEP. Dominion must file revisions to the plan as schedules change. The plan shall identify:

   a. how Dominion will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EA, and required by this order;

   b. how Dominion will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to on-site construction and inspection personnel;

   c. the number of EIs assigned for the facility sites, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;

   d. company personnel, including EIs and contractors, who will receive copies of the appropriate materials;

   e. the location and dates of the environmental compliance training and instructions Dominion will give to all personnel involved with construction and restoration (initial and refresher training as the project progresses and personnel change), with the opportunity for OEP staff to participate in the training session(s);

   f. the company personnel (if known) and specific portion of Dominion's organization having responsibility for compliance;

   g. the procedures (including use of contract penalties) Dominion will follow if noncompliance occurs; and

   h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:

      (1) the completion of all required surveys and reports;

      (2) the environmental compliance training of on-site personnel;

      (3) the start of construction; and

      (4) the start and completion of restoration.

8. Dominion shall employ at least two EIs for the project, one for the Cove Point Liquefaction Project and one for the Virginia Facilities. The EIs shall be:

   a. responsible for monitoring and ensuring compliance with all mitigation measures required by this order and other grants, permits, certificates, or other authorizing documents;

   b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 6 above) and any other authorizing document;

   c. empowered to order correction of acts that violate the environmental conditions of this order, and any other authorizing document;

   d. a full-time position, separate from all other activity inspectors;

   e. responsible for documenting compliance with the environmental conditions of this order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

   f. responsible for maintaining status reports.

9. Beginning with the filing of its Implementation Plan, Dominion shall file updated status reports on a **monthly** basis for the project until all construction and restoration activities are complete. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on Dominion's efforts to obtain the necessary federal authorizations;

   b. the construction status of the project sites, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally-sensitive areas;

   c. a listing of all problems encountered and each instance of noncompliance observed by each EI(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

   d. a description of the corrective actions implemented in response to all instances of noncompliance, and their cost;

   e. the effectiveness of all corrective actions implemented;

f. a description of any landowner/resident complaints which may relate to compliance with the requirements of this order, and the measures taken to satisfy their concerns; and

g. copies of any correspondence received by Dominion from other federal, state, or local permitting agencies concerning instances of noncompliance, and Dominion's response.

10. Dominion shall develop and implement an environmental complaint resolution procedure. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the project and restoration of the project facility sites. **Prior to construction**, Dominion shall mail the complaint procedures to each landowner whose property would be adjacent to the project or within 0.5 mile of the project facilities.

a. In its letter to landowners, Dominion shall:

(1) provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

(2) instruct the landowners that if they are not satisfied with the response, they should call Dominion's Hotline; the letter should indicate how soon to expect a response; and

(3) instruct the landowners that if they are still not satisfied with the response from Dominion's Hotline, they should contact the Commission's Dispute Resolution Division Helpline at 877-337-2237 or at ferc.adr@ferc.gov.

b. In addition, Dominion shall include in its monthly status report a copy of a table that contains the following information for each problem/concern:

(1) the identity of the caller and date of the call;

(2) the location of the affected property;

(3) a description of the problem/concern; and

(4) an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

11. Dominion must receive written authorization from the Director of OEP **prior to introducing hazardous fluids into the project facilities**. Instrumentation and

controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

12. Dominion must receive written authorization from the Director of OEP **before placing into service the project facilities**. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with Commission approval and applicable standards, can be expected to operate safely as designed, and the rehabilitation and restoration of the right-of-way and other areas affected by the project are proceeding satisfactorily.

13. **Within 30 days of placing the authorized facilities in service**, Dominion shall file an affirmative statement with the Secretary, certified by a senior company official:

    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

    b. identifying which of the authorization conditions Dominion has complied with or will comply with. This statement shall also identify any areas affected by the project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

14. Dominion shall file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary for review by the Director of OEP:

    a. structure and foundation design drawings and calculations of the Cove Point Liquefaction Project;

    b. foundations and pile design drawings and calculations for all vibratory equipment, including gas turbines, heat recovery steam generators, steam generators, and compressors supported on piles; and

    c. quality control procedures to be used for design and construction.

    In addition, Dominion shall file, in its Implementation Plan, the schedule for producing this information.

15. **Prior to starting any work on the Pleasant Valley Compressor Station**, Dominion shall file the results of the geotechnical investigation, foundation recommendations, project design, and construction details with the Secretary for review by the Director of OEP.

16. Dominion shall file with the Secretary the final Artificial Reef Plan **before implementation of the plan.**

17. **Within 7 days prior to the start of tree clearing in the Fenced Area and Offsite Area A between the dates of April 1 and August 31**, Dominion shall conduct a survey to identify whether any nesting Birds of Conservation Concern (BCC) birds are present in the Fenced Area and Offsite Area A. If nesting BCC birds are identified, Dominion shall avoid tree clearing and other project activities within 50 feet of active nests until young have fledged the nest and vacated the project area, or it is determined by a qualified biologist that the nest has been abandoned. We note that the Fenced Area is defined as the 131-acre area that includes the land-based components of the LNG Terminal.

18. **Prior to commissioning of the Cove Point Liquefaction Project**, Dominion shall file with the Secretary the final landscaping plan, developed in consultation with the Maryland DNR, for the LNG Terminal sound barrier.

19. **Prior to commissioning of the Cove Point Liquefaction Project**, Dominion shall file the final lighting distribution plan for the Cove Point Liquefaction Project, developed in consultation with the Maryland DNR, with the Secretary for review and written approval by the Director of OEP.

20. **Prior to construction**, Dominion shall install protective fencing around the buffer area for site 18CV505 at Offsite Area A.

21. **Prior to construction**, Dominion shall file a revised Fugitive Dust Control Plan with the Secretary for review and written approval by the Director of OEP. The plan shall specify the precautions that Dominion will take to minimize fugitive dust emissions from construction activities and identify additional mitigation measures to control fugitive dust emissions of Total Suspended Particulates, particulate matter less than 10 microns (PM_{10}), and particulate matter less than 2.5. microns ($PM_{2.5}$), including:

    a. identifying how Dominion will implement these measures (e.g., identification of speed limits, usage of speed limit signage, use of gravel at construction entrances to reduce track-out);

    b. clarifying that the EI has the authority to determine if/when water or a palliative needs to be used for dust control; and

    c. clarifying that the EI has the authority to stop work if the contractor does not comply with dust control measures.

22. **Prior to commissioning of the Cove Point Liquefaction Project**, Dominion shall file with the Secretary the specific noise mitigation measures that would be

used on the ground flares and a noise analysis demonstrating that the noise from all of the equipment operated during commissioning (including ground flares) would not exceed a day-night sound level (L_{dn}) of 55 decibels on the A-weighted scale (dBA) at the nearby noise sensitive areas (NSA).

23. **Prior to construction at the Terminal or Offsite Area A during nighttime hours (10:00 pm to 7:00 am)**, Dominion shall file with the Secretary for review and written approval by the Director of OEP, a revised nighttime construction noise analysis and mitigation plan. The revised plan shall include:

    a. clear identification of all NSAs within one half mile of Offsite Area A, the projected noise levels of construction activities at night at the NSAs, and the mitigation measures Dominion commits to implementing at Offsite Area A;

    b. specifications regarding the input parameters that were modeled (particularly the number of each equipment and the consideration of back-up alarms);

    c. details for mitigation measures (e.g. height and material of moveable barriers, when back-up alarms over a spotter are required, the availability of lower-pitched back-up alarm equipment); and

    d. noise information related to construction in the quarterly public newsletter, and clarification identifying who will receive this newsletter.

24. Dominion shall file a full load noise survey at the Cove Point Liquefaction Project with the Secretary **no later than 60 days** after placing the Cove Point Liquefaction Project in service. If a full load condition noise survey is not possible, Dominion shall provide an interim survey at the maximum possible operation **within 60 days** of placing the Cove Point Liquefaction Project in service and file the full load operational survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the LNG Terminal, under interim or full load conditions, exceeds an Ldn of 55 dBA at any nearby NSAs, Dominion shall file a report on what changes are needed and shall install the additional noise controls to meet the **level within 1 year** of the in-service date. Dominion shall confirm compliance with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls.

    In its full load noise survey at the Cove Point Liquefaction Project, Dominion shall establish an additional measurement position representing a noise sensitive area to the east of the LNG Terminal. This position shall be located at the closest residence along Chesapeake Drive in Lusby, Maryland.

25. Dominion shall file noise surveys with the Secretary **no later than 60 days** after placing the modified Pleasant Valley Compressor Station in service. If a full load condition noise survey is not possible, Dominion shall provide an interim survey at the maximum possible horsepower load and provide the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the compressor station, under interim or full horsepower load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, Dominion shall file a report on what changes are needed and should install the additional noise controls to meet the level **within 1 year** of the in-service date. Dominion shall confirm compliance with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls.

Measures 26 to 76 shall apply to the proposed Cove Point Liquefaction Project at Dominion Cove Point's LNG Terminal. Information pertaining to these specific recommendations shall be filed with the Secretary for review and written approval by the Director of OEP either: **prior to initial site preparation**; **prior to construction of final design**; **prior to commissioning**; **prior to introduction of hazardous fluids**; or **prior to commencement of service**, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, should be submitted as critical energy infrastructure information pursuant to 18 C.F.R. § 388.112. *See Critical Energy Infrastructure Information*, Order No. 683, 71 Fed. Reg. 58273 (Oct. 3, 2006), FERC Stats. & Regs. ¶ 31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements, will be subject to public disclosure. All information shall be filed **a minimum of 30 days** before approval to proceed is requested.

26. **Prior to initial site preparation**, Dominion shall provide procedures for controlling access during construction.

27. **Prior to initial site preparation**, Dominion shall file the quality assurance and quality control procedures for construction activities.

28. **Prior to initial site preparation**, Dominion shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.

29. **Prior to initial site preparation**, a technical review of facility design shall be filed that:

a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids, and flammable gases); and

b. demonstrates that these areas are adequately covered by hazard detection devices and indicate how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.

30. **Prior to initial site preparation**, Dominion shall resize the Trucking Area Sump to adequately contain the maximum content of a condensate truck.

31. **Prior to initial site preparation**, Dominion shall file its updated Emergency Response Plan (ERP) to include the Cove Point Liquefaction Project as well as instructions to handle on-site refrigerant and NGL-related emergencies.

32. **Prior to initial site preparation**, Dominion shall file an ERP that includes a Cost-Sharing Plan identifying the mechanisms for funding all project-specific security/emergency management costs that would be imposed on state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base.

33. The **final design** shall include information/revisions pertaining to Dominion's response numbers 3, 19, 21, and 64 of its July 16, 2013 filing, which indicated features to be included or considered in the final design.

34. The **final design** shall include change logs that list and explain any changes made from the Front-End Engineering Design (FEED) provided in Dominion's application and filings. A list of all changes with an explanation for the design alteration shall be provided and all changes shall be clearly indicated on all diagrams and drawings.

35. The **final design** shall provide up-to-date Process Flow Diagrams with heat and material balances and piping and instrumentation designs (P&IDs), which include the following information:

a. equipment tag number, name, size, duty, capacity, and design conditions;

b. equipment insulation type and thickness;

c. valve high pressure side and internal and external vent locations;

d. piping with line number, piping class specification, size, and insulation type and thickness;

e. piping specification breaks and insulation limits;

f. all control and manual valves numbered;

g. relief valves with set points; and

h. drawing revision number and date.

36. The **final design** shall provide P&IDs, specifications, and procedure that clearly show and specify the tie-in details required to safely connect the project to the existing facility.

37. The **final design** shall provide an up-to-date complete equipment list, process and mechanical data sheets, and specifications.

38. The **final design** shall provide complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment. The list shall include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment.

39. The **final design** shall provide complete plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Drawings shall clearly show the location by tag number of all fixed, wheeled, and hand-held extinguishers. The list shall include the equipment tag number, type, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units.

40. The **final design** shall provide facility plans and drawings that show the location of the firewater and foam systems. Drawings shall clearly show: firewater and foam piping; post indicator valves; and the location of, and area covered by, each monitor, hydrant, deluge system, foam system, water-mist system, and sprinkler. The drawings shall also include P&IDs of the firewater and foam system.

41. The **final design** shall include an updated fire protection evaluation of the proposed facilities carried out in accordance with the requirements of National Fire Protection Association (NFPA) 59A 2001, chapter 9.1.2 as required by 49 C.F.R. Part 193. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed.

42. The **final design** shall specify that for hazardous fluids, piping and piping nipples 2 inches or less are consistent with the existing facility's piping specifications.

43. The **final design** shall include drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A.

44. The **final design** shall provide an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that: shall continuously monitor for the presence of a flammable fluid; shall alarm the hazardous condition; and shall shutdown the appropriate systems.

45. The **final design** shall provide electrical area classification drawings.

46. The **final design** shall provide spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments.

47. The **final design** of the hazard detectors shall account for the calibration gas when determining the lower flammability limit (LFL) set points for methane, propane, ethane, and condensate.

48. The **final design** shall include a hazard and operability review of the completed design prior to issuing the P&IDs for construction. A copy of the review, a list of recommendations, and actions taken on the recommendations, shall be filed.

49. The **final design** shall include the cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown (ESD) system. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points.

50. The **final design** shall include a drawing that shows the location of the ESD buttons. ESD buttons shall be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.

51. The **final design** shall include a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice required by 49 C.F.R. Part 193, and shall provide justification if not using an inert or non-flammable gas for cleanout, dry-out, purging, and tightness testing.

52. The **final design** shall include the sizing basis and capacity for the final design of pressure and vacuum relief valves for major process equipment, vessels, and storage tanks.

53. The **final design** shall provide the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3, as required by 49 C.F.R. Part 193.

54. The **final design** shall provide the specifications, procedures, and schedule to modify the tunnel expansion joints.

55. The **final design** shall either set the pressure relief valves at the Mole Sieve Gas Dehydrators to the design pressure of the closed loop system or design the Mole Sieve Gas Dehydrators and the associated hot piping system for the regeneration design temperature and the feed gas design pressure of the pretreatment system.

56. The **final design** shall include double isolation for each sulfur removal vessel. Manual isolation valves shall be installed upstream of the inlet pneumatic valve and downstream of the outlet pneumatic valve with vent and purge connections between the manual and pneumatic valves.

57. The **final design** shall provide coarse mesh strainers in the bottom outlet piping of the adsorbers to prevent support material and molecular sieve migrating from Mole Sieve Gas Dehydrators to the piping system.

58. The **final design** shall provide a redundant low temperature shutdown system for the Flash Gas Compressors. The set point shall be set at no less than -50°F.

59. The **final design** of the Ethane Make-Up Drum and associated piping system shall include stress analysis of the system at the equilibrium temperature of the Ethane at barometric pressure.

60. The **final design** shall provide all tests, investigations, and reports to ensure the existing firewater system's compatibility and reliability.

61. The **final design** shall equip the hydrocarbon removal unit (HRU) Column with permanent drainage piping to the cold flare, designed for cryogenic conditions.

62. The **final design** shall provide drainage piping to the cold flare from the Nitrogen Stripper Reboiler bottom inlet piping and Nitrogen Stripper bottom outlet piping upstream of the shutoff valve.

63. The **final design** shall equip the Stabilizer with permanent drainage piping to the flare system.

64. The **final design** of the refrigerant and stabilized condensate storage system shall provide dual full capacity relief valves that allow the isolation of individual pressure relief valves while providing full relief capacity during pressure relief valve maintenance or testing.

65. Dominion shall certify that the **final design** is consistent with the information provided to the U.S. Department of Transportation (DOT) as described in the design spill determination letter dated February 27, 2014 (Accession Number 20140227-4004) and supplemental information filed by Dominion on March 7, 2014 (Accession Numbers 20140307-5050 and 20140307-5051), March 14, 2014 (Accession Numbers 20140314-5099 and 20140317-5100), and April 11, 2014

(Accession Numbers 20140411-5252 and 20140411-5253). In the event that any modifications to the design alters the candidate design spills on which the Title 49 C.F.R. Part 193 siting analysis was based, Dominion shall consult with DOT on any actions necessary to comply with Part 193.

66. The **final design** shall include the details of the vapor fences as well as procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 C.F.R. § 193.2059.

67. **Prior to commissioning**, Dominion shall file plans and detailed procedures for: testing the integrity of on-site mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service.

68. **Prior to commissioning**, Dominion shall provide a detailed schedule for commissioning through equipment startup. The schedule shall include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids; and during commissioning and startup. Dominion shall file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued.

69. **Prior to commissioning**, Dominion shall tag all equipment, instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.

70. **Prior to commissioning**, Dominion shall file a tabulated list and drawings of the proposed hand-held fire extinguishers. The list shall include the equipment tag number, extinguishing agent type, capacity, number, and location. The drawings shall show the extinguishing agent type, capacity, and tag number of all hand-held fire extinguishers.

71. **Prior to commissioning**, Dominion shall file updates addressing the liquefaction facilities in the operation and maintenance procedures and manuals, as well as safety procedures.

72. **Prior to commissioning**, Dominion shall maintain a detailed training log to demonstrate that operating staff has completed the required training.

73. **Prior to introduction of hazardous fluids**, Dominion shall complete a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s).

74. **Prior to introduction of hazardous fluids**, Dominion shall complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests)

associated with the Distributed Control System and the Safety Instrumented System that demonstrates full functionality and operability of the system.

75. **Prior to commencement of service**, Dominion shall label piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A.

76. **Prior to commencement of service**, progress on the construction of the proposed systems shall be reported in **monthly** reports filed with the Secretary. Details shall include a summary of activities, problems encountered, contractor non-conformance/deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude shall be reported to the Commission **within 24 hours**.

Measures 77 to 79 shall apply throughout the life of the facility:

77. The facility shall be subject to regular Commission staff technical reviews and site inspections on at least an **annual basis** or more frequently as circumstances indicate. Prior to each Commission staff technical review and site inspection, Dominion shall respond to a specific data request, including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted.

78. Semi-annual operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to: unloading/loading/shipping problems, potential hazardous conditions from off-site vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boil-off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" also shall be included in

the semi-annual operational reports. Such information would provide Commission staff with early notice of anticipated future construction/maintenance projects at the LNG facility.

79. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) shall be reported to Commission staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to Commission staff **within 24 hours**. This notification practice shall be incorporated into the LNG facility's emergency plan. Examples of reportable hazardous fluids related incidents include:

a. fire;

b. explosion;

c. estimated property damage of $50,000 or more;

d. death or personal injury necessitating in-patient hospitalization;

e. release of hazardous fluids for 5 minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (MAOP) (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;

i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes hazardous fluids;

l. safety-related incidents to hazardous fluids vessels occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, Commission staff would determine the need for a separate follow-up report or follow-up in the upcoming semi-annual operational report. All company follow-up reports shall include investigation results and recommendations to minimize a reoccurrence of the incident.

Document Content(s)

151 FERC ¶ 61,095
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

Dominion Cove Point LNG, LP Docket No. CP13-113-001

ORDER DENYING REHEARING AND STAY

(Issued May 4, 2015)

1. On September 29, 2014, the Commission authorized Dominion Cove Point LNG, LP (Dominion),[1] pursuant to section 3 of the Natural Gas Act (NGA), to site, construct, and operate facilities for the liquefaction and export of domestically-produced natural gas at Dominion's existing Cove Point liquefied natural gas (LNG) import terminal in Calvert County, Maryland (Cove Point Liquefaction Project).[2] The September 29 Order also authorized Dominion, pursuant to section 7(c) of the NGA, to construct and operate facilities at its existing compressor station and metering and regulating sites in Fairfax County, Virginia and at a metering and regulating site in Loudoun County, Virginia (Virginia Facilities). Allegheny Defense Project and Wild Virginia (jointly, Allegheny); BP Energy Company (BP); and EarthReports, Inc. (dba Patuxent Riverkeeper), Potomac Riverkeeper, Inc., Shenandoah Riverkeeper, Sierra Club, and Stewards of the Lower Susquehanna, Inc. (collectively, EarthReports) filed timely rehearing requests. Allegheny and EarthReports also request a stay. As discussed below, this order denies the requests for rehearing and stay.

Background

2. Dominion owns the existing Cove Point LNG Terminal (Cove Point Terminal) near Lusby, in Calvert County, Maryland, as well as an 88-mile-long natural gas pipeline (Cove Point Pipeline) that extends west from the terminal to connections with interstate

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[1] Dominion Cove Point LNG, LP is a subsidiary of Dominion Resources, Inc.

[2] *Dominion Cove Point LNG, LP*, 148 FERC ¶ 61,244 (2014) (September 29 Order).

pipelines in Loudoun and Fairfax Counties, Virginia. In 1972, the Commission authorized Dominion's predecessor to begin receiving LNG imports at the Cove Point Terminal and transport natural gas through the Cove Point Pipeline.[3] LNG import services were suspended in 1980 and then reactivated in 2001.[4]

3. The September 29 Order authorized Dominion to construct and operate the Cove Point Liquefaction Project and Virginia Facilities. The Cove Point Liquefaction Project adds a liquefaction train with an expected nameplate capacity of up to 5.75 million metric tons per annum of LNG. The liquefaction train contains gas turbine-driven refrigerant compressors, draft air coolers, process vessels, pumps, and heat exchangers for liquefying natural gas. The Virginia Facilities include: (1) four additional electric-driven compressor units at the existing Pleasant Valley Compressor Station; (2) a 1,200-foot-long, 36-inch-diameter replacement discharge pipeline extending from the Pleasant Valley Compressor Station to the existing Pleasant Valley meter and regulating (M&R) site; (3) a 1,200-foot-long, 36-inch-diameter suction pipeline extending from the compressor station to the existing Pleasant Valley M&R site; and (4) miscellaneous pipeline and measurement upgrades at the Pleasant Valley and Loudoun M&R sites.

4. The Cove Point Liquefaction Project, combined with Dominion's existing facilities, will enable Dominion to provide import or export service for Pacific Summit Energy, LLC[5] and a U.S. subsidiary of GAIL (India) Limited,[6] (collectively, the Export

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[3] On June 28, 1972, the Commission authorized Columbia LNG Corporation and Consolidated System LNG Company to construct and operate the Cove Point Terminal and the Cove Point Pipeline. *Columbia LNG Corp.*, Opinion No. 622, 47 FPC 1624 (1972), *aff'd and modified,* Opinion No. 622-A, 48 FPC 723 (1972). Subsequently, the Commission authorized: (1) Consolidated System LNG Company to abandon its undivided one-half interest in the LNG facilities to Columbia LNG Corporation in *Consolidated System LNG Co.*, 42 FERC ¶ 61,078 (1988); and (2) Columbia LNG Corporation to abandon all of its jurisdictional facilities by transfer to Cove Point LNG Limited Partnership in *Cove Point LNG Limited Partnership*, 68 FERC ¶ 61,128 (1994). In 2002, Dominion Resources, Inc. acquired the equity shares of the two companies comprising Cove Point LNG Limited Partnership, and later that year, Cove Point LNG Limited Partnership became Dominion Cove Point LNG, LP.

[4] *See Cove Point LNG Limited Partnership*, 97 FERC ¶ 61,043 (2001).

[5] Pacific Summit is a United States (U.S.) subsidiary of Sumitomo Corporation, a Japanese trading company.

[6] GAIL Limited is the largest natural gas processing and distribution company in India. In an October 30, 2013 filing, Dominion requested that GAIL Global (USA) LNG, LLC (GAIL Global) be used as the identified export customer.

Customers). The Export Customers initially contracted for export service, but may jointly elect once a year to receive import and regasification service or liquefaction and export service.

Late Request for Rehearing

5. On Wednesday, October 29, 2014, at 10:38:59 p.m., Myersville Citizens for a Rural Community Inc. (Myersville) electronically filed a request for rehearing.[7] Because Myersville's rehearing request was filed after 5:00 p.m. Eastern time, the end of the Commission's regular business hours, we consider the rehearing request filed on the next business day, October 30, 2014.[8] Pursuant to section 19(a) of the NGA,[9] an aggrieved party must file a request for rehearing within 30 days after the issuance of a final Commission decision, in this case no later than October 29, 2014. The Commission cannot waive the 30-day statutory deadline for filing requests for rehearing. Consequently, because the rehearing request was filed on October 30th, we will deny Myersville's rehearing request.[10] Nevertheless, Myersville's concerns regarding the adequacy of the environmental analysis are addressed below in our response to the same issues raised by Allegheny and EarthReports.[11]

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[7] On November 3, 2014, Dominion filed a request that the Commission reject Myersville's rehearing request because Dominion claimed the request was late.

[8] *See* 18 C.F.R. § 385.2001(a)(2) (2014) ("Any document received after regular business hours is considered filed on the next regular business day.").

[9] 15 U.S.C. 717r (2012).

[10] *Cameron LNG, LLC*, 148 FERC ¶ 61,237, at P 19 (2014) (citing *Boston Gas Co. v. FERC*, 575 F.2d 975, 978 (1st Cir. 1978)).

[11] Myersville's rehearing request also raised issues about noise and property values. While not addressed further below, these issues were raised previously and were addressed adequately in the Environmental Assessment (sections 2.7.2 and 2.9.8 for noise and section 2.5.5 for property values) and in the September 29 Order (paragraphs 178-183 for noise and paragraphs 146-147 for property values).

Discussion

A. BP's Rehearing Request

6. In 2001, the Commission authorized Dominion's predecessor to construct new facilities and reactivate the existing LNG terminal to recommence LNG imports.[12] BP was one of three customers that contracted for NGA section 7 LNG terminal service under Rate Schedule LTD-1.

7. In 2006, the Commission approved the Cove Point Expansion Project authorizing the expansion of the Cove Point Terminal and Pipeline, as well as the construction of related downstream pipeline and storage facilities.[13] The sole expansion customer, Statoil Natural Gas LLC (Statoil), entered into a non-open access agreement for NGA section 3 terminal service for all of the expanded capacity, and the Commission granted Dominion market-based rate treatment under the policy announced in *Hackberry LNG Terminal, L.L.C.*[14] for the expansion capacity. In addition, Statoil subscribed to jurisdictional service under Rate Schedule FTS for service on the expanded Cove Point Pipeline. Section 30 of the General Terms and Conditions (GT&C) of Dominion's tariff provides that existing customers such as BP, and the expansion customer, Statoil, are to be treated in a not unduly discriminatory manner.

8. To support the Cove Point Liquefaction Project proposed in this proceeding, Dominion held an open season and a reverse open season for transportation capacity on the Cove Point Pipeline in the spring of 2012 and received no requests under either open season. Dominion did not hold an open season for section 3 terminal service.

9. Separately, Dominion and Statoil agreed to an early termination of the non-open access Cove Point Expansion service agreement for Statoil's section 3 terminal service and section 7 Cove Point Pipeline capacity.

10. BP protested Dominion's Cove Point Liquefaction Project application, asserting that Dominion's agreement to offer Statoil the opportunity to turnback or relinquish

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[12] *Cove Point LNG Limited Partnership*, 97 FERC ¶ 61,043.

[13] *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,337 (2006), *order on reh'g*, 118 FERC ¶ 61,007 (2007), *vacated and remanded sub nom. Washington Gas Light Co. v. FERC*, 532 F.3d 928 (D.C. Cir. 2008), *order on remand*, 125 FERC ¶ 61,018 (2008), *order on reh'g and clarification*, 126 FERC ¶ 61,036 (2009), *petition for review denied sub nom. Washington Gas Light Co. v. FERC*, 603 F.3d 55 (D.C. Cir. 2010).

[14] 101 FERC ¶ 61,294 (2002).

Statoil's section 3 terminal service, without offering BP the opportunity to turnback or relinquish its terminal service, constituted unlawful discrimination among similarly situated customers.[15] The September 29 Order found that BP and Statoil were not similarly situated for the purposes of relinquishing terminal service because Statoil was an expansion customer receiving non-open access service under section 3, while BP was a LTD-1 shipper receiving open access terminal service under section 7.

11. On rehearing, BP renews its arguments, contending that BP and Statoil are similarly situated customers because they receive fundamentally the same services, have binding contracts with Dominion, and share the same market risks.[16] BP asserts that the difference in the "regulatory regimes" under which it and Statoil receive service is irrelevant to the issue of whether Dominion granted an undue preference to Statoil.[17] BP also contends that the September 29 Order erred in denying its request that the Commission require revisions to Dominion's tariff to guard against such alleged discrimination.[18]

12. EPAct 2005 amended the NGA to prohibit undue preferences and undue discrimination in the context of LNG terminals providing service under sections 3 and 7 of the NGA, which is the case at the Cove Point Terminal:

> An order issued for an LNG terminal that also offers service to customers on an open access basis shall not result in subsidization of expansion capacity by existing customers, degradation of service to existing customers, or undue discrimination against existing customers as to their terms or conditions of service at the facility, as all of those terms are defined by the Commission.[19]

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[15] BP Rehearing Request at 4. Dominion offered both BP and Statoil the opportunity to relinquish their section 7 pipeline capacity.

[16] BP Rehearing Request at 4.

[17] *Id.* at 12.

[18] *Id.* at 1-5.

[19] 15 U.S.C. § 717b(e)(4) (2012).

13. The September 29 Order explained that not all discrimination is undue, and only similarly situated customers need to be treated similarly.[20] BP notes that in *Columbia Gas Transmission Corp.*, the Commission found that an NGA section 7 pipeline may provide early termination rights to one group of shippers and not to another where the two groups were not similarly situated on account of different risks faced.[21] There, the Commission found no unlawful discrimination between groups where the risk that local distribution companies assumed under their service obligations differed from the risk faced by industrial end users who had not been subject to mandatory unbundling at the state level. Here, BP argues we should find the converse true, that is, that where two companies share a regulatory risk, they are similarly situated. However, different levels of market risk is not the only circumstance that might justify treating two groups of customers as being not similarly situated. Here, notwithstanding BP's assertions to the contrary, the difference in "regulatory regime" between open access and non-open access service is a relevant one. While BP and Statoil may face the same risk that the market for imported natural gas might change, as an open access customer, BP has protections not afforded Statoil. For example, BP has a regulatory right to release all or a portion of its terminal service to another shipper. BP also has regulatory rights regarding retention of its capacity upon expiration of its initial service agreement. The fact that market conditions might render these rights more or less valuable to BP at any given point in time does not negate the fact that they exist. Thus, we reaffirm our finding that section 7 and section 3 terminal services are distinguishable, and conclusion that BP and Statoil are not similarly situated.[22]

14. BP contends that our finding Statoil and BP to be not similarly situated based on the fact that they receive similar service under different regulatory regimes would effectively render the antidiscriminatory provision of NGA section 3 meaningless. We disagree. Indeed, as BP acknowledges, the terminal service that it receives from Dominion is fundamentally the same as that provided to Statoil – Statoil receives no preference in nominating, scheduling, or the quality of the terminal service provided. The Commission approved the implementation of section 30 of the GT&C of Dominion's tariff, which directly addresses the subject of providing service to different classes of

[20] September 29 Order, 148 FERC ¶ 61,244 at P 47 (citing *Associated Gas Distributors v. FERC*, 824 F.2d 981, 1009 (D.C. Cir. 1987), *cert. denied sub nom. Interstate Natural Gas Ass'n v. FERC*, 485 U.S. 1006 (1988); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1139 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984)).

[21] *Columbia Gas Transmission Corp.*, 103 FERC ¶ 61,388, *order on reh'g*, 105 FERC ¶ 61,373 (2003).

[22] September 29 Order, 148 FERC ¶ 61,244 at P 47.

customers at a single facility. The Commission found that section 30 was adequate to prevent undue discrimination, stating, "we are satisfied that there will be no undue discrimination against the existing LTD customers as to their terms and conditions of service in the critical tariff areas, such as nominations, scheduling and operating conditions."[23] Thus, there is no reason to revise Dominion's tariff to address alleged discrimination.

15. The September 29 Order held that the Commission was "not concerned with the fact that in addition to relinquishing section 3 terminal service Statoil also turned back section 7 service on the Cove Point Pipeline because Dominion held an open season providing all shippers an opportunity to turnback this service."[24] BP contends however, that relinquishing Cove Point Pipeline capacity without a corresponding relinquishment of storage and regasification capacity would have rendered BP's existing storage and regasification capacity at the Cove Point Terminal virtually useless. Whether or not it was in BP's business interest to relinquish section 7 service on the Cove Point Pipeline does not alter our observation that Dominion's open season provided all shippers the chance to turn back section 7 service.

16. BP further contends that Dominion provided Statoil with inappropriate preferential treatment in consideration for commercial benefits to Dominion's parent company.[25] BP references a fourth-quarter 2010 earnings call held on January 28, 2011, where the Chief Executive Officer of Dominion's parent company mentioned plans to work with Statoil in the development of infrastructure out of the Marcellus region, when explaining why Statoil was provided with the relinquishment opportunity. BP asserts that this rationale clearly constitutes undue discrimination. As discussed above, Dominion had no obligation to offer BP, an open access section 7 customer, the same opportunity to turn back terminal service that it offered to its customer receiving non-open access section 3 service. As Statoil is Dominion's only current non-open access section 3 customer, there is no reason for the Commission to consider whether Dominion's actions might have constituted discrimination against another such customer for inappropriate reasons.

17. For the reasons discussed above, we affirm our finding in the September 29 Order that BP was not subject to undue discrimination.

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[23] *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,337 at P 108.

[24] *Id.* P 47.

[25] BP Rehearing Request at 7-8.

B. Environmental Issues

1. Environmental Review Background

18. On June 26, 2012, Commission staff granted Dominion's request to use the prefiling process in Docket No. PF12-16-000. On September 24, 2012, the Commission issued a *Notice of Intent to Prepare an Environmental Assessment* (NOI).

19. On April 1, 2013, Dominion filed its application under NGA sections 3 and 7 requesting authorization to site, construct, and operate the Cove Point Liquefaction Project and the Virginia Facilities. Commission staff evaluated the potential environmental impacts of the proposed facilities in an Environmental Assessment (EA) in accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA).[26] The U.S. Department of Energy, Office of Fossil Energy (DOE/FE), U.S. Army Corps of Engineers (Army Corps), U.S. Department of Transportation, U.S. Coast Guard (Coast Guard), and Maryland Department of Natural Resources (Maryland DNR) participated as cooperating agencies in the preparation of the EA.

20. The EA for Dominion's proposed project was placed into the public record on May 15, 2014.[27] All substantive comments received in response to the NOI and during the public scoping process were addressed in the EA.

21. The September 29 Order found that Dominion's proposal was thoroughly analyzed in the EA. The order found that there were no significant direct or indirect impacts and thus concluded that approval of the project would not constitute a major federal action significantly affecting the quality of the human environment and, consistent with the Council on Environmental Quality (CEQ) regulations, no Environmental Impact Statement (EIS) was required.

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[26] 42 U.S.C. §§ 4321 *et seq.* (2012). *See* 18 C.F.R. pt 380 (2014) for the Commission's NEPA-implementing regulations.

[27] The Commission published notice of the EA in the *Federal Register* on May 22, 2014. 79 Fed. Reg. 29,435 (May 22, 2014).

2. Induced Production

22. Allegheny[28] and EarthReports[29] contend that the September 29 Order failed to adequately analyze the indirect and cumulative effects of alleged induced natural gas drilling and hydraulic fracturing activities in the Marcellus and Utica Shale formations and the associated environmental harms.[30]

23. CEQ regulations require agencies to consider the indirect and cumulative impacts of proposed actions. Indirect impacts are "caused by the proposed action" and occur later in time or farther removed in distance than direct project impacts, but are still "reasonably foreseeable."[31] 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.[32] For an agency to include consideration of an impact in its NEPA analysis as an indirect effect, approval of the

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[28] Allegheny Defense Project is an environmental organization with a stated mission of protecting and restoring the wild forests and rivers of the Allegheny National Forest in Pennsylvania. Wild Virginia is an environmental organization with a stated mission of preserving wild forest ecosystems in Virginia's national forests.

[29] EarthReports consists of organizations largely focused on addressing environmental issues in the Mid-Atlantic region.

[30] Allegheny faults the September 29 Order for failing to specifically address concerns raised about alleged induced production in the Utica Shale region. The Utica Shale region extends from West Virginia and Ohio northeast through Maryland, Pennsylvania, and New York, and the shale itself is located a few thousand feet below the Marcellus Shale. The September 29 Order focused on responding to comments regarding impacts from drilling in the Marcellus Shale region. However, since the Utica Shale underlies significant portions of the Marcellus Shale, our analysis concerning alleged induced production in the Marcellus Shale region applies equally to Utica Shale production.

[31] 40 C.F.R. § 1508.8(b) (2014).

[32] *Id.*

proposed project and the related secondary effect must be causally related, i.e., the agency action and the effect must be "two links of a single chain."[33]

24. Cumulative impacts are defined by CEQ as the "impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions."[34] A cumulative impacts analysis may require an analysis of actions unrelated to the proposed project if they occur in the project area being analyzed.

25. An 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."[35] Courts have noted the starting point of any NEPA analysis is a "rule of reason," under which NEPA documents "need not address remote and highly speculative consequences."[36]

a. <u>Lack of Causality</u>

26. The September 29 Order explained that potential environmental effects associated with shale region production are not sufficiently causally related to the Cove Point Liquefaction Project to warrant detailed analysis as indirect impacts.[37] The order explained that future Marcellus Shale production is not an essential predicate for the

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[33] *Sylvester v. U.S. Army Corps of Engineers*, 884 F.2d 394 (9th Cir. 1980). On rehearing, EarthReports notes that the EA contained language implying that the scope of our NEPA review is limited to natural gas facilities under the Commission's jurisdiction. The September 29 Order does not reference or rely on such a limitation in considering impacts and further, the EA appropriately analyzes cumulative and indirect impacts where required and correctly notes a lack of sufficient causality or reasonable foreseeability for those activities not analyzed.

[34] 40 C.F.R. § 1508.7 (2014).

[35] *Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992).

[36] *Hammond v. Norton*, 370 F.Supp.2d 226, 245-46 (D.D.C. 2005).

[37] The Commission has been upheld in finding that it need not consider the environmental impacts of Marcellus shale region production when authorizing projects that may (or may not) make use of such supplies. *Central NewYork Oil and Gas Co., LLC*, 137 FERC ¶ 61,121, at PP 81-101 (2011), *order on reh'g*, 138 FERC ¶ 61,104, at PP 33-49 (2012), *petition for review dismissed*, *sub nom*., *Coalition for Responsible Growth*, *v. FERC*, 485 Fed. Appx. 472, 2012 WL 1596341 (2nd Cir., Apr. 17, 2012) (unpublished opinion).

Cove Point Liquefaction Project, which can receive natural gas through interconnects with three interstate natural gas pipeline systems. Further, development of the Marcellus Shale region will likely continue regardless of whether the Cove Point Liquefaction Project is approved.

27. Allegheny and EarthReports assert that the September 29 Order misapplied the causation element for assessing indirect impacts. EarthReports contends that agencies are routinely required to consider the environmental consequences that follow from approval of infrastructure projects.[38] The cases cited by EarthReports are not applicable here. The environmental impacts at issue in these cases, including impacts of development spurred by a new federal highway project, emissions caused by new electricity generation made possible by a new transmission line, and impacts from increased coal consumption made possible by providing new rail service to mines, are effects that would not have occurred had the specific federal authorizations not been granted. Here, natural gas development will likely continue with or without the Cove Point Liquefaction Project.

28. Allegheny sites two reports from the National Petroleum Council (NPC)[39] published in 2007 and 2011 to support its contention that Marcellus and Utica Shale region gas extraction activities and the Cove Point Liquefaction Project are "two links of a single chain."[40] The reports note that growing international trade in natural gas will require the development of new infrastructure and that the LNG supply chain will need to consider capital investment including upstream development.[41] Allegheny also cites a

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[38] EarthReports Rehearing Request at 27 (citing *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1081-82 (9th Cir. 2011) (*Northern Plains*) (environmental review must consider induced coal production for a rail project to serve specific new coal mines); *Mid States Coalition for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549-50 (8th Cir. 2003) (*Mid States*) (environmental effects of increased coal consumption due to construction of a new rail line to reach coal mines were reasonably foreseeable); *Border Power Plant Working Group v. Dep't. 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); and *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)).

[39] The NPC is a federal advisory committee that reports to the Secretary of Energy.

[40] Allegheny Rehearing Request at 5-6.

[41] *Id.* at 6.

2014 speech given by the Principal Deputy Assistant Secretary for DOE/FE that draws a link between applications to export LNG and domestic shale gas production.[42]

29. We disagree with Allegheny's contention that the NPC reports and the 2014 speech demonstrates a clear causal connection that requires further analysis. The September 29 Order noted that it is axiomatic that natural gas exports require natural gas supplies. The fact that natural gas production, transportation, and export facilities are all components of the general supply chain required to bring domestic natural gas to market for export is not in dispute. As we found in the September 29 Order, Marcellus Shale production is not required for the Cove Point Liquefaction Project and production is likely to increase in the area regardless of whether the Cove Point Liquefaction Project is approved. Production activities in the Marcellus Shale region and the associated impacts are thus not sufficiently causally related for the Commission to consider them as indirect effects of the Cove Point Liquefaction Project.

30. Allegheny contends that the Commission erred in recognizing the DOE/FE orders,[43] which reference statements made by Dominion about the economic benefits to Marcellus Shale region producers resulting from the Cove Point Liquefaction Project, and then refusing to consider the environmental consequences of that production.[44] Allegheny also contends that the Commission should not allow Dominion to tout the "continued development of domestic natural gas" as an alleged public interest benefit to be derived from the project while simultaneously refusing to consider the environmental consequences of that development by finding it to be not sufficiently causally related to the project.

31. The September 29 Order did not rely on the benefits cited by Dominion as justification for the Commission's public interest determination. Because the Commission does not have jurisdiction over the question of whether the export of natural gas as a commodity is in the public interest, the Commission merely restated DOE/FE's determination regarding the benefits of exporting natural gas. The September 29 Order found that with the conditions required, the Cove Point Liquefaction Project results in

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[42] *Id.* at 7.

[43] In 2011, DOE/FE authorized Dominion to export up to the equivalent of 1.0 Bcf per day of domestically-produced natural gas by vessel to Free Trade Agreement (FTA) Nations. DOE/FE Order No. 3019 (2011). DOE/FE subsequently authorized Dominion to export up to 0.77 Bcf per day of natural gas to non-FTA nations, finding the potential export of such volumes to be not inconsistent with the public interest. DOE/FE Order No. 3331 (2013).

[44] Allegheny Rehearing Request at 7, 8, and 17.

minimal environmental impacts and can be constructed and operated safely. The September 29 Order therefore concluded that the siting, construction, and operation of the export facilities (the portion of Dominion's export proposal under the Commission's jurisdiction) is not inconsistent with the public interest.

b. Lack of Reasonable Foreseeability

32. The September 29 Order found that shale gas development did not need to be analyzed as an indirect or cumulative impact because such production was not reasonably foreseeable within the meaning of NEPA. As the Commission has consistently found under the circumstances presented to date, impacts from additional shale gas development upstream of LNG export projects are not reasonably foreseeable within the meaning of CEQ's regulations.[45] The source of the gas to be exported via any individual project is speculative and would likely change throughout the operation of the project. The Cove Point Liquefaction Project will receive natural gas through the Cove Point Pipeline, which as described above, interconnects with three interstate natural gas pipeline systems. Those interstate pipelines cross multiple shale-gas, as well as conventional-gas, plays and through their interconnections with other pipeline systems effectively provide access to essentially all of the production areas in the lower-forty-eight states. Thus, assessing where the gas processed by the project will originate, much less where the wells and gathering lines will be located, and where the potential associated environmental impacts occur, would require significant speculation. Engaging in speculative analysis would not provide meaningful information to inform our decision.[46]

33. The September 29 Order and the EA explain that cumulative impacts can result from the construction of other projects in the same vicinity that impact the same resource areas as the proposed facilities. In such a situation, although the impacts associated with each project might be minor, the cumulative impact resulting from all projects being constructed in the same general area could be greater. Thus, the cumulative impacts analysis in the EA evaluated other projects in the vicinity of the proposed project that affect the same resources in the same approximate time frame.[47] The EA considered

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[45] *Sabine Pass Liquefaction, LLC*, 139 FERC ¶ 61,039, at PP 94-99 (2012), *order on reh'g*, 140 FERC ¶ 61,076, at PP 8-22 (2012); *Cheniere Creole Trail Pipeline, L.P.*, 142 FERC ¶ 61,137, at PP 51-60, *order on reh'g*, 145 FERC ¶ 61,074, at PP 8-19 (2013).

[46] *See Habitat Education Center v. U.S. Forest Service*, 609 F.3d 897 (7th Cir. 2010) (an environmental impact would be considered too speculative for inclusion in the NEPA document if at the time the document is drafted the impact cannot be described with sufficient specificity to make its consideration useful to a reasoned decision maker.).

[47] September 29 Order, 148 FERC ¶ 61,244 at PP 240-241.

several such projects including a proposed addition to the Calvert Cliffs Nuclear Power Plant, road and bridge upgrades and improvements, residential development, and sewer system construction.

34. Allegheny contends that the Commission takes an unjustifiably constricted view of cumulative impacts and asserts that geographic proximity is not in and of itself the standard for including other actions in a cumulative impacts analysis.[48] Allegheny cites CEQ guidance that states:

> For a project-specific analysis, it is often sufficient to analyze effects within the immediate area of the proposed action. When analyzing the contribution of this proposed action to cumulative effects, however, the geographic boundaries of the analysis almost always should be expanded. These expanded boundaries can be thought of as differences in hierarchy or scale. Project-specific analyses are usually conducted on the scale of counties, forest management units, or installation boundaries, whereas cumulative effects analysis should be conducted on the scale of human communities, landscapes, watersheds, or airsheds.[49]

35. Allegheny's criticism of our analysis ignores the distinction between the geographic scope of projects to be included in a cumulative effects analysis and the geographic scope of the cumulative effects of such projects. CEQ's guidance stated above provides direction to agencies on the appropriate geographic scope of effects to consider when analyzing the impacts of projects or actions that may impact resources cumulatively. It does not delineate which projects should be included in that analysis.

36. In their rehearing requests, Allegheny and EarthReports cite *Mid States*[50] referencing the application of the "reasonably foreseeable" standard in circumstances they claim to be analogous to those present here. *Mid States* involved the Surface Transportation Board's failure, in approving a proposal to construct 280 miles of new railroad and upgrade 600 miles of existing railroad to reach the coal mines of Wyoming's Powder River, to examine the effects on air quality that a reasonably foreseeable increase

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[48] Allegheny Rehearing Request at 19.

[49] *Id.* at 18 (citing CEQ, Considering Cumulative Effects under the National Environmental Policy Act at 12 (1997)).

[50] 345 F.3d 520.

in the supply of low-sulfur coal to power plants would produce. The court held that the Surface Transportation Board was required under NEPA to examine the effects that may occur as a result of the reasonably foreseeable increase in coal consumption, stating that: (1) due to Clean Air Act restrictions, many utilities will likely shift to the low-sulfur coal that will be made available by this project; (2) long-term demand for coal will almost certainly increase as a result of the increased availability of inexpensive coal that the project will provide; (3) the indirect effect, specifically, degradation of air quality resulting from the emission of noxious air pollutants, was identifiable; and (4) parties identified computer models widely used in the electric power industry that could be used to forecast the effects of the project on coal consumption.

37. Here, unlike the circumstances in *Mid States*, the indirect effect is not identifiable. The court in *Mid States* found that "when the *nature* of an effect is reasonably foreseeable, but the extent is not, an agency may not simply ignore the effect."[51] However, in this proceeding, the nature of the effect of any induced natural gas production from the proposed project is not "reasonably foreseeable," as contemplated by the CEQ regulations. Here, it is unknown at this time where, and to what extent, gas development will occur. As the Commission has made clear in prior LNG export cases, it is virtually impossible to accurately estimate how much, if any, of the export volumes at a particular facility will come from existing or new gas production.[52] In addition, it was not disputed in *Mid States* that computer modeling software existed to forecast the project's effects on coal consumption. In contrast, the parties to this proceeding have cited no such modeling software that forecasts when, where, and how gas development attributable to exports from the Cove Point Liquefaction Project will occur.

38. EarthReports asserts that the Commission has not made appropriate use of available tools or news announcements. EarthReports states that the Commission should follow the DOE's lead and undertake a conceptual analysis of the impacts of natural gas production like that included the DOE's Draft Addendum report concerning unconventional gas production for use in its environmental review of LNG projects.[53]

39. The September 29 Order explained that while the DOE Draft Addendum provides certain general estimates about the environmental impacts associated with natural gas production, those impacts have no particular relationship to Dominion's proposal. In its own report, DOE explained:

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[51] *Id.* at 549.

[52] *See Cheniere Creole Trail Pipeline, L.P.*, 145 FERC ¶ 61,074 at P 17.

[53] EarthReports Rehearing Request at 29-30.

> By including this discussion of natural gas production activities, DOE is going beyond what NEPA requires. While DOE has made broad projections about the types of resources from which additional production may come, DOE cannot meaningfully estimate where, when, or by what method any additional natural gas would be produced. Therefore, DOE cannot meaningfully analyze the specific environmental impacts of such production, which are nearly all local or regional in nature.[54]

We affirm the conclusion made in the September 29 Order that the existence of the DOE Draft Addendum provides no basis to alter the conclusions of the EA with regard to whether our environmental review should analyze shale gas.

40. EarthReports also asserts that the September 29 Order failed to adequately consider information from news clips filed in the proceeding indicating that Cabot Oil & Gas (Cabot) has committed to supply gas to one of Dominion's customers. EarthReports contends that the Commission cannot demand certainty about the location of additional well pads, gathering lines, and transmission systems, and refuse to investigate announcements that would provide additional clarity.[55]

41. The September 29 Order addressed this issue and disagreed with the assertions that the cited news clips provided a level of certainty sufficient to support a meaningful analysis of impacts associated with increased natural gas production.[56] The order noted that Pacific Summit Energy, LLC's contract with Cabot has not been submitted as part of the record in the proceeding and that nothing in the record indicates where gas will originate. Even if we were to assume that the gas was to come from Marcellus Shale region supplies, the record lacks sufficient specificity for a meaningful analysis of potential impacts from production. As we explained in the September 29 Order, the Commission has found the impacts of production to be beyond the scope of our review,

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[54] DOE *Addendum to Environmental Review Documents Concerning the Export of Natural Gas from the United States Draft Report* (DOE Addendum) (May 29, 2014), *available at* http://energy.gov/sites/prod/files/2014/05/f16/Addendum_0.pdf.

[55] EarthReports Rehearing Request at 29-31.

[56] September 29 Order, 148 FERC ¶ 61,244 at P 233.

even when particular producers were known to be shippers on the proposed pipeline.[57] The tie between Dominion's customers' gas supplier and the project is more attenuated than in those cases where the producer was a customer of a pipeline project. Moreover, knowing the identity of a supplier, and even the area where its existing wells are located, does not alter the fact that the number, location, and impacts associated with any additional production that the producer may engage in to supply Dominion's customers are matters of speculation.

42. Allegheny and EarthReports cite *Northern Plains*[58] in support of their contention that induced production is a reasonably foreseeable effect of the Cove Point Liquefaction Project's exportation of domestically produced natural gas. *Northern Plains* addressed the issue of whether the Surface Transportation Board should have considered the cumulative impacts of coal bed methane well development as part of its NEPA analysis of a proposed 89-mile-long rail line intended to serve specific new coal mines in three Montana counties. *Northern Plains* is distinguishable because, as part of an earlier, programmatic EIS, the Bureau of Land Management had already analyzed reasonably foreseeable coal bed methane well development which provided the Surface Transportation Board with information about the timing, scope, and location of future coal bed methane well development, whereas the Commission has no similar information in the present case about the timing, location, and scope of future shale (or conventional) well development which might be associated with the proposed Cove Point Liquefaction Project. Moreover, as the Commission stated in the September 29 Order, *Northern Plains* establishes that while agencies must engage in reasonable forecasting in considering cumulative impacts, NEPA does not require an agency to "engage in speculative analysis."[59]

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[57] *See*, *Texas Eastern Transmission, LP*, 139 FERC ¶ 61,138, at PP 70-73, *order on reh'g*, 141 FERC ¶ 61,043, at PP 37-41 (2012); *Tennessee Gas Pipeline Co., L.L.C.*, 139 FERC ¶ 61,161, at PP 178-200, *order on reh'g*, 142 FERC ¶ 61,025, at PP 72-87 (2012), *rev'd on other grounds*, *Delaware Riverkeeper Network v. FERC*, Case No. 13-1015 (D.C. Cir., June 6, 2014); *Transcontinental Gas Pipe Line Co., LLC,* 141 FERC ¶ 61,091, at PP 127-141 (2012), *order on reh'g*, 143 FERC ¶ 61,132, at PP 49-60 (2013).

[58] 668 F.3d 1067.

[59] September 29 Order, 148 FERC ¶ 61,244 at P 230. *See also Natural Res. Defense Council v. Callaway*, 524 F.2d 79, 90 (2d Cir. 1975) (holding that an agency need not "consider other projects so far removed in time or distance from its own that the interrelationship, if any, between them is unknown or speculative").

43. Allegheny notes that *Northern Plains* states that projects need not be finalized before they are reasonably foreseeable and that NEPA requires reasonable forecasting. As noted above, *Northern Plains* concerned the foreseeability of impacts from coal bed methane well development in specific new coal mines in three Montana counties. Here, Allegheny is not asking the Commission to consider the effects of specific proposed but non-finalized projects. Rather, Allegheny asks us to consider the environmental impacts from potential gas production activities in a multistate region. As stated in *Northern Plains*, agencies are not required "to do the impractical, if not enough information is available to permit meaningful consideration."

44. To support its claim that an analysis of the environmental impacts of shale gas production is not impractical, Allegheny points to surveys conducted by agencies and interest groups that estimate the average footprint of well pads for shale gas drilling and associated infrastructure.[60] We affirm our finding in the September 29 Order that the impacts from additional shale gas development supported by LNG export projects are not reasonably foreseeable within the meaning of the CEQ regulations and find that engaging in speculative analysis of survey estimates and projections would not provide meaningful information to inform our decision. This is particularly true where, as discussed above, our approval of the Cove Point Liquefaction Project is not conditioned on an assumption that Dominion's customers will receive gas from any particular supplier or production area. Dominion's customers are not required to enter into purchase contracts prior to our approval of the export facilities and, the source of supply could change over the course of the project's operation. Consequently, our environmental review should not indicate that project approval is tied to assumptions concerning potential gas supply.

3. <u>Air Emissions</u>

45. EarthReports states that the Commission erred in relying on Dominion's plan to purchase nitrogen oxide (NOx) emission offsets to eliminate impacts because these offsets are intended to mitigate for ozone formation and do not mitigate local NOx health impacts.[61] We disagree with EarthReports' interpretation of our analysis. When NOx offsets are discussed throughout the EA, it is in reference to mitigating ozone precursor pollutants impacts.[62] Therefore, the EA also includes detailed air dispersion modeling to identify localized NOx impacts.[63] The September 29 Order explained that the results of

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[60] Allegheny Rehearing Request at 13-14.

[61] EarthReports Rehearing Request at 9-10.

[62] *See* EA at section 2.7.1.

[63] *See* EA at 113 through 116.

this modeling demonstrate that NOx impacts will be below the National Ambient Air Quality Standards (NAAQS), which are set by EPA to be protective of human health and welfare.

46. EarthReports maintains that any amount of nitrogen dioxide emissions is linked to significant health impacts and states that the EPA is reconsidering the NAAQS standard. Section 2.7.1 of the EA includes detailed air dispersion modeling in comparison with the NAAQS. In developing each NAAQS, EPA periodically reconsiders the standards, taking into account the latest research on health impacts.[64] Further, the September 29 Order explains that while the EPA may consider available studies and re-evaluate the need to change the applicable thresholds in the future, our environmental analysis was based on the current standards that were issued by EPA following a proposed rulemaking and public comment period.[65]

47. It is speculative to assume the outcome of a potential future EPA rulemaking updating the nitrogen dioxide NAAQS and the final basis for that standard. EPA routinely proposes ranges of NAAQS thresholds for comment and there currently is no proposed range even under consideration. Each standard is developed to provide an adequate margin of safety and considers concentrations for the more sensitive populations at risk for each pollutant (e.g. asthmatics, those with cardiovascular disease, children, the elderly, etc.).

48. EarthReports states that assuming compliance with the Clean Air Act (CAA) does not address potentially significant impacts from hazardous air pollutants. While the EA compares hazardous air pollutant emissions and sources with the CAA's permitting requirements and National Emission Standards for Hazardous Air Pollutants, this is not the sole basis for our analysis. The EA and September 29 Order also explain the toxic air pollutant assessment performed under the Maryland air permitting regulations.[66] The modeled results indicate that the project’s air emissions would fall well below Maryland's

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[64] In considering carbon monoxide concentrations, EPA placed less emphasis on health impacts of infrequent concentrations and placed more emphasis on the impacts of repeated exposure concentrations. *Review of National Ambient Air Quality Standards for Carbon Monoxide*; Final Rule. 76 Fed. Reg. 54,293-343 (Aug. 31, 2011).

[65] September 29 Order, 148 FERC ¶ 61,244 at 174.

[66] *See* EA at 116 and September 29 Order, 148 FERC ¶ 61,244 at P 172.

acceptable ambient levels.[67] Therefore, we continue to find the EA's analysis appropriate in determining that impacts would not be significant.

49. EarthReports states that the EA does not include a description of methane emissions, a more potent GHG.[68] EarthReports also contends that the Commission mischaracterized the significance of the project's direct GHG emissions.[69] EarthReports states that the expected direct $CO_{2\text{-eq}}$ emissions from the project are nearly two orders of magnitude greater than the threshold the CEQ has set, in draft guidance, beyond which quantification is recommended in NEPA discussion of GHG emissions.[70]

50. We note that the EA is a summary document that presents all GHG emissions converted to $CO_{2\text{-eq}}$ based on the individual GHG's global warming potential (GWP).[71] All assumptions and detailed calculations for each GHG are available publicly as part of Resource Report 9 to Dominion's application and supplemental filings for the project. Also, the EPA has recognized that GHG emissions are orders of magnitude greater than conventional pollutants. The CEQ has clearly stated that its recommended threshold is not a significance criterion, but rather an indicator of when GHG emissions should be discussed in a NEPA document. Further, the quantity of emissions of a pollutant does not indicate the level of impact on the environment. The EA does follow the CEQ's guidance of quantitatively discussing GHG emissions from project construction and operation.[72] The EA also identifies several climate change related environmental effects in the northeast region resulting from overall GHG emissions.[73]

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[67] Maryland's acceptable ambient levels are concentrations of a toxic air pollutant in the atmosphere that provide a margin of safety to protect public health from toxic, noncarcinogenic effects that may be caused by the toxic air pollutant.

[68] EarthReports Rehearing Request at 33.

[69] EarthReports Rehearing Request at 32-33.

[70] EarthReports Rehearing Request at 33.

[71] The GWP is a ratio relative to carbon dioxide that is based on the properties of the GHG's ability to absorb solar radiation, as well as the residence time within the atmosphere. *See* EA at 98.

[72] EA at 107-112.

[73] EA at 170.

51. EarthReports maintains that the Commission should have based the methane $CO_{2\text{-eq}}$ emissions on GWPs published by the Intergovernmental Panel on Climate Change in its 5th assessment report, which was finalized after the EA was issued.[74] EarthReports also continues to state that the Commission's use of a 100-year time period for methane's GWP is inappropriate because the pollutant is short-lived.

52. The new studies that were completed after Commission staff issued the EA do not represent significant new circumstances or information that would require the preparation of a supplemental environmental document.[75] While it is important to consider the latest science, NEPA does not require agencies to constantly revise their issued analyses as new information becomes available. Further, the September 29 Order clearly justifies the Commission's selection of a 100-year GWP value for methane.[76] However, we also note that the liquefaction project's GHG emissions are primarily carbon dioxide (CO_2), as a result of combustion. Direct CO_2 emission comprise about 99.7 percent of the $CO_{2\text{-eq}}$ GHG emissions. Even under the new IPCC report's 20-year methane GWP, direct CO_2 emissions would still constitute over 99 percent of the $CO_{2\text{-eq}}$ emissions. Therefore, methane emissions under any timescale or GWP value would not meaningfully modify the emissions or impacts presented in our analysis.

53. Additionally, EarthReports states that the Commission failed to use the social cost of carbon tool. EarthReports estimates that over the next 20 years the social cost of carbon for the project's GHG emissions will exceed $2 billion and challenges our conclusion that the direct GHG emissions of the project are insignificant.[77]

54. The social cost of carbon tool is used to estimate the comprehensive costs associated with a project’s GHG emissions. The tool provides monetized values, on a global level, of addressing climate change impacts and is intended for estimating the climate benefits of rulemakings and policy initiatives. While we recognize the availability of this tool, we believe that for the following reasons, it would not be

[74] The IPCC's 5th assessment report was finalized in November 2014. http://www.ipcc.ch/publications_and_data/publications_and_data.shtml

[75] *See AES Sparrows Point LNG, LLC*, 129 FERC ¶ 61,245, at P 13 (2009) (citing *State of Wisconsin v Weinberger*, 745 F.2d 412, 418 (7th Cir. 1984) (finding a supplement EIS only merited if “new information provides a seriously different picture of the environmental landscape.”)). *See also, Altamont Gas Transmission Co.*, 69 FERC ¶ 61,034, at 61,150 (1994).

[76] *See* September 29 Order, 148 FERC ¶ 61,244 at P 245.

[77] EarthReports Rehearing Request at 32.

appropriate or informative to use for this project: (1) the EPA states that "no consensus exists on the appropriate [discount] rate to use for analyses spanning multiple generations"[78] and consequently, significant variation in output can result;[79] (2) the tool does not measure the actual incremental impacts of a project on the environment; and (3) there are no established criteria identifying the monetized values that are to be considered significant for NEPA purposes. While the tool may be useful for rulemakings or comparing alternatives using cost-benefit analyses where the same discount rate is consistently applied, it is not appropriate for estimating a specific project's impacts or informing our analysis under NEPA.

55. EarthReports cites a recent court decision cautioning that although NEPA does not require an explicit cost-benefit analysis, where such an analysis is included it cannot be misleading.[80] In *High Country*, the court stated that "[e]ven though NEPA does not require a cost-benefit analysis, it was nonetheless arbitrary and capricious to quantify the benefits of the lease modification and then explain that a similar analysis of the costs was impossible when such an analysis was in fact possible and was included in an earlier draft EIS."[81] As we explained in the September 29 Order, unlike in *High Country*, our environmental analysis did not attempt to quantify anticipated benefits of project approval while excluding potential costs from a cost-benefit analysis. Although the EA recognizes the unquantified, generic economic benefit of the project in considering the no-action alternative, EarthReports incorrectly assumes that the EA's conclusions and Commission decision relied solely on the economic benefits, supporting its belief that a cost-benefit analysis has occurred. To the contrary, the EA and the September 29 Order note non-economic factors supporting the Cove Point Liquefaction Project, such as the fact that the project will utilize existing facilities and storage tanks and the export facilities will be located on its existing property.[82] Also, the EA clearly explains that under the no-action alternative, the export customers would likely seek alternatives to

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[78] *See Fact Sheet: Social Cost of Carbon* issued by EPA in November 2013, *available at* http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf.

[79] Depending on the selected discount rate, the tool can also project a 20-year value of about $611 million, resulting in an over 200 percent difference in results compared to EarthReports' estimate.

[80] *Id.* at 36 (citing *High Country Conservation Advocates v. U. S. Forest Service*, No. 13-cv-01723-RBJ, 2014 WL 2922751 (D. Colo. June 27, 2014) (*High Country*).

[81] *Id.* at *10.

[82] September 29 Order, 148 FERC ¶ 61,244 at P 10 and P 11.

meet the contracted service, resulting in similar impacts, or costs, for the construction and operation of other facilities.[83] For these reasons, the social cost of carbon tool does not aid or further inform our decision on the project.[84]

4. Indirect and Cumulative Greenhouse Gas Impacts

56. EarthReports contends that the Commission was obligated to analyze the cumulative and indirect impacts of climate change from GHG emissions associated with drilling, transportation, and ultimate burning oversees.[85] EarthReports states that DOE has undertaken a life cycle assessment of GHG emissions from LNG exports and asserts that this demonstrates the feasibility of calculating life cycle GHG emissions from LNG export facilities.[86]

57. As discussed above and in the September 29 Order, the future development of upstream production is speculative and not reasonably foreseeable.[87] DOE acknowledges that its life cycle analysis contained in the Draft Addendum report goes beyond NEPA requirements and states that DOE cannot meaningfully analyze specific upstream impacts.[88] DOE found in the Sabine Pass Liquefaction, LLC Project (DOE/FE Order No 2961-A) that without knowing the specific location and timing for upstream

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[83] *See* EA at 173 and September 29 Order, 148 FERC ¶ 61,244 at P 264 and PP 275 -277.

[84] Our consideration of GHG emissions and climate change was sufficiently informed by section 2.9.9 of the EA which identifies the potential future impacts of climate change in the region and the impact that climate change would have on the project facilities, acknowledges that the emissions associated with the project would increase atmospheric GHG concentrations, and discusses mitigation measures to reduce GHG emissions from the project and protect the facilities from climate change impacts.

[85] EarthReports Rehearing Request at 35.

[86] *Id.* (citing DOE *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas* (DOE Life Cycle Report) (May 29, 2014) *available at*: http://energy.gov/fe/downloads/life-cycle-greenhouse-gas-perspective-exporting-liquefied-natural-gas-united-states.) (A life cycle GHG analysis compares medium and long distance LNG export scenarios with regional fuel alternatives in the destination import markets).

[87] September 29 Order, 148 FERC ¶ 61,244 at P 246.

[88] *Id.* P 236.

production, the environmental impacts are not reasonably foreseeable within the meaning of CEQ's NEPA regulations.[89] Upstream production is therefore outside the scope of our environmental analysis.

58. Similarly, countries seeking to import natural gas will continue to negotiate and find natural gas supplies. Therefore, end use consumption of natural gas will likely occur regardless of whether this project is approved. Although DOE's Life Cycle report concludes that LNG exports will not increase the life cycle GHG emissions, the report also references limitations and uncertainty in the modeling data.[90] The EA considered air emissions, including GHG emissions, attributable to the construction and operation of the project. Air emissions and the climate change impacts of such emissions from the transportation and ultimate consumption of gas exported from the Cove Point Liquefaction Project is not part of the project before us. Accordingly, the Commission believes the information provided in the DOE Addendum and Life Cycle reports is too general to assist us in our consideration of the specific proposal before us.

59. EarthReports also contends that the September 29 Order failed to analyze all of the impacts of climate change on the project, particularly from more intense winds and storms.[91] We disagree. The EA and September 29 Order state that the potential climate change impacts most likely to affect project facilities are increased sea level rise and storm surge.[92] The EA states that the project facilities would be constructed at a

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[89] We note that although EarthReports points to DOE's report to support its contention that this type of life cycle analysis is possible, EarthReports also contends that DOE's analysis and conclusions are incorrect. This further supports our view that this type of forecasting is complex and unreliable, involving speculation and too many uncertainties to be appropriate for NEPA.

[90] The Life Cycle report states that "[t]he natural gas power results are based on U.S. natural gas production in 2010. The results do not include the anticipated 30 percent reduction in upstream life cycle greenhouse gas emissions for new marginal unconventional wells in compliance with EPA's 2012 New Source Performance Standards for the oil and gas sector." DOE Life Cycle Report at 10. In addition, while the DOE Addendum does include an assumed reduction percentage based on the EPA regulation, it notes that "[s]ome states directly adopt federal regulations and standards, but can also make the standards more stringent. For example, in 2013 Pennsylvania revised the requirements associated with its General Permit for Air Pollution Control in Natural Gas Compression and/ or Processing Facilities (GP-5), making it more stringent than some federal standards." DOE Addendum at 22.

[91] EarthReports Rehearing Request at 26.

[92] EA at 171 and September 29 Order, 148 FERC ¶ 61,244 at P 247.

sufficient elevation to avoid conflict with future projected sea level rise and storm surge. With respect to impacts from intense winds and storms, the EA and September 29 Order identify that the facility will be designed to withstand 150 miles per hour sustained wind speeds (equivalent to a category 4 hurricane).[93] Further, Dominion has the ability to safely shut-down operations of the facility and the Coast Guard has the authority to restrict LNG vessel transit in the Chesapeake Bay during or in anticipation of high intensity storm events. Therefore, the impacts of climate change on the project were adequately considered.

5. Segmentation

60. Allegheny contends that our EA improperly segmented the review of upstream pipeline infrastructure. Allegheny asserts that the Commission should have considered Dominion's Atlantic Coast Pipeline and nine other projects intended to connect Marcellus and Utica Shale gas to downstream markets together with the Cove Point Liquefaction Project in a programmatic EIS.[94]

61. When assessing a proposed project's scope under NEPA, an agency must examine both connected and cumulative actions, and may examine similar actions. An agency impermissibly "segments" NEPA review when it divides these federal actions "into separate projects and thereby fails to address the true scope and impact of the activities that should be under consideration." Only by comprehensively considering "pending proposals can the agency evaluate different courses of action."

62. Actions are "connected" if they: "[a]utomatically trigger other actions which may require environmental impact statements;" "[c]annot or will not proceed unless other actions are taken previously or simultaneously;" or "[a]re interdependent parts of a larger action and depend on the larger action for their justification." Actions are not "connected" if they have "independent utility."

63. Actions are "cumulative" if they, when viewed with other proposed actions, have cumulatively significant impacts and should therefore be discussed in the same impact statement. Similar to connected actions, cumulative actions must be proposed.

64. In evaluating whether actions are improperly segmented courts typically employ an "independent utility" test, which "asks whether each project would have taken place in

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[93] EA at 133 and September 29 Order, 148 FERC ¶ 61,244 at P 106 and P 211.

[94] Allegheny Rehearing Request at 25.

the other's absence. If so, they have independent utility and are not considered connected actions."[95]

65. Dominion's Atlantic Coast Pipeline is planned to span approximately 550 miles, from Harrison County, West Virginia southeast through Greensville County, Virginia, and terminate in southern North Carolina.[96] The Atlantic Coast Pipeline and other natural gas pipeline projects planned to transport natural gas from the Marcellus and Utica Shale regions to downstream markets are not "connected actions" here within the meaning of NEPA. The Cove Point Liquefaction Project is in no way connected with, or dependent upon, the Atlantic Coast Pipeline, or any other pipeline transportation project. The Cove Point Liquefaction Project can go forward regardless of whether the Atlantic Coast Pipeline or any other pipeline project is authorized by the Commission.[97] Nor will these projects cumulatively affect the same resources impacted by Cove Point Liquefaction Project. Instead of reviewing these non-connected projects in a programmatic analysis, the Commission will consider each proposed project on its own merits, based on the facts and circumstances specific to each proposal.

6. <u>Safety</u>

66. EarthReports contends that the Commission failed to independently analyze the safety impacts of the project and instead referenced compliance with safety regulations promulgated by the U.S. Department of Transportation (DOT).[98] EarthReports also challenges the September 29 Order's explanation of why a quantitative risk assessment was not conducted.[99]

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[95] *Webster v. U.S. Dep't. of Agric.*, 685 F.3d 411, 426 (4th Cir. 2012).

[96] *See* Atlantic Coast Pipeline Frequently Asked Questions, available at https://www.dom.com/library/domcom/pdfs/gas-transmission/atlantic-coast-pipeline/acp-faq-general.pdf. Dominion states that the purpose of the project is to move Marcellus Shale gas from Ohio, West Virginia, and Pennsylvania to Virginia and North Carolina in response to growing market needs for both power generation and for local distribution to customers.

[97] September 29 Order, 148 FERC ¶ 61,244 at P 252.

[98] EarthReports Rehearing Request at 12.

[99] EarthReports Rehearing Request at 13.

67. EarthReports' statement that the Commission did not analyze the safety impacts of the proposed project is inaccurate. Safety impacts were addressed in both the EA and in the September 29 Order. The order explained that the EA's principal focus in summarizing potential hazards is on facilities that may pose a hazard to the public. Commission staff reviewed the engineering design, including specifications, control systems, emergency shutdown systems, hazard detection, hazard control, structural fire protection, and other safety and reliability material in addition to the siting requirements, for all proposed equipment including the liquefaction facilities, power generation equipment, the mixed refrigeration system, offshore gas blowers, gas flares, and the plant air system.[100]

68. The September 29 Order further notes that Commission staff's review focused on the engineering design and safety concepts of the various protection layers, as well as the projected operational reliability of the proposed facilities.[101] These layers would generally be independent of one another so each could perform its function of preventing an incident or of mitigating the severity of an incident, regardless of the failure of any other protection layer. We agree with Commission staff's conclusion in the EA that the inclusion of such systems or safeguards in the facility design minimizes the potential for incidents that could impact the safety of the off-site public.

69. The September 29 Order explains that Dominion's facility must comply with the DOT's *Federal Safety Standards for Liquefied Natural Gas Facilities* in 49 C.F.R. Part 193.[102] Those regulations incorporate by reference portions of the 2001 and 2006 edition of National Fire Protection Association (NFPA) 59A, *Standard for the Production, Storage, and Handling of LNG*. The order notes that Chapter 15 of the 2013 edition of NFPA 59A allows use of a quantitative risk assessment subject to acceptance by DOT. The order goes on to explain however that the 2013 edition of NFPA 59A is not currently part of the federal regulations covering LNG. There are multiple unresolved issues with the NFPA 59A quantitative risk assessment methodology requiring the establishment of specific assumptions, inputs, databases, and models on which to base such an analysis.[103] The September 29 Order explains that a quantitative risk-based siting methodology must be able to produce consistent results when used by different parties examining the same installation. Until these issues are resolved, the methods provided for conducting a quantitative risk assessment can be manipulated to

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[100] September 29 Order, 148 FERC ¶ 61,244 at P 194.

[101] *Id.* P 195 (citing EA at 132).

[102] *Id.* P 184.

[103] EA at 148.

achieve widely divergent results, which questions their appropriateness as a siting methodology. In addition, there are no quantified acceptance criteria for acceptable or tolerable risks in the U.S. regulatory framework.[104] Even after issues such as equipment failure frequency and selection of appropriate consequence models are settled, there are no established criteria on which to judge the resulting numerical estimates of risk. As a result, the Commission relies on an assessment of whether the proposed facilities would be able to operate safely and securely and minimize potential public safety impacts.[105] This review is based on a technical review of the facility engineering design, as well as a review of the siting analysis that Dominion must perform in order to comply with the DOT's regulations in 49 C.F.R. Part 193. We find that the September 29 Order and the EA independently analyzed potential safety impacts and that the order adequately explained our rationale for not performing a quantitative risk assessment.

7. <u>Shipping and Ballast Water Impacts</u>

70. EarthReports challenges the September 29 Order's reliance on Maryland Department of the Environment Science Services Administration's statement that "because the project does not entail increased shipping traffic over and above prior approvals, there is no anticipated increased risk of ballast water introduction from the project."[106] EarthReports asserts that because import vessels did not discharge ballast water, whereas the export vessels will, Dominion's change in operations does present an increased risk that the ballast water will introduce invasive species or otherwise pollute the Chesapeake Bay.[107]

71. EarthReports criticizes the September 29 Order's finding that current regulations requiring an open ocean ballast water exchange and new Coast Guard regulations likely to take effect before the project is operational provide best management practices.[108] EarthReports contends that potentially significant impacts from ballast water discharges may still occur if the Coast Guard delays the new ballast water regulations. EarthReports

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[104] Although the 2013 edition of NFPA 59A presents individual and societal risk acceptability criteria (Tables 15.10.1 and 15.10.2, respectively), these have not been reviewed and incorporated into the federal regulations on LNG facility siting.

[105] EA at 125.

[106] EarthReports Rehearing Request at 15 (citing September 29 Order, 148 FERC ¶ 61,244 at P 127).

[107] *Id.* at 15.

[108] *Id.* at 16 (citing September 29 Order, 148 FERC ¶ 61,244 at 127-129).

further asserts that the new regulations do not remove the threat of invasive species and biofouling organisms.[109]

72. The Commission's conclusion on impacts associated with shipping and ballast water impacts was presented in the EA and did not rely solely upon comments provided by the Maryland Department of the Environment Science Services Administration, which were received after issuance of the EA. As indicated in the September 29 Order, the EA acknowledges and appropriately discloses the risks of invasive species introduction and water quality impacts from shipping even with federal controls.[110] The EA and order also state that the currently-required measures for all ships entering U.S. waters, including offshore ballast water exchange, provide best management practices to minimize risks from invasive species and contamination from non-U.S. ports. Dominion's vessel operators will be required to comply with current and future Coast Guard regulations. Whether the regulations are updated in 2016 or at some point in the future, Dominion's operators will be subject to the most recent regulations.

73. While EarthReports may believe that current regulations, including the use of offshore ballast water exchange, are not adequate to protect water quality, the Commission has disclosed the impacts associated with compliance and implementation of these regulations. EarthReports believes that our analysis should result in the elimination of all risk from ballast water exchange and biofouling organisms and the Commission should be "requiring mitigation beyond the current regulations."

74. NEPA requires that possible mitigation be discussed in sufficient detail to ensure that environmental consequences have been fairly evaluated, but does not require that a complete plan to mitigate environmental harm be formulated before an agency may act.[111] Moreover, an agency need not conclude that all impacts require mitigation; NEPA does not constrain an agency from concluding that other values outweigh the environmental costs of a proposed action.[112] It is outside of the Commission's jurisdiction and expertise to promulgate regulations or invent best management practices

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[109] *Id.* at 16-19.

[110] September 29 Order, 148 FERC ¶ 61,244 at P 128, EA at 53-54.

[111] *See, Public Service Co. of New Hampshire*, 68 FERC ¶ 61,177, at 61,870 (1994) (citing *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989)). *See also, Ruby Pipeline, L.L.C.*, 133 FERC ¶ 61,015, at P 33 (2010); and *Southern Natural Gas Co.*, 85 FERC ¶ 61,134, at 61,512 (1998).

[112] *See, Public Service Co. of New Hampshire*, 68 FERC ¶ 61,177 at 61,870. *See also, Millennium Pipeline Co., L.L.C.*, 141 FERC ¶ 61,198, at P 29 (2012).

regarding ballast water exchange and invasive species control that go above and beyond the currently-approved regulations enforced by the Coast Guard. Given these factors, in addition to the fact that Maryland does not currently require more stringent standards than the federal ballast water program, the Commission has no grounds to presume the established regulations are not satisfactory for maintaining the quality of the environment in the project area. Therefore, we affirm that the EA and the September 20 Order adequately disclose the potential impacts and discuss potential mitigation for impacts associated with ballast water exchange and introduced invasive species.

8. North Atlantic Right Whale

75. EarthReports states that the Commission and the U.S. National Oceanic and Atmospheric Administration (NOAA) failed to adequately analyze potential impacts on the North Atlantic right whale.[113] Specifically, EarthReports challenges Commission and NOAA staff's reliance on a six-year-old study of impacts associated with Dominion's 2007 import expansion project.[114] In addition, EarthReports asserts that the agencies also should have considered how current and future development of area ports and other infrastructure, such as offshore drilling and seismic activities, as well as climate change, might affect the North Atlantic right whale and compound the effects of the project.[115]

76. The Commission staff and NOAA, during the informal consultation process, reviewed previous extensive analyses for past Cove Point projects (the Cove Point Expansion Project and Pier Reinforcement Project) that originally assessed the effects of vessel traffic of up to 200 LNG vessels annually, a quantity greater than the currently-approved 85 LNG vessels per year with an additional 42 barges anticipated over an 18-month period during construction.[116] Staff reviewed the potential impacts and the measures required in Dominion's existing Vessel Strike Avoidance Measurers and Injured and Dead Protected Species Reporting Plan, as well as NOAA's regulations regarding vessel speed restrictions. During this review, both Commission staff and NOAA did not find a significant difference in the type of impacts and available mitigation measures associated with the project that would necessitate a change in the previous determination of effect for the North Atlantic right whale.

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[113] EarthReports Rehearing Request at 21.

[114] *Id.* at 21-25

[115] *Id.* at 26.

[116] *See* the Environmental Impact Statement for the Cove Point Expansion Project, April 2006, Docket No. CP05-130-000 *et al.* and EA for the Pier Reinforcement Project, May 2009, Docket No. CP09-60-000.

77. With regard to the purported increase in vessel traffic, the potential change in LNG vessel transit and ship traffic since the previous analyses was also evaluated for the project and presented in the EA.[117] The Coast Guard concurred that the project should not result in an increase in the size and/or frequency of LNG marine traffic beyond what was originally envisioned in the current Waterway Suitability Assessment for the Cove Point Terminal. The EA also indicated that the volume and size of vessels authorized would not change from the previous analyses and that the maximum authorized ship traffic to the Cove Point Terminal would only account for 1.6 percent of commercial ship traffic transitioning past the Cove Point Terminal annually.[118] As such, we conclude that the analyses for the previous Cove Point projects and in the EA adequately considered the effects of vessel traffic and indicated that the project would not substantially increase the number and type of vessels previously reviewed for the Cove Point Terminal. Thus, we conclude that the review of impacts on the North Atlantic right whale from vessel transit associated with the project did not trigger a significant change that would necessitate an alteration in the previous determination of effect for the North Atlantic right whale.

78. Regarding potential effects on whales compounded from current and future development of area ports and other infrastructure, offshore drilling and seismic activities, and climate change, the analysis contained in the EA for this project and past Cove Point projects adequately characterizes the threat of impact on the North Atlantic right whale. The Commission is unaware of future development that would increase ship traffic and does not speculate on the scope or effect of these undefined activities. However, the Commission is comfortable that in the review of future threats to the North Atlantic right whale, NOAA will direct appropriate measures to protect the species. Therefore, we affirm the determination in the September 20 Order that the EA properly concluded that the project is not likely to adversely affect the North Atlantic right whale and that consultation is complete for this species.

9. Sufficiency of the EA

79. Allegheny and EarthReports assert that the Commission violated NEPA by failing to prepare an EIS for the project.[119] Allegheny notes that the Commission's regulations state that an EIS will normally be prepared for authorizations under sections 3 or 7 of the Natural Gas Act for the siting, construction, and operation of jurisdictional LNG import/export facilities.[120] Allegheny states that when indirect and cumulative effects of

[117] EA at 89.

[118] *Id.*

[119] Allegheny Rehearing Request at 21; EarthReports Rehearing Request at 4-9.

[120] Allegheny Rehearing Request at 21-22 (citing 18 C.F.R. § 380.6(a)(1)).

natural gas production and downstream emissions are considered, the EA cannot support the finding of no significant impact. EarthReports contends that proposed construction activities (including building a pier to receive construction equipment, clearing land for a construction staging area, and constructing a 130 megawatt power plant) combined with the on-site storage of chemicals and receipt of LNG tankers once the project is operational justifies the preparation of an EIS.

80. Though the CEQ regulations do not provide an explicit definition of the term "significant impacts," they do provide that whether a project's impacts on the environment will be considered "significant" depends on both "context" and "intensity."[121] Context means that the "significance of an action must be analyzed in several contexts," including "the affected region, the affected interest, and the locality."[122] With regard to "intensity," the CEQ regulations set forth 10 factors agencies should consider, including: the unique characteristics of the geographic area, the degree to which the effects are highly controversial or highly uncertain or unknown, the degree to which the action may establish a precedent for future actions, whether the action is related to other actions with insignificant but cumulatively significant impacts, and the degree to which the action may adversely affect threatened and endangered species.[123]

81. Commission staff determined that an EA was appropriate in this case because the proposed facilities would be within the footprint of the existing Cove Point Terminal and because the relevant issues that needed to be considered were relatively small in number and well-defined. The project impacts listed are discussed in detail in the EA and the September 29 Order, and we are satisfied that the potential impacts are not significant.

82. As detailed above, the Commission has found that impacts resulting from additional production of natural gas are beyond the necessary scope of its inquiry and that no substantial question relating to the impacts of air emissions from the project exists. The impacts associated with additional gas production, as they relate to Dominion's project, are not reasonably foreseeable and do not qualify as "highly controversial" for NEPA purposes. For an action to qualify as "highly controversial" for NEPA purposes, there must be a "dispute over the size, nature, or effect of the action, rather than the existence of opposition to it."[124] A controversy does not exist merely because

[121] 40 C.F.R. § 1508.27 (2014).

[122] *Id.*

[123] *Id.*

[124] *See Cheniere Creole Trail Pipeline, L.P.*, 145 FERC ¶ 61,074 at P 23 (citing *Friends of the Ompompanoosuc v. FERC*, 968 F.2d 1549, 1557 (2d Cir. 1992)).

individuals or groups vigorously oppose, or have raised questions about, an action.[125] We do not find that our action here meets the standard of "controversial" so as to require the preparation of an EIS. The EA concludes, and we agree, that the project would not have a significant impact on the quality of the human environment. Thus, an EIS is not required.

10. Conformity with the Natural Gas Act

83. Allegheny and EarthReports contend that the September 29 Order erred in its determination of whether the Virginia Facilities should be authorized under the Natural Gas Act, as implemented through the Certificate Policy Statement.[126]

84. The September 29 Order states that since Dominion's proposed Virginia Facilities will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA.[127] The Certificate Policy Statement provides guidance for evaluating proposals to certificate new construction.[128] The Certificate Policy Statement established criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explained that in deciding whether to authorize the construction of major new natural gas facilities, the Commission balances the public benefits against the potential adverse consequences.

85. Allegheny and EarthReports repeat their contentions that: (1) the September 29 Order failed to adequately consider indirect and cumulative impacts of upstream production; and (2) the finding of no significant environmental impact was unjustified. For those reasons, Allegheny and EarthReports assert that the order failed to appropriately balance public benefits against potential adverse environmental impacts. As discussed above, the Commission need not analyze the impacts of upstream production for the purposes of our environmental analysis for this project and the EA's conclusion that the project would result in no significant environmental impact is supported. Thus, we find no error in the September 29 Order's application of the Certificate Policy Statement.

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[125] *Id.*

[126] Allegheny Rehearing Request at 26 and EarthReports Rehearing Request at 41.

[127] 15 U.S.C. §§ 717f(c) and 717f(e) (2012).

[128] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

C. Stay Requests

86. On October 15, 2014 and December 24, 2014, respectively, EarthReports and Allegheny filed motions for stay of the September 29 Order pending rehearing and judicial review, claiming that the project would cause irreparable environmental impacts.[129] Dominion filed an answer to EarthReports' request for stay. Since the Commission is now acting on the requests for rehearing and there is no pending judicial appeal of this order, the requests for stay are moot.

The Commission orders:

Allegheny, BP, and EarthReports' requests for rehearing of the September 29 Order are denied as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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[129] In addition, on October 3, 3014 EarthReports filed comments in opposition to Dominion's request for approval of its Implementation Plans, and for a notice to proceed with initial site preparation. EarthReports argued that certain compliance information was inadequate or improperly filed. Commission staff found Dominion to be in compliance with the conditions of the September 29 Order and granted Dominion's request to proceed with site preparation.

Document Content(s)