ML 155481

ORDER NO. 86372

IN THE MATTER OF THE APPLICATION OF DOMINION COVE POINT LNG, LP FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT A GENERATING STATION WITH A NAME-PLATE CAPACITY OF 130 MW AT THE DOMINION COVE POINT LIQUEFIED NATURAL GAS TERMINAL IN CALVERT COUNTY, MARYLAND	* * * * * * * * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9318

Before: W. Kevin Hughes, Chairman
Lawrence Brenner, Commissioner
Kelly Speakes-Backman, Commissioner
Anne E. Hoskins, Commissioner

Issued: May 30, 2014

APPEARANCES:

Lisa S. Booth, William H. Baxter II, John H. Burnes, Jr., Kevin Finto, Harry M. Johnson, III, Janna R. Chesno, and Paul Korman, on behalf of Dominion Cove Point LNG, LP.

Sean Canavan, on behalf of Accokeek, Mattawoman, Piscataway Creeks Communities Council, Inc.

Joshua Berman, Curtis Cooper, and Diana Dascalu-Joffe, on behalf of the Sierra Club and Chesapeake Climate Action Network.

Brent Bolea and Sondra McLemore, on behalf of the Maryland Department of Natural Resources, Power Plant Research Program.

Donald R. Hayes on behalf of Washington Gas Light Company.

Peter Saar, on behalf of the Office of Maryland People's Counsel.

Janice M. Flynn and Ryan C. McLean on behalf of the Staff of the Public Service Commission of Maryland.

I. INTRODUCTION/ EXECUTIVE SUMMARY

On April 1, 2013, Dominion Cove Point LNG, LP ("DCP" or the "Company") filed with this Commission an application for a Certificate of Public Convenience and Necessity ("CPCN") pursuant to § 7-207 and § 7-208 of the Public Utilities Article ("PUA") of the Maryland Annotated Code and Code of Maryland Regulations ("COMAR") Title 20, Subtitle 79 to construct an electric Generating Station with a name-plate capacity of 130 MW ("Generating Station" or "Station") at its existing liquefied natural gas ("LNG") terminal site in Calvert County, Maryland. DCP also seeks a waiver of the requirement to request the CPCN at least two years before beginning construction of the Station. PUA § 7-208(b)(1).

DCP is a limited partnership existing under the laws of Delaware. DCP owns and operates a federally-approved LNG terminal ("Terminal") near Cove Point in Calvert County, Maryland. The Terminal is designed to receive imported LNG from tanker ships, store LNG in tanks, and vaporize and transport the vaporized LNG over an 88-mile pipeline to the interstate gas transmission system.

DCP is proposing to construct the Station to provide electricity to an expanded bi-directional import and export LNG facility ("LNG facility" or "Project"), for which it is seeking regulatory approval from the Federal Energy Regulatory Commission ("FERC").[1] The proposed 130 MW Generating Station will serve only the liquefaction Project's needs, with no current plans to connect it to the State's electric grid.

[1] This application is pending before FERC in Docket No. CP-13-113-000. The documents supporting DCP's FERC application were also supplied to this Commission, along with updates and supplements.

This application for a CPCN is more complex than most because it involves overlapping consideration by us of the Generating Station and by the FERC of the larger LNG facility. However even DCP acknowledges, and we agree, that the two are intertwined. We have recognized the unique circumstances of this case as we have applied the considerations our statute requires to the facts presented by the parties and the public in their comments.

For the reasons discussed in this order, we grant the CPCN for the electric Generating Station, subject to significant new conditions. One of the new conditions is that this CPCN is conditional upon FERC approval of the Cove Point LNG expanded export facility, and all FERC conditions associated with that approval, because the sole purpose of the Generating Station would be to serve the proposed expanded LNG operations and because of the functional integration of the generation station within the LNG facility.

Because we have found that, as proposed by DCP, the Generating Station and the LNG facility will not provide net economic benefit to Maryland citizens, we have modified the proposed conditions to require DCP to contribute $8 million per year for five years ($40 million total) to the State's Strategic Energy Investment Fund ("SEIF"), to be used for the development of renewable and clean energy resources in Maryland, greenhouse gas mitigation, energy efficiency programs, or demand response programs. We have also modified the proposed condition of a contribution to the Maryland Energy Assistance Program to direct that DCP contribute $400,000 per year for each of the 20 years the terminal is under contract to operate, for a total of $8 million. We direct DCP to advise us in writing within ten days of its acceptance or rejection of the Conditions set forth in Appendix A of this Order.

II. PROCEDURAL HISTORY

Upon receiving DCP's application, the Commission docketed Case No. 9318 and delegated it to the Public Utility Law Judge Division. A pre-hearing conference was held on May 8, 2013, at which the entities present were DCP, the Maryland Department of Natural Resources ("DNR") Power Plant Research Program ("PPRP"), Washington Gas Light Company ("WGL"), the Office of People's Counsel ("OPC"), the Sierra Club ("SC"), and the Staff of the Public Service Commission ("Staff"). Motions to intervene from SC, WGL, and Chesapeake Climate Action Network ("CCAN") were granted. DCP stated that a copy of the public version of the CPCN Application had been made available at the library in Calvert County. The application was deemed complete on June 5, 2013. DCP filed numerous supplements to the application between April and November 1, 2013, when the Public Utility Law Judge issued an order adopting a procedural schedule that had been proposed by the parties.[2] On November 25, 2013, by Order No. 86025, the Commission rescinded its delegation to the Public Utility Law Judge Division and, without disturbing the amended procedural schedule adopted on November 14, 2014, determined that it would hear the case *en banc*. On December 10, 2013, the Accokeek, Mattawoman, Piscataway Creeks Communities Council, Inc. ("AMP Creeks Council" or "AMP") filed a Petition to Intervene Out-of-Time ("Petition") in Case No. 9318. The Commission granted the Petition on January 7, 2014.

[2] That schedule was amended on November 14, 2013 to correct an administrative error.

On July 17, 2013, DCP filed the direct testimony of Robert B. McKinley, Vice President, Generation Construction for Dominion Resources Services, Inc.; Robert M. Bisha, Director, Environmental Business Support for Dominion Resources Services, Inc.; and Richard B. Gangle, an Environmental Consultant with the Environmental Business Support Group at Dominion Resources Services, Inc. The direct testimony of all other parties was filed on January 15, 2014, including PPRP witnesses Susan T. Gray, Deputy Director of PPRP and the project manager for reviewing the CPCN Application filed by DCP; William V. Paul, Chief of the Combustion and Metallurgical Division of the Maryland Department of the Environment's ("MDE") Air and Radiation Management Administration ("ARMA" or "MDE-ARMA") (air quality impacts); Mark DiPrinzio, a partner and senior air quality professional at Environmental Resources Management, Inc. ("ERM"); John W. Grace, Chief of the Source Protection and Appropriation Division of MDE's Water Management Administration ("WMA"); Robert W. Keating, a geologist with ERM; Peter D. Hall, President of Metametrics, Inc., and a consulting economist with specialties in regional economics and socioeconomic impact assessments; Steve Harriott, an Ecologist and Professional Wetland Scientist with Versar, Inc., the Biology Integrator contractor to PPRP; and Diane Mountain, Senior Project Manager at ERM and a registered Professional Engineer in Maryland. Dr. Steven L. Estomin, Senior Economist and Principal with Exeter Associates, Inc., submitted reply testimony on behalf of PPRP. Direct testimony also was filed by AMP witness Dr. Donald Helm, who currently occupies the Samuel P. Massey Chair of Excellence, Emeritus at the United States Department of Energy ("DOE"); Sierra Club and CCAN (jointly "SC-CCAN") witnesses William E. Powers, a consultant on environmental permitting and energy matters and the owner of Powers Engineering, and Susan E. Allison, an instructional assistant with the Calvert County Adult Education Program; and Staff witness Ralph DeGeeter, a Generation/Transmission Engineer with the Commission's Engineering Division.

Reply testimony was filed on January 29, 2014. DCP filed reply testimony by its witnesses McKinley, Bisha, and Gangle, as well as that of Michael D. Frederick, Vice President, LNG Operations for DCP. PPRP filed the reply testimony of its witnesses Gray, Paul, DiPrinzio, Grace, Hall and Estomin. SC-CCAN filed the reply testimony of its witnesses Powers and Allison.

On January 15, 2014, PPRP filed its Environmental Review of the proposed 130 MW Generating Station within the Project (the “Environmental Review”). PPRP's Initial Recommended License Conditions were included as Appendix A to the Environmental Review. The Environmental Review concludes that although the proposed 130 MW Generating Station is only a portion of the proposed Project, its impact cannot be separated from the larger liquefaction Project; therefore the State's environmental review was not limited to the Generating Station, but rather “examined the proposed Project as a whole.”[3] In the Secretarial Letter dated January 15, 2014, the participating State Agencies provided their conclusion that “the power plant site is suitable and that the proposed generating facility can be constructed and operated in accordance with all applicable environmental regulations, provided that [the State Agencies'] recommendations are incorporated as conditions to the CPCN.”[4]

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[3] Environmental Review at 2.

[4] Letter dated January 15, 2014, to W. Kevin Hughes, Chairman from Earl F. Hance, Secretary, *et al.*, filed on January 27, 2014 (the "Secretarial Letter").

On January 23, 2014, DCP filed a Motion to Strike Portions of Intervener Testimony Related to Hydraulic Fracturing, seeking to exclude a portion of Dr. Helm's testimony. On January 27, 2014, AMP filed its opposition to DCP's Motion to Strike and on January 31, 2014, DCP filed a Reply Memorandum in support of its Motion to Strike. PPRP filed comments in support of the Motion to Strike and SC-CCAN filed comments opposing the Motion to Strike. The Commission granted DCP's Motion to Strike on the first day of evidentiary hearings, February 20, 2014, concluding that Dr. Helm's testimony relating to the environmental and geological impacts of hydraulic fracturing is outside the scope of this proceeding and is instead within FERC's purview to evaluate the environmental impacts as they relate to the proposed LNG facility.[5]

On February 5, 2014 SC-CCAN and AMP filed a Request for Extension of Time to file Public Comments (Request) seeking an additional 60 days for the public to file comments after the March 1, 2014 public hearing. DCP opposed the Request. On February 21, 2014, the Commission ruled and granted an extension of 30 days for public comment.

The Commission held evidentiary hearings on February 20, 21, and 24, 2014 in Baltimore, MD and conducted a public hearing on March 1, 2014 in Lusby, Maryland.

PPRP filed the State Agencies' final recommendations and conditions for the Project on April 17, 2014, which proposed four new conditions and modified three other proposed conditions. On April 30, 2014, the Commission sought additional comment on the new and modified proposed conditions, to which Commission Staff, DCP, and /SC-CCAN filed comments on May 14, 2014. On May 6, 2014, the Commission requested

[5] Tr. p. 9.

comment regarding the existence of a risk study for this Project, to which PPRP, DCP, SC-CCAN and Commission Staff filed comments on May 14, 2014.

On May 15, 2014, FERC issued its Staff Environmental Assessment ("EA"), of which the Commission takes judicial notice.[6] FERC has not yet completed its regulatory review of the proposed LNG Project or addressed the recommendations contained in the Environmental Assessment.

III. APPLICABLE LAW

The scope of the State's jurisdiction over the siting and operation of this LNG Project is complex, due to the integrated components of the proposed Generating Station and the liquefaction facilities. As PPRP witness Susan Gray noted:

> This Project is unlike other CPCN reviews in my experience in that it involves a generating station that is located within and is integral to a larger Liquefaction Project that DCP is seeking to construct and operate ... Moreover, the generating station ... is very closely intertwined with the components of the broader Liquefaction Project ... the combustion turbines themselves are dual purpose; they are used both to mechanically drive the compressors used for liquefaction process and to provide the electricity that is needed to serve other aspects of the liquefaction process. Further, the DCP's Liquefaction Project is concurrently under review by the Federal Energy Regulatory Commission.

Statutory authority for reviewing a CPCN application is found in § 7-207(e) of the Public Utilities Article, which states that prior to taking action on an application for a CPCN for a generating station, the Commission must give due consideration to the following factors:

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[6] Judicial Notice, May 21, 2014. On May 27, 2014 DCP and SC-CCAN filed Comments on the Judicial Notice, neither of which objected to it.

(1) The recommendation of the governing body of each county or municipal corporation in which any portion of the construction of the generating station or overhead transmission line is proposed to be located; and

(2) The effect of the generating station or overhead transmission line on:

(i) the stability and reliability of the electric system;

(ii) economics;

(iii) esthetics;

(iv) historic sites;

(v) aviation safety, as determined by the Maryland Aviation Administration and the administrator of the Federal Aviation Administration;

(vi) when applicable, air and water pollution; and

(vii) the availability of means for the required timely disposal of wastes produced by any generating station.

Under § 7-208 of the PUA, the Commission also is required to include in the CPCN the requirements of the Federal and State environmental laws and standards that are identified by MDE, and the methods and conditions that the Commission determines are appropriate to comply with those environmental laws and standards.[7]

While this application raises unique questions of law and fact given the interdependency between the electric Generating Station and the larger liquefaction Project, FERC has primary jurisdiction for evaluating and licensing the liquefaction Project.[8] Federal law includes provisions for State input into LNG licensing determinations, recognizing State interests in protecting the environment and the health

[7] Although § 7-208 is silent as to specific considerations the Commission is to apply, § 7-208(b)(1) provides, "To obtain the certificate of public convenience and necessity required under § 7-207 of this subtitle for construction under this section … ." thus incorporating of all of § 7-207, including its considerations which we apply herein.

[8] Pub. L. 109-58, § 372(b); 42 USC § 15928(b).

and safety of its residents when LNG facilities are constructed and operated. Moreover, in 2005, the Maryland General Assembly passed legislation requiring the Commission to adopt regulations "to ensure to the greatest extent practicable the operational safety of liquefied natural gas facilities".[9] In response, the Commission promulgated COMAR 20.55.02.02(A)(4), which incorporates by reference the federal regulations governing federal safety standards for liquefied natural gas facilities.

This is not the first time this Commission has reviewed an application involving the LNG facility at Cove Point. From 2002 through 2004, in Case No. 8917, the Commission reviewed the operational safety of the Cove Point facility prior to the resumption of imports to ensure the facility posed little or no safety risks. In that proceeding, Cove Point LNG Limited Partnership (the predecessor of DCP) acknowledged the Commission's role under PUA 11-101(b) to "ensure to the greatest extent practicable the operational safety of liquefied natural gas facilities."[10]

IV. SUMMARY OF PARTIES' POSITIONS

A. Dominion Cove Point

DCP urges that the scope of the Commission's review in this case is not simply limited to the Generating Station for which DCP seeks this CPCN. Noting that "DCP's Project is not just to construct an electric generating facility" and that the "Generating Facility is an integral part of this unique Project," DCP concludes that an "analysis of the costs and benefits of the Generating Facility must consider the costs and benefits of the

[9] PUA 11-101(b).

[10] Cove Point LNG Limited Partnership Case No. 8917 Initial Report at 7. Dominion Resources, Inc. acquired Cove Point LNG Limited Partnership on September 5, 2002, and the company changed its name to Dominion Cove Point, LP or DCP effective December 17, 2002.

entire Project."[11] As a result, in much of its analysis, DCP submits the characteristics of the overall Project, not on the Generating Station characteristics alone.

DCP challenges AMP's assertion that the Commission has no authority to review the economic impact of the overall Project. "The record," according to DCP, "reflects that the generating facility and the liquefaction process are inseparably integrated."[12] DCP also rejects AMP's argument that, as Federal permits are also necessary for construction of the Project, any action by this Commission would establish a new permit requirement, impermissibly conflicting with Federal law. DCP argues that "under AMP's ... specious reasoning, no state could ever evaluate a federally permitted project because that review would be preempted by the federal action."[13] Under the same logic, DCP rejects AMP's arguments that approval by the Calvert County Board of Commissioners is preempted by Federal Law.[14]

Dominion Cove Point states that "the Project meets the criteria set out in Section 7-207(e) of the Public Utility Article."[15] Addressing each of those requirements in turn, DCP then notes that "the Project and the CPCN have the unanimous support of the Calvert County Board of Commissioners," an indication that the Project will have significant public benefits, according to DCP.[16]

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[11] DCP In. Br. at 10.

[12] DCP Rep. Br. at 4, citing Tr. 234-235 (Gangle).

[13] DCP Rep. Br. at 4-5.

[14] Given that the County Commissioners unanimously approved the Project, DCP stated that no conflict between Federal and State law currently exists. DCP admits that if a conflict between Federal and State decisions were to arise, Federal law would govern. (DCP Rep. Br. at 6, citations omitted.)

[15] DCP In. Br. at 1.

[16] DCP In. Br. at 12.

As to the question of the Generating Station's impact on the stability and reliability of Maryland's electric system, DCP urges that the facility will have no adverse impact, as all the power it supplies will be consumed within the LNG plant.[17] DCP stated in its brief that it accepted the Staff's proposal to undertake a "collaborative study of a potential interconnection with the grid." If a study shows that grid interconnection is feasible and "warranted," DCP concludes that such interconnection would not undermine the electric system's stability and reliability. Further, according to DCP, this Commission would be able to review any new transmission line in a separate CPCN proceeding.[18]

Addressing economics, DCP states that "the Project will result in significant net economic benefits in Maryland."[19] In support of its assertion, DCP states that "thousands" of workers will be employed in construction of the overall LNG facility, and that 75 full-time permanent jobs will be created. DCP also asserts that "the Project will yield approximately $40 million per year in incremental revenue to the County," which will satisfy a net present value analysis and likely outweigh any increase in the price of natural gas caused by export of LNG.[20] During the evidentiary hearing, DCP witness McKinley testified that construction of the new Generating Station will account for approximately 20 percent of the man-hours and overall costs of the entire project. Additionally, he estimated that the Generating Station would employ approximately 20 to 23 full-time employees or about 30 percent of the full-time permanent jobs for the entire project.[21]

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[17] DCP In. Br. at 13.
[18] DCP In. Br. at 13.
[19] DCP In. Br. at14.
[20] DCP Rep. Br. at 11-12.
[21] Tr. at 343-345.

To bolster its position, DCP cites a U.S. Department of Energy study showing consistent net economic benefits from the export of liquefied natural gas on a national basis. While the Company admitted that liquefaction of natural gas at Cove Point could put some upward pressure on the prices of natural gas and electricity, the Company also maintains that such increases would be spread over the entire period that Cove Point exports LNG. The benefits of increased employment, however, would be "front loaded," so that the local economy would see growth before it felt any effects of increased natural gas prices.[22]

Addressing esthetic, noise, and historic site issues, DCP states, as a general matter, that the Cove Point site has been an industrial site for 40 years. "The site is a 131-acre industrial area within a 1,017-acre forested site that is otherwise undeveloped."[23] The new Generating Station will be contained within the 131 acre site and will be obscured by old growth trees, according to DCP. Where legal requirements are subjective, such as the areas of esthetics and historic site impacts, DCP provides the reasons that Project impacts will either be nonexistent, insignificant, temporary, or well contained. Further, DCP states that exhaust stacks at the new site will be the same height as existing LNG storage tanks, and vapor plumes from those stacks would likely not be visible, due to low moisture exhaust from the combustion turbines ("CTs"). To further mitigate any esthetic impact arising from the Project, DCP plans to build a 60 foot tall sound wall that, while partially visible from Cove Point Road, will not be visible from the Cove Point recreation

[22] DCP In. Br. at 16.
[23] DCP In. Br. at 17.

area. DCP also states that it will work with PPRP to determine if other measures to limit views of the sound wall are feasible.[24]

To accommodate construction vehicles and equipment, DCP will clear nearly 100 acres in "Offsite Area A." DCP will plant a 100 foot tree buffer to shield Offsite Area A, will keep 13.5 acres of Offsite Area A forested, and will replant trees, where possible, under a Forest Conservation Plan with Calvert County. At the end of construction, Offsite Area A will be transferred to Calvert County.[25]

Visual effects at Offsite Area B, which will be used for barge deliveries, equipment storage, and parking during construction, will be temporary. Once construction is finished, DCP states that it will remove its temporary barge pier and return Offsite Area B to its original condition within 30 days. For that reason, DCP concludes that Offsite Area B will "not significantly affect the cultural attractiveness of the Lower Patuxent Peninsula."[26]

As to noise impacts, DCP notes that the Project is required to meet all applicable limitations on the noise it emits. DCP claims that it is "buying ... the quietest equipment available" and "we're spending tens of millions of dollars to make sure we are meeting the noise requirements."[27]

Referring to the possible effect of the Project on historic sites, DCP first notes that it will abide by a request by the Maryland Historic Trust to preserve a 50 foot buffer around a likely historic site on Offsite Area A. Further, it will avoid five sites on Offsite

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[24] DCP In. Br. at 17-18.
[25] DCP In. Br. at 18-19.
[26] DCP In. Br. at 19, citing PPRP Ex. 12 at 12 (Hall Direct).
[27] DCP In. Br. at 19-20, citing Tr. 392, McKinley.

Area B that possibly contain historic material. DCP therefore concludes that its actions will not adversely affect Maryland historic resources.[28]

DCP asserts that the Project will have no adverse effect on aviation safety. DCP consulted with the Patuxent Naval Air Station, which had no concerns about the proposed facility. The Company further notes that Federal Aviation Administration ("FAA") guidelines do not require that the FAA be notified about the Project's details unless proposed structures exceed 200 feet in height, and none of the permanent or proposed structures at the Project do so.[29]

The issue of the Project's compliance with Federal and State clean air laws has taken up perhaps the largest amount of time and testimony in this proceeding. DCP maintains that "the Project complies with all of the applicable major statutory source permitting requirements under the Federal Clean Air Act ("CAA") and COMAR, Title 26 (Department of the Environment), Subtitle 11 (Air Quality)." DCP also asserts that it has complied with all other elements and standards that are applicable to the proposed Project.[30] DCP maintains that overall, the Project will minimize emissions. It will use "process gas" for generation, rather than burning off (or "flaring") such gas into the atmosphere. Further, purchase of emissions offsets "ensures that the Project will not add incremental emissions, and DCP has acquired the necessary offsets."[31]

Specifically addressing Federal New Source requirements, DCP notes that there are two components; Non-Attainment New Source Review ("NA-NSR") and Prevention

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[28] DCP In. Br. at 20-21.

[29] DCP In. Br. at 21.

[30] Included in those categories are New Source Performance Standards ("NSPS"), Maximum Achievable Control Technology ("MACT"), National Ambient Air Quality Standards ("NAAQs"), visibility standards and impacts to vegetation and growth, and modeling of air toxins. DCP In. Br. at 21-22.

[31] DCP Rep. Br. at 22.

of Significant Deterioration ("PSD"). NA-NSR is generally the more stringent standard. Maryland is in a non-attainment area for ozone, meaning its ozone levels exceed Federal standards during certain seasons.[32] As the Project will emit ozone precursors, specifically nitrogen oxide ("NO_x") and volatile organic compounds ("VOCs") in a non-attainment area for ozone, those emissions will be subject to Lowest Achievable Emission Rate ("LAER") standards. The LAER standards require DCP to employ specific technologies, purchase emissions offsets, and conduct an alternatives analysis.[33] NO_x is also subject to the Best Available Control Technology ("BACT") standard, as are greenhouse gasses ("GHGs"), particulate matter ("PM"), carbon monoxide ("CO"), and sulfur dioxide ("SO_2"). DCP states that the Project has "an inherently low-emitting design" and "was designed from the beginning to meet LAER and BACT."[34] For example, the Cove Point LNG facility will be "the only LNG facility in the United States using exhaust heat to generate electricity." Other LNG plants simply release exhaust heat to the atmosphere.[35]

DCP has accepted all of PPRP's proposed conditions relating to applicable PSD and NA-NSR requirements, an action that DCP concludes satisfies all applicable Federal and State emissions requirements. DCP therefore focused its arguments on rebutting challenges from those parties urging that the emission rates and amounts approved by PPRP are not low enough. In approaching challenges to its emissions levels, DCP notes that COMAR 26.11.17.01(B)(15)(ii) defines LAER as "[t]he most stringent emissions limitation which is achieved in practice by the class or category or statutory sources, with

[32] Gangle Dir. at 6.
[33] DCP In. Br. at 22.
[34] DCP In. Br. at 23.
[35] DCP In. Br. at 24.

this limitation, when applied to a modification, meaning the lowest achievable emissions rate for the new or modified emissions units within the stationary source." The same principle underlies the definition of BACT, as "LAER is similar to BACT, but 'is always at least as stringent as BACT'."[36] DCP maintains that "the courts and EPA have interpreted the word 'achievable' to mean that a facility can comply with the BACT limit continuously under all reasonably foreseeable worst case conditions."[37]

Based on its definition of BACT and LAER, DCP rejects arguments by other parties that LAER and BACT limits lower than those predicted at Cove Point were achievable at other plants and should be achievable at Cove Point. DCP asserts that while LAER for "typical turbines" that burn pipeline natural gas is 2.0 ppm, the Project cannot meet that low emission level because it will use "process" gas, which is created when pipeline natural gas is pre-treated during the liquefaction process.[38] Because of this pre-treating, it contains more NO_x than pipeline gas. As a result, according to DCP, it cannot produce emissions at the 2.0 ppm level.

In addition to relying on the use of process gas rather than pipeline natural gas to justify a 2.5 ppm rather than a 2.0 NO_x emission rate, DCP addressed legal emission rates in Southern California, upon which the environmental intervenors had relied for their 2.0 ppm NO_x recommendation. DCP noted that California's South Coast Air Quality Management District ("SCAQMD") covers the smoggiest region of the United States, an area classified as an extreme ozone non-attainment area."[39] Supporting its position that

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[36] DCP In. Br. at 24, citing PPRP Ex. 4 at 4-5 (Paul Direct).
[37] DCP In. Br. at 26.
[38] DCP In. Br. at 27, 28.
[39] DCP Rep. Br. at 16.

different NO_x limits are appropriate for differently sized gas boilers, and that, in general, one emissions limit is not right for all technologies, DCP notes that the rules governing NO_x emissions in SCAQMD are different for boilers used to generate electricity, boilers in petroleum refineries, or boilers at reclamation sites.[40] Further, DCP maintains that Rule 114b, applicable in SCAQMD, would regulate process gas in a way not applicable to DCP's boilers, even if they were located in the SCAQMD district.[41]

DCP illustrates its position with other references to differences between technology in SCAQMD and the Cove Point facility. According to DCP, SC-CCAN make the same mistake regarding emission limits for combustion turbines as for boilers – that is, they "ignore both the type of unit and fuel in arguing that the NO_x limit for the combustion turbines should be 2 ppm in this case."[42] DCP claims that SC-CCAN for the first time in their initial brief argued that scrubbers on combustion turbines should be able to achieve 92% reduction of NO_x emissions, resulting in an overall emission limit of 2 ppm. There is no evidence, according to DCP, that supports 92% or counters responses from combustion turbine vendors that an emission limit lower than 2.5 ppm could not be achieved.[43]

DCP objects to SC-CCAN's proposal to implement a "safety valve," a requirement for a specific emissions limit with a qualification that a higher limit could be accepted if the lower limit proved unachievable. DCP argues that such a "limit" would not qualify as

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[40] DCP Rep. Br. at 17.
[41] DCP Rep. Br. at 17.
[42] DCP Rep. Br. at 19.
[43] DCP Rep. Br. at 19-20.

LAER, which "is based on what is known to be achievable at the time of permitting."[44] Based on its analysis, DCP concludes that LAER for the combustion turbines is 2.5 ppm NO_x.[45]

DCP also opposes SC-CCAN's proposal that only leakless components be used in its piping system. SC-CCAN, DCP states, cited no comparable facility that employed only leakless technology, or cited to any permit or regulation requiring such usage. As there are "thousands of valves, connectors, and pumps in a variety of services and locations," and leakless connectors are welded shut and are inaccessible, DCP finds a totally leakless requirement impractical.[46] According to DCP, because the leak detection and repair ("LDAR") program is designed to satisfy LAER requirements, DCP has proffered that as the appropriate standard in this case.[47]

As to water usage, DCP states there is a lack of evidence that subsidence due to such usage will be a problem. Nonetheless, DCP agreed after conclusion of the hearings to a new condition that will provide $190,000 for the Maryland Geological Survey ("MGS") to conduct subsidence monitoring in and near Calvert County.[48]

DCP also urges Commission acceptance of its waiver request under PUA § 7-208(b)(1), to enable it to begin construction prior to the two-year required waiting period. In support, DCP cites the thorough study to which its CPCN application has been

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[44] DCP Rep. Br. at 21.
[45] DCP Rep. Br. at 21.
[46] DCP Rep. Br. at 23.
[47] DCP Rep. Br. at 23.
[48] *See* Final Recommended Licensing Conditions of the Reviewing State Agencies, April 17, 2014, proposed additional consideration J-2.

subjected, DCP's acceptance of all proposed conditions, and the lack of any opposition to its waiver request.[49]

B. Power Plant Research Program

PPRP submitted testimony through DNR in this proceeding. PPRP witness Susan T. Gray explained that PPRP is responsible for coordinating the review of projects requiring a CPCN from the Public Service Commission with other units within the DNR and with various State agencies, including MDE, the Department of Agriculture, the Departments of Business and Economic Development, Planning, and Transportation, and the Maryland Energy Administration. Ms. Gray further explained the connection between this Commission's work and PPRP's responsibility in CPCN cases as follows:

> Under Maryland's Power Plant Siting Act of 1971, Chapter 31 of the Laws of Maryland of 1971, which is codified in various parts of the Maryland Code, including Sections 7-207 and 7-208 of the Public Utility Companies Article and Sections 3-301 through 3-306 of the Natural Resources Article, the Public Service Commission is required to consider environmental and socioeconomic impacts associated with the construction and operation of ... electric Generating Stations in the state.[50]

Ms. Gray also noted that Region III of the Environmental Protection Agency reviews DCP's CPCN application and forwards its comments to MDE and PPRP for evaluation and response. She noted that "no CPCN should be issued until EPA and public comments on the air permit and conditions are responded to in this case."[51]

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[49] DCP Rep. Br. at 25. DCP also notes the reasons that the Project will not be subject to RGGI emissions requirements and will not be required to purchase GHG allowances. The Company will be subject to RGGI reporting requirements and will apply for a waiver of any remaining requirements to purchase RGGI allowances. DCP Rep. Br. at 24.

[50] Gray Dir. at 2.

[51] Gray Dir. at 4. PPRP and MDE provided responses to public comments on air quality related to the proposed Project in its April 17, 2014 filing.

Ms. Gray summarized the testimony of DNR witnesses by noting that "based on the information provided, the proposed Project can be constructed and operated in such a way that complies with all applicable environmental and socioeconomic regulations, provided that the proposed licensing conditions are incorporated into [a] CPCN that may be issued in this case, and that DCP complies with those conditions."[52]

DNR has submitted numerous conditions ("licensing conditions") applicable to DCP's proposed Generating Station at the Cove Point LNG facility. As DNR reviewed the Project in light of Federal as well as State environmental standards, its testimony and proposed conditions are keyed to those standards. The conditions cover all stages of the Generating Station from preparation for construction to post-construction and operation. Some PPRP conditions were submitted after formal hearings in this matter and are discussed throughout this Order.

DNR witness Paul detailed the reports, scientific literature, and proposed emission sources that he consulted in reaching his conclusions that "emissions from the proposed Project will not adversely affect the relevant National Ambient Air Quality Standards ("NAAQS") or PSD increments and impacts from emissions from the proposed Project will be acceptable[53]."

The potential emissions from these sources reviewed by Mr. Paul include six "criteria pollutants":

1. Carbon monoxide ("CO");
2. Nitrogen Dioxide ("NO_2");

[52] Gray Dir. at 8.
[53] Paul Dir. at 9.

3. Sulfur dioxide (“SO_2”);

4. Particulate matter (“PM”):

    a. PM less than 10 microns (“PM_{10}”);
    b. PM less than 2.5 microns (“$PM_{2.5}$”)

5. Lead;

6. Ozone, formed from precursor pollutants:

    a. Volatile organic compounds (“VOCs”); and
    b. Nitrogen oxides (“NO_x”)[54]

Mr. Paul stated that the air quality in Calvert County near the Project is “in attainment” of the NAAQS for all criteria pollutants except ozone. Due to the area's attainment status for most criteria pollutants, emission of those pollutants must meet Prevention of Significant Deterioration (“PSD”) standards, expressed in tons of emissions per year. Emission sources subject to PSD standards must show that emission of criteria pollutants are controlled to a level representing BACT and do not violate NAAQS.[55]

Emissions in nonattainment Areas must meet more stringent standards, including a level of control technology that results in the LAER. Additionally, sources subject to NA-NSR must also, among other efforts, secure emission reduction credits or offsets sufficient to result in a net positive air quality benefit from the Project. He also noted that the two Frame 7 CTs, which are part of the Generating Station, are subject to New Source Performance Standards for Stationary Combustion Turbines (40 CFR Part 60, Subpart

[54] Paul Dir. at 2-3.
[55] Paul Dir. at 5-8.

KKKK). Further, individual combustion turbines in the Project will be subject to State air quality requirements in COMAR.[56]

Mr. Paul noted that the emission sources subject to BACT for the Project are: the combustion turbines, the auxiliary boilers, the emergency generator, the fire pump engines, thermal oxidizer, ground flares, piping components, and paved roads. All of the foregoing emission sources, except the paved roads, are also subject to LAER, presumably for ozone precursors.[57] While his testimony contains further details, Mr. Paul's conclusion is "that DCP will be able to construct and operate the proposed Project in conformance with applicable PSD and NA-NSR requirements, provided that the CPCN incorporates the recommended licensing conditions … and that the proposed Project is constructed and operated in accordance with these conditions."[58]

DNR witness DiPrinzio discussed the ambient air quality present in Calvert County, and described the operating restrictions and pollution control systems that will limit air emissions from the Project to acceptable levels.[59] In addition to the criteria pollutants discussed by Mr. Paul, Mr. DiPrinzio referred to hazardous air pollutants ("HAPs"), toxic air pollutants ("TAPs"), and GHGs, consisting of CO_2, methane ("CH_4"), NO_2, hydrofluorocarbons ("HFCs"), per fluorocarbons ("PFCs"), and sulfur hexafluoride ("SF_6").[60]

Mr. DiPrinzio's testimony differs from Mr. Paul's in that Mr. DiPrinzio discussed the specific operating restrictions and technologies the various emitters at the Project, such

[56] Paul Dir. at 14-15.
[57] Paul Dir. at 7-8.
[58] Paul Dir. at 12.
[59] DiPrinzio Dir. at 2-3.
[60] DiPrinzio Dir. at 4.

as the combustion turbines and auxiliary boilers, will use to reduce emissions.[61] He concluded that emissions of TAP and HAP from the Project were in compliance with Maryland regulations. Mr. DiPrinzio cautioned that without proper control by oxidation catalysts, emissions of formaldehyde could exceed the 10 ton per year major HAP threshold.[62]

Overall, Mr. DiPrinzio concluded that the potential emissions projected by DCP for the proposed Project were reasonable and acceptable.[63] The remainder of Mr. DiPrinzio's direct testimony described the various BACT and LAER protocols applicable to the various Project emissions, as summarized in Appendix B attached to this Order.

Mr. DiPrinzio also discussed the concept of General Conformity, designed to ensure that Federal actions comply with NAAQS and with State Implementation Plans. Generally, emission sources subject to PSD or NA-NSR requirements are deemed in conformance.[64] A General Conformity evaluation, however, revealed that construction and operations at the Project but outside PSD NA-NSR permit areas will exceed the General Conformity threshold for NO_x and VOCs in the D.C. area until 2017. Therefore, as required, DCP has purchased emission reduction credits for 625 tons of NO_x and 166 tons of VOCs to offset its own emissions of those pollutants.[65]

Mr. DiPrinzio stated that there were three forms of NO_x emissions,[66] and also noted control of 95% NO_x emissions (as opposed to PPRP's proposed condition of 90%

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[61] DiPrinzio Dir. at 4-5.
[62] DiPrinzio Dir. at 11.
[63] DiPrinzio Dir. at 12.
[64] DiPrinzio Dir. at 9. A general Conformity analysis is performed by FERC, not by the State. (Tr. at 598 – Paul.)
[65] DiPrinzio Dir. at 10.
[66] Tr. at 572.

NO_x control) was hypothetically achievable in a short period of time, but not across the wide range of operating conditions for years in the future.[67]

On the issue of NO_x emissions comparisons and in response to SC-CCAN assertions that lower emissions levels are possible, PPRP adds the additional detail in its reply testimony:

> …[t]he University of California permit, to which [SC-CCAN] witness Powers refers, does include a 5 ppmvd NO_x limit; however, this is based on a calendar quarter average. The more comparable NO_x limit of 9 ppmvd on a 3 hour rolling average (also included in the referenced permit) is in fact higher than the NO_x LAER limit proposed by DCP and recommended by PPRP and MDE-ARMA.[68]

Addressing Mr. Powers' assertion that "Dominion has not adequately mitigated the air impacts of emissions from marine vessels" and "therefore understated Dominion's offsetting obligations," and that "[a] requirement that LNG tankers only operate on natural gas and that tugboats be equipped with selective catalytic reduction (SCR) would result in no net increase in air emissions from marine vessels," Mr. DiPrinzio noted that such emissions were subject to FERC's General Conformity determination. However, as General Conformity is included in Maryland regulations as COMAR 26.11.26, "PPRP and MDE-ARMA reviewed General Conformity and determined that DCP has met all regulatory requirements as set forth in COMAR."[69]

Another means of reducing NO_x emissions is through the use of leakless components, which eliminate the need for piping joints. Mr. DiPrinzio, however, stated

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[67] Tr. at 583-84.
[68] DiPrinzio Rep. T. at 4.
[69] DiPrinzio Rep. T. at 7.

that LAER for NO_x could be achieved without use of leakless components through the 28 LAER program and best practice conditions PPRP has proposed.[70]

Mr. DiPrinzio also addressed the concept of conformity; he explained that a conformity analysis addresses overall unpermitted emissions "that may result from the Project, and may require, even after adherence to conditions, a purchase of pollution offsets. The purpose of conformity review is to ensure that the State is not worse off, in terms of environmental pollution, than before the Project was constructed."[71]

DNR witness Garrison performed an independent review of DCP's analysis of potential air quality impacts due to increased emissions from DCP's Project. His testimony examines in further detail certain air quality tests and procedures and pollution limits already described by Mr. DiPrinzio and Mr. Paul. He assessed the Project's emissions compared to NAAQS PSD increments, Class I area air quality thresholds, impacts of growth related to the Project, and other impacts, such as to visibility and soil.[72]

Mr. Garrison noted that in determining if specific emissions would violate NAAQS, significant impact levels ("SILs") are established for each pollutant and averaging period under study. Air quality modeling is then performed in the area where the project will be located. Mr. Garrison determined that DCP used an appropriate modeling methodology to determine the impact of significant emissions from the

[70] Tr. at 588-594.

[71] Tr. at 629-631.

[72] Mr. Garrison defined NAAQS as prescribing ground-level concentrations of specific pollutants at levels that the EPA concludes protect public health with a margin of safety. Concentrations of pollutants are expressed in terms of parts per million or micrograms per cubic meter ("$\mu g/m^3$"). "Attainment" areas are those with ambient pollutant concentrations below the NAAQS, and nonattainment areas have higher levels of pollutants than NAAQS allows. PSD increments represent the increase in ambient air concentrations of NO^2, SO^2, PM^{10} and $PM^{2.5}$ that NAAQS allow, but to be acceptable, PSD increments must be significantly lower than NAAQS. The amount of increase in pollutants is determined by whether the source of the pollutant is categorized as in a Class I, II, or III region. Class I regions are the most sensitive and subject to the highest degree of protection. National and state parks are often Class I regions. Garrison Dir. at 2-3.

proposed Project. He noted that maximum emission impacts from the Project were expected to exceed the SILs for $PM_{2.5}$ using 24-hour averages and annual averages and NO_2 for one-hour averages. Those results triggered the need for additional cumulative modeling, which demonstrated compliance with applicant NAAQS and PSD increments.[73] Mr. Garrison also performed his own modeling, which "verified that the proposed Project is not expected to cause or contribute to any violation of applicable NAAQS or PSD increments."[74]

PPRP and MDE-ARMA requested further tests to determine if $PM_{2.5}$, which can develop from NO_x emissions, would exceed the $PM_{2.5}$ NAAQS. Because Calvert County is a nonattainment area for ozone, of which NO_x is a precursor, and because DCP will have to purchase NO_x offsets in the local air shed, "it is reasonable to conclude that the net effect of secondary formation of $PM_{2.5}$ due to NO_x to the local air shed as a whole is zero or less."[75]

Mr. Garrison also reviewed DCP's studies of possible visibility impairment and soil pollution from air emissions. He agreed with DCP's conclusion that no such adverse effects were likely due to emissions from the Project.[76]

It also was necessary to determine the effect of Project emissions on Federal Class I areas, which are particularly sensitive to impacts on visibility. Of special concern in this case was visibility at Calvert Cliffs State Park, only 1.5 kilometers above the Cove Point LNG terminal. Mr. Garrison concluded that any plume from the Project would be "well

[73] Garrison Dir. at 8.
[74] Garrison Dir. at 10.
[75] Garrison Dir. at 10.
[76] Garrison Dir. at 11.

below ... critical contract criteria for visibility impairment against an open background."[77] Mr. Garrison also reviewed DCP's toxic air pollutant analysis for 20 toxic compounds, and found they were all "well below the acceptable Ambient Levels found in COMAR 26.11.16.09," and are otherwise in compliance with Maryland TAPs requirements.[78]

Maryland requires a permit to appropriate and use the waters of the State. The CPCN application at issue here also constitutes an application for a water use permit, which is included in the grant of a CPCN.[79] DNR witness Grace addressed water issues in this proceeding for PPRP. He concluded that the various licensing conditions that he proposed, if included in any CPCN granted to DCP in this case, "will ensure that all State regulatory requirements applicable to the requested appropriation are met."[80]

Mr. Grace noted that the sources of information for his evaluation were an Environmental Review Document prepared by the PPRP, DCP's Application to Appropriate and Use Waters of the State, other DNR publications, previous permit decisions by the DNR-WMA, and his own personal knowledge.

He further noted that COMAR authorizes a permit for use of the State's water only if three criteria are satisfied: (1) the amount of water appropriated must be reasonable in relation to anticipated use during the permit period; (2) the anticipated use must not unreasonably impact the waters of the State; and (3) the proposed use must not unreasonably impact other users of the water at issue.[81]

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77 Garrison Dir. at 14.
78 Garrison Dir. at 14-15.
79 DCP In. Br. at 9.
80 Grace Dir. at 2-3.
81 Grace Dir. at 4-5.

In examining DCP's water use proposal through the lens of the above requirements, Mr. Grace reported DCP's projected water requirements as follows:

> DCP has requested to use the following average water amounts per day of groundwater from the Lower Patapsco aquifer:
>
> > 200,000 gallons per day for steam turbine boiler makeup;
> >
> > 26,000 gallons per day for operating vaporizers in the event that LNG import occurs;
> >
> > 23,000 gallons per day, a 10% contingency on top of the estimated demand;
> >
> > 250,000 average total gallons per day (rounded).

DCP's month of maximum use estimate was 375,000 gallons per day (1.5 times the average amount). DCP requested an additional groundwater appropriation to support construction of the project as follows:

> 40,000 gallons per day;
>
> 60,000 during month of maximum use.[82]

DNR's own estimates of appropriate water usage for the Project differed from those of Mr. Grace, as follows:

> 233,000 gallons per day;
>
> 275,000 maximum monthly usage, based on the assumption that the facility operates 100% of the time for the entire month.[83]

DNR-WMA determined that the estimated withdrawal amounts of 233,000 and 275,000 gallons per day were reasonable.[84]

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[82] Grace Dir. at 5-6.
[83] Grace Dir. at 6-7.

Mr. Grace determined that the withdrawal of the stated amounts over a 12-year period would result in a maximum five foot drop in the level of the Lower Patapsco aquifer and that DCP's water appropriation would not exceed the sustained yield of the Lower Patapsco aquifer. When combined with "regional drawdown" of the aquifer of 14.4 additional feet, the withdrawal could create a maximum drawdown of water from the aquifer of 20.0 feet, from an aquifer with 1,025 feet of drawdown available.[85]

Mr. Grace concluded that there were no other locally available sources of water, such as the Chesapeake Bay, Lake Levy, or Calvert County's water supply, to satisfy DCP's needs at the Project.[86] He concluded, however, that DCP's proposed drawdowns from the Lower Patapsco aquifer would not adversely impact other water users, would be consistent with the State's regulations, and would be consistent with conditions imposed on other water users in the State.[87]

DNR witness Keating supported the analysis of Mr. Grace in estimating DCP's potential usage of groundwater from the Lower Patapsco aquifer. Mr. Keating used an equation to calculate drawdown of the water level in the Lower Patapsco aquifer over 12 years, at 233,000 gallons per day, at various distances from the pumping well. The estimated drawdowns were as follows:

Distance From Well	**12 Year Drawdown**
¼ mile	5.6 feet
½ mile	4.9 feet
1 mile	4.2 feet

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84 Grace Dir. at 8-9.
85 Grace Dir. at 11.
86 Grace Dir. at 8.
87 Grace Dir. at 12-14.

In addition, Mr. Keating estimated the regional rate of aquifer decline, from general usage other than that of the Project, to be 1.2 feet per year, for 12 years, for a total of 14.4 feet. When combined with the drawdown specifically from the Project, the estimated drawdowns for the above distances would total 20.0, 19.3, and 18.6 feet, respectively. All numbers are based on an assumed daily usage of 233,000 gallons of water per day. Mr. Keating noted that there are 1,025 feet of water available in the Lower Patapsco aquifer at Cove Point.

To address concerns about the Project's effect on water available to the Calvert County Department of Public Works ("DPW"), Mr. Keating also evaluated the effect of withdrawal of 275,000 gallons per day for a 60-day period and concluded that the effect on the Lower Patapsco aquifer of an additional drawdown of 42,000 gallons per day (above 233,000) gallons per day, at a distance of 14 miles from the Project, would result in a drawdown of 0.0 feet. In short, according to Mr. Keating the maximum monthly drawdown would have "no discernible effect" on the water supply of the Calvert County Department of Public Works ("Calvert County DPW").[88]

Mr. Grace addressed the testimony of AMP's witness Dr. Helms in reply testimony. He reported that even accounting for water usage by residents of Calvert and Charles Counties between 2002 and 2030, there would still be 1000 feet of water available in the Lower Patapsco aquifer above the 80% management level. Further, an on-site aquifer test predicted that water usage by DCP would only result in a drawdown of five feet at one-half mile from the production well. Mr. Grace concluded that "given the large amount of available drawdown in the region of the use, and the relatively small drawdown

[88] Keating Dir. at 11.

projected from the proposed use, the MDE WMA does not concur with Dr. Helm's recommendation of the need to evaluate the additional impact from DCP's request on water levels."[89] However, after conclusion of the hearings, PPRP submitted a proposed additional condition that requires DCP to establish a trust in the amount of $190,000 for the Maryland Geological Survey to conduct subsidence monitoring in or near Calvert County.[90]

The effect of the Project on local economic conditions was also an issue in this case. Some parties also raised economic concerns relating to the State as a whole. DNR witness Hall addressed a wide range of economic issues. As esthetic concerns may also affect economics, especially in areas such as Calvert County where tourism is important, Mr. Hall also addressed issues surrounding visual impact. Mr. Hall is a consulting economist who specializes in regional economies and socioeconomic impact assessments.[91] Mr. Hall's sources for his analyses and conclusions included documentation filed in support of the Project, interviews with experts at "many" State agencies, including the State Highway Administration ("SHA") and the Maryland Historical Trust. He also visited the Cove Point site in person. His review covered economic impacts, population and housing impacts, and transportation, land use, property value, visual, government revenue, and historical and cultural resource impacts. Mr. Hall's analyses at times attempt to isolate the effects of the Generating Station, while at other times he reviewed the effect of the entire Project.

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89 Grace Rep. at 4.

90 *See* Final Recommended Licensing Conditions of the Reviewing State Agencies, April 17, 2014, at 56.

91 Hall Dir. at 1.

Mr. Hall concluded that the employment and income effects of the Project would be significant, but that only a small portion of such effects would be attributable to the electric Generating Station.[92] He estimated that construction of the Generating Station would result in an on-site construction labor force of about 120 full-time equivalent ("FTE") jobs (360 person years over three years) and more than $14 million in wage and salary compensation He noted that his estimates were "significantly less than the 6,300 person-years and $700 million in labor income DCP estimated the entire project would generate." (Emphasis supplied.) He also estimated that the entire Project would generate 26 FTE jobs, but FTE jobs generated by the Generating Station alone would, again, be significantly fewer.[93] He concluded that the overall impacts of the Generating Station would be "relatively small" compared to the overall Project[94]. Mr. Hall also concluded that "few population and housing impacts would be attributable to the electric generation component of the overall Project."[95]

Traffic affecting several places on Calvert County roads and intersections are cause for concern, according to Mr. Hall. Those concerns have given rise to licensing conditions H-1 through H-7 proposed by PPRP. The conditions require DCP to develop and submit traffic management plans for construction equipment to the appropriate local and state authorities, and to monitor traffic at key intersections during construction.

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[92] Hall Dir. at 4.
[93] Hall Dir. at 4-5.
[94] Hall Dir. at 5.
[95] Hall Dir. at 6.

The Project's impact on Calvert County's Department of Public Works would be limited, according to Mr. Hall, to the requirement that DPW issue grading permits, and provide personnel to accompany oversized/overweight loads.[96]

Mr. Hall predicted that, overall, direct and permanent impacts to land use would be confined to the DCP site within an area already developed. Few indirect impacts on land use from the LNG site are expected, according to Mr. Hall, as the LNG site is buffered by forest area under conservation easement, State park land, and a recreation area.[97]

Mr. Hall concluded that, as Calvert County's population has grown by more than 250% during the 30 years the Cove Point facility has been in place, the proposed Project will have little or no effect on property values. He expects that the proposed Generating Station will have an especially limited effect, due to construction of a sound barrier within the perimeter of the site.[98]

Mr. Hall forecasted the following revenue impacts:

- $25 million payment in lieu of taxes (“PILOT”) (2018);
- $15.1 million in annual payments on existing equipment for the duration of the five-year PILOT 2019-2022);
- After the PILOT expires, DCP will receive 42% relief on real and personal property taxes for nine years (2023-2031);
- At the end of the nine-year period, the Project will be taxable at 100% of its value, at an estimated $55 million in annual tax revenues (2032 and thereafter).[99]

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96 Hall Dir. at 17.
97 Hall Dir. at 12-13.
98 Hall Dir. at 13-14.
99 Hall Dir. at 15-16.

As Calvert County's fire, rescue, and emergency medical departments are volunteer systems, Mr. Hall concluded that the Project could have some adverse impact on those resources. PPRP has proposed a licensing condition requiring development of timely response options between the Project and Calvert County's Fire-Rescue-EMS Division and creation of emergency vehicle access lanes on the site.[100]

Mr. Hall's overall conclusion was that the net fiscal impact of the Project will be positive for Calvert County, given the size of potential tax revenue and minimal Project-related outlays by the County.[101]

Visual impacts of the Project would be limited, according to Mr. Hall, due to forest buffers. Outdoor lighting required by OSHA and Homeland Security should be mitigated by PPRP's proposed licensing condition that DCP develop a lighting distribution and glare reduction plan.[102].

Mr. Hall noted that there are few cultural resources close to DCP and that previous archaeological surveys at the DCP site revealed no cultural resources to be present. A formerly unknown historic site was discovered in Offsite Area A, which the Maryland Historical Trust has determined to be eligible for listing in the National Registry of Historic Places and which should be protected by a 50 foot buffer zone. Testing also identified four underwater locations possibly representing submerged cultural resources. PPRP recommended a licensing condition directing DCP, in constructing its barge pier in Offsite Area B, to avoid those spots by as much as 20 to 35 feet.[103]

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[100] Hall Dir. at 16-17.
[101] *Id.*
[102] Hall Dir. at 14-15.
[103] Hall Dir. at 20.

Mr. Hall reported that PPRP has concluded that construction and operation of the Project would not affect cultural resources such as the Southern Maryland Heritage Area, Baltimore and Drum Point Rail Trail, Flag Ponds-to-Solomons Trail, Captain John Smith Chesapeake National Historic Trail, Star Spangled Banner National Historic Trail, or The Chesapeake Bay Gateways Network.[104]

Construction of the Project will disturb certain areas of existing forest and shoreline, or "aquatic and terrestrial resources." DNR witness Harriott assessed possible Project impacts on those resources, including construction sites A and B, which are not at the LNG terminal. He noted 103.99 acres of forest will be lost, but it will be mitigated by 217 to 227 acres of forest protected per PPRP condition B-6.[105]

Mr. Harriott also maintained that destruction of forest in Offsite Area A could adversely affect forest interior dwelling species ("FIDS"), such as the scarlet tanager, barred owl, pileated woodpecker, and eastern whippoorwill. He further stated that during the construction period, light, noise, and activity would affect wildlife, and vegetation clearing could cause loss of nests and nestlings, as well as colonization of invasion species[106].

DCP proposes to mitigate clearing effects in Offsite Area A with 100 foot stream and wetland buffers, planting of native vegetation, and use of best practices. Mr. Harriott noted that Offsite Area B is a temporary site that will be restored after the construction

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[104] Hall Dir. at 21-22.
[105] Harriott Dir. at 3-4.
[106] Harriott Dir. at 5-6.

phase of the Project, it is not located in a migrating bird nesting area, and that construction effects will be short term.[107]

The proposed Project will result in the permanent filling of 0.06 acre of non-tidal wetlands at the LNG terminal, and 0.17 acre of non-tidal wetlands at offsite Area A. Mr. Harriott noted that forest clearing in Offsite Area A "will likely increase polluted runoff and sedimentation into the stream systems and wetlands ... . This will result in degradation of the existing habitat, increased sedimentation, and increased water temperatures," due to "the conversion of stream water from subservice to surface." Mr. Harriott emphasized that "DCP ... must evaluate [stream water management] using the 2011 [Maryland Department of the Environment] standards and by maximizing stream buffers and reforestation when applicable." DCP has completed "an updated, final maximized stream buffer plan to protect the riparian areas and natural infiltration capability …" of Offsite Area A.[108]

Mr. Harriott stressed that a stream to be bridged at Offsite Area A is upstream of Helen Creek Hemlock Preserve, the southern most hemlock forest in the United States. He noted that excessive sedimentation and pollution from upstream sources would be detrimental to the hemlock forest.[109]

Mr. Harriott referenced other threatened or endangered species that could be affected by the construction or operation of the Project, including rare dragonflies and

[107] Harriott Dir. at 6-7.
[108] Harriott Dir. at 8.
[109] Harriott Dir. at 10.

sturgeon, as well as certain plants. He relied on DNR's recommended conditions as the appropriate means of mitigating potential adverse impacts on those species.[110]

As construction of the temporary barge offloading pier in Offsite Area B will potentially have adverse noise impacts, Mr. Harriott noted that a vibratory rather than an impact hammer would reduce noise and also reduce water turbidity. He further pointed out that Dominion will contribute to oyster restoration efforts, prepare an oyster mitigation plan, plant oyster shell and spat near Offsite Area B, and create artificial reefs following the end of construction and the dismantling of the barge pier at Offsite Area B.[111]

DNR witness Mountain examined the potential noise levels associated with the construction and operation of the Project. She noted, first, that noise from the power plant will be indistinguishable from overall Project noise. Accordingly, she evaluated the noise sources associated both with the proposed Generating Station and with associated facilities at the proposed LNG terminal.[112]

Ms. Mountain noted that COMAR 26.02.03 specifies that maximum allowable noise levels for residential areas are 55 dBA at night and 65 dBA during the day. She estimated potential noise impacts of 57.2 and 52.6 at the nearest property boundaries, indicating “a slight exceedance of the 55 dBA nighttime limit at one location.” She opined that PPRP's assumptions were conservative, however, and actual noise levels were expected to be less than those calculated. With adherence to PPRP's license conditions, Ms. Mountain concluded that DCP was capable of meeting regulatory standards regarding

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[110] Harriott Dir. at 10-12.
[111] Harriott Dir. at 13-16.
[112] Mountain Dir. at 3.

noise, noting that the licensing conditions simply require DCP to measure sound levels and "make operational or design changes as needed to assure regulatory compliance."[113]

In his reply testimony, Mr. Hall addressed esthetic, sewerage, traffic, deforestation, and viewscape issues, several of them raised by Mrs. Susan Allison in letters commenting on DCP's CPCN application. As to sewerage capacity during the Project's construction phase, Mr. Hall stated that the Calvert County Department of Public Works "expects the water and [sewer] mains will be in place before the commencement of construction at the terminal site."[114]

Regarding traffic, Mr. Hall referred to recommended license condition H-2, which requires DCP to submit a Transportation Management Plan and a Maintenance of Traffic Plan for overweight loads to the State Highway Authority. Further, Mr. Hall noted that DCP would be required to monitor traffic congestion at the intersection of MD 2/MD 4 and make shift changes or roadway improvements, if necessary.[115]

As to esthetic concerns, Mr. Hall added, in relation to concealment of the 60 foot sound barrier along the west and south sides of the Cove Point site, DCP has proposed installing additional natural screening at the site, and that PPRP is continuing to evaluate the potential visual impact of the proposed installation.[116]

Dr. Estomin submitted reply testimony in response to the direct testimony of SC-CCAN witness Powers. Dr. Estomin addressed Mr. Powers' assertion that export of liquefied natural gas from Cove Point would raise natural gas prices in Maryland, to the

[113] Mountain Dir. at 4-5.
[114] Hall Rep. T. at 4.
[115] Hall Rep. T. at 4-5.
[116] Hall Rep. T. at 6.

detriment of Maryland customers. Dr. Estomin countered that Mr. Powers had not demonstrated his conclusion "with any reasonable degree of certainty."[117] Dr. Estomin also asserted that Mr. Powers had not quantified the price impact of natural gas export to determine if economic impacts on prices and employment in Maryland would be meaningful.

Dr. Estomin also related that the U.S. Department of Energy, Office of Fossil Energy ("DOE/FE") addressed the issue of economic benefits related to LNG export in its Docket No. 11-128-LNG. DOE/FE concluded that export from Cove Point of 0.77 Bcf/day of natural gas was "not inconsistent with the public interest." The DOE/FE further found that LNG exports were not likely to affect the overall level of employment in the United States, or reduce the quantity of natural gas to domestic customers such that the economic benefits of export would be negated.[118]

On April 17, 2014, PPRP submitted new conditions for incorporation into the CPCN. Those conditions addressed new landscaping requirements, monitoring ground subsidence due to water usage, and a requirement that DCP make a one-time contribution to the Maryland Energy Assistance Program. In addition, a newly proposed condition (J-4) is intended to support the State's greenhouse gas reduction goals through either an offer to support adoption of DCP's EDGE[SM] technology by Maryland utilities or establishment of a trust or similar instrument in the event that any utilities have not executed a licensing agreement for the technology by January 1, 2017. Included in the conditions are provisions allowing PPRP to inspect and confirm that DCP is adhering to all

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[117] Estomin Rep. T. at 4.
[118] Estomin Rep. T. at 7.

requirements. DCP has agreed to all prior and new conditions. Certain of these conditions are discussed elsewhere in this Order.

C. Accokeek, Mattawoman, Piscataway Creeks Communities Council, Inc.

AMP opposes granting the CPCN. It turns first to a general legal argument regarding the issue of Calvert County's right to approve or disapprove of the LNG Project. Noting that this Commission is required to give weight to the opinions of local governing bodies, and that testimony at the March 1, 2014 public hearing indicated that the Calvert County Board of County Commissioners ("Board") was unanimously in favor of the Project, AMP nonetheless asserted that the Board was preempted from attempting to use its recommendation power to approve the liquefaction project by the National Gas Act ("NGA") in U.S.C.S. § 717, *et seq.*, which gives the FERC "exclusive power" to regulate the siting, construction, and operation of LNG terminals.[119].

AMP also argues that the Board is preempted from any intentional attempt to regulate the siting of an LNG terminal based on the economics of LNG export. According to AMP, the DOE, under the NGA, has exclusive power to consider the economic impact of LNG export and import.[120] In sum, AMP maintains that as "the DOE specifically considered many of the facts that DCP and Commissioner Clark now put forth in favor of the Liquefaction Project," the Board's arguments cannot be given weight in the ultimate decision in this case, as that would essentially preempt overriding Federal authority.[121]

AMP further urges that the Board's recommendation lacks validity, as it was not based on the Comprehensive Plan of Calvert County. AMP's argument is that the Board

[119] AMP In. Br. at 17.
[120] AMP In. Br. at 19, citing 15 U.S.C.S. § 717 b.
[121] AMP In. Br. at 20-21.

has not actually made a determination specifically regarding the Generating Station, so it cannot have determined that the Generating Station was consistent with Calvert County's Comprehensive Plan.[122]

AMP then asserted that "construction of a Generating Station is not consistent with the Energy subsection of the Calvert County Comprehensive Plan."[123] The first objective of the Comprehensive Plan, AMP notes, is to promote energy conservation and efficient use of energy resources. AMP contends that construction of the Generating Station would accomplish neither of those objectives. Even at a 50% capacity factor, according to AMP, the "station would still use more energy than all Calvert County residences combined."[124] AMP also concludes that other goals of the Comprehensive Plan, including ensuring that renewable energy sources are used, that energy use does not adversely impact the environment, and that energy consumption is reduced, are inconsistent with approval of the Generating Station. The Project's use of natural gas, in AMP's view, would expel "millions of tons" of pollution per year into the atmosphere, and will increase energy consumption.[125]

AMP finds that the Board did not base its recommended approval of the Generating Station on the County's Comprehensive Plan, and that the Plan's requirements do not support construction of the Generating Station. Therefore, AMP proposes that "the

[122] AMP In. Br. at 21-22.
[123] AMP In. Br. at 22.
[124] AMP In. Br. at 22-23.
[125] AMP In. Br. at 24

PSC should consider this application as if the Board had made the negative recommendation required by the County Comprehensive Plan."[126]

As to economic issues, AMP argues, first, that DCP's Project does not have sufficient economic benefit to merit grant of a CPCN. AMP's thesis, essentially, is that an electric Generating Station that is not connected to the PJM grid, and benefits only one customer, has no benefit to the public at large that justifies the pollution from its fossil fuel-based generation.

AMP asserts that "the only benefits [that DCP] asserted under § 7-207(e)(2) are economic benefits," and those benefits are either uncertain or inadequate.[127] AMP rejects what it understands as DCP's "statutory interpretation" of the § 7-207 standards, specifically that "the mere construction of a new [generating] facility would satisfy the requirements of § 7-20(e)(2)(ii)." Such an interpretation, according to AMP, would ironically take economic impacts out of the picture, rendering the statute meaningless.[128] AMP further points out that the Maryland Legislature exempted some smaller generating stations that serve only one customer from CPCN requirements, including consideration of the stations' economic effects, but did not exempt from economic scrutiny generating stations of the size DCP proposes to build, requiring a focus on economics in the case of DCP's proposal for a large generator. AMP admits that "new generating capacity is presumed to create a benefit under the Electric Customer Choice and Competition Act" because new generating stations supposedly compete with existing stations, creating economic efficiency. As DCP's generating station will not provide power to the

[126] AMP In. Br. at 24.
[127] AMP In. Br. at 3-4.
[128] AMP In. Br. at 6.

marketplace, AMP concludes that its economic benefits would be “substantially smaller” than a plant of equal capacity that did provide electricity to the grid.[129]

AMP also argues against the Project because it will not contribute to the stability and reliability of Maryland's electric system. AMP points out that DCP itself does not assert that the Project will contribute to stability and reliability, as it will not export any power. AMP therefore urges that the Project's failure to actively contribute to the stability and reliability of the State's electric system is a negative where grant of a CPCN is concerned.[130] AMP argues an agreement DCP signed with the Sierra Club and the Maryland Conservation Council also prohibits export of power from the Cove Point site. AMP states that the agreement would prohibit export of power by DCP from Cove Point even if a study agreed to by DCP showed that such export was feasible.[131]

AMP also claims that DCP has failed to provide the Commission with enough information for it to evaluate the economic impact of the Generating Station. AMP notes that, according to PPRP, DCP's application covered the liquefaction project as a whole, and was not focused on the generating plant.[132] DCP witness McKinley's estimate that the generating plant accounted for about 20% of the entire project's effects was undocumented and unsupported, according to AMP.[133] As it concludes that DCP has not provided complete or even adequate information on the Generating Station itself, and that the Commission cannot consider the effect of the Generating Station on economics without

[129] AMP In. Br. at 11.
[130] AMP In. Br. at 12.
[131] AMPIn.Br.at13-14
[132] AMP In. Br. at 25.
[133] AMP In. Br. at 27 and 42-43.

such information, AMP therefore urges the Commission to deny DCP's request for a CPCN.

AMP also contends that the Commission cannot approve the overall Project based on DCP's economic arguments. The Department of Energy, according to AMP, has “exclusive authority” to consider the economic benefits of LNG export, for the Commission to rule on the Project based on economic considerations would, in DCP's view, establish a new licensing condition.[134]

AMP concludes that the economic consequences of the overall Project are currently unknown, and would be negative if known. While AMP admits that the Project will likely generate $34.1 million in total tax revenue per year for Calvert County, it argues that negatives, including air pollution, decrease in manufacturing, and costs of additional County services, outweigh the monetary benefits.

More broadly, AMP contends that the economic studies submitted by DCP to this record focus on national costs and benefits rather than those unique to Maryland. Further, the studies show that those who would benefit most from LNG export would be “gas companies, resource owners, and owners of natural resource stocks.”[135] In support of its argument, AMP notes that the Cove Point terminal is owned by Dominion Cove Point LNG, LP, which is in turn owned by other Dominion entities, and that Dominion Resources will be the ultimate beneficiary of contracts for LNG export. In addition, AMP

[134] AMP In. Br. at 28.
[135] AMP In. Br. at 31-32, citing Tr. at 708,

contends that such export to other countries will increase natural gas prices in Maryland, to the detriment of Maryland consumers.[136]

AMP focuses its reply brief on an analysis of the Commission's statutory responsibility in deciding to grant or deny DCP's application for a CPCN. AMP urges the Commission to consider its broader statutory authority, and it should "look beyond the applicable [permitting] regulations."[137] AMP argues that if the Commission were to simply grant the CPCN based on the analyses and recommendations of State agencies, essentially in a rubber stamp process, that would not satisfy the requirement of PUA § 7-207(e) that the Commission exercise "due consideration" of various effects the Generating Station could have on air, water, the environment, etc.[138] AMP emphasizes that "[i]f the Commission were merely collecting and rubber stamping the Maryland Department of the Environment's, and other bodies' determinations, that would not require consideration."[139] AMP also notes, however, that "[i]t is clear that the necessary technical expertise to understand and apply the relevant environmental regulations rests with the Maryland Department of the Environment, Department of Natural Resources, and associated bodies, rather than with the Commission."[140] AMP therefore sees that "a larger purpose" for the Commission is necessary if the entity with "lesser expertise" (the Commission) had permitting power over "state authorities, with presumably greater expertise."[141]

AMP concludes as follows:

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[136] AMP In. Br. at 34-35.
[137] AMP Rep. Br. at 6.
[138] AMP Rep. Br. at 6.
[139] AMP Rep. Br. at 6.
[140] AMP Rep. Br. at 9.
[141] AMP Rep. Br. at 9.

> The only statutory construction that doesn't render the statute ridiculous is that the relevant Maryland Departments are required to inform the Commission of the Generating Station's impacts on the environment, including compliance with the applicable regulations and satisfaction of permit conditions, and then the Commission uses that information to inform its analysis of whether the harms to the environment outweigh the benefits generated by the other factors.
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> These provisions only make sense if the Commission is empowered to consider the overall effects on the environment, rather than simply judging compliance.[142]

AMP concludes that "the Commission may look at environmental damage that may be legally allowable, but nonetheless not in the public interest in Maryland."[143]

AMP argues that, even though the Generating Station for which DCP requests a CPCN and the larger LNG plant are intertwined, the Commission has authority only to review the Generating Station. AMP contends that DCP did not demonstrate the economic effects of the Generating Station in isolation, even though DCP admitted that would be possible, and that DCP attempted to place on other parties the burden of quantifying the negative effects of DCP's Generating Station.

AMP contends that DCP "has simply decided not to" model the economic impact of LNG export on Maryland consumers.[144] While AMP maintains that the Commission may only address the CPCN request related to the Generating Station, AMP also maintains that even if the Commission were to address the larger economic effects of the

[142] AMP Rep. Br. at 10-11.
[143] AMP Rep. Br. at 12.
[144] AMP Rep. Br. at 18.

LNG plant, it has neither the necessary information nor the legal authority to do so. On the latter point, AMP contends that Maryland's Federally approved Coastal Zone Management Program grants the Commission power to license Generating Stations under § 7-207(e), but not to consider the economics of LNG export. AMP states that "[i]n general, states are prohibited from regulating LNG terminals by the Natural Gas Act, 15 U.S.C. §§ 717 *et seq.*,"[145] but that the National Oceanic Atmospheric Administration specifically permits Maryland to exercise its authority over Generating Stations under existing State law. AMP reiterates, however, that under federal law, the Commission cannot consider the economics of the LNG plant, as that would essentially open the way for the Commission to impose conditions on the entire LNG facility, contrary to Federal law.

D. Sierra Club – Chesapeake Climate Action Network

SC-CCAN oppose the Project on grounds that, when considered in light of the statutory criteria of PUA § 7-207(e)(2)(i)-(vii), it is a net negative. SC-CCAN first note that the 130 MW Generating Station will not contribute to the "stability and reliability" of the State's electric grid, as the plant will be for the sole use of the Cove Point LNG facility and will not, at this time nor in the near future, provide electricity to the grid. SC-CCAN points out that while DCP agreed to assist in a study of the feasibility of running a transmission line from the plant to the grid, the Company has consistently maintained that running such a line is not possible and is in fact prohibited by an agreement among Dominion, Sierra Club, and the Maryland Conservation Council.[146]

[145] AMP Rep. Br. at 19.
[146] SC-CCAN In. Br. at 9-10.

SC-CCAN focused its analysis on the air pollution impacts of the generating plant, as well as on whether the Project will have economic benefits outweighing likely negatives, or "dis-benefits." As to air emissions, SC-CCAN emphasizes the general point that DCP is seeking to emit more than two million tons of GHGs per year and will be compensating only by withdrawing emission allowances from a Limited Industrial Exemption Set-Aside, rather than purchasing new allowances.[147]

At a more detailed level, SC-CCAN contends that DCP has not minimized air pollution consistent with the Federal BACT and LAER requirements, especially as Calvert County and Maryland as a whole are non-attainment areas for ozone and its precursors, NO_x and VOCs. Specifically, "the NO_x LAER for auxiliary boilers should be 5 ppm ... as a 3-hour average, <u>not</u> 8.2 ppm as currently proposed."[148] In support of this assertion, SC-CCAN reports that "numerous comparable boilers" have achieved the 5 ppm, 3-hour limit, and that California's SCAQMD requires all boilers, steam generators, and process heaters of size 75 MMBtu or larger burning natural gas to achieve a NO_x emission rate of 5 ppm on a 15 minute average, and all such equipment between 20 and 75 MMBtu/hr burning any gaseous fuel to achieve the same limits.[149] Those limits, according to SC-CCAN, are "considerably more stringent than DCP's proposed 8.2 ppm rate at a 3-hour average."[150]

SC-CCAN rejects DCP's and PPRP's arguments that the large size of the proposed Cove Point boilers would prevent achievement of a 5 ppm, three-hour average emission.

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[147] SC-CCAN In. Br. at 27-28.
[148] SC-CCAN In. Br. at 30. *Emphasis original.*
[149] SC-CCAN In. Br. at 30.
[150] SC-CCAN In. Br. at 30-31.

SC-CCAN point out that larger sources, even according to PPRP, are usually subject to more restrictive requirements than smaller sources. SC-CCAN also rejects arguments by PPRP that the larger amount of nitrogen in process gas would inevitably lead to higher NO_x emissions when combusted. SC-CCAN points out that witness Powers testified that the Company's testimony acknowledged that process gas has a lower heating value than pipeline gas. As process gas burns cooler than pipeline gas, it would not emit as much NO_x as pipeline gas.[151] Most fundamentally, SC-CCAN rejects PPRP's witness Powers' assertion that the ability of a pollution source in California to reduce emissions below DCP's projected level is irrelevant to DCP's Project. On the contrary, SC-CCAN argues that adopting a lower rate of emissions achievable elsewhere "is in fact precisely what LAER requires." (Emphasis in original) SC-CCAN emphasizes that "if a class of sources is required to achieve an emission rate in California, under Maryland's definition of LAER this class of sources must meet the same standard in Maryland."[152] As PPRP has not chosen to adopt LAER standards applicable in California, SC-CCAN argues that Marylanders will be exposed to unnecessarily high levels of air pollution.[153]

SC-CCAN similarly contends that DCP's and PPRP's NO_x limit for combustion turbines is not LAER – and for the same reason: DCP and PPRP have ignored lower limits achieved elsewhere. "The NO_x LAER ... for combustion turbines should be 2.0 ppm ... as a 3-hour average, not 2.5 ppm as currently proposed."[154] SC-

151 SC-CCAN In. Br. at 32.
152 SC-CCAN In. Br. at 33.
153 SC-CCAN In. Br. at 34.
154 SC-CCAN In. Br. at 34.

CCAN concludes that the 2.0 ppm NO_x emission rate on a 3-hour average "has been achieved in practice by many units," and therefore can and must be achieved by DCP.[155]

In sum, SC-CCAN asserts that PPRP's response that emissions from this Project will not contribute to a violation of ambient air quality standards is "perverse and incorrect," and apparently based on DCP's purchase of emission offsets from facilities already curtailing their emissions.[156]

On the subject of air quality, SC-CCAN argues that DCP should control fugitive emissions through use of all "leakless" components at its Cove Point facility.[157] At present, however, DCP plans to rely on leak detection and repair ("LDAR") to prevent some fugitive emissions, rather than on 100% leakless technology. SC-CCAN argues that instead of employing an LDAR approach that, according to DCP, could entail a 15-day lapse between leak and repair, DCP should install leakless technology that would prevent leaks altogether.[158]

To DCP's contention that strict California NO_x emission limits are not applicable to the Cove Point boilers due to use of process gas, SC-CCAN responds that the SCAQMD rules require "<u>any unit burning gaseous fuels</u>" to meet a "5 ppm NO_x with a stringent 15 minute average time." (Emphasis in original). SC-CCAN further claims that

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155 At a more detailed level, SC-CCAN notes that to achieve a LAER NOx emissions rate of 2.0 ppm, the selected catalytic converters attached to the turbines would need to reduce NO_x concentration by 92%. DCP determined, from information provided by PPRP in response to data requests, that Cormetech and Haldor Topsoe, providers of SCRs to the Project, could achieve a NO_x removal efficiency of 95%. SC-CCAN also criticizes DCP for supporting DCP's proposed selective catalytic reduction ("SCR") 90% control efficiency limitation only with an EPA document from 2000 that references control efficiencies from 65% to 90%. SC-CCAN also notes that NOx emissions can be reduced to 2.0 by injection of additional ammonia into the combustion process, and that this has been done at "other combustion turbines" with less ammonia emission ("ammonia slip") than DCP currently predicts.SC-CCAN In. Br. at 35-36.

156 SC-CCAN In. Br. at 36-37.

157 . (SC-CCAN admits that DCP plans to use some leakless products, including leakless canned motor pumps, magnetic drive pumps, welded connections, and possible other technologies at Cove Point.)

158 SC-CCAN In. Br. at 38.

the SCAQMD Rule 1146 applies to an "extremely broad class of units" that includes boilers, steam generators, and process heaters larger than 5 MMBH, which SC-CCAN claims belongs to the same class of category as DCP's auxiliary boilers that burn process gas.[159]

SC-CCAN dismisses DCP's reliance on vendor statements that NO_x emissions proposed by PPRP are the lowest achievable. The only vendor guarantee, SC-CCAN notes, is from Cleaver-Brooks, manufacturer of the auxiliary boiler, not Haldor Topsoe, and that the guarantee promises to achieve DCP's goals, not a specific emission level. Based on its analysis, SC-CCAN continues its insistence that 5.0 ppm NO_x is LAER for DCP's auxiliary boilers.

SC-CCAN also claims that NO_x LAER for the Project's combustion turbines is 2.0 ppm and asserts that DCP appears to rely on a hearsay conversation and information from a boiler manufacturer rather than an SCR manufacturer for its claim that 2.5 ppm is LAER for NO_x in this case.[160] SC-CCAN further objected to PPRP's LAER review as not including "the right sources." Specifically, SC-CCAN objected that Southern California sources were left out of PPRP's study, but that PPRP would have discovered in the SCAQMD area comparable boilers with more stringent limits than PPRP was proposing.[161]

SC-CCAN also devotes considerable argument to showing that the generating plant (and indeed the entire Cove Point facility) will entail a net economic disadvantage for Maryland and the surrounding region. While SC-CCAN admits that the Project will

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[159] SC-CCAN Rep. Br. at 8.
[160] SC-CCAN Rep. Br. at 11.
[161] SC-CCAN Rep. Br. at 12. SC-CCAN's position on the need for leakless components is the same as in its initial brief.

have "localized tax and wage benefits" in Calvert County, SC-CCAN urges that other "dis-benefits" of the Project significantly outweigh the benefits. A main focus of SC-CCAN's concern is its contention that export of LNG from Cove Point will cause a significant increase in natural gas prices for Maryland residents. Such price increases will not only harm most Maryland residents, SC-CCAN claims, but it will help only the oil and gas industry, owners of domestic gas resources, and other investors in the gas industry.[162] SC-CCAN hypothesized that increased natural gas prices would lead to increased coal usage in Maryland, with added air pollution "in [a] state suffering from the worst air quality in the east."[163]

SC-CCAN notes, however, that only one study, the Navigant study commissioned by DCP, has attempted to isolate the impact of LNG exports from Cove Point. That study, according to SC-CCAN, "casts serious doubts on the benefits of [the Cove Point] project." It found that at the Henry Hub natural gas prices would increase from 4.1% to 6.0% over the years 2020 to 2040 if during that period DCP were regularly exporting LNG from Cove Point.[164] In its Reply Brief, SC-CCAN states that the Navigant study predicted an increase in natural gas prices between $47 million and $107 million for the 2017 – 2040 period.[165]

SC-CCAN further notes that a September 2013 DOE order approving exports of 770 million cubic feet of natural gas to "non-free-trade countries" does not give DCP's argument the support that DCP contends it does. The DOE order takes a national

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[162] SC-CCAN In. Br. at 12-13.
[163] SC-CCAN In. Br. at 15.
[164] SC-CCAN In. Br. at 18
[165] SC-CCAN Rep. Br. at 15.

perspective, is not specific to Maryland or the East Coast, is based on studies that pre-date the Navigant study, and does not address environmental issues. SC-CCAN also points out that the broad national scope of the DOE order, combined with DOE's presumption that export projects are beneficial unless specifically shown to be otherwise, undermines the DOE study as support for the Project.[166] In addition, SC-CCAN argues that Dr. Estomin's contention that increased LNG export could raise natural gas prices region-wide does not help Maryland customers.[167]

SC-CCAN also challenges PPRP's conclusion as to the positive economic impacts of the Project. SC-CCAN notes that DCP will participate in a PILOT program that requires a one-time payment of $25 million to Calvert County in 2018, followed by five years of additional payments by DCP to Calvert County, followed in turn by 42% tax relief on all real and personal taxes paid by DCP for the following nine years.[168]

"The income stream," from property taxes SC-CCAN assert, "will drop precipitously between years 5 and 6" after Project construction to levels that could result in lower tax income to the County than if DCP had simply been taxed on its existing infrastructure.[169] SC-CCAN also points out that as DCP could not move its facility to another locale or close – in violation of its contracts to supply LNG – Calvert County does not need to provide DCP with such generous tax incentives to remain.

SC-CCAN also claims that an economic analysis focused narrowly on DCP's Generating Station will show that construction could not be shown to be economic. The

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[166] SC-CCAN In. Br. at 23.
[167] SC-CCAN Rep. Br. at 16.
[168] SC-CCAN In. Br. at 24; We note that Hall's Direct Testimony refers to a one-time payment of $25 million to Calvert County in 2018 as the first year of the five year PILOT, with the additional $15.1 million annual payments taking place in years two through five (Hall Dir. At 15-16).
[169] SC-CCAM Rep. Br. at 16.

data on which to base such a showing has never been provided, according to SC-CCAN. Without such data, SC-CCAN argues that the adverse environmental and esthetic impacts of the Generating Station would outweigh the (unquantified) economic benefits.

As to esthetic benefits or "dis-benefits" of the Project, SC-CCAN notes that the offshore pier at Offsite Area B and related construction equipment will be visible from Solomons Island, a significant tourist venue. SC-CCAN predicts that such a visible change "will alter the character and reduce the tourism appeal of the island."[170] The Project will also increase traffic congestion in the area, and will stress the locale's sewage disposal capacity, according to SC-CCAN. Planning for the sanitary needs of 1,441 construction workers has not been adequate, SC-CCAN maintains.[171]

In its reply filing, SC-CCAN posits that regardless of whether the Commission addresses only the effects of the proposed Generating Station or the entire Project, the "dis-benefits" outweigh the benefits.[172] The visual impacts, combined with concerns about traffic, inadequate sewage treatment, and limitations on transmitting electricity to the grid, combined with air emission issues, all fail to support DCP's CPCN application. SC-CCAN also reiterates that the Project's incremental greenhouse gas emissions significantly impair Maryland's ability to achieve in-state greenhouse gas reduction targets. Because the facility will be exempt from RGGI and instead would utilize a Limited Industrial Set-Aside, SC-CCAN asserts that greenhouse gas emissions in Maryland will "rise precipitously."[173]

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[170] SC-CCAN In. Br. at 40-41.
[171] SC-CCAN In. Br. at 43.
[172] SC-CCAN Rep. Br. at 5.
[173] SC-CCAN Rep. Br. at 6.

Should the Commission approve the CPCN over its objection, SC-CCAN would require several additional conditions be imposed. First, SC-CCAN proposes DCP make "[a] significant investment in carbon-free Maryland-based renewables." Such an investment in wind and solar generation would, according to SC-CCAN, mitigate the Project's greenhouse gas emissions, benefit the stability and reliability of the electric grid once the wind and solar generators were connected to the grid, and by adding electricity to the system, would help lower electricity prices.[174]

The second new condition SC-CCAN would impose would be a fuel emission limit for the combustion turbines of 2.0 ppm NO_x as a three-hour average and a final emission limit for the auxiliary boilers of 5.0 ppm NO_x as a three-hour average. SC-CCAN also urges the Commission to require DCP to maximize the use of leakless piping components at the facility.[175]

The final additional conditions proposed by SC-CCAN address esthetic impacts. They would require an additional tree buffer around the Project's 60 foot high sound wall and the parking lot and warehouse area at Offsite Area A, and would require that the barge offloading and other functions at Offsite Area B be moved to another location.[176]

E. Commission Staff

Staff witness DeGeeter addressed only the possible effect of DCP's Project on the stability and reliability of the electric transmission system in Maryland. Mr. DeGeeter concluded that the Project would have no adverse impact on the grid, as long as Staff's proposed conditions were adopted. While noting that the plant would not contribute to the

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174 SC-CCAN Rep. Br. at 24-28.

175 SC-CCAN Rep. Br. at 28.

176 SC-CCAN Rep. Br. at 29.

stability and reliability of the grid, as it will serve solely the liquefaction facility and will not be available to support other demand, he also notes that the Commission previously has approved islanded projects that benefited a single customer. Staff disagrees with AMP's division of the PUA § 7-207(e)(2) considerations into positive, negative, and neutral categories. Further, Staff asserts that "[t]he statute ... does not create a distinction between entities that will sell power to the grid and those that do not", as AMP also tried to create. Staff also denies other assertions by AMP, including a claim that power from generating plants larger than 70 MW must be sold to the grid, and therefore that power from DCP's generators must be sold to the grid. In sum, Staff states that "there is no statutory requirement that the project provide positive benefits to the grid." Instead, the Project could not be approved by the Commission if it would adversely impact the grid's stability or reliability.[177]

Mr. DeGeeter proposes a condition that DCP undertake a detailed feasibility study of the costs and benefits of interconnecting to PJM's system, and report on the results on a quarterly calendar basis. A second proposed condition would require DCP to submit to the Commission and other relevant State agencies a status report on the FERC licensing of the proposed facility within six months after the effective date of the CPCN and every three months thereafter. Three other conditions involved notification of changes in the physical set-up of the facility, delay in meeting the June 30, 2017 in-service date, and notice of compliance with all requirements five days before start-up.[178]

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[177] Staff Rep. Br. at 2.
[178] Staff In. Br. at 9-12.

F. Public Comment

At the March 1, 2014 Public Hearing, approximately 80 members of the public provided comments (some representing larger groups of people) both in support of and opposed to the proposed Project. Few, if any, of the commenters specifically separated out the potential impacts of the Generating Station from the broader impacts of the integrated LNG Project. Comments were related to potential economic, environmental, social and safety impacts from the Project, including the Generating Station. In addition, over 60,000 written public comments and letters, both for and against the Project, were submitted to the Commission prior to the extended comment period deadline. CCAN submitted thousands of these letters to the record in this case, essentially all of them opposing construction of the Project and its Generating Station. Many of the letters forwarded by CCAN raised concerns relating to fracking.[179] Many also requested that the Commission urge FERC to require completion of a full Environmental Impact Statement as part of the review of the Project,[180] and that the Commission reject the entire LNG Project. Letters in opposition were also sent individually from members of the public, some raising concerns about potential safety hazards to neighborhoods adjacent to the Project.

Letters supporting DCP's proposal were received from State and county officials and members of the public, many of them also members of construction unions. These letters focused predominantly on potential economic benefits that would flow from the Project.

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[179] The Commission ruled that fracking is outside the scope of this proceeding. Therefore, we do not give weight to comments relating to potential impacts to or from hydraulic fracturing.

[180] FERC has primary jurisdiction to review the entire Project and to determine whether an EIS is required. On May 15, 2014, FERC issued a draft Environmental Assessment which concluded that an EIS is not required for this Project.

V. DISCUSSION AND FINDINGS

A. Introduction

On April 1, 2013, Dominion Cove Point, LNG, LP filed with this Commission an application for a CPCN for 130 MW of generating capacity at its proposed Cove Point LNG export facility in Calvert County, Maryland. While we note that the Generating Station and the larger liquefaction Project are integrally related (for example, the generating facility would not be needed if the LNG export facility is not built and operated), our task is to review DCP's request for a CPCN for the Generating Station. That task is made more difficult by the fact that DCP, and to some extent other parties, have provided testimony that addresses the Project as a whole and have not seriously attempted to isolate information that applies uniquely to the Generating Station that we must review. In fact, DCP states that "the Generation Facility and the liquefaction process are inseparably integrated."[181] In contrast, AMP argues that the Commission must limit its review of the economic impacts of the proposed project to the generating facility, citing PUA § 7-207(e)(2)[182] and asserts that the Commission is preempted from considering the economic benefits associated with the entire Project, arguing that responsibility rests with FERC and the DOE.[183]

Oral testimony roughly estimates that the effects of the generating facilities may account for between 5% and 20% of the overall effects of the Project, but we have nothing beyond that to further refine the appropriate number. Nonetheless, the generating station,

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[181] DCP Rep. Br. at 4, citing Tr. 234-235 (Day 1, Gangle).
[182] AMP In. Br. at 3.
[183] AMP In. Br. at 17-18, 27-28.

being only a component of the larger facility, is likely directly responsible for only a fraction of the air emissions, water impacts, and economic effects of the entire Project.

As DCP notes, the Natural Gas Act and FERC precedent expressly contemplate that states will conduct their own review of LNG terminal facilities under applicable state and federal laws.[184] However, DCP selectively identifies which issues it believes the Maryland Commission can and should review. In its Motion to Strike testimony regarding the potential impact of hydraulic fracturing ("fracking") on the economic and environmental impacts of the Project, Dominion argued:

> DCP seeks Commission approval to construct and operate an electric generating station as part of a project to provide liquefaction services to customers who will supply their own natural gas. While there is broad environmental review of DCP's proposed project ... this case is ultimately, like case No. 9218, limited in its inquiry to the proposed generation station.[185]

DCP witness McKinley testified at the hearing that the Company's position is that the CPCN only covers the power block, not the entire liquefaction facility.[186]

Given the unique factual and jurisdictional situation, we conclude that the environmental impacts of the generating facility should be evaluated as part of the entire project or "stationary source" pursuant to the legal requirements under the Federal Clean Air Act.[187] Similarly, the evaluation of potential safety and security impacts of siting the proposed generating facility adjacent to (and intertwined with) the liquefaction facility and storage tanks also should take into account the possibility of a combined accident. In that

[184] DCP Rep. Br. at 4, citing *Sabine Pass Liquefaction, LLC*, pp. 32-40.
[185] DCP Motion to Strike at 6, citing *In the Matter of Calvert Cliffs 3 Nuclear Project*, 2010.
[186] Mr. McKinley notes that the CPCN covers the entire facility for air emissions. Tr. at 364-365.
[187] *See* DCP In. Br. at 11, citing CAA.

situation, the safety impact of the generating facility cannot be segregated from the safety impact of the overall facility.

In contrast, the economic and reliability impacts of the proposed generating facility can be evaluated independently of the economic impacts of the liquefaction facility, which will be reviewed by the FERC. The liquefaction facility has received conditional approval from DOE to export LNG.[188] DCP failed to provide either Maryland-specific or facility-specific economic impact analysis for the liquefaction facility, although it acknowledges that natural gas prices will increase at least to some degree for Maryland customers as a result of increased exports of LNG. Consequently, the record is insufficient to assess the economic element of PUA § 7-207 based on the liquefaction Project as a whole.

As noted earlier, we heard from approximately 80 members of the public at our March 1, 2014, public hearing in Lusby, Maryland and received over 60,000 written comments after the public hearing. We are greatly appreciative of the time and effort citizens have taken to share their views on the proposed LNG Project, including the Generating Station. We have carefully reviewed the in-person and written comments of citizens in favor of and against the Project, as those comments relate to the proposed Generating Station which is within our jurisdiction. We have considered public comments about potential safety and environmental impacts of the Generating Station, which will be located within the LNG facility footprint and near residential neighborhoods, as well as potential economic benefits and harms. Consistent with the limited nature of the CPCN

[188] DOE Order No. 3331, FE Docket No. 11-128-LNG (2013) (Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cove Point LNG Terminal to Non-Free Trade Agreement Nations); DCP In. Br. at 5-6, citing DCP Ex. 8 (DOE Order).

application filed with us, we cannot give weight to arguments that we should reject the entire LNG Project, as that issue is not before us.

We have reviewed the extensive record in this matter carefully. We conclude that if all conditions imposed under this Order are met to address the environmental, economic, health and safety impacts demonstrated in this proceeding, the Generating Station can be built in conformity with applicable Maryland and Federal laws and standards, and in a way that will be consistent with the public convenience and necessity standard. Therefore, we grant the CPCN, subject to the significant conditions proposed by PPRP and subject to the additional conditions we impose, including a new condition of FERC approval and issuance of a permit for the LNG export facility.

B. PUA Section 7-207 Elements

To justify issuance of a CPCN, DCP has the burden to demonstrate that the benefits of the generating facility, including economic benefits, outweigh the environmental, safety, and societal costs of siting the generating facility within the liquefaction Project in Lusby, Maryland. In determining if DCP has met its burden, the Commission must consider the factors delineated in PUA §7-207 of the Public Utilities Article, including but not limited to (1) the recommendation of the local government; (2) the effect of the generating station on the stability and reliability of the electric system; (3) economics; (4) esthetics, historic sites, and aviation safety as determined by the Maryland Aviation Administration and the administrator of the Federal Aviation Administration; (5) air and water pollution; and (6) the availability of means for the required timely disposal of wastes produced by the generating station.

1. Recommendations of Local Government

The Calvert County Board of Commissioners voted unanimously to support this Project.[189] We decline to go behind or discount those recommendations as requested by AMP.

2. The Stability and Reliability of the Electric System

DCP decided to build a generation plant that would solely serve DCP's liquefaction Project. There is no tie to the electric grid and as a result, and no evidence that the generation station will contribute to the stability of the State's electric grid; however AMP and SC-CCAN acknowledge it will not have an adverse impact either.[190] While Commission Staff proposed a condition whereby DCP would study the potential of connecting the plant to the grid, and DCP accepted this condition, the proposal is too speculative to be quantifiable or counted as a potential benefit of this generation station. DCP acknowledged that it would be difficult to tie to the grid, both technically and legally.[191] Consequently, we do not adopt Staff's proposed condition for DCP to undertake an interconnection study.

3. Economics

PPRP witness Hall concluded that the employment and income effects of the LNG Project would be significant, but that only a small portion of such effects would be attributable to the electric generation station. He estimated that construction of the Generating Station would result in an on-site construction labor force of about 120 full-time equivalent ("FTE") jobs for three years. He noted that his estimates were

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189 March 1, 2014 Tr., p. 10; Letter to David Collins from Calvert County Board of County Commissioners (March 25, 2014).

190 AMP In. Br. at 12; SC/CAN In. Br. at 10.

191 DCP Reply Br. at 10; SC-CCAN In. Br. pp. 10-11.; DCP In. Br. at 13

"significantly less" than DCP estimated the entire project would generate. He also estimated that the entire Project would provide 26 FTE permanent jobs, but FTE jobs needed to operate the Generating Station alone would also be significantly fewer. He concluded that the overall impacts of the Generating Station would be "relatively small" compared to the overall Project.[192] DCP did not provide a study to support the number of construction jobs that will be needed to build the generating stations or the number of new, permanent jobs that will be required to operate the Station. In response to questioning at the hearing, Dominion estimated that approximately 20% of the "dollar impact" from the Project could be attributed to the Generating Station,[193] PPRP estimated that the economic effects of the generating facility would be much smaller, approximately 5% of the total LNG facility temporary construction jobs and 2% of the overall salary and wage costs.[194] DCP testified that it will pay $40 million in new revenue to the County, some through a Payment in Lieu of Taxes agreement due to the LNG project expansion.[195] In November, 2013 the Calvert County Board of County Commissioners approved a five-year Payment in Lieu of Taxes (PILOT) and tax relief agreement with DCP that includes a one-time payment in FY 2018 of $25 million and guarantees $15.1 million in annual payments on existing equipment for the duration of the PILOT. After the PILOT term, DCP will receive 42% relief on real and personal property taxes for nine years, after which the Project will become taxable at 100% of its value. Calvert County estimates that it will receive an average of $55 million in total tax revenues annually once the facility is

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[192] DCP In. Br. at 1.
[193] Tr. p. 344.
[194] PPRP In. Br. at 19.
[195] DCP In. Br., p. 14.

operational.[196] AMP challenged the purported tax revenue benefit, and claimed that rather than generating up to $40 million per year in property taxes for Calvert County, the Project will generate $34.1 million.[197] Beyond tax revenues, DCP and local supporters cite benefits including re-establishment of disturbed oyster beds at Offsite Area B, limited highway improvements and the possibility of additional land preserved from development.[198]

The Generating Station's "island mode" of electricity generation is not a positive factor in calculating its economic effects. It provides no additional economic benefits as a source of electric capacity and energy for Maryland customers. Nor does it provide value as a potential "Black Start" facility that could be used in electric outages to support the needs of residents and businesses. Additionally, by not connecting to the larger grid, the generation station is exempt from purchasing Regional Greenhouse Gas Initiative ("RGGI") carbon emission allowances, even though it will emit significant carbon emissions. Therefore it will not contribute to the strategic energy infrastructure that would otherwise be gained for Maryland consumers, as it would be if it were connected to the grid. Instead, DCP plans to avail itself of a portion of the free Limited Industrial Exemption set-aside allowances to account for its carbon emissions.[199] Consequently, there is no economic or environmental benefit from the purchase of RGGI allowances; instead there is a loss of industrial allowances which might otherwise be used by a future industrial project or power plant.

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[196] Hall Dir. T., pp. 15-16. Other parties descriptions of the PILOT are less clear and we accept Mr. Hall's testimony.
[197] AMP In. Br. at 29-30.
[198] Conditions B-3, B-6, B-8, and H-7.
[199] DCP Reply Br., p. 24.

4. Esthetics, Historic Sites, Aviation Safety, and Waste Disposal.

As to the issue of historic sites, aviation safety, esthetics, and waste disposal, we incorporate conditions proposed by PPRP related to cultural resources (conditions E1- E-3), visual quality (condition F-1), traffic (conditions H-1- H-7), noise (condition I1- I2) and landscaping (condition J-1).[200] We find these conditions adequately address the concerns raised by AMP and SC-CCAN ("Environmental Parties").

5. Air and Water Pollution

A serious consideration in determining whether a power generation plant warrants a CPCN is the impact the proposed facility will have on the surrounding air and water quality. As to air pollution, the proposed power plant will emit carbon dioxide, NOx, VOCs, and will utilize other hazardous materials, including ammonia. There is significant contention among the parties regarding the degree to which air emissions can and should be controlled, in order to comply with the requirements under the Federal Clean Air Act. The dispute focuses on the LAER and on the BACT limits for the combustion turbines and auxiliary boilers, on greenhouse gas emissions, on the possible utilization of leakless piping, and on the extent of pollution from export ships.

DCP asserts, and PPRP agrees, that higher emissions levels than those advocated by SC-CCAN are appropriate because the Project is the only United States LNG plant to use "process gas" to generate electricity rather than to flare it; by re-using process gas, DCP avoids adding 195 lb/hr of NOx per hour to the atmosphere.[201] Due to the use of process gas, DCP claims that NOx emissions at the Project will be 2.5 ppm, rather than

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[200] See Final Recommended Licensing Conditions of the Reviewing State Agencies. April 17, 2014.
[201] DCP In. Br., pp. 27-28.

the 2.0 ppm proposed by the Environmental Parties. DCP explains that "the NOx level in the gas stream exiting the combustion turbine to the inlet of the SCR (here, 25 [sic] ppm)."[202] The dispute with the Environmental Parties revolves around whether the SCR can reduce NO_x by 90% or 95%. In support of its 90% number, DCP reports that its vendors could not cost effectively and reliably design SCRs to achieve an emission limit lower than 2.5 ppm using process gas. DCP's witness Gangle also explained the engineering restrictions, such as back pressure and structural loss, prevent addition of enough catalysts to the SCR to effect a reduction in NO_x from 2.5 to 2.0 ppm.

We find that the Project's use of process gas in electricity generation and the configuration of the site - essentially a re-use of gas - gives the Project unique features that make one-to-one comparisons to other LNG plants difficult. This is especially true when other plants, which may have lower emissions of certain pollutants, use only pipeline gas and may use different equipment, or measure emissions over different time periods, than the Cove Point Project. We also note there is a benefit from DCP's use of process gas at Cove Point, which is the reduction of flared gas at the site. We accept the testimony of witnesses Gangle and DiPrinzio that the appropriate level of reduction in NOx emissions is 2.5 ppm.[203] We do not find the record evidence proffered by the Environmental Parties overcomes PPRP's conclusion that a reduction in NOx emissions from 2.5 ppm to 2.0 ppm is not feasible, given boiler manufacturers' engineering constraints, the use of process gas, and avoidance of more than the minimal necessary amounts of flared gas. In short, we find based on the record that DCP's proposed

[202] DCP In. Br. at 29.
[203] Gangle Rep. T. at 3; DiPrinzio Rep. T. at 3.

treatment of NOx and VOCs will result in LAER for those emissions, even though lower emission rates may be achievable in other locations using other technologies or with different fuel sources.

In reviewing PPRP's BACT recommendations, we note that BACT is based on the individual characteristics of each plant. In many cases BACT in the present case consists of best combustion practices. The record does not provide detail about the actual nature of such best practices. Given that PPRP will be monitoring the ongoing construction and operation of the Cove Point facility, we encourage PPRP or its designee to ensure that the application of best combustion practices is defined precisely and makes use of current techniques.

We approve the NO_x emission levels proposed by PPRP and DCP for the Generating Station's combustion turbine and auxiliary boilers. PPRP identified several emissions permits, similar to those identified by AMP witness Powers, that included lower emission levels than DCP proposes here. Those permits, however, "were all for auxiliary boilers burning only pipeline natural gas." According to PPRP, some of the permits "had not yet been demonstrated" and were for boilers of smaller size than the proposed Cove Point boiler.[204]

Other findings by PPRP also suggest that DCP has achieved the lowest emission levels that it can reasonably achieve on a sustained basis. Specifically, while PPRP agrees that the type of auxiliary boilers to be used at Cove Point could achieve an "instantaneous" emissions reduction of 95%, such a reduction has not been shown to be sustainable over the life of the catalytic reduction technology used on the boiler. DCP

[204] DiPrinzio Rep. T. at 4.

states that when process gas is used, engineers for the vendors providing DCP's pollution reduction equipment agree that PPRP's proposed emission limits are the lowest achievable over the long term.[205] While SC-CCAN identify examples of lower emission levels in California, the factual circumstances are different and not transferable to this Project. We will not deny a CPCN on the basis of testimony that DCP *could* achieve lower rates of emissions with technology using a different fuel, or at a different sized facility, or to achieve a goal that the manufacturer of the technology cannot affirm is routinely achievable.

We are satisfied that DCP has achieved VOC LAER and GHG BACT for emissions from piping component leakage. While it would be desirable if no emissions from piping components occurred, the record does not support requiring DCP to install 100% leakless components, as SC-CCAN urge. Some pipe joints need to be constructed so they can open, according to the Company, and leakless components would not retain that capability.[206] Use of certain leakless components, plus requirement of a formalized leak detection and repair program ("LDAR") in PPRP's proposed conditions meets even stringent national requirements in non-attainment areas.[207] We accept that DCP's procedures for controlling NO_x emissions from its two gas flares will achieve LAER for that emission and BACT for CO.

DCP has accepted all of PPRP's conditions relating to air pollution from the Project, which we adopt herein.[208] The Project's emissions will comply with Maryland

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[205] DCP In. Br. at 27-28.
[206] DCP In. Br., 36 – 37.
[207] DCP In. Br., p. 35.
[208] See PPRP Final Recommended License Conditions; Air Quality Requirements, pp 2-46. April 17, 2014.

standards for toxic air pollutants, with visibility standards, standards for impact on vegetation, and with the requisite Federal air pollution standards.[209]

As to the facility's use of water resources of the State, the record contains no evidence that water usage by the Project will cause any water shortage for other users of the same aquifer. There is likewise no evidence that water usage at issue here will cause any statistically significant level of subsidence in land above or around the aquifer. Even AMP's expert witness, Dr. Helm, acknowledged that DCP's water drawdown will not cause any significant land subsidence.[210] We note, however, that very little, if any subsidence research has been undertaken in Southern Maryland. Therefore, we adopt the additional condition (J-2) proposed by PPRP requiring DCP to establish a trust in the amount of $190,000 to conduct on-going subsistence monitoring.

C. Evaluation of Statutory Factors

In evaluating the delineated statutory factors under PUA § 7-207, we weigh the economic benefits created by construction and operation of the Generating Station against a number of negative impacts, including most significantly increased emissions of criteria pollutants, VOCs and GHGs that will impact air quality and our climate; use of a limited supply of free industrial GHG emission set aside allowances; increased noise from the Generating Station; clear cutting of trees; and additional burden on Calvert County's transportation infrastructure and on the water resources of the State.[211]

These potential negative impacts of the generation station are considerable, many of which will continue through the operational life of the Generating Station. DCP has

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[209] DCP In. Br. at 23-24.

[210] Tr. 510.

[211] See, e.g., In re Mirant Mid-Atlantic, LLC, 96 Md. P.S.C. 241, 2005 WL 4658876, at *13 (Md. P.S.C. 2005).

not demonstrated that these impacts would be offset by the relatively limited and short-lived monetary benefits accruing to Calvert County through construction employment or through the longer-term tax payments from the Generating Station. The negative impacts also occur without the positive benefit of the Generating Station contributing to the Maryland grid, or to the State's efforts to curtail climate change and to conserve energy. Moreover, the larger LNG Project, of which the generation plant is an essential part, is reported as likely to increase natural gas prices in Maryland to some extent,[212] an increase that will have a disproportionate impact on residential customers.

We note that the Navigant Study found that Henry Hub natural gas prices would be 5.7% higher in 2020 due to the additional demand created by the projects exports.[213] Dr. Estomin, using an averaged value of $0.13/Mcf, calculated that the incremental gas cost to Maryland attributable to the Cove Point LNG exports would be $26.8 million per year in real dollars.[214] In addition to not being connected to the grid and participating in RGGI, even under the most conservative of RGGI allowance price scenarios, Maryland citizens are deprived of nearly $16 million in revenues associated with compliance costs between the projected in-service date of the DCP plant through the year 2020.[215] It is clear to us that the “costs” to Maryland’s ratepayers could be well in excess of $75 million by 2025.

We therefore conclude, based on the record, that the construction of the island mode Generating Station with the conditions proposed by PPRP does not provide

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[212] SCCAN Exhibit 1 (Navigant Study);DCP Rep. Br. at 12.

[213] Navigant at 20.

[214] SC-CCAN Rep. Br. at 15.

[215] The “minimum reserve price” of a RGGI allowance is defined by regulation as $2.00 in 2014, increased by a factor of 1.025 every calendar year thereafter. COMAR 26.09.01.02(B)(72-2).

sufficient economic and other benefits to residents of Maryland to justify granting a CPCN.

In the aggregate, the negatives created by construction and operation of the Generating Station require provision of additional economic benefits to the State before the CPCN can be approved. We find that DCP's last minute agreement to Condition J-4 of a $20.38 million "in-kind" contribution and funding to support Maryland's Greenhouse Gas Reduction Act ("GGRA")[216] goals too speculative and insufficient to provide the necessary offsetting economic benefits to Maryland residents.

In developing additional conditions, we focus on actions that will benefit both the environmental and economic interests of the State by benefiting renewable and clean energy resources, reducing or mitigating climate change effects, and promoting beneficial changes in generation and electric usage by consumers. SC-CCAN suggested that we add an additional condition that DCP make "[a] significant investment in carbon-free Maryland-based renewables."[217] We concur with SC-CCAN and Commission Staff that DCP's proposal to contribute their conservation voltage reduction services valued at $20.38 million could be more effectively utilized through a direct contribution to the consumer side, through the State's Strategic Energy Investment Fund ("SEIF").[218] In finding so, and in considering the longer term impact of the Generating Station, we also conclude that the proposed amount of contribution is insufficient. We therefore direct that the funds earmarked by DCP to provide grants to utilities wishing to adopt DCP's

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[216] Environment Article, §§ 2-11201 – 1211.

[217] SC-CCAN Rep. Br. at 24-28.

[218] See Staff Comment on PPRP Modified Final Conditions and Cove Point LNG Terminal Expansion Project Risk Study, May 14, 2014.

EDGE technology be increased to $40 million and contributed, over a five-year period, to the SEIF, a fund administered by the Maryland Energy Administration ("MEA") and authorized by State Government Article § 9-2013-05.

If DCP accepts this modified condition, within 90 days of the commencement of construction of the Generating Station, DCP shall make the first of five annual installments of $8 million, for a total of $40 million, into the SEIF. The funds shall be used solely for the purpose of investing in the promotion, development, and implementation of one or more of the following categories: (1) renewable and clean energy resources; (2) greenhouse gas reduction or mitigation programs; (3) cost-effective energy efficiency and conservation programs, projects, or activities; or (4) demand response programs that are designed to promote changes in electric usage by customers.

Given the expected impact from the Project of increasing gas rates to Maryland residents, we are particularly sensitive to the potential increase in gas prices for low income residents. We find that the proposed condition J-3 that would require DCP to provide a one-time contribution of $400,000 to the Maryland Energy Assistance Program or other Maryland low income energy assistance program to be insufficient.[219] We direct instead that DCP provide this level of contribution for each of the expected 20 years that the plant is under contract to operate, for a total of $8 million.

D. Ensuring Public Safety

Separate from the delineated statutory elements in PUA § 7-207, we consider potential safety risks from an accident at the 130 MW Generating Station that may be exacerbated by the facility's integration with the LNG facility. As noted previously, our

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[219] SC-
Ccan In. Br., pp. 17-18; SC-CCAN Ex. 1 at 20.

review of these facilities is also consistent with our duty under PUA § 11-101(b), and the regulations thereunder, to ensure "to the greatest extent practicable" the operational safety of these facilities. As an integrated project, including LNG facilities and a large electric generation station, we consider the operational safety of DCP's proposal on a total project basis.

The physical integration of the combustion turbines with the LNG facilities, and the location of the integrated facilities in a condensed footprint and in very close proximity to thousands of residents raise safety and security questions that must be considered. Safety issues are of significant concern to us in evaluating whether construction of the proposed Generating Station is in the public interest and whether additional protections are necessary. We are committed to ensuring that all available safety measures, including a comprehensive Emergency Response Plan ("ERP") for the facility and the surrounding population, and a plan for compensating jurisdictions for funding project-specific security and emergency management costs, are developed and implemented prior to site preparation of the Generating Station.

We recognize that FERC has responsibility for evaluating the risk and potential impact of explosions and other hazardous incidents as part of its LNG licensing determination. FERC has oversight in ensuring that on-site facilities are safely constructed and installed, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (DOT/PHMSA) is responsible for setting the federal safety standards for natural gas pipelines and related facilities. Design, construction, and operation of the facilities must be done in accordance with FERC and PHMSA standards. We also acknowledge that FERC has oversight over LNG ERPs, and established related guidance in 2005 pursuant to the Energy Policy Act of 2005. However, Federal law also includes provisions for State input into LNG licensing determinations, recognizing State interests in ensuring the health and safety of its residents are protected when LNG facilities are constructed and operated.

At the March 1, 2014 public hearing in Lusby, Maryland we heard earnest and significant concerns from members of the public, particularly residents who live in close proximity to the facility, about potential safety hazards and inadequate emergency response and evacuation procedures. In addition, members of the public submitted written comments expressing safety-related concerns. The commenters raised the issue of potential increased risk for residents who live in close proximity to the plant due to the tight spacing of the new generators, process equipment and storage tanks within the sound abatement walled-area.[220]

Commenters also cited a DNR/PPRP study titled "Cove Point LNG Terminal Expansion Project Risk Study," dated June 28, 2006 and revised January 14, 2010, which reported the results of a detailed quantitative risk analysis ("QRA") that was conducted when the generation facilities were last expanded, and questioned why a QRA was not completed for this expansion Project.[221] On May 6, 2014, the Commission requested comment on whether an updated risk analysis had been performed for the expanded Project and whether such an analysis has been filed with the FERC or any other government agency. On May 14, 2014, PPRP filed comments stating that FERC had not requested an updated QRA for the proposed LNG Project and PPRP had not prepared

[220] Dale Allison Letter dated March 30, 2014.
[221] Susan Allison Letter dated March 30, 2014.

one.[222] PPRP further noted that FERC Staff's Environmental Assessment ("EA") of the proposed DCP LNG Project was scheduled to be released on May 15, 2014, which it was.[223]

DCP noted that the Project was designed to be consistent with the requirements set forth in 49 CFR Part 193 (federal regulations governing safety, security and environmental protection of LNG facilities). It also noted that the public safety and risk assessment issues for which the Commission sought comment are being "thoroughly addressed" by FERC and DOT PHMSA, referring us also to the EA noted above by PPRP.

The EA includes an extensive discussion of potential safety risks related to the proposed facility. Among the significant EA safety findings and conclusions are the following:

- The principal hazards associated with the substances involved in the liquefaction, storage, and vaporization of LNG result from cryogenic and flashing liquid releases; flammable vapor dispersion; vapor cloud ignition; pool fires; overpressures, and toxicity.[224]

- Siting of the facility with regard to potential off-site consequences from these hazards is also required by DOT's regulations under 49 CFR 193, Subpart B.[225]

- DCP's siting analysis indicates that the siting of the proposed facility would not have a significant impact on public safety.[226]

[222] May 14, 2014 Letter from Susan T. Gray, Deputy Director, PPRP.

[223] FERC Staff concluded that with appropriate mitigating measures, the proposed Project would "not constitute a major federal action significantly affecting the quality of the human environment," and thus an Environmental Impact Statement (EIS) was not warranted. (cite) Pursuant to PUA § 3-111(d), on May 21, 2014 the Commission took judicial notice of the document titled "Environmental Assessment for the Cove Point Liquefaction Project" issued by FERC on May 15, 2014 as filed for Comment in FERC Docket No. CP13-113-000.

[224] Id.

[225] Id.

- Sufficient layers of safeguards would be included in the facility designs to mitigate the potential that could impact the safety of the off-site public.

The EA requires DCP to fulfill a number of safety-related conditions before construction can commence, including filing and FERC approval of final project design elements relating to, and not limited to, DOT's spill determination, wind speeds and vapor fences.[227]

In addition, the EA indicates that pursuant to NGA section 3A(e), FERC must require an LNG terminal operator "to develop an emergency response plan (ERP) in consultation with the U.S. Coast Guard and state and local agencies."[228] The EA notes that there is an existing ERP in place at the site. It has been updated periodically since 1978 as new projects have changed the configuration of the facility. However, the report states that "the existing ERP would need to be updated to include the proposed liquefaction facilities and emergencies related to refrigerant handling."[229] Therefore, the EA concludes that:

- Prior to initial site preparation, DCP should file its updated ERP to include the Liquefaction Facilities as well as instructions to handle on-site refrigerant and NGL-related emergencies. DCP should file the updated ERP with the Secretary [of FERC] for review and written approval by the Director of OEP.

- Prior to initial site preparation, DCP should file an ERP that includes a Cost-Sharing Plan identifying the mechanism for funding all Project-specific security/emergency management costs that would be imposed on state and

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226 Id. FERC staff also declined to require a Quantitative Risk Assessment as part of the EA and instead evaluated the project based on compliance with DOT's federal safety standards as delineated in 49 CFR 193. See EA at 148.

227 See EA at 133, 148, 150.

228 FERC May 15, 2014 EA Report (Emergency Response §2.8.7) at 158.

229 Id. OEP refers to the Office of Energy Programs at FERC.

> local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan should include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. DCP should file the ERP, including the Cost-Sharing Plan, with the Secretary for review and written approval by the Director of OEP.[230]

The EA also noted receipt of a comment on the evacuation route stating that "[it] did not identify any incident from the siting analysis that would change or impact the evacuation routes that have been established for the existing facility."[231] The EA further states that "the Memorandums of Understanding established between the USCG, Calvert County Sheriff's Office, and the [Maryland DNR] ensures enforcement of the safety/security zone while LNG vessels are in transit and moored at the facility."[232]

In recognition of the EA's findings and recommendations and the proximity of residents to the proposed new Generating Station, which would be integrated with the proposed expanded liquefaction Project, we find that a revised and strengthened condition G-1 is required; that is, a condition requiring completion of an updated ERP as reflected in the EA before commencement of construction of the generation facilities.[233] We find that directing DCP to address any additional emergency planning - including offsite - that is

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[230] Id. (Emphasis original)

[231] Id. The EA describes that "DCP's existing emergency response plan indicates coordination with the Maryland State Police and Calvert County Sheriff's Office for offsite emergency organization. The Maryland State Police and Calvert County Sheriff's Office would provide the necessary law enforcement assistance, which includes evacuating individuals from designated public and private areas."

[232] Id. at 159.

[233] DCP has previously filed a Cove Point ERP with this Commission. On August 19. 2003 it filed a Supplemental Report in CN 8917 describing the Cove Point ERP which had been upgraded to include: then current emergency and safety equipment; improved communication systems with local emergency response and law enforcement agencies; guidance to aid in the emergency classification process; results of coordination meetings held with various first responder organizations. DCP also described the 2003 revised ERP which was to incorporate among other elements an offsite evacuation plan developed in conjunction with the Calvert County Division of Emergency Management. (DCP CN 8913 2003 Supplemental Report at 2.)

identified during the ERP updating process would further ensure the operational safety of the facility and the safety of residents who live close by.

Therefore, we direct DCP to file with us prior to initial site preparation for the Generating Station any updates proposed to its existing ERP in accordance with the recommendations set forth in the EA, and to address any safety issues raised by or associated with the proposed generation facilities approved under this CPCN.

As noted above, the EA also proposes to require DCP to file a cost-sharing plan with FERC that will identify the mechanisms for funding all project-specific security and emergency management equipment costs that would be imposed on State and local agencies. We expect that existing relationships with State and local emergency response officials as described in the current ERP will continue, or that those relationships would be enhanced. DCP has notified the Maryland State Fire Marshall and Calvert County Public Safety personnel about the planned expansion and the need to revise the ERP. DCP states that a more formal emergency planning dialogue with these stakeholders will be completed during final site design. We direct DCP to work with Maryland State and local law enforcement and emergency management agencies (including Maryland Emergency Management Agency) during that process to ensure that the ERP adequately incorporates each agency's vital emergency preparedness and response capabilities in the event of an emergency at the facility.

The key elements of ERP plans and procedures include identification and assessment of hazards; prompt notification and mobilization of emergency response resources; development and maintenance of appropriate emergency response capabilities; and ongoing training programs. In order to ensure that the revised ERP incorporates sufficient safety protocols, we direct as a condition of our approval that DCP's updated ERP be filed 60 days before any site preparation begins. If we find the revised ERP deficient with regard to off-site safety protocols, the 60-day period will allow us the opportunity to take steps to address those deficiencies or raise any concerns with the federal agencies with which we cooperate in assuring the operational safety of these facilities.

We revise condition G-1 to read as follows:

G-1. At least 60 days prior to commencing site preparation for construction, DCP shall file with the PSC the State Fire Marshall's final report regarding this Project, including any measures to address any additional conditions or requirements identified by the State Fire Marshall. Also, at least 60 days prior to commencing site preparation for construction, DCP shall file a revised Emergency Response Plan (ERP) that reflects and responds to the findings of the EA and any related FERC Order, and addresses the need for additional off-site safety protocols and resources. Without supplanting revisions responsive to FERC, the updated ERP shall address:

1. Site safety EMS coverage during construction and operations, including timely response options and emergency vehicle access throughout the site in case of an accident, injury or other emergency;
2. Where additional hazards are identified in the ERP process or existing emergency response capabilities are determined to be inadequate, DCP shall plan for implementing necessary upgrades, including assisting emergency response organizations through contributions, requisite training and general support to ensure the public's safety. Prior to commencing construction of the

Generating Station, DCP shall file with the Commission an executed cost-sharing plan that has the concurrence of each affected State and local agency identified in the ERP;

3. DCP will work with Federal, State and local officials to determine in the updated ERP whether an off-site emergency plan is needed as part of emergency management, including whether an off-site evacuation plan is needed, and if so present the plan to develop an off-site emergency plan that includes consideration of residents who would have to rely on Cove Point Road to evacuate the area in the event of an emergency at the LNG facility. If DCP and the Federal, State and local officials with responsibilities for emergency planning and response in the event of an emergency at the LNG facility conclude that an off-site emergency plan or an off-site evacuation plan is not needed, the bases for these conclusions shall be set forth in conjunction with and at the time of issuance of the revised ERP.

Recognizing that we have added conditions and changed the conditions proposed by PPRP on April 17, 2014, we direct DCP to advise us in writing of its acceptance or rejection of the Conditions set forth in Appendix A within ten days of this Order.

IT IS, THEREFORE, this 30th day of May, in the year Two Thousand Fourteen, by the Public Service Commission of Maryland,

ORDERED: (1) That the Certificate of Public Convenience and Necessity for which Dominion Cove Point applied on April 1, 2013, is hereby granted, subject to the conditions and requirements set out in Appendix A to this Order; and

(2) That DCP's request for a waiver of section § 7-208(b)(1) of the PUA is hereby granted, contingent upon DCP fulfilling all pre-construction conditions and requirements as directed by FERC and by this Commission.

/s/ W. Kevin Hughes

/s/ Lawrence Brenner

/s/ Kelly Speakes-Backman

/s/ Anne E. Hoskins
Commissioners*

*Commissioner Harold D. Williams did not participate in this decision.

APPENDIX A

Final License Conditions
PSC Case No. 9318
Dominion Cove Point Project

CPCN GENERAL REQUIREMENTS

Gen.-1 Prior to commencing construction of the generating station, DCP shall file with the Commission notification that FERC has issued all required pre-construction approvals pursuant to the EA and the final FERC order authorizing construction of the LNG facility.

Gen.-2 Except as otherwise provided for in the following provisions, the application for the Certificate of Public Convenience and Necessity (CPCN) is considered to be part of this CPCN for the Dominion Cove Point (DCP) Project. In the application, estimates of dimensions, volumes, emission rates, operating rates, feed rates and hours of operation are not deemed to constitute enforceable numeric limits except to the extent that they are necessary to make a determination of applicable regulations. Construction of the DCP Project shall be undertaken in accordance with the CPCN application filed with the Maryland Public Service Commission (PSC) on 1 April 2013 and supplemental filings on 15 May 2013, 20 May 2013, 21 May 2013, 23 May 2013, 31 May 2013, 3 June 2013, 19 June 2013, 3 July 2013, 8 July 2013, 19 July 2013, 29 July 2013, 5 August 2013, 14 August 2013, 16 August 2013, 23 August 2013, 5 September 2013, 16 September 2013, 25 September 2013, 26 September 2013, 27 September 2013, 2 October 2013, 8 October 2013, 11 October 2013, 15 October 2013, 21 October 2013, 31 October 2013, 12 November 2013, 2 December 2013, 18 December 2013, and 2 January 2014. If there are any inconsistencies between the conditions specified below and the application, the conditions in this CPCN shall take precedence. If CPCN conditions incorporate federal or state laws through paraphrased language, where there is any inconsistency between the paraphrased language and the actual state or federal laws being paraphrased, the applicable federal or state laws shall take precedence.

Gen.-3 All provisions of this CPCN that apply to DCP shall apply to all subsequent owners and/or operators of the facility. In the event of any change in control or ownership, DCP shall notify the succeeding owner/operator of the existence of the requirements of this CPCN by letter and shall send a copy of that letter to the PSC and the Maryland Department of the Environment (MDE).

Gen.-4 If any provision of this CPCN shall be held invalid for any reason, the remaining provisions shall remain in full force and effect and such invalid provision shall be considered severed and deleted from this CPCN.

Gen.-5 Representatives of the PSC shall be afforded access to the DCP Project facility at any reasonable time to conduct inspections and evaluations necessary to assure compliance with the CPCN. DCP shall provide such assistance as may be necessary to conduct such inspections and evaluations by representatives of the PSC effectively and safely.

Gen.-6 Representatives of the Maryland Department of the Environment (MDE), Department of Natural Resources (DNR), and the Calvert County Health Department shall be afforded access to the DCP Project facility at any reasonable time to conduct inspections and evaluations necessary to assure compliance with the CPCN requirements. DCP shall provide such assistance as reasonably may be necessary to conduct such inspections and evaluations effectively and safely, which may include but need not be limited to the following:

a) Inspecting construction authorized under this CPCN;

b) Sampling any materials stored or processed on site, or any waste or discharge into the environment;

c) Inspecting any monitoring or recording equipment required by this CPCN or applicable regulations;

d) Having access to or copying any records required to be kept by DCP pursuant to this CPCN or applicable regulations;

e) Obtaining any photographic documentation and evidence; and

f) Determining compliance with the conditions and regulations specified in the CPCN.

AIR QUALITY REQUIREMENTS

I. GENERAL

A-I-1 MDE Air and Radiation Management Administration (ARMA) shall have concurrent jurisdiction with the PSC to enforce the air quality conditions of the CPCN.

A-I-2 The CPCN serves as the Prevention of Significant Deterioration (PSD) approval, Nonattainment New Source Review (NA-NSR) approval, and air quality construction permit for the DCP Project and does not constitute the permit to construct or approvals until such time as DCP has provided documentation demonstrating that nitrogen oxides (NO_x) emission offsets totaling at least 375 tons and volatile organic compound (VOC) emission offsets totaling at least 45 tons, each based on an offset ratio of 1.3 to 1.0, have been obtained and approved by MDE-ARMA and are federally enforceable.

A-I-3 For air permitting purposes, the DCP Project shall be defined as the following:

a) Two General Electric (GE) Frame 7EA combustion turbines (CTs) with heat recovery steam generators (HRSGs) each rated at 1,062 million British Thermal Units per hour (MMBtu/hr) with a nominal net 87.2 megawatt (MW) rated capacity, equipped with dry low-NO_x (DLN1) combustors, selective catalytic reduction systems (SCRs), and oxidation catalysts (F7CT-A, F7CT-B).

b) Two auxiliary boilers, each rated at 435 MMBtu/hr, equipped with an oxidation catalyst, low-NOx burner, and SCR (AUXB-A, AUXB-B).

c) One 1,550-horsepower (hp) diesel-fired emergency generator (EG-A).

d) Five 350-hp diesel-fired emergency fire pump engines (FP-A, FP-B, FP-C, FP-D, FP-E).

e) One 56-MMBtu/hr thermal oxidizer equipped with SCR and an oxidization catalyst (TO-A).

f) Two ground flares, North Flare and South Flare (NF, SF).

g) Two existing GE MS5001 Frame 5 combustion turbines providing a total maximum of 25 MW on a continuous basis (F5CT 214 JA, F5CT 214 JB).

h) Piping components associated with this project, including valves, connectors, flanges, pump seals, and pressure relief valves within the facility boundary (FUG-A).

i) Eight storage vessels:

1. Four 102,500-gallon propane make-up tanks (TANK-P1, TANK-P2, TANK-P3, TANK-P4)

2. Two 34,000-gallon ethane make-up tanks (TANK-E1, TANK-E2)

3. Two 35,000-gallon condensate storage tanks (TANK-C1, TANK-C2)

A-I-4 In accordance with COMAR 26.11.02.04B, the air quality provisions expire if, as determined by MDE-ARMA:

a) Substantial construction or modification is not commenced within 18 months after the date of issuance of the CPCN final order;

b) Construction or modification is substantially discontinued for a period of 18 months after the construction or modification has commenced; or

c) The source is not completed within a reasonable period after the date of issuance of the CPCN final order.

A-I-5 At least 60 days prior to the anticipated date of start-up of the Project, DCP shall submit to MDE-ARMA an application for a State permit to operate.

A-I-6 DCP shall submit to MDE-ARMA, not later than 12 months after the date the affected source commences operation, an administratively complete application for modification of the Dominion Cove Point facility Part 70 (Title V Operating) Permit. [COMAR 26.11.03.17(F)(2) & 26.11.03.02(B)(4)]

A-I-7 All records and logs required by this CPCN shall be maintained at the facility for at least five years (unless otherwise noted) after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of MDE-ARMA.

A-I-8 **Maryland CO_2 Budget Trading Program –** DCP shall comply with all applicable requirements for CO_2 reporting and emission reduction program. [COMAR 26.09]

II. DEFINITIONS

A-II-1 "Commence" as applied to the construction of the Project means that the owner or operator either has:

a) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

b) Entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of actual on-site construction of the source to be completed within a reasonable time.

A-II-2 "Facility Restart" as it relates to the DCP Project North and South Flares is defined as the startup of project operations, the period during which mixed refrigerant, propane, and/or natural gas in the system are vented to the North and South Flares prior to the startup of the sources.

A-II-3 "Normal Operation" as it relates to the DCP Project combustion turbines and auxiliary boilers is defined as the period of time from when startup ceases until shutdown begins.

A-II-4 "Startup" as it relates to the DCP Project combustion turbines is defined as the period of time from initiation of combustion firing until the unit reaches at least 60% load. Startup as it relates to the DCP Project auxiliary boilers is defined as the period of time from initiation of fuel combustion until the unit reaches at least 25% load.

A-II-5 "Shutdown" as it relates to the DCP Project combustion turbines is defined as that period of time during which the turbine output is lowered with the intent to shut down, beginning at the point at which the load drops below 60%. Shutdown as it relates to the DCP Project auxiliary boilers is defined as the period of time during which the auxiliary boiler steam output is lowered with the intent to shut down, beginning at the point at which the unit reaches at least 25% load.

A-II-6 "Malfunction" is defined as any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process that operates in an abnormal or unusual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

A-II-7 "Warm Ships" as they relate to the DCP Project North and South Flares are defined as ships which come into the terminal and require a cool-down process prior to commencing loading of the liquefied natural gas (LNG).

III. PROJECT-WIDE CONDITIONS

A-III-1 Any circuit breakers DCP installs in conjunction with this Project shall not contain sulfur hexafluoride (SF_6).

A-III-2 The proposed DCP Project is subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Testing and Monitoring** - Requires DCP to follow test methods described in 26.11.01.04C to determine compliance. MDE-ARMA may require DCP to install, use, and maintain monitoring equipment or employ other methods as specified by MDE-ARMA to determine the quantity or quality, or both, of emissions discharged into the atmosphere and to maintain records and make reports on these emissions to MDE-ARMA in a manner and on a schedule approved by MDE-ARMA or the control officer. [COMAR 26.11.01.04]

b) **Emission Statements** - Requires DCP to submit a certified, facility-wide emission statement to MDE-ARMA by April 1 of each year for the previous calendar year. [COMAR 26.11.01.05-1]

c) **Malfunctions and Other Temporary Increases of Emissions** - Requires DCP to report the onset and the termination of the occurrence of excess emissions, expected to last or actually lasting for one hour or more to MDE-ARMA by telephone. Telephone reports shall include all information required by COMAR 26.11.01.07C(2). [COMAR 26.11.01.07]

d) **Continuous Emission Monitoring Requirements** - Requires DCP to operate all Continuous Emission Monitors (CEMS) under the requirements of COMAR 26.11.01.11. This requirement is applicable to the NO_x and oxygen (O_2) (or carbon dioxide, CO_2) CEMS that are planned to be installed to meet 40 CFR §60 Subpart Db requirements for the auxiliary boilers and 40 CFR §60 Subpart KKKK requirements for the combustion turbines. This requirement is also applicable to the CO CEMS that are required to be installed on the Frame 7 combustion turbines under COMAR 26.11.01.04B. [COMAR 26.11.01.11]

e) **Particulate Matter From Confined Sources** - Prohibits DCP from causing or permitting particulate matter to be discharged from any installation constructed on or after January 17, 1972 in excess of 0.05 gr/SCFD (115 mg/dscm). [COMAR 26.11.06.03B(1)(a)]

f) **Particulate Matter From Unconfined Sources** - Prohibits DCP from causing or permitting emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, when appropriate as determined by MDE-ARMA, the installation and use of hoods, fans, and dust collectors to enclose, capture, and vent emissions. In making this determination, MDE-ARMA shall consider technological feasibility, practicality, economic impact, and the environmental consequences of the decision. [COMAR 26.11.06.03C]

g) **Particulate Matter from Materials Handling and Construction** - Prohibits DCP from causing or permitting any material to be handled, transported, or stored, or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. [COMAR 26.11.06.03D]

h) **Control of NSPS Sources** - Prohibits DCP from constructing, modifying, or operating, or causing to be constructed, modified, or operated, a New Source Performance Standard (NSPS) source as defined in COMAR 26.11.01.01B(23), which results or will result in violation of the provisions of 40 CFR §60, as amended. [COMAR 26.11.06.12]

i) **Control of PSD Sources –** Prohibits DCP from constructing, modifying, or operating, or causing to be constructed, modified, or operated, a Prevention of Significant Deterioration (PSD) source as defined in COMAR 26.11.01.01B(37), which results or will result in violation of the provisions of 40 CFR §52.21, as amended, except that the reviewing authority is MDE-ARMA instead of the U.S. Environmental Protection Agency (EPA) Administrator unless otherwise specified in 40 CFR §52.116, and the applicable procedures are those set forth in COMAR 26.11.02. [COMAR 26.11.06.14]

j) **Nonattainment Provisions for Major New Sources and Major Modifications - General Conditions –** Prohibits DCP from commencing construction or modification of any proposed emissions unit without first obtaining all permits and approvals required. Requires DCP to certify that all existing major stationary sources owned or operated by DCP, or any entity controlling, controlled by, or under common control with DCP, in the State are in compliance with all applicable emission limitations or are in compliance with an approved federally enforceable plan for compliance. Requires DCP to obtain more than equivalent emission offsets from existing sources in the area impacted by the proposed new major stationary source or major modification. The offset ratio for VOC and NO_x shall equal or exceed 1.3 to 1 for sources of VOC or NO_x in Calvert County. Requires DCP to comply with all other applicable requirements of COMAR 26.11.17.03A and COMAR 26.11.17.03B(1-7). [COMAR 26.11.17.03]

k) **General Conformity –** Requires DCP to comply with the general conformity requirements of 40 CFR 93 Subpart B. [COMAR 26.11.26.09]

A-III-3 The proposed DCP Project is subject to all applicable State-Only air quality requirements including, but not limited to, the following regulations:

a) **Nuisance –** Prohibits DCP from operating or maintaining the facility in such a manner that a nuisance or air pollution is created. [COMAR 26.11.06.08]

b) **Odors –** Prohibits DCP from causing or permitting the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created. [COMAR 26.11.06.09]

c) **Toxic Air Pollutants -** Requires DCP to quantify emissions of each toxic air pollutant (TAP) that will be discharged from affected installations and submit that information to MDE-ARMA. Prohibits DCP from constructing, reconstructing, operating, or causing to be constructed, reconstructed, or operated, any new installation or source that will discharge a TAP to the atmosphere without installing and operating the Best Available Control Technology for toxics (T-BACT) and demonstrating that emissions discharged by the new installation or source will not unreasonably endanger human health by performing an analysis as specified under COMAR 26.11.15 and 26.11.16. [COMAR 26.11.15 and COMAR 26.11.16]

d) **Fee Schedule –** Requires DCP to pay annual Title V operating permit fees. [COMAR 26.11.02.19A]

e) **Emission Certification –** Requires DCP to certify the actual emissions of regulated air pollutants from all installations at the plant or facility. Certification shall be on a form obtained from MDE-ARMA and shall be submitted to MDE-ARMA not later than April 1 of the year following the year for which certification is required. An emission certification submitted pursuant to this section and which contains all information required by COMAR 26.11.01.05-1 for NO_x and VOC, satisfies the requirements of COMAR 26.11.01.05-1. [COMAR 26.11.02.19D]

A-III-4 Emissions for all sources identified as part of the DCP Project, including emissions during periods of startup and shutdown, shall be limited to the following, in tons per year, in any consecutive 12-month rolling period:

Pollutant	**Project-Wide Emission Limit (tons per year)**
Particulate Matter (PM) – Filterable	55.7
Particulate Matter less than 10 microns (PM10) – Filterable and Condensable	124.2
Particulate Matter less than 2.5 microns (PM2.5) – Filterable and Condensable	124.2
Nitrogen Oxides (NO_x)	279.3
Carbon Monoxide (CO)	146.6
Volatile Organic Compounds (VOCs)	33.3
Greenhouse Gas (GHG) as Carbon Dioxide Equivalent (CO_2e)	2,030,988
Formaldehyde	6.2

A-III-5 To meet BACT, DCP shall take precautions to minimize particulate matter emissions from onsite roadways including, but not limited to, the use of water or chemical suppression and sweeping.

Compliance Demonstration

Testing and Monitoring Requirements

A-III-6 Compliance with the Project-wide GHG limit is based on the currently accepted global warming potentials (GWPs) from 40 CFR §98 Subpart A of 1 for CO_2, 25 for methane (CH_4), and 298 for nitrous oxide (N_2O).

A-III-7 DCP may submit to MDE-ARMA a request to reduce the frequency of stack testing for any source.

Recordkeeping and Reporting Requirements

A-III-8 DCP shall submit a quarterly report to MDE-ARMA to be postmarked by the 30th day of the month following the end of each calendar quarter that includes the following information:

a) Lists instances of deviations from permit requirements.

b) Summarizes separately the date, time, and duration of each startup, shutdown, or malfunction that occurred for each Frame 7 combustion turbine or auxiliary boiler identified as part of the DCP Project during the prior quarterly period. The report shall include total monthly and consecutive rolling 12-month hours of startup, shutdown, and malfunction for each source. The report shall also include the total NO_x, VOC, CO, PM, PM10, PM2.5 and GHG emissions for each startup and shutdown event.

c) Summarizes the downtime or malfunction of all CEMS required for DCP Project emission sources. The report shall include the date and time of each period during which the CEMS was inoperative and the nature of the monitoring system repairs or adjustments completed.

d) Summarizes the monthly and consecutive rolling 12-month total emissions (in tons per month and tons per year) of PM, PM10, PM2.5, NO_x, CO, VOCs, and GHGs (as CO_2e) separately for each emission unit and total emissions of those pollutants for all DCP Project sources.

A-III-9 DCP shall provide MDE-ARMA with the manufacturer, make, and model, vendor specifications, or other details requested by MDE-ARMA upon selection of auxiliary sources (thermal oxidizer, emergency engines, flare).

A-III-10 DCP shall furnish written notification to MDE-ARMA and EPA for the Frame 7 combustion turbines and auxiliary boilers subject to an NSPS of the following events: [40 CFR §60.7(a)]

a) The date construction commenced within 30 days after such date;

b) The actual startup date within 15 days after such date; and

c) The anticipated date of compliance stack testing at least 30 days prior to such date.

IV. COMBUSTION TURBINES

Emission Unit Number(s):
F7CT-A, F7CT-B
Two GE Frame 7EA combustion turbines (CTs) with heat recovery steam generators (HRSGs) equipped with dry low-NO_x (DLN1) combustors, SCRs, and oxidation catalysts

Applicable Requirements

A-IV-1 The Frame 7 CT/HRSGs are subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Visible Emissions –** Prohibits DCP from causing or permitting the discharge of emissions from any fuel burning equipment, other than water in an uncombined form as specified in Table A-1. [COMAR 26.11.09.05A(1)]

b) **Control of Sulfur Oxides From Fuel Burning Equipment** - Prohibits DCP from burning, selling, or making available for sale process gas used as fuel with a sulfur content by weight of greater than 0.3 percent. [COMAR 26.11.09.07A(1)(d)]

c) **Control of NO_x Emissions for Major Stationary Sources –** Requires DCP to comply with all applicable provisions of COMAR 26.11.09.08. DCP shall demonstrate compliance with the emission limits of COMAR 26.11.09.08 by complying with the emission limits specified in Table A-1. [COMAR 26.11.09.08]

A-IV-2 The Frame 7 CT/HRSGs are subject to 40 CFR §60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines; 40 CFR §60.4300, et seq., which contain various requirements for emission limitations, monitoring, testing, recordkeeping, and reporting for NO_x and SO_2, including but not limited to those specified in Table A-1 and the following:

a) **Excess Emissions—**DCP shall follow the calculation procedures set forth in 40 CFR §60.4350 for purposes of identifying excess emissions. [40 CFR §60.4350]

b) **Fuel Sulfur Content—**DCP may elect not to monitor the total sulfur content of the fuel combusted in the turbines, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng sulfur dioxide (SO_2)/Joule (J) (0.060 lb SO_2/MMBtu) heat input using one of the methods given in 40 CFR §60.4365. If DCP elects to comply with the minimum fuel sulfur content limit under 40 CFR§60.4330, DCP must monitor the total sulfur content of the fuel using the methods described in 40 CFR §60.4415 at a frequency described in 40 CFR §60.4370. [40 CFR §60.4360]

Operational and Emission Limits

A-IV-3 **Best Available Control Technology (BACT) -** BACT for each Frame 7 CT shall be the efficient design of the CTs with dry low NO_x (DLN1) combustors and heat recovery steam generators (HRSGs), use of facility process fuel gas or pipeline quality natural gas fuel only, operation of an oxidation catalyst, operation of an SCR system, and application of good combustion practices to achieve the emission limitations and operational limits as specified in Table A-1.

A-IV-4 **Lowest Achievable Emission Rate (LAER) -** LAER for each Frame 7 CTs shall be to meet the emission limitations and operational limits as specified in Table A-1 to be achieved through the use of a selective catalytic reduction (SCR) system, DLN1 combustors, oxidation catalyst, and good combustion practices.

A-IV-5 DCP shall comply with emission limitations during facility startup and shutdown events specified in Table A-1. These emissions shall be included in demonstrating compliance with the Project-wide emissions (Condition A-III-4) limits, on a consecutive 12-month rolling basis.

A-IV-6 DCP shall limit emissions of ammonia resulting from un-reacted ammonia (ammonia slip) from each of the SCRs to be installed on the Frame 7 CTs as specified in Table A-1.

Compliance Demonstration

Testing and Monitoring Requirements

A-IV-7 At least 30 days prior to conducting any compliance stack test, DCP shall submit a test protocol to MDE-ARMA for review and approval.

a) Compliance stack testing shall be conducted in accordance with MDE-ARMA Technical Memorandum (TM) 91-01, "Test Methods and Equipment Specifications for Stationary Sources" (January 1991), as amended by Supplement 3 (December 1997), 40 CFR §60, or subsequent test protocols approved by MDE-ARMA; and

b) Test ports shall be located in accordance with TM 91-01 (January 1991), or subsequent or alternative measures approved by MDE-ARMA.

A-IV- 8 Initial compliance stack testing of each Frame 7 CT shall be conducted within 180 days after initial startup to quantify pollutant emissions and demonstrate compliance with the emission limits specified in the CPCN for the following pollutants: NO_x, VOC, PM, PM10, PM2.5, CO, ammonia, and CO_2 while operating at 90% or higher capacity. Subsequent stack tests shall be conducted annually for NO_x, VOC, PM, PM10, PM2.5, CO, and CO_2 and at least every five years for ammonia. As an alternative to annual stack testing for NOx, VOC, CO, and CO_2, DCP may choose to demonstrate compliance with emission limitations by installing and operating a certified CEMS, upon written notification to MDE-ARMA.

A-IV- 9 Compliance testing shall be conducted by the methods specified in Table A-1.

A-IV-10 DCP shall conduct initial and subsequent performance tests on the Frame 7 CTs for NO_x as specified in Table A-1. [40 CFR §60.4400]

A-IV-11 DCP shall conduct an initial and subsequent performance tests on each of the Frame 7 CTs for SO_2 according to applicable procedures in 40 CFR §60.4415 only if periodic monitoring of sulfur content is performed for compliance with the alternative fuel sulfur content limit. [40 CFR §60.4415]

A-IV-12 Compliance stack testing of each of the Frame 7 CTs shall be conducted within 180 days after initial startup to demonstrate that the formaldehyde emission rate is in compliance with the emission limit specified in Condition A-III-4. Testing for formaldehyde emissions shall be conducted according to EPA Method 323, or equivalent method approved by MDE.

A-IV-13 Continuous compliance monitoring for the Frame 7 CTs shall be conducted as specified in Table A-1.

A-IV-14 Unless otherwise approved by MDE-ARMA, DCP shall install on each Frame 7 CT a CO_2 CEMS or calibrated in-line fuel flow-meters as specified under 40 CFR 75.10(3) to measure CO_2 emissions associated with the production of electricity. Emissions of CO_2 from the Frame 7 CTs are to be monitored and recorded hourly utilizing a data handling acquisition system (DHAS) installed, calibrated, and maintained in accordance with 40 CFR 75. [40 CFR 75.10(3)]

A-IV-15 DCP shall meet the emission limitations for visible emissions as specified in Table A-1. [COMAR 26.11.09.05A(1&5)]

A-IV-16 DCP shall install a fuel flow meter and continuously monitor the fuel flow for each Frame 7 CT. The fuel flow shall be recorded monthly.

A-IV-17 Compliance with the BACT and LAER emission limitations shall be demonstrated as follows:

a) DCP shall obtain vendor guarantees to demonstrate compliance with the BACT and LAER emission limits.

b) Emissions of NO_x, CO and VOC shall be calculated using vendor guaranteed emission rates, stack exhaust oxygen content, stack outlet flowrate, and hours of operation. Emissions of PM, PM10, and PM2.5 shall be calculated using vendor guaranteed emission rates and hours of operation. Monthly emission totals shall be used to calculate 12-month rolling period emissions.

c) CH_4 and N_2O emissions from the Frame 7 CTs shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart C. On a monthly basis, fuel consumption, coupled with the appropriate emission factors and global warming potentials (25 for CH_4 and 298 for N_2O), shall be used to calculate the CH_4 and N_2O emissions on a CO_2e basis. These emission rates, summed with the monthly CO_2 emissions based on stack testing shall be used to establish GHG emissions from the Frame 7 CTs on a CO_2e basis.

Recordkeeping and Reporting Requirements

A-IV-18 Final results of each compliance stack test must be submitted to MDE-ARMA within 60 days after completion of the test.

A-IV-19 DCP shall submit a formaldehyde emission analysis following the completion of the initial stack testing for the Frame 7 CTs, auxiliary boilers, and thermal oxidizer which demonstrates that the combined formaldehyde emissions from these tests in addition to the formaldehyde emissions from the other project sources as calculated based on approved emission factors, are less than the limit specified in Condition A-III-4.

A-IV-20 Unless otherwise approved by MDE-ARMA, DCP shall submit electronic quarterly reports from the DHAS of CO_2 emissions to the EPA Clean Air Markets Business System as specified in 40 CFR 75.64. [40 CFR 75.64]

A-IV-21 DCP shall submit to MDE-ARMA the results of visible emissions observations in each quarterly report.

A-IV-22 DCP shall submit the following CEMS reports to MDE-ARMA for all CEMS required to be operated under this Project:

a) CEMS System Downtime Reports as required by COMAR 26.11.01.11E(1).

b) Quarterly CEMS Summary Reports as required by COMAR 26.11.01.11E(2)(c). [COMAR 26.11.01.11E]

A-IV-23 DCP shall submit reports of excess emissions and monitor downtime associated with the Frame 7 CTs, in accordance with 40 CFR §60.7(c). Excess emissions as defined in 40 CFR §60.4380 (NO_x) and 40 CFR §60.4385 (SO_2) must be reported for all periods of unit operation, including startup, shutdown, and malfunction. [40 CFR §60.4375]

A-IV-24 DCP shall maintain annual fuel use records on site for not less than 3 years, and make these records available to MDE-ARMA upon request. [COMAR 26.11.09.08K]

A-IV-25 DCP shall comply with all applicable NO_x reporting and recordkeeping requirements for each of the Frame 7 CTs as specified in 40 CFR §60.4375-40 CFR §60.4395.

A-IV-26 If DCP elects to demonstrate compliance with the SO_2 emissions limit in 40 CFR §60.4330 using methods described in §60.4415(a) as described in Table A-1, DCP shall submit periodic representative fuel sampling records as part of the quarterly report to MDE-ARMA to be postmarked by the 30th day of the month following the end of each calendar quarter.

V. AUXILIARY BOILERS

Emission Unit Number(s):
AUXB-A, AUXB-B
Two auxiliary boilers with SCRs, low-NO_x burners, and catalytic oxidizers

Applicable Requirements

A-V-1 The auxiliary boilers are each subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Visible Emissions** - Prohibits DCP from causing or permitting the discharge of emissions from auxiliary boilers, other than water in an uncombined form, as specified in Table A-2. [COMAR 26.11.09.05A(1)]

b) **Control of Sulfur Oxides From Fuel Burning Equipment** - Prohibits DCP from burning, selling, or making available for sale process gas used as fuel with a sulfur content by weight of greater than 0.3 percent. [COMAR 26.11.09.07A(1)(d)]

c) **Control of NO_x Emissions for Major Stationary Sources** - Requires DCP to comply with all applicable provisions of COMAR 26.11.09.08. DCP shall demonstrate compliance with the emission limits of COMAR 26.11.09.08 by complying with the emission limits specified in Table A-2.

A-V-2 The auxiliary boilers are subject to NSPS 40 CFR §60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Generating Units, which contain various requirements for emission limitations, monitoring, testing, recordkeeping, and reporting for $NO_{x,}$ including but not limited to those specified in Table A-2.

Operational and Emission Limits

A-V-3 **Best Available Control Technology (BACT) -** For each of the auxiliary boilers, BACT shall be the efficient boiler design of the auxiliary boiler, use of facility process fuel only during normal operation, operation of a low-NO_x burner, operation of an oxidation catalyst, operation of a SCR system, and application of good combustion controls in order to comply with the emission limits specified in Table A-2.

A-V-4 **Lowest Achievable Emission Rate (LAER) -** Emissions from the auxiliary boilers shall meet the LAER limits specified in Table A-2, through the use of efficient boiler design, use of facility process fuel only during normal operation, SCRs, low-NOx burners, oxidation catalysts, and good combustion practices.

A-V-5 DCP shall comply with the emission limitations during facility startup and shutdown events as specified in Table A-2 for each auxiliary boiler. These emissions shall be included in demonstrating compliance with the Project-wide emissions (Condition A-III-4) limits, on a consecutive 12-month rolling average basis.

A-V-6 DCP shall limit emissions of ammonia resulting from un-reacted ammonia (ammonia slip) from each of the SCRs to be installed on the auxiliary boilers as specified in Table A-2.

Compliance Demonstration

Testing and Monitoring Requirements

A-V-7 At least 30 days prior to conducting any compliance stack test, DCP shall submit a test protocol to MDE-ARMA for review and approval.

a) Compliance stack testing shall be conducted in accordance with MDE-ARMA Technical Memorandum (TM) 91-01, "Test Methods and Equipment Specifications for Stationary Sources" (January 1991), as amended by Supplement 3 (December 1997), 40 CFR §60, or subsequent test protocols approved by MDE-ARMA; and

b) Test ports shall be located in accordance with TM 91-01 (January 1991), or subsequent or alternative measures approved by MDE-ARMA.

A-V-8 Initial compliance stack testing of the auxiliary boilers shall be conducted within 180 days after initial startup to quantify emissions and demonstrate compliance with emission limits specified in the CPCN for the following pollutants: NO_x, VOC, PM, PM10, PM2.5, CO, ammonia, and CO_2. Subsequent stack tests shall be conducted annually for NO_x, VOC, PM, PM10, PM2.5, CO, and CO_2 and at least every five years for ammonia. As an alternative to annual stack testing for VOC, CO, and CO_2, DCP may choose to demonstrate compliance with emission limitations by installing and operating a certified CEMS, upon written notification to MDE-ARMA.

A-V-9 Compliance testing shall be conducted by the methods specified in Table A-2.

A-V-10 DCP shall conduct initial and subsequent performance tests on the auxiliary boilers, for NO_x as specified in Table A-2. [40 CFR §60.46b(c)]

A-V-11 Compliance stack testing of each of the auxiliary boilers shall be conducted within 180 days after initial startup to demonstrate that the formaldehyde emission rate is in compliance with the emission limit specified in Condition A-III-4. Testing for formaldehyde emissions shall be conducted according to EPA Method 323, or equivalent method approved by MDE.

A-V-12 Continuous compliance monitoring for the auxiliary boilers shall be conducted as specified in Table A-2.

A-V-13 Unless otherwise approved by MDE-ARMA, DCP shall install on each auxiliary boiler a CO_2 CEMS or calibrated in-line fuel flow-meters as specified under 40 CFR 75.10(3) to measure CO_2 emissions associated with the production of electricity. Emissions of CO_2 from the auxiliary boilers are to be monitored and recorded hourly utilizing a data handling collection system (DHAS) installed, calibrated, and maintained in accordance with 40 CFR 75. [40 CFR 75.10(3)]

A-V-14 To demonstrate compliance with the GHG BACT, DCP shall conduct an annual combustion tune-up on the auxiliary boilers to ensure efficient operation.

A-V-15 DCP shall meet the emission limitations for visible emissions as specified in Table A-2. [COMAR 26.11.09.05A(1&5)]

A-V-16 DCP shall install a fuel flow meter on each auxiliary boiler and continuously monitor the fuel flow to each auxiliary boiler. The fuel flow shall be recorded monthly.

A-V-17 Compliance with the BACT and LAER emission limitations shall be demonstrated as follows:

a) DCP shall obtain vendor guarantees to demonstrate compliance with the BACT and LAER emission limits.

b) Emissions of NO_x, VOC, CO, PM, PM10 filterable, and PM2.5 filterable shall be calculated using fuel measurements, vendor guaranteed emission rates, and hours of operation. Emissions of PM10 condensable and PM2.5 condensable shall be calculated using fuel measurements, AP-42 emissions factors, and hours of operation. Monthly emission totals shall be used to calculate 12-month rolling period emissions.

c) CH_4 and N_2O emissions from the auxiliary boilers shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart C. On a monthly basis, fuel consumption, coupled with the appropriate emission factors and global warming potentials (25 for CH_4 and

298 for N_2O), shall be used to calculate the CH_4 and N_2O emissions on a CO_2e basis. These emission rates, summed with the monthly CO_2 emissions based on stack testing shall be used to establish GHG emissions from the auxiliary boilers on a CO_2e basis.

A-V-18 All monitoring devices required to demonstrate continuous compliance shall be installed, calibrated, and maintained according to manufacturer's specifications.

Recordkeeping and Reporting Requirements

A-V-19 DCP shall comply with all applicable NO_x reporting and recordkeeping requirements for each of the auxiliary boilers as specified in 40 CFR §60.49(b).

A-V-20 Final results of each compliance stack test must be submitted to MDE-ARMA within 60 days after completion of the test.

A-V-21 DCP shall submit a formaldehyde emission analysis following the completion of initial stack testing for the Frame 7 CTs, auxiliary boilers, and thermal oxidizer which demonstrates that the combined formaldehyde emissions from these tests in addition to the formaldehyde emissions from the other project sources as calculated based on approved emission factors, are less than the limit specified in Condition A-III-4.

A-V-22 Unless otherwise approved by MDE-ARMA, DCP shall submit electronic quarterly reports from the DHAS of CO_2 emissions to the EPA Clean Air Markets Business System as specified in 40 CFR 75.64. [40 CFR 75.64]

A-V-23 The results of the combustion tune-up required to satisfy the GHG BACT compliance demonstration requirement for the auxiliary boilers shall be provided to MDE-ARMA in the subsequent quarterly report.

A-V-24 DCP shall submit to MDE-ARMA the results of the visible emissions observations in each quarterly report.

A-V-25 DCP shall maintain annual fuel use records on site for not less than 3 years, and make these records available to MDE-ARMA upon request. [COMAR 26.11.09.08K]

VI. DIESEL-FIRED EMERGENCY ENGINES

Emission Unit Number(s):
EG-A 1,550-hp emergency generator

FP-A, FP-B, FP-C,
FP-D, and FP-E Five 350-hp diesel-fired emergency fire pump engines

Applicable Requirements

A-VI-1 The emergency generator and five emergency fire pump engines are each subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Visible Emissions During Idle Mode –** Except as provided in COMAR 26.11.09.05E(4), prohibits DCP from causing or permitting the discharge of emissions from any internal combustion engine, operating at idle, greater than 10 percent opacity. [COMAR 26.11.09.05E(2)]

b) **Visible Emissions During Operating Mode -** Except as provided in COMAR 26.11.09.05E(4), prohibits DCP from causing or permitting the discharge of emissions from any internal combustion engine, operating at other than idle conditions, greater than 40 percent opacity. [COMAR 26.11.09.05E(3)]

c) **Exceptions to Visible Emissions Standards for Internal Combustion Engines**:

i. COMAR 26.11.09.05E(2) does not apply for a period of two consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

ii. COMAR 26.11.09.05E(3) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
1. Engines that are idled continuously when not in service: 30 minutes
2. All other engines: 15 minutes.

iii. COMAR 26.11.09.05E(2) and (3) do not apply while maintenance, repair, or testing is being performed by qualified mechanics. [COMAR 26.11.09.05E(4)]

d) **Control of Sulfur Oxides From Fuel Burning Equipment –** Prohibits DCP from burning, selling, or making available for sale distillate fuel oils with a sulfur content of greater than 0.3 percent. [COMAR 26.11.09.07A(1)(c)]

e) **Control of NO_x Emissions for Major Stationary Sources – Fuel Burning Equipment with a Rated Heat Input of Less than 100 MMBtu/hr** - Requires DCP to comply with the requirements of COMAR 26.11.09.08E, including conducting a combustion analysis for each installation and attending operator training programs sponsored by MDE-ARMA, EPA, or equipment vendors every three years. [COMAR 26.11.09.08E]

f) **Control of NO_x Emissions for Major Stationary Sources** - Requires DCP, for all fuel burning equipment with a capacity factor (as defined in 40 CFR §72.2) of 15 percent or less, to comply with the following requirements.

i. Provide certification of the capacity factor of the equipment to MDE-ARMA in writing; and

ii. Require each operator of an installation to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the MDE, the EPA, or equipment vendors. [COMAR 26.11.09.08G(1)]

A-VI-2 The emergency generator is subject to all applicable State-Only air quality requirements including the prohibition of operation of the emergency generator except for emergencies, testing, and maintenance purposes, and the operation of the emergency generator for testing or maintenance purposes between 12:01 a.m. and 2:00 p.m. on any day on which the MDE-ARMA forecasts that the air quality will be code orange, code red, or code purple unless the engine fails a test and engine maintenance and a re-test are necessary. [COMAR 26.11.36.03A]

A-VI-3 The emergency generator and fire pump engines shall be fueled with ultra-low sulfur diesel fuel only with a sulfur content not to exceed 15 parts per million by weight (ppmw).

A-VI-4 The emergency generator and each of the five fire pump engines are subject to 40 CFR §63 Subpart ZZZZ - National Emission Standards of Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The emergency generator and the five fire pump engines shall comply with all the applicable requirements of NSPS Subparts IIII under 40 CFR §63.6590(c)(1).

Operational and Emission Limits

A-VI-5 The emergency generator and the five fire pump engines are subject to NSPS 40 CFR §60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. DCP shall meet the monitoring, compliance, testing, notification, reporting, and recordkeeping requirements of 40 CFR §60.4200 to 40 CFR §60.4219 and related applicable provisions of 40 CFR §60.7 and 40 CFR §60.8. The diesel fuel combusted in the emergency generator and the five fire pump engines shall meet the requirements of 40 CFR §60.4207. DCP shall meet the following limits for the emergency generator and the five fire pump engines:

a) Under 40 CFR §60.4202 and 40 CFR §89.112, Table 1, emissions from the 1,550-hp emergency generator shall not exceed 6.4 g/kW-hour (4.8 g/hp-hr) combined non-methane hydrocarbons (NMHC) and NO_x, 3.5 g/kW-hour (2.6 g/hp-hr) CO, and 0.20 g/kW-hour (0.15 g/hp-hr) PM filterable.

b) Under 40 CFR §60 Subpart IIII, Table 4, emissions from the five 350-hp fire pump engines shall not exceed 4.0 g/kW-hr (3.0 g/hp-hour) combined NMHC and NO_x and 0.20 g/kW-hr (0.15 g/hp-hour) PM filterable.

c) Under 40 CFR §60.4211(f), DCP shall be restricted to operating the emergency generator and each fire pump engine no more than 100 hours per calendar year each for routine maintenance and testing.

A-VI-6 **Best Available Control Technology (BACT) –** For the 1,550-hp emergency diesel generator, BACT shall be the exclusive use of ultra low sulfur diesel (ULSD) fuel and good combustion practices. The emergency generator shall be designed to meet the following emission limits at all times:

a) NO_x and NMHC emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr);

b) CO emissions shall not exceed 3.5 g/kW-hr (2.6 g/hp-hr);

c) PM filterable emissions shall each not exceed 0.20 g/kW-hr (0.15 g/hp-hr);

d) PM10 filterable and condensable emissions shall not exceed 0.23 g/kW-hr (0.17 g/hp-hr);

e) PM2.5 filterable and condensable emissions shall not exceed 0.23 g/kW-hr (0.17 g/hp-hr); and

f) GHG emissions shall be calculated and included in the project-wide GHG 12-month rolling limit.

A-VI-7 **Best Available Control Technology (BACT) –** For each of the five nominal 350-hp fire pump engines, BACT shall be the exclusive use of ULSD fuel and good combustion practices. The fire pump engines shall be designed to meet the following emission limits at all times:

a) NO_x and NMHC emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr);

b) CO emissions shall not exceed 6.68e^{-3} lb/hp-hr (3.0 g/bhp-hr or 4.0 g/kW-hr);

c) PM filterable emissions shall not exceed 0.20 g/kW-hr (0.15 g/hp-hr);

d) PM10 filterable and condensable emissions shall not exceed 0.23 g/kW-hr (0.17 g/bhp-hr);

e) PM2.5 filterable and condensable emissions shall not exceed 0.23 g/kW-hr (0.17 g/bhp-hr); and

f) GHG emissions shall be calculated and included in the project-wide GHG 12-month rolling limit.

A-VI-8 **Lowest Achievable Emission Rate (LAER) -** The emergency generator and five fire pump engines shall be designed to meet the following limits through the use of ULSD fuel and good combustion practices at all times:

a) Combined NO_x and NMHC emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr) for the 1,550-hp emergency generator; and

b) Combined NO_x and NMHC emissions shall not exceed 4.00 g/kW-hr (3.0 g/hp-hr) for each of the five fire pump engines.

A-VI-9 The emergency generators and fire water pump engine are subject to the following requirements of 40 CFR Part 60 Subpart IIII:

a) DCP shall purchase an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications [40 CFR 60.4211(c)].

b) DCP must operate and maintain the stationary CI ICE according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine. [40 CFR 60.4206]

<u>Compliance Determination</u>

Testing and Monitoring Requirements

A-VI-10 For the emergency generator, DCP shall install and maintain a non-resettable operating hour meter, or equivalent, to indicate the elapsed operating time.

A-VI-11 For each of the fire pump engines, DCP shall install and maintain a non-resettable operating hour meter, or equivalent, to indicate the elapsed operating time.

A-VI-12 Compliance with the BACT and LAER emission limitations for the emergency generator and fire water pump engines shall be demonstrated as follows:

a) DCP shall obtain vendor guarantees to demonstrate compliance with the BACT and LAER emission limits.

b) Emissions of NO_x, CO, PM, PM10 filterable, and PM2.5 filterable shall be calculated using fuel measurements, NSPS Subpart IIII emissions standards, and hours of operation. Emissions of VOC, PM10 condensable, and PM2.5 condensable shall be calculated using fuel measurements, AP-42 emissions factors, and hours of operation. Monthly emission totals shall be used to calculate 12-month rolling period emissions.

c) CH_4 and N_2O emissions from the emergency generators and fire water pumps shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart C. On a monthly basis, fuel consumption, coupled with the appropriate emission factors and global warming potentials (25 for CH_4 and 298 for N_2O), shall be used to calculate the CH_4 and N_2O emissions on a CO_2e basis. These emission rates, summed with the monthly CO_2 emissions based on stack testing shall be used to establish GHG emissions from the auxiliary boilers on a CO_2e basis.

Recordkeeping and Reporting Requirements

A-VI-13 DCP shall comply will all applicable reporting and recordkeeping requirements for the emergency generator and each of the five fire pump engines as specified in 40 CFR §60.4214.

A-VI-14 DCP shall maintain records onsite of the hours of operation of the emergency generator and each of the five fire pump engines, including date, time, and duration and an explanation of reasons for operation of each engine.

A-VI-15 DCP shall maintain the following records required by COMAR 26.11.09.08G(1):

a) Maintain the results of the combustion analysis at the site for at least 2 years and make these results available to the MDE-ARMA and the EPA upon request; and

b) Maintain a record of training program attendance for each operator at the site, and make these records available to the MDE-ARMA upon request [COMAR 26.11.09.08G(1)].

A-VI–16 DCP shall provide fuel supplier certifications for each fuel delivery that documents the sulfur content of the ultra-low sulfur diesel (ULSD) is 15 ppm sulfur by weight or less. Fuel supplier certification shall include the following information:

a) The name of the oil supplier;

b) The date of the delivery;

c) The amount of fuel delivered; and

d) A statement from the fuel supplier that the diesel fuel oil complies with the specifications of 40 CFR 80.510.

A-VI-17 DCP shall maintain annual fuel use records on site for not less than 3 years, and make these records available to MDE-ARMA upon request. [COMAR 26.11.09.08K(3)]

VII. THERMAL OXIDIZER

Emission Unit Number(s):
TO-A 56 MMBtu/hr thermal oxidizer with SCR and oxidation catalyst

Applicable Requirements

A-VII-1 The Thermal Oxidizer is subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Visible Emission Limit -** Prohibits DCP from causing or permitting the discharge of emissions from any installation or building, other than water in an uncombined form, as specified in Table A-3. [COMAR 26.11.06.02C(1)]

b) **Sulfur Compounds From Other Than Fuel Burning Equipment –** Prohibits DCP from causing or permitting the discharge into the atmosphere from installations other than fuel-burning equipment of gases containing more than 500 ppm of sulfur dioxide. [COMAR 26.11.06.05B(1)]

c) **Sulfur Compounds From Other Than Fuel Burning Equipment** - Prohibits DCP from causing or permitting the discharge into the atmosphere from installations other than fuel burning equipment of gases containing sulfuric acid, sulfur trioxide, or any combination of them greater than 35 milligrams per cubic meter reported as sulfuric acid. [COMAR 26.11.06.05B(2)]

Operational and Emission Limits

A-VII-2 **Best Available Control Technology (BACT) –** For the thermal oxidizer, BACT shall be the operation of an oxidation catalyst, operation of a SCR system, and good combustion practices to achieve the emission limitations specified in Table A-3.

A-VII-3 **Lowest Achievable Emission Rate (LAER) -** Emissions from the thermal oxidizer shall meet the LAER limits specified in Table A-3 through the use of an SCR, oxidation catalyst, and good combustion practices.

A-VII-4 **Best Available Control Technology for Toxics (T-BACT) –** Emissions from the thermal oxidizer shall comply with T-BACT requirements through the use of an SCR, oxidation catalyst, good operating practices, and shall minimize ammonia slip emissions by not injecting ammonia until the SCR reaches an appropriate operating temperature. [COMAR 26.11.15.05]

A-VII-5 DCP shall limit emissions of ammonia resulting from un-reacted ammonia (ammonia slip) from the SCR to be installed on the thermal oxidizer as specified in Table A-3.

Compliance Determination

Testing and Monitoring Requirements

A-VII-6 At least 30 days prior to conducting any compliance stack test, DCP shall submit a test protocol to MDE-ARMA for review and approval.

a) Compliance stack testing shall be conducted in accordance with MDE-ARMA Technical Memorandum (TM) 91-01, "Test Methods and Equipment Specifications for Stationary Sources" (January 1991), as amended by Supplement 3 (December 1997), 40 CFR §60, or subsequent test protocols approved by MDE-ARMA; and

b) Test ports shall be located in accordance with TM 91-01 (January 1991), or subsequent or alternative measures approved by MDE-ARMA.

A-VII-7 Initial compliance stack testing of the thermal oxidizer shall be conducted within 180 days after initial startup to quantify pollutant emissions and demonstrate compliance with the emission limits specified in the CPCN for the following pollutants: NO_x, VOC, PM, PM10, PM2.5, ammonia, and CO. Subsequent stack tests shall be conducted annually.

A-VII-8 Compliance testing shall be conducted by the methods specified in Table A-3.

A-VII-9 Compliance stack testing for the thermal oxidizer shall be conducted within 180 days after initial startup to demonstrate that the formaldehyde emission rate is in compliance with the emission limit specified in Condition A-III-4. Testing for formaldehyde emissions shall be conducted according to EPA Method 323, or equivalent method approved by MDE.

A-VII-10 Continuous compliance monitoring for the thermal oxidizer shall be achieved as specified in Table A-3.

A-VII-11 DCP shall install a fuel flow meter and continuously monitor the fuel flow for the thermal oxidizer. The fuel flow shall be recorded monthly.

A-VII-12 Compliance with the BACT and LAER emission limitations shall be demonstrated as follows:

a) DCP shall obtain vendor guarantees to demonstrate compliance with the BACT and LAER emission limits.

b) Emissions of NO_x and CO shall be calculated using vendor guaranteed emission rates, stack exhaust oxygen content, stack outlet flowrate, and hours of operation. Emissions of VOC, PM, PM10, and PM2.5 shall be calculated using vendor guaranteed emission rates and hours of operation. Monthly emission totals shall be used to calculate 12-month rolling period emissions.

c) CO_2, CH_4 and N_2O emissions from the combustion of fuel in the thermal oxidizer shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart C. On a monthly basis, fuel consumption, coupled with the appropriate emission factors and global warming potentials (1 for CO_2, 25 for CH_4 and 298 for N_2O), shall be used to calculate emissions on a CO_2e basis. CO_2, CH_4 and N_2O emissions resulting from combusted and un-combusted off-gas (i.e., acid gas) in the thermal oxidizer shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart W. The sum of these emission rates shall establish GHG emissions from the thermal oxidizer on a CO_2e basis.

A-VII-13 All monitoring devices required to demonstrate continuous compliance shall be installed, calibrated, and maintained according to manufacturer's specifications.

Recordkeeping and Reporting

A-VII-14 Final results of each compliance stack test must be submitted to MDE-ARMA within 60 days after completion of the test.

A-VII-15 DCP shall submit a formaldehyde emission analysis following the completion of the initial stack testing for the Frame 7 CTs, auxiliary boilers, and thermal oxidizer which demonstrates that the combined formaldehyde emissions from these tests in addition to formaldehyde emissions from the other project sources as calculated based on approved emission factors, are less than the limit specified in Condition A-III-4.

VIII. NORTH AND SOUTH FLARES

Emission Unit Number(s):

NF	North Flare (26 pilots)
SF	South Flare (12 pilots)

Applicable Requirements

A-VIII-1 The North and South Flares are each subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Visible Emission Limit -** Except as provided in COMAR26.11.06.02A(2), prohibits DCP from causing or permitting the discharge of emissions from any installation or building, other than water in an uncombined form, which is greater than 20 percent opacity. [COMAR 26.11.06.02C(1)]

b) **Sulfur Compounds From Other Than Fuel Burning Equipment –** Prohibits DCP from causing or permitting the discharge into the atmosphere from installations other than fuel-burning equipment of gases containing more than 500 ppm of sulfur dioxide. [COMAR 26.11.06.05B(1)]

c) **Sulfur Compounds From Other Than Fuel Burning Equipment** - Prohibits DCP from causing or permitting the discharge into the atmosphere from installations other than fuel-burning equipment of gases containing sulfuric acid, sulfur trioxide, or any combination of them greater than 35 milligrams per cubic meter reported as sulfuric acid. [COMAR 26.11.06.05B(2)]

Operational and Emission Limits

A-VIII-2 **Best Available Control Technology (BACT) –** For the North and South flares, BACT shall be the presence of pilot flame, good operating practices, proper combustion, and designed to achieve the following emission limits:

a) For the North Flare:

i. NO_x emissions shall not exceed 69.0 tpy on a 12-month rolling basis, at all times;

ii. PM emissions shall not exceed 0.7 tpy, on a 12-month rolling basis, at all times;

iii. PM10 and PM2.5 each shall not exceed 2.8 tpy, on a 12-month rolling basis, at all times; and

iv. CO emissions shall not exceed 31.2 tpy, on a 12-month rolling basis, at all times.

b) For the South Flare:

i. NO_x emissions shall not exceed 41.0 tpy on a 12-month rolling basis, at all times;

ii. PM emissions shall not exceed 0.4 tpy, on a 12-month rolling basis, at all times;

iii. PM10 and PM2.5 each shall not exceed 1.7 tpy, on a 12-month rolling basis, at all times; and

iv. CO emissions shall not exceed 18.4 tpy, on a 12-month rolling basis, at all times.

c) GHG emissions shall be calculated and included in the project-wide GHG 12-month rolling limit.

A-VIII-3 **Lowest Achievable Emission Rate (LAER) –** For the North and South flares LAER shall be the presence of pilot flame, good operating practices, proper combustion and designed to achieve the following emission limits:

a) For the North Flare:

i. NO_x emissions shall not exceed 69.0 tpy on a 12-month rolling average basis, at all times; and

ii. VOC emissions shall not exceed 10.8 tpy on a 12-month rolling average basis, at all times.

b) For the South Flare:

i. NO_x emissions shall not exceed 41.0 tpy on a 12-month rolling average basis, at all times; and

ii. VOC emissions shall not exceed 4.0 tpy on a 12-month rolling average basis, at all times.

A-VIII-4 **Best Available Control Technology for Toxics (T-BACT) –** Emissions from the North and South Flares shall comply with T-BACT requirements through the presence of pilot flame and the use of good operating practices and maintaining proper combustion efficiency. [COMAR 26.11.15.05]

A-VIII-5 DCP shall be limited to 10 facility restarts during any 12-month rolling period to meet BACT and LAER requirements. These restarts can be warm or cold facility restarts, but venting to flares during any restart shall be limited to one hour to each flare (North and South) per restart event.

A-VIII-6 DCP shall limit flaring of gas vented from warm ships during the cool-down process to a maximum of 12 events in any rolling 12-month period.

<u>Compliance Determination</u>

Testing and Monitoring Requirements

A-VIII-7 Compliance with the BACT and LAER emission limitations shall be demonstrated as follows:

a) The facility shall continuously monitor for the presence of pilot flame.

b) Emissions of NO_x, VOC, CO, PM, PM10, and PM2.5 shall be calculated using fuel measurements, AP-42 emissions factors, and hours of operation. Monthly emission totals shall be used to calculate 12-month rolling period emissions.

c) CO_2, CH_4 and N_2O emissions from the flare pilots shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart C. CO_2, CH_4 and N_2O emissions resulting from flaring combusted and un-combusted gas streams during facility restarts and cool-downs shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart W and the chemical composition of each gas stream. On a monthly basis, fuel consumption, coupled with the appropriate emission factors and global warming potentials (1 for CO_2, 25 for CH_4 and 298 for N_2O), shall be used to calculate emissions on a CO_2e basis. The sum of these emission rates shall establish GHG emissions from the North and South Flare on a CO_2e basis.

Recordkeeping and Reporting

A-VIII-8 DCP shall continuously monitor for the presence of pilot flame during operations through the use of a thermocouple or equivalent monitoring method.

IX. COMPONENT LEAKS

Emission Unit Number(s):

FUG-A Piping components associated with this project, including valves, connectors, flanges, pump seals, and pressure relief valves within the facility boundary

Applicable Requirements

A-IX-1 The component leaks are subject to all applicable federally enforceable State air quality requirements including, but not limited to, the control of VOC Component Leaks, except as provided in COMAR 26.11.19.16D, requires DCP to comply with the following:

a) Visually inspect all components on the premises for leaks at least once each calendar month;

b) Tag any leak immediately so that the tag is clearly visible. The tag shall be made of a material that will withstand any weather or corrosive conditions to which it may be normally exposed. The tag shall bear an identification number, the date the leak was discovered, and the name of the person who discovered the leak. The tag shall remain in place until the leak has been repaired;

c) Take immediate action to repair all observed VOC leaks that can be repaired within 48 hours;

d) Repair all other leaking components not later than 15 days after the leak is discovered. If a replacement part is needed, the part shall be ordered within 3 days after discovery of the leak, and the leak shall be repaired within 48 hours after receiving the part;

e) Maintain a supply of components or component parts that are recognized by the source to wear or corrode, or that otherwise need to be routinely replaced, such as seals, gaskets, packing, and pipe fittings;

f) Maintain a log that includes the name of the person conducting the inspection and the date on which leak inspections are made, the findings of the inspection, and a list of leaks by tag identification number. The log shall be made available to the MDE-ARMA upon request. Leak records shall be maintained for a period of not less than 2 years from the date of their occurrence; and

g) Components that cannot be repaired as required because they are inaccessible, or that cannot be repaired during operation of the source, shall be identified in the log and included within the source's maintenance schedule for repair during the next source shutdown. [COMAR 26.11.19.16]

Operational and Emission Limits

A-IX-2 **Best Available Control Technology (BACT) –** GHG BACT shall be the implementation of an LDAR Monitoring Plan and Program following the procedures outlined in the TCEQ 28LAER Texas Commission of Environmental Quality's (TCEQ's) *Control Efficiencies for TCEQ Leak Detection and Repair Programs*, as amended. GHG emissions shall be calculated and included in the project-wide GHG 12-month rolling limit.

A-IX-3 **Lowest Achievable Emission Rate (LAER) –** VOC **e**missions from component leaks shall not exceed 2.53 tpy from all components associated with the project on a 12-month rolling basis through the implementation of the VOC LDAR Monitoring Plan and Program.

A-IX-4 **Best Available Control Technology for Toxics (T-BACT) –** Emissions from component leaks shall comply with T-BACT requirements through the implementation of a VOC LDAR Monitoring Plan and Program. [COMAR 26.11.15.05]

A-IX-5Emissions from component leaks shall be calculated based on the results of gas analyzer monitoring and through the use of Table 2-4 of EPA's *Protocol for Equipment Leak Emission Estimates* and the chemical composition of each material and shall consider the control efficiencies based on 28LAER LDAR program.

X. VOLATILE ORGANIC COMPOUND VESSELS (STORAGE TANKS)

Emission Unit Number(s):

TANK-P1	Propane make-up tank, 102,500 gallons
TANK-P2	Propane make-up tank, 102,500 gallons
TANK-P3	Propane make-up tank, 102,500 gallons
TANK-P4	Propane make-up tank, 102,500 gallons
TANK-E1	Ethane make-up tank, 34,000 gallons
TANK-E2	Ethane make-up tank, 34,000 gallons
TANK-C1	Condensate storage tank, 35,000 gallons
TANK-C2	Condensate storage tank, 35,000 gallons

Applicable Requirements

A-X-1 The volatile organic compound storage tanks are each subject to all applicable federally enforceable State air quality requirements including, but not limited to, the following regulations:

a) **Control of Gasoline and Volatile Organic Compound Storage and Handling, General Standards – Large Storage Tanks –** Prohibits DCP from placing or storing VOC having a true vapor pressure (TVP) between 1.5 psia (10.3 kilonewtons/square meter) and 11 psia (75.6 kilonewtons/square meter) in any closed tank with a capacity of 40,000 gallons or greater unless the tank is equipped with a properly installed, operating, and well maintained vapor control system capable of collecting the vapors from the tank and disposing of these vapors to prevent their emissions to the atmosphere. [COMAR 26.11.13.03A(1)(b)(iii)]

b) **Control of Gasoline and Volatile Organic Compound Storage and Handling, General Standards –** For loading of trucks to haul condensate from the two 67,000-gallon condensate storage tanks offsite, prohibits DCP from causing or permitting gasoline or VOC having a TVP of 1.5 psia (10.3 kilonewtons/square meter) or greater to be loaded into any tank truck, railroad tank car, or other contrivance unless the:

i. Loading connections on the vapor lines are equipped with fittings that have no leaks and that automatically and immediately close upon disconnection to prevent release of gasoline or VOC from these fittings; and

ii. Equipment is maintained and operated in a manner to prevent avoidable liquid leaks during loading or unloading operations. [COMAR 26.11.13.04(D)]

A-X-2 The volatile organic compound storage vessels are each subject to NSPS 40 CFR §60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. DCP shall comply with the requirements of Subpart Kb through the use of a closed-loop system such that there are no emissions to the atmosphere from the four Propane Make-Up Tanks, two Ethane Make-Up Tanks, and two Condensate Storage Tanks.

XI. NOTIFICATION REQUIREMENTS

A-XI-1 All air quality notifications and reports required by this CPCN shall be submitted to:

Administrator, Compliance Program
Air and Radiation Management Administration
1800 Washington Boulevard
Baltimore, Maryland 21230

A-XI-2 All notifications and reports required by 40 CFR §60 Subpart KKKK, Subpart IIII, Subpart Db, Subpart Kb, and 40 CFR §63 Subpart ZZZZ shall be submitted to:

Director, Air Protection Division
U.S. EPA – Region 3
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

A-XI-3 Information copies of the reports regarding air quality requirements as described in the conditions of Case 9318 (A-I-2, A-I-5, A-I-6, A-III-2b, A-III-7, A-III-8, A-III-9, A-III-10, A-IV-7, A-IV-18, A-V-7, A-V-20, A-VII-6, A-VII-14) shall be submitted to the Power Plant Research Program at:

Director
Power Plant Assessment Division
Department of Natural Resources
Tawes State Office Building, B-3
580 Taylor Avenue
Annapolis, Maryland 21401

Table A-1—Emissions Standards for Each DCP Frame 7 CT

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
Ammonia	5 ppmvd at 15% O_2	COMAR 26.11.15.05	24-hour block average	Initial stack test using EPA Method CTM-027 or equivalent method approved by MDE-ARMA	Performance stack tests at least once every five years using EPA Method CTM-027 or equivalent method approved by MDE-ARMA
CO	1.5 ppmvd at 15% O_2, except during periods of startup and shutdown	BACT	3-hour block average	Initial and annual performance test using EPA Method 10 or equivalent method approved by MDE-ARMA or CEMS installed and certified under 40 CFR 60 Appendix B and F	Emissions shall be continuously monitored via CEMS. [COMAR 26.11.01.04B]
CO During Startup/ Shutdown	562.4 lb/startup event 59.2 lb/shutdown event	BACT	Limits are total for both Frame 7 CTs per startup or shutdown event	None required	Emissions shall be continuously monitored via CEMS. [COMAR 26.11.01.04B]
GHG (as CO_2e)	117 lb/MMBtu	BACT	3-hour block average	Initial and annual performance test for CO_2 using EPA Method 3A or equivalent method approved by MDE-ARMA or CEMS installed and certified under 40 CFR 60 Appendix B and F	Calculate emissions based on fuel flow and emission factors developed during annual stack testing for CO_2, or using CO_2 CEMS, and emission factors from 40 CFR 98, Subpart C for CH_4 and N_2O, and update emissions on a rolling 12-month basis.

Table A-1—Emissions Standards for Each DCP Frame 7 CT

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
NO_x	15 ppmvd at 15% O_2 or 54 ng/J (0.43 lb/MWh) of useful output, except during periods of startup and shutdown	NSPS Subpart KKKK [40 CFR §60.4320]	30-day rolling	Initial and annual performance test as required by 40 CFR§60.4400 or CEMS in accordance with 40 CFR §60.4405	Emissions shall be continuously monitored via CEMS. [40 CFR §60.4340(a)-(b)]
NO_x	42 ppm at 15% O_2, except during periods of startup and shutdown	COMAR 26.11.09.08G(2)	3-hour block average	Initial and annual performance test using EPA Method 7E or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	Emissions shall be continuously monitored via NO_x CEMS.
NO_x	2.5 ppmvd at 15% O_2, except during periods of startup and shutdown	BACT and LAER *<u>Note</u>: BACT and LAER limit is more stringent than NSPS and COMAR limits*	3-hour block average	Initial and annual performance test using EPA Method 7E or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	Emissions shall be continuously monitored via CEMS. [40 CFR §60.4340(a)-(b)]
NO_x During Startup/ Shutdown	1,304.5 lb/startup event 48.5 lb/shutdown event	BACT and LAER	Limits are total for both Frame 7 CTs per startup or shutdown event	None Required	Emissions shall be continuously monitored via CEMS.

Table A-1—Emissions Standards for Each DCP Frame 7 CT

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
PM Filterable	0.0033 lb/MMBtu (filterable only)	BACT	Average of three test runs	Initial and annual performance test using EPA Method 5 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis
PM10 filterable and condensable	0.007 lb/MMBtu (filterable and condensable), except during periods of startup and shutdown	BACT	Average of three test runs	Initial and annual performance test using EPA Methods 201A/202 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis.
PM10 filterable and condensable During Startup/ Shutdown	300.8 lbs/startup event 5.6 lbs/shutdown event	BACT	Limits are total for both Frame 7 CTs per startup or shutdown event	None Required	Designed to meet emission limits.
PM2.5 filterable and condensable	0.007 lb/MMBtu (filterable and condensable), except during periods of startup and shutdown	BACT	Average of three test runs	Initial and annual performance test using EPA Methods 201A/202 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis.

Table A-1—Emissions Standards for Each DCP Frame 7 CT

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
PM2.5 filterable and condensable During Startup/ Shutdown	300.8 lbs/startup event 5.6 lbs/shutdown event	BACT	Limits are total for both Frame 7 CTs per startup or shutdown event	None Required	Designed to meet emission limits.
SO_2	110 ng/J (0.90 lb/MWh) gross output SO_2 emissions OR No fuel burned with total potential sulfur emissions in excess of 26 ng/J (0.060 lb/MMBtu) heat input	NSPS [40 CFR §60.4330]	At all times	Initial and annual performance tests per 40 CFR §60.4415 OR N/A if DCP elects to comply with the minimum fuel sulfur content limit under 40 CFR§60.4330	N/A if DCP elects to demonstrate compliance with the emission limits by performing stack tests OR If DCP elects to comply with the minimum fuel sulfur content limit under 40 CFR§60.4330, DCP must monitor the total sulfur content of the fuel using the methods described in 40 CFR §60.4415 at a frequency described in 40 CFR §60.4370. [40 CFR §60.4360]

Table A-1—Emissions Standards for Each DCP Frame 7 CT

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
Visible Emissions	20% Opacity	COMAR 26.11.09.05A(1)	At all times, except as provided in COMAR 26.11.09.05A(3)	Initial Method 9 for 1 hour within 180 days of initial startup [COMAR 26.11.09.05A(1&5)]	Visible observation in accordance with EPA Reference Method 22 at least once each calendar quarter to verify that there are no visible emissions during operation. If visible emissions are observed then inspect combustion control system, perform necessary adjustments and/or repairs within 48 hours, and document in writing the results of inspection, adjustments and or repairs. After 48 hours, if the required adjustments and/or repairs have not eliminated the visible emissions, perform Method 9 observations once daily for at least one hour until corrective actions have reduced the visible emissions to less than 20 percent opacity. [COMAR 26.11.02.02(H)]

Table A-1—Emissions Standards for Each DCP Frame 7 CT

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
VOC	0.7 ppmvd at 15% O_2, except during periods of startup and shutdown *Note: Emissions from SU/SD events will be calculated based on the number of these events and the projected emission factor and included in the facility VOC emission cap to serve as LAER during SU/SD events*	LAER	3-hour block average	Initial and annual performance test using EPA Method 18/25A or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	CO CEMS data shall be used as a surrogate for VOC emissions. A correlation shall be developed between CO and VOC emissions based on an initial stack test. The emission correlation shall be verified annually by stack test or a new correlation established.
VOC During Startup/ Shutdown	101.1 lbs/startup event 4.8 lbs/shutdown event	LAER	Limits are total for both Frame 7 CTs per startup or shutdown event	None Required	Designed to meet emission limits.

Table A-2—Emissions Standards for Each DCP Auxiliary Boiler

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
Ammonia	5 ppmvd at 15% O_2	COMAR 26.11.02.02H	24-hour block average	Initial stack test using EPA Method CTM-027 or equivalent method approved by MDE-ARMA	Performance stack tests at least once every five years using EPA Method CTM-027 or equivalent method approved by MDE-ARMA
CO	0.0088 lb/MMBtu, except during periods of startup and shutdown	BACT	3-hour block average	Initial and annual performance test using EPA Method 10 or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Continuously monitor and record inlet and outlet catalyst bed temperature.
CO During Startup and Shutdown	2,618.5 lb/startup event 35.9 lb/shutdown event	BACT	Limits per startup or shutdown event	None Required	Designed to meet emission limit.

Table A-2—Emissions Standards for Each DCP Auxiliary Boiler

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
GHG (as CO_2e)	117 lb/MMBtu	BACT	3-hour block average	Initial and annual performance test for CO_2 using EPA Method 3A or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	Calculate emissions based on fuel flow and emission factors developed during annual stack testing for CO_2, or using CO_2 CEMS, and emission factors from 40 CFR 98, Subpart C for CH_4 and N_2O, and update emissions on a rolling 12-month basis.
NO_x	86 ng/J (0.20 lb/MMBtu)	NSPS Subpart Db [40 CFR§60.44b(a)] *Note: NSPS limit is as or more stringent than COMAR 26.11.09.08B(1)(c) and COMAR 26.11.09.08G(1).*	30-day rolling, at all times	Initial and annual performance test per 40 CFR §60.46b(c)	NO_x and CO_2 or O_2 emissions shall be continuously monitored via CEMS. [40 CFR §60.48b(b)]
NO_x	0.0099 lb/MMBtu, except during periods of startup and shutdown	BACT and LAER *Note: BACT and LAER limit is more stringent than COMAR and NSPS limits.*	3-hour block average	Initial and annual performance test using EPA Method 7E or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	NO_x and CO_2 or O_2 emissions shall be continuously monitored via CEMS. [40 CFR §60.48b(b)]
NO_x During Startup/ Shutdown	2,946.2 lb/startup event 38.9 lb/shutdown event	BACT and LAER	Limits per startup or shutdown event	None Required	NO_x and CO_2 or O_2 emissions shall be continuously monitored via CEMS. [40 CFR §60.48b(b)]

Table A-2—Emissions Standards for Each DCP Auxiliary Boiler

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
PM Filterable	0.005 lb/MMBtu (filterable only)	BACT	Average of three test runs	Initial and annual performance test using EPA Method 5 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis.
PM10 filterable and condensable	0.014 lb/MMBtu (filterable and condensable), except during periods of startup and shutdown	BACT	Average of three test runs	Initial and annual performance test using EPA Methods 201A/202 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis.
PM10 filterable and condensable During Startup/ Shutdown	296.8 lb/startup event 4.9 lb/shutdown event	BACT	Limits per startup or shutdown event	None Required	Designed to meet emission limit.

Table A-2—Emissions Standards for Each DCP Auxiliary Boiler

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
PM2.5 filterable and condensable	0.014 lb/MMBtu (filterable and condensable), except during periods of startup and shutdown *Note: Emissions from SU/SD events will be calculated based on the number of these events and the projected emission factor and included in the facility PM2.5 emission cap to serve as BACT during SU/SD events*	BACT	Average of three test runs	Initial and annual performance test using EPA Methods 201A/202 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis.
PM2.5 filterable and condensable During Startup/ Shutdown	296.8 lb/startup event 4.9 lb/shutdown event	BACT	Limits per startup or shutdown event	None Required	Designed to meet emission limit.

Table A-2—Emissions Standards for Each DCP Auxiliary Boiler

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
Visible Emissions	20% Opacity	COMAR 26.11.09.05A(1)	At all times, except as provided in COMAR 26.11.09.05A(3)	Initial Method 9 for 1 hour within 180 days of initial startup [COMAR 26.11.09.05A(1&5)]	Visible observation in accordance with EPA Reference Method 22 at least once each calendar quarter to verify that there are no visible emissions during operation. If visible emissions are observed then inspect combustion control system, perform necessary adjustments and/or repairs within 48 hours, and document in writing the results of inspection, adjustments and or repairs. After 48 hours, if the required adjustments and/or repairs have not eliminated the visible emissions, perform Method 9 observations once daily for at least one hour until corrective actions have reduced the visible emissions to less than 20 percent opacity. [COMAR 26.11.02.02(H)]

Table A-2—Emissions Standards for Each DCP Auxiliary Boiler

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
VOC	0.001 lb/MMBtu, except during periods of startup and shutdown *Note: Emissions from SU/SD events will be calculated based on the number of these events and the projected emission factor and included in the facility VOC emission cap to serve as LAER during SU/SD events*	LAER	3-hour block average	Initial and annual performance test using EPA Method 18/25A or equivalent method approved by MDE-ARMA or CEMs installed and certified under 40 CFR 60 Appendix B and F	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Continuously monitor and record inlet and outlet catalyst bed temperature.
VOC During Startup/ Shutdown	130.6 lb/startup event 1.8 lb/shutdown event	LAER	Limits per startup or shutdown event	None Required	Designed to meet emission limit.

Table A-3—Emissions Standards for DCP Thermal Oxidizer

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
Ammonia	5 ppmvd at 15% O_2	COMAR 26.11.15.05	24-hour block average	Initial stack test using EPA Method CTM-027 or equivalent method approved by MDE-ARMA	Performance stack tests at least once every five years using EPA Method CTM-027 or equivalent method approved by MDE-ARMA
CO	1.5 ppmvd at 15% O_2	BACT	3-hour block average	Initial and annual performance test using EPA Method 10, or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Continuously monitor and record inlet and outlet catalyst bed temperature. Designed to meet emission limit at all times.

Table A-3—Emissions Standards for DCP Thermal Oxidizer

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
NO_x	2.5 ppmvd at 15% O_2	BACT and LAER	3-hour block average	Initial and annual performance test using EPA Method 7E or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Continuously monitor ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Designed to meet emission limit at all times.
PM Filterable	0.013 lb/MMBtu (filterable only)	BACT	Average of three test runs	Initial and annual performance test using EPA Method 5 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis.

Table A-3—Emissions Standards for DCP Thermal Oxidizer

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
PM10 filterable and condensable	0.016 lb/MMBtu (filterable and condensable)	BACT	Average of three test runs	Initial and annual performance test using EPA Methods 201A/202 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Designed to meet emission limit at all times.
PM2.5 filterable and condensable	0.016 lb/MMBtu (filterable and condensable)	BACT	Average of three test runs	Initial and annual performance test using EPA Methods 201A/202 or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Designed to meet emission limit at all times.

Table A-3—Emissions Standards for DCP Thermal Oxidizer

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
Visible Emissions	20% Opacity	COMAR 26.11.06.02C(1)	At all times, except as provided in COMAR 26.11.06.02A(2)	Not Required	Visible observation in accordance with EPA Reference Method 22 at least once each calendar quarter to verify that there are no visible emissions during operation. If visible emissions are observed then inspect combustion control system, perform necessary adjustments and/or repairs within 48 hours, and document in writing the results of inspection, adjustments and or repairs. After 48 hours, if the required adjustments and/or repairs have not eliminated the visible emissions, perform Method 9 observations once daily for at least one hour until corrective actions have reduced the visible emissions to less than 20 percent opacity. [COMAR 26.11.02.02(H)]

Table A-3—Emissions Standards for DCP Thermal Oxidizer

Pollutant/ Operation	Emission Limit (not to exceed)	Underlying Requirement	Averaging Period	Performance Test	Continuous Compliance Demonstration Method
VOC	0.03 lb/hr	LAER	3-hour block average	Initial and annual performance test using EPA Method 18/25A or equivalent method approved by MDE-ARMA	Calculate emissions based on fuel flow and emission factors developed during annual stack testing and update emissions on a rolling 12-month basis. Continuously monitor and record inlet and outlet catalyst bed temperature. Designed to meet emission limit at all times.

TERRESTRIAL AND AQUATIC ECOLOGY

B-1. Construction and operation of the DCP facility, including its appurtenant features and two Offsite Areas A and B, shall be undertaken in accordance with this CPCN and shall comply with all applicable local, State, and Federal laws and regulations, including but not limited to the following:

a. Nontidal Wetlands - COMAR 26.23 applies to activities conducted in nontidal wetlands.

b. Waterway Construction – COMAR 26.17.04 applies to activities in State waterways.

c. Water Quality and Water Pollution Control - COMAR 26.08.01 through COMAR 26.08.04 applies to discharges to surface water and maintenance of surface water quality.

d. Erosion and Sediment Control - COMAR 26.17.01 applies to the preparation, submittal, review, approval, and enforcement of erosion and sediment control plans.

e. Forest Conservation - Maryland's Forest Conservation regulations, COMAR 08.19.01 through 08.19.06, apply to the development of local forest conservation programs and the preparation of forest conservation plans.

f. Wildlife Conservation – Maryland Natural Resource Article §10-2A-01, the Nongame and Endangered Species Conservation Act.

B-2. DCP shall comply with Best Management Practices for Nontidal Wetlands of Special State Concern and Expanded Buffers, COMAR 26.23.06.03. DCP shall implement these practices at the edges of 100-foot buffers along all streams and nontidal wetlands at Offsite Area A. These practices and techniques will include but not be limited to use of adequately sized temporary sediment traps, bioretention, super silt fencing, and other specialized techniques specifically needed for limiting the quantity of sediment entering existing forested wetlands and streams during the construction process.

B-3. All portions of the main plant and Offsite Areas disturbed during construction shall be stabilized as soon as practicable after the cessation of construction activities within that portion of the construction footprint, followed by seed application, in accordance with the best management practices presented in the MDE document *2011 Maryland Standards and Specifications for Soil Erosion and Sediment Control*, and as approved by Calvert County. In wetlands and wetland buffers, seed application shall consist of the following species: annual ryegrass (*Lolium multiflorum*), millet (*Setaria italica*), barley (*Hordeum* spp.), oats (*Uniola* spp.), and/or rye (*Secale cereale*). Other non-persistent vegetation may be acceptable, but must be approved by MDE Water Management Administration. Kentucky 31 fescue and other non-native invasive species shall never be used in wetlands or buffers.

B-4. DCP shall advise the PSC and PPRP that copies of contract specifications for tree clearing, construction, and rehabilitation of the construction footprints are available sixty (60) days prior to the beginning of construction. During any site clearing, DCP and its contractors shall leave tree roots and stumps in place, except where such roots and stumps interfere with structure locations, access roads, or other components of the power or linear facilities. Cleared trees may be cut and windrowed along the edges of the construction footprint for wildlife habitat where acceptable. Brush may be shredded and distributed along the edges of the cleared construction footprint as a ground cover to stabilize the soil surface.

B-5. DCP shall reduce tree clearing or trimming to the maximum extent practicable. At least sixty (60) days prior to clearing or construction within these areas DCP will submit to the Maryland Department of Natural Resources Department of Forestry (DNR Forestry) and PPRP for approval all Calvert County-approved Forest Conservation Plans. Grasses will be planted along streams and other open areas where acceptable. If the areas along streams are wetlands or wetland buffers, only grasses listed in Condition B-3 or others approved by MDE Water Management Administration shall be used. If areas along streams are uplands, the following grass species may be used: blue joint grass (*Calamagrostis canadensis*), switchgrass (*Panicum virgatum*), little bluestem (*Schizachyrium scoparium*), or Indian grass (*Sorghastrum nutans*). Other non-persistent vegetation may be acceptable, but must be approved by DNR or MDE Water Management Administration. Kentucky 31 fescue and silky bush clover (*Lespedeza cuneata*) shall never be used.

B-6. DCP shall work with DNR and Calvert County to determine areas within Offsite Area A where trees can be planted after construction of the proposed Project is complete, and will replant those areas as requested by Calvert County. In addition, DCP shall provide mitigation in compensation for the loss of mature forest and other natural resources at Offsite Area A. This mitigation shall consist of a combination of property purchase and preservation in perpetuity of existing forest tracts; purchase of transferable development rights (TDRs); and new tree planting in Calvert County and/or surrounding areas. All tree planting areas shall be maintained on at least an annual basis for a minimum of five years, and must be preserved in perpetuity. At least sixty (60) days prior to clearing or construction within Offsite Area A, DCP will submit for approval a draft mitigation/preservation plan to the Maryland Department of Natural Resources and Calvert County. At a minimum, this mitigation/preservation plan shall include the following:

a. Preservation of an additional 13.5 acres of the Forest Retention Area on Offsite Area A above the County's required retention threshold.
b. Preservation in perpetuity of Offsite Area E, which is already owned by Dominion, in an undeveloped condition.
c. Purchase of 88 TDRs from one or more landowners in Calvert County, to be applied to the Offsite Area E property.
d. Arranging for the 88.8 forested acres on Offsite Area E to be designated as Forest Retention Area to be reviewed and approved by Calvert County.
e. Purchase of Preservation Site 1 (Barrett site), and preservation in perpetuity of 26.2 acres, resulting in 13.1 acres of mitigation credit.
f. Preservation in perpetuity of 9.64 acres on Preservation Site 2 (DOH site, already owned by Dominion), resulting in 4.82 acres of mitigation credit.

g. Tree planting at sites within Calvert County or, if necessary, outside the county, totaling 15.0 acres.

B-7. Prior to construction of any part of the DCP facilities, DCP shall submit comprehensive protection plans for rare, threatened and endangered species at Offsite Area A, for approval by DNR Wildlife and Heritage Service and PPRP. These will include plans for protection and future expansion of tobaccoweed (*Elephantopus tomentosus*) populations at Offsite Area A. The plans must be prepared by qualified personnel, and will contain exact current mapping of the known site populations of this species, with reference to the proposed Offsite A facilities, depicted at an appropriate scale. The plans will also contain, at a minimum, a description of effective measures for avoiding impacts to this species, as well as all other appropriate mitigative measures.

B-8. DCP shall prepare and implement an oyster mitigation plan that includes restoring hard bottom and planting oyster shell/spat in the vicinity of Offsite Area B. DCP shall obtain DNR approval of the plan prior to the start of construction. The plan must include the following elements:

a. The area of mitigation shall encompass a minimum of 4 acres, and shall entail placing 2 to 4 inches of a shell/cultch base with a top layer of spat on shell. This represents 2:1 mitigation for the anticipated maximum impact area of 2 acres.

b. DCP shall provide funding to DNR to support the following surveys of the natural oyster bar near Offsite Area B: once prior to the start of construction, at least once during construction, and at the conclusion of the construction period.

c. Based on an evaluation of the survey results, DNR will determine the extent of impacts to the natural oyster bar as a result of DCP's construction support activities. If the extent of impacts exceeds the anticipated maximum of 2 acres, DCP will conduct additional mitigation at a 2:1 ratio, with a minimum of 1 additional acre of mitigation to be implemented.

d. If there is any incidence of tug or barge grounding or other direct impacts observed during the construction period, DCP shall notify DNR regarding the date and time of such incident, the likely cause of the incident, and the steps that DCP will take to prevent recurrence. Barge deliveries to Offsite Area B shall not continue until DCP receives approval from DNR.

B-9. DCP shall prepare and implement a plan to utilize as artificial reef components those materials that may be suitable for such use at the end of the construction period. Suitable materials may include some portion or all of the barge pier and concrete foundations removed from the terminal site. DCP shall submit a draft plan prior to the start of construction, and shall obtain DNR approval of the plan prior to the start of operation. The plan must cover the following elements:

a. Maryland's Artificial Reef Management Plan must be followed at all times (http://www.dnr.maryland.gov/fisheries/reefs/MarylandReefPlanFINALWOAPPENDIXB.pdf).

b. DCP shall contact DNR twelve months (one year) prior to pier dismantling so that DNR can provide to DCP updated material requirements and confirmation of the deposition site. In addition, DNR also requests a three-month notice prior to reef material deposition.
c. Pier material must be dismantled in such a way to eliminate exposed rebar or metal that would pose an underwater hazard.
d. Pier material must be deposited on a DNR approved site.
e. The proposed reef material will be sized appropriately for an oyster and fish reef.
f. Placement of reef material will minimize fine material deposition (to less than two inches) including sediment attached to the pier material.
g. DCP will wet the material prior to onsite deposition.
h. The DNR Artificial Reef Coordinator or a designated DNR staff person must be on site to inspect the material before overboard deployment. DNR may reject the material if it does not meet specifications.
i. DCP must place DNR buoys at the four corners of the proposed reef site to ensure proper deposition and to warn boaters of potential hazardous conditions. Once the deposition of reef material is complete, the site must be inspected to ensure stability of the material on the bottom and that no hazardous conditions exist resulting from deposition such as sharp edges, exposed rebar, or structurally unsound stacking. After underwater inspection and DNR review ensuring that the material is safely deposited on the bottom, the buoys may be removed, but long-term buoy placement at this reef site is at the discretion of the United States Coast Guard (USCG) regional commander.
j. Reef material must have a minimum of 15 feet of top clearance at mean-low-water to ensure navigational access.
k. Two months prior to the first deployment of reef material, DCP must contact the USCG so that the USCG can prepare a "notice to mariners" (NTM) and Marine Information Broadcast (MIB), and provide two weeks notice for any additional buoy deployments.
l. DCP must provide a schedule for material deposition on the reef to DNR to ensure that staff will have sufficient time to observe and confirm coordinates and location of material deployment. Where practicable, DNR staff shall be allowed to ride on the tug and/or barge. DNR staff must be provided 3 months notice prior to first deployment date, to ensure that DNR staff have sufficient time to confer with USCG.
m. DNR will not take ownership of this material until it is deposited on the bottom and it has been inspected and the inspection report provided to DNR for review and concurrence.

B-10. To minimize potential impacts to oysters near Offsite Area B, DCP shall not conduct any in-river construction work, including pier and piling installation and removal, during the periods 16 December through 14 March and 1 June through 30 September.

B-11. The CPCN is not an authorization to discharge wastewater to waters of the State. If required by MDE, DCP shall obtain a discharge permit from MDE under the National Pollutant Discharge Elimination System (NPDES) for the DCP facility.

B-12. DCP shall ensure that the dock, barges, tugs, and all other facilities do not delay public ingress/egress from the public boating ramp adjacent to Offsite Area B.

B-13. DCP shall obtain applicable State and federal dredge-and-fill and waterway construction permits. DCP shall not commence construction of any aspect of the project that is under the jurisdiction of Section 404 of the Clean Water Act covered by the *Joint Federal/State Application for the Alteration of Any Floodplain, Waterway, Tidal or Nontidal Wetland in Maryland*, until such application has been approved by the U.S. Army Corps of Engineers and MDE.

B-14. DCP shall not commence construction on any aspect of the project that is under the jurisdiction of the Chesapeake Bay Critical Area Commission (CAC) until it has received approval from the CAC. All site preparation and construction activities shall be implemented in accordance with the CAC-approved plans.

B-15. No in-stream work at Offsite Area A can be conducted from 1 March through 15 June in order to protect spawning resident and anadromous fish.

STORMWATER MANAGEMENT/EROSION AND SEDIMENT CONTROL

C-1. At a minimum, sediment control during construction of all aspects of this project shall include the following Best Management Practices (BMPs): construction of earth dikes and retaining walls in appropriate locations, sediment traps, use of super silt fences, stabilizing disturbed areas as quickly as possible, and converting silt traps to permanent features as soon as practicable. In addition, on Offsite Area A, a double row of super silt fence (spaced 3′ to 4′ apart) shall be used at all locations where super silt fence is shown on the overall sediment and erosion control plan (File No. B-47-4N). The first row of super silt fence must be routinely cleared as needed and there is no need to place hay bales in between the two rows.

C-2. Topsoil from those areas to be graded on Offsite Area A, that are located between the populations of known rare, threatened, and endangered plants shall be separately stockpiled and later re-spread in the same areas for final grading of the project. These stockpiled topsoils shall be placed in upland areas, and shall be protected during construction by using double rows of super silt fence until they are used and re-spread.

C-3. At a minimum, storm water management plans for all aspects of this project shall include:

- groundwater infiltration and peak flow attenuation;
- grading to encourage overland flow;
- slope minimization to decrease flow velocities and reduce erosion;
- conveyance of runoff via a closed storm water sewer system discharging into an engineered stormwater management facility consistent with the latest MDE guidelines when overland flow is not desirable;
- utilize a storm water drain collection system;
- minimize slopes to decrease flows;

- utilize vegetation filters, physical structures, including outfall pipes, to control release rates from an engineered stormwater management facility consistent with MDE's latest guidelines; and
- direct controlled flow to existing culverts under road to natural drainage area.

WATER SUPPLY

D-1. This CPCN authorizes Dominion Cove Point to appropriate and use groundwaters of the State from the Lower Patapsco aquifer. The appropriation will be tracked under MDE WMA permit number CA1973G114. The groundwater appropriation will be subject to the following conditions:

a. Allocation—The groundwater withdrawal granted by this appropriation is limited to a daily average of 233,000 gallons on a yearly basis and a daily average of 275,000 gallons for the month of maximum use;

b. Use—The water is to be used to support the operation of the Dominion Cove Point (DCP) LNG liquefaction and vaporization facility and construction-related activities for the liquefaction facility. Uses for the water for operations include, but are limited to, potable and sanitary uses, steam turbine boiler makeup, fire suppression, LNG vaporizer, tank/line hydrostatic testing, and general maintenance. Uses for the water for construction of the liquefaction facility include, but are limited to, dust suppression, hydrostatic testing of pipes and tanks, steam flushing, potable water, and concrete curing and grout preparation;

c. Source—The water shall be withdrawn from one existing production well completed in the Lower Patapsco Aquifer; and

d. Location—The point of withdrawal shall be located at the site of the DCP facility, 2100 Cove Point Road, Lusby, Calvert County, Maryland.

D-2. Well pump or water intake of well pump placement—DCP shall not place a submersible well pump or water intake part of the well pump lower than the top of the confined aquifer from which the water is being withdrawn.

D-3. Change of Operations—DCP shall report any anticipated change in appropriation, which may result in a new or different use, quantity, source, or place of use of water, to MDE WMA by submission of a new application.

D-4. Permit Review—DCP shall be queried every three years (triennial review) regarding water withdrawal under the terms and conditions of this appropriation. Failure to return the triennial review query will result in suspension or revocation of this appropriation.

D-5. Appropriation Duration and Renewal—The appropriation will expire in twelve (12) years from the effective date of this CPCN. In order to renew the permit, DCP shall file a renewal application with MDE WMA no later than 45 days prior to the expiration.

D-6. Additional Permit Conditions—MDE WMA may at any time (including triennial review or when a change application is submitted) revise any condition of this appropriation or add additional conditions concerning the character, amount, means, and manner of the appropriation or use, which may be necessary to properly protect, control, and manage the water resources of the State. Condition revisions and additions will be accompanied by issuance of a revised appropriation.

D-7. Right of Entry—DCP shall allow authorized representatives of MDE WMA and the PSC access to the facility to conduct inspections and evaluations necessary to assure compliance with the conditions of this appropriation. DCP shall provide such assistance as may be necessary to effectively and safely conduct such inspections and evaluations.

D-8. Appropriation Suspension or Revocation—MDE WMA may suspend or revoke this appropriation upon violation of the conditions of this appropriation, or upon violation of any regulation promulgated pursuant to Title 5 of the Environment Article, Annotated Code of Maryland (2007 replacement volume) as amended.

D-9. Drought Period Emergency Restrictions—If MDE WMA determines that a drought period or emergency exists, DCP may be required under MDE WMA's direction to stop or reduce groundwater withdrawal. Any cessation or reduction of water withdrawal must continue for the duration of the drought period or emergency, or until MDE WMA directs Dominion Cove Point that water withdrawal under standard appropriation conditions may be resumed.

D-10. Non-Transferable—This appropriation is only transferable to a new owner if the new owner acquires prior authorization to continue this appropriation by filing a new application with MDE WMA. Authorization will be accomplished by issuance of a new appropriation permit by MDE WMA.

D-11. DCP shall conduct the following monitoring activities in support of the groundwater appropriation:

a. Flow Measurement—Measure all groundwater withdrawn using a flow meter;

b. Water Level Measurements—Install pumping equipment in the production well so that water levels can be measured during withdrawal and non-withdrawal periods without dismantling any equipment. Any opening for tape measurements of water levels shall have a minimum inside diameter of 0.5 inch and be sealed by a removable cap or plug. DCP shall provide a tap for taking raw groundwater samples before water enters a treatment facility, pressure tank, or storage tank.

c. Withdrawal Reports—Submit withdrawal records to MDE WMA semi-annually (for July-December, no later than January 31; for January-June, no later than July 31). These records shall show the total quantity of groundwater withdrawn each month under this appropriation.

CULTURAL RESOURCES

E-1. DCP shall establish an archeological protection zone for site 18CV505 in Offsite Area A by erecting temporary protective fencing around it during construction and avoiding any ground disturbance within the perimeter of this area, except with the written approval of the Maryland Historical Trust (MHT).

E-2. DCP shall avoid identified offshore underwater targets in Offsite Area B that could represent submerged cultural resources by the following minimum recommended distances.

Target	Avoidance Distance from Center Point (meters)
01	20
03	30
07	20
09	35
10	30

E-3. In the event that relics of unforeseen archeological sites are revealed and identified during construction within the LNG Terminal site, Offsite Area A, or Offsite Area B, DCP shall consult with the MHT and shall develop and implement a plan for avoidance and protection, data recovery, or destruction without recovery of such relics or sites, subject to MHT's written approval.

VISUAL QUALITY

F-1. DCP shall develop a lighting distribution plan for operation that will mitigate intrusive night lighting and avoid undue glare onto adjoining properties. The plan shall conform to Article 6-6 of the Calvert County Zoning Ordinance. DCP shall coordinate development of the plan with PPRP and the Calvert County Department of Planning and Zoning. DCP shall submit the plan to PPRP and the PSC for review and approval prior to operation of the facility.

EMERGENCY PREPAREDNESS AND SECURITY

G-1.
At least 60 days prior to commencing site preparation for construction, DCP shall file with the PSC the State Fire Marshall's final report regarding this Project, including any measures to

address any additional conditions or requirements identified by the State Fire Marshall. Also at least 60 days prior to commencing site preparation for construction, DCP shall file a revised Emergency Response Plan (ERP) that reflects and responds to the findings of the EA and any related FERC Order, and addresses the need for additional off-site safety protocols and resources. Without supplanting revisions responsive to FERC, the updated ERP shall address:

1. Site safety/ EMS coverage during construction and operations, including timely response options and emergency vehicle access throughout the site in case of an accident, injury or other emergency;

2. Where additional hazards are identified in the ERP process or existing emergency response capabilities are determined to be inadequate, DCP shall plan for implementing necessary upgrades, including assisting emergency response organizations through contributions, requisite training and general support to ensure the public's safety. Prior to commencing construction of the generating station, DCP shall file with the Commission an executed cost-sharing plan that has the concurrence of each affected State and local agency identified in the ERP;

3. DCP shall work with Federal, State and local officials to determine in the updated ERP whether an off-site emergency plan is needed as part of emergency management, including whether an off-site evacuation plan is needed, and if so present the plan to develop an off-site emergency plan that includes consideration of residents who would have to rely on Cove Point Road to evacuate the area in the event of an emergency at the LNG facility. If DCP and the federal, state and local officials with responsibilities for emergency planning and response in the event of an emergency at the LNG facility conclude that an off-site emergency plan or an off-site

evacuation plan is not needed, the bases for these conclusions shall be set forth in conjunction with and at the time of issuance of the revised ERP.

TRAFFIC

H-1. DCP shall obtain any required utility and lane closure permits from the District Office of the Maryland State Highway Administration and access permits for work on the State roadways from SHA's Access Management Division and permits from the Calvert County Department of Public Works, as appropriate.

H-2. DCP shall submit to the SHA a Transportation Management Plan (TMP) that details work zone impact management strategies at intersections that will be reconstructed for the Project, and how they will be implemented. The TMP will, at minimum, include a Traffic Control Plan, Transportation Operations strategies and Public Information and Outreach strategies. The TMP must be approved by the SHA prior to the issuance of an access permit for construction within the right-of-way.

H-3. Prior to dispatching oversize/overweight vehicles to the staging or construction site for the Project, DCP shall comply with all weight and size restrictions and/or bonding requirements on all State and Calvert County roadways and obtain appropriate oversize/overweight approvals as necessary.

H-4. DCP shall submit to the SHA a mobile Maintenance of Traffic (MOT) plan for the transport of oversize/overweight loads over State highways. The plan shall address utility adjustments, utility line clearances, bridging over culverts, loads on bridges, adjustment to traffic signals, road closures, median cross-overs and emergency vehicle access. The MOT plan must be approved by the SHA prior to dispatching oversize/overweight vehicles to staging or construction sites.

H-5. DCP shall submit a travel routing plan to the Calvert County Department of Public Works prior to dispatching oversize/overweight vehicles on County roads to the staging or construction site.

H-6. DCP shall dispatch large equipment from Offsite Area B at night to mitigate disruptions to traffic unless otherwise specified by SHA.

H-7. During construction, DCP shall monitor traffic congestion at the intersections of MD 2/MD 4 both north and south of the MD 2/MD 4 intersection with MD 497 in the morning and evening peak periods to determine if construction worker traffic is congesting these intersections. If intersections are determined to operate at an unacceptable Level-of-Service (LOS "E" or "F") or are expected to operate at an unacceptable LOS when construction worker traffic peaks, DCP shall, in consultation with and with the approval of the SHA, develop a plan to mitigate the Project generated traffic impacts through shift scheduling, roadway improvements or other means. Mitigation shall be in place prior to the peak construction year.

NOISE

I-1. DCP shall monitor noise levels after the plant is operational. The scope of work for the noise monitoring shall be provided to PPRP and the PSC for review and approval, and to Calvert County, within one year after the issuance of this CPCN. Measurements shall be taken while the plant is operating at full load, to represent maximum noise emissions. At a minimum, DCP shall monitor noise levels at the two noise sensitive areas identified in the CPCN Application. DCP shall submit noise monitoring results to PPRP and the PSC within six months after the facility first begins commercial operation.

I-2. DCP shall operate all equipment at the Cove Point terminal site in compliance with applicable noise regulations. If the post-construction noise monitoring indicates that the facility is not operating in compliance with those standards, DCP shall work with PPRP, the PSC and Calvert County to incorporate appropriate noise mitigation strategies into facility design or operation to ensure regulatory compliance.

ADDITIONAL CONDITIONS

J-1. Prior to beginning operation of the facility, DCP shall submit to PPRP for review and approval a landscaping plan that, at minimum, addresses the visibility of the proposed sound barrier from Cove Point Road in the vicinity of the site entrance. The plan shall include representative photo simulations of views of the proposed facility from Cove Point Road at the site entrance both before and after landscaping is in place, and during seasons of peak and minimum foliage.

J-2. (a) To confirm the findings of the Reviewing State Agencies that no statistically significant indication of subsidence is expected to occur as a result of the Project, DCP shall establish a trust or similar instrument in the amount of $190,000 for the Maryland Geological Survey (MGS) to conduct subsidence monitoring in and near Calvert County. The trust or similar instrument, which is a one-time contribution from DCP, must be established prior to the start of construction. The terms and conditions of the trust or similar instrument shall be mutually agreeable to both parties.

(b) DCP shall allow authorized representatives of MGS reasonable access to the facility to conduct monitoring for the Calvert County subsidence study. DCP shall provide reasonable assistance as may be necessary to effectively and safely conduct such monitoring.

J-3. During the first twenty years of operation of the facility, DCP shall make an annual contribution in the amount of $400,000 to the Maryland Energy Assistance Program, or other Maryland low income energy assistance program to be specified by the Maryland Public Service Commission by January 1, 2016.

J-4. Within 90 days of the commencement of construction of the generating station, DCP shall make the first of five annual installments of $8 million (for a total of $40 million) into the Maryland Strategic Energy Investment Fund (SEIF) to be used by the Maryland Energy Administration solely for the purpose of investing in the promotion, development, and implementation of one or more of the following categories: (1) renewable and clean energy resources; (2) greenhouse gas reduction or mitigation programs; (3) cost-effective energy efficiency and conservation programs, projects, or activities; or (4) demand response programs that are designed to promote changes in electric usage by customers.

APPENDIX B

Pollutant or Emittor	PM BACT
PM, PM_{10}, $PM_{2.5}$	Good combustion practices.
PM, PM_{10}, $PM_{2.5}$ for ground flares	Good operating practices; combustion efficiency; use of a pilot flame.
PM, PM_{10}, $PM_{2.5}$ for paved roads	Expected to be negligible; take reasonable precautions.
Frame 7 Combustion Turbines	Exclusive use of facility process fuel gas or pipeline quality natural gas, oxidation catalyst system, efficient combustion.
Auxiliary Boilers	Same as for Frame 7 CTs.
Emergency Engines	Good combustion practices; use of ultra low sulfur diesel ("ULSD").
Thermal Oxidizer	Use of oxidation catalyst and good combustion practices.
Ground flares	Use of a pilot flame.

Pollutant or Emittor	CO BACT
Frame 7 CTs	Exclusive use of facility process fuel gas or pipeline quality natural gas, use of oxidation catalyst system, and efficient combustion.
Auxiliary Boilers	Same as for Frame 7 CTs.
Emergency Engines	Good combustion practices, use of ultra-low sulfur diesel.
Thermal Oxidizer	Oxidation catalyst and good combustion practices
Ground Flares	Pilot flame, proper combustion designed to achieve an emissions limit of 31.2 tpy for north flare, 18.4 tpy for south flare.

Pollutant or Emittor	Green House Gasses BACT
Frame 7 CTs	Use of GE 7 EA turbines with dry low NO_x combustors firing pipeline natural gas or process fuel gas.
Auxiliary Boilers	Use of pipeline quality natural gas and process fuel gas from LNG production; good combustion practices, efficient steam boiler design.
Emergency Engines	Good combustion practices.
Thermal Oxidizer	Good combustion practices.
Ground Flares	Use of pilot flame; good operating practices.
Piping Components	Use of LDAR monitoring program.

Pollutant or Emittor	**LAER**
NO_X LAER for Frame 7 CTs	An emission limit of 2.5 ppmvd at 15% O_2 on a three-hour block average.
NO_X LAER for Auxiliary Boilers	An emission limit of 0.009916/MMBtu based on a three-hour block average.
NO_X LAER for Emergency Engines	6.4 g/kW-hr based on a combination of NO_x and non-methane hydrocarbon emissions.
NO_X LAER for Thermal Oxidizer	2.5 ppmvd at 15% O_2 based on a three-hour averaging period.
NO_X LAER for the Ground Flares	69.0 tons per year for the North flare and 41.0 tons per year for the South flare.
VOC LAER for the Frame 7 CTs	0.7 ppmvd at 15% 0_2 on a three-hour average basis.
VOC LAER for Auxiliary Boilers	Emission limit of 0.001 lb/MMBtu during normal operations, based on a three-hour block averaging period.
VOC LAER for the Emergency Engines	6.4 g/kW-hr (4.8 g/hp-hr), based on a combination of NO_x and NMHC emissions, when NMHC equals NO_x.
VOC LAER for the Thermal Oxidizer	0.03 lb/hr through use of an oxidation catalyst.
VOC LAER for the Ground Flares	10.8 tpy for the north flare and 4.0 tpy for the south flare to be achieved by presence of a pilot flame, good operating practices, proper combustion efficiency.
VOC LAER for the piping components	Use of an LDAR Monitoring Program following procedures outlined in the TCEQ 28 LAER LDR program.