Attachment 1

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, MARCH 29, 2016

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUE-2015-00075

For approval and certification of the proposed Greensville County Power Station and related transmission facilities pursuant to §§ 56-580 D, 56-265.2, and 56-46.1 of the Code of Virginia, and for approval of a rate adjustment clause, designated Rider GV, pursuant to § 56-585.1 A 6 of the Code of Virginia

FINAL ORDER

On July 1, 2015, Virginia Electric and Power Company d/b/a Dominion Virginia Power ("Dominion" or "Company") filed with the State Corporation Commission ("Commission") an application and supporting documents (collectively, "Application") for approval of electric generation and related transmission facilities (collectively, the "Project") and for approval of a rate adjustment clause ("RAC"). Dominion seeks approval of these related requests under various sections of the Code of Virginia ("Code").

Dominion seeks a certificate of public convenience and necessity as well as approval to construct and operate the Greensville County Power Station, an approximately 1,588 megawatt ("MW") (nominal) natural gas-fired combined-cycle electric generating facility in Greensville County, Virginia, pursuant to §§ 56-580 D and 56-46.1 of the Code.[1] The Company seeks a separate certificate of public convenience and necessity and approval to construct new 500 kilovolt transmission lines, a new switching station, and associated facilities in Brunswick and Greensville Counties, Virginia (collectively, the "Transmission Interconnection Facilities"),

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[1] Exhibit ("Ex"). 2 (Application) at 1.

pursuant to §§ 56-265.2 and 56-46.1 of the Code.[2] Finally, Dominion seeks approval of a RAC, designated Rider GV, for the recovery of Project costs, pursuant to § 56-585.1 A 6 of the Code ("Section A 6").[3]

As estimated by the Company, the total projected cost of the Project is $1.33 billion, excluding financing costs.[4] Dominion seeks to recover, through rates proposed to be effective beginning April 1, 2016, an annual revenue requirement of approximately $41,643,000 in projected financing costs and allowance for funds used during construction of the Project.[5]

On July 29, 2015, the Commission entered an Order for Notice and Hearing that, among other things, required the Company to publish notice of its Application; established a schedule for the filing of notices of participation and the submission of prefiled testimony; and scheduled a public evidentiary hearing. Notices of participation were filed by the Old Dominion Electric Cooperative; the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"); the Virginia Committee for Fair Utility Rates ("Committee"); the Virginia Chapter of the Sierra Club ("Sierra Club"); and Appalachian Voices, the Chesapeake Climate Action Network, and the Natural Resources Defense Council (collectively, "Environmental Respondents").

The hearing was convened on January 12, 2016, and concluded on January 13, 2016. The Company, Consumer Counsel, Environmental Respondents, the Committee, the Sierra Club, and the Commission's Staff ("Staff") participated in the hearing. The Commission also received

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[2] *Id.*

[3] *Id.* at 2, 15.

[4] *Id.* at 7.

[5] *Id.* at 17. The proposed rate year for this proceeding is from April 1, 2016, through March 31, 2017. *Id.* at 16.

public comments regarding the Company's Application as well as testimony from public witnesses.

On February 19, 2016, the Company, Staff, Consumer Counsel, Sierra Club and Environmental Respondents filed post-hearing briefs.

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds as follows.

Code of Virginia

Section 56-580 D of the Code states in part:

> The Commission shall permit the construction and operation of electrical generating facilities in Virginia upon a finding that such generating facility and associated facilities (i) will have no material adverse effect upon reliability of electric service provided by any regulated public utility, (ii) are required by the public convenience and necessity, if a petition for such permit is filed after July 1, 2007, and if they are to be constructed and operated by any regulated utility whose rates are regulated pursuant to § 56-585.1, and (iii) are not otherwise contrary to the public interest.

Further, with regard to generating facilities, § 56-580 D of the Code directs that "the Commission shall give consideration to the effect of the facility and associated facilities on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact as provided in § 56-46.1...." Section 56-46.1 A of the Code states in part:

> Whenever the Commission is required to approve the construction of any electrical utility facility, it shall give consideration to the effect of that facility on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact.... In every proceeding under this subsection, the Commission shall receive and give consideration to all reports that relate to the proposed facility by state agencies concerned with environmental protection; and if requested by any county or municipality in which the facility is proposed to be built, to local comprehensive plans that have been adopted pursuant to Article 3 (§ 15.2-2223 et seq.) of Chapter 22 of Title 15.2.

Section 56-46.1 A of the Code also states:

> In order to avoid duplication of governmental activities, any valid permit or approval required for an electric generating plant and associated facilities issued or granted by a federal, state or local governmental entity charged by law with responsibility for issuing permits or approvals regulating environmental impact and mitigation of adverse environmental impact or for other specific public interest issues such as building codes, transportation plans, and public safety, whether such permit or approval is granted prior to or after the Commission's decision, shall be deemed to satisfy the requirements of this section with respect to all matters that (i) are governed by the permit or approval or (ii) are within the authority of, and were considered by, the governmental entity in issuing such permit or approval, and the Commission shall impose no additional conditions with respect to such matters.

Section 56-580 D of the Code contains language limiting the Commission's authority that is nearly identical to the language set forth in § 56-46.1 A.

Section 56-46.1 B of the Code states that, with regard to overhead transmission lines, "[a]s a condition to approval the Commission shall determine that the line is needed and that the corridor or route the line is to follow will reasonably minimize adverse impact on the scenic assets, historic districts and environment of the area concerned." Section 56-46.1 B of the Code also directs that "[i]n making the determinations about need, corridor or route, and method of installation, the Commission shall verify the applicant's load flow modeling, contingency analyses, and reliability needs presented to justify the new line and its proposed method of installation." Section 56-46.1 D of the Code explains that "'environment' or 'environmental' shall be deemed to include in meaning 'historic,' as well as a consideration of the probable effects of the line on the health and safety of the persons in the area concerned."

Section 56-46.1 C of the Code directs that "[i]n any hearing the public service company shall provide adequate evidence that existing rights-of-way cannot adequately serve the needs of the company." Section 56-259 C of the Code states that "[p]rior to acquiring any easement of right-of-way, public service corporations will consider the feasibility of locating such facilities on, over, or under existing easements of rights-of-way."

The Code also directs the Commission to consider the effect of a proposed project on economic development in Virginia. Section 56-46.1 A of the Code states in part:

> Additionally, the Commission (a) shall consider the effect of the proposed facility on economic development within the Commonwealth, including but not limited to furtherance of the economic and job creation objectives of the Commonwealth Energy Policy set forth in §§ 67-101 and 67-102, and (b) shall consider any improvements in service reliability that may result from the construction of such facility.

Similarly, § 56-596 A of the Code states that "[i]n all relevant proceedings pursuant to [the Virginia Electric Utility Regulation Act], the Commission shall take into consideration, among other things, the goal of economic development in the Commonwealth."

Section A 6, pursuant to which the Company applied for a RAC, includes the following:

> To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of ... (ii) one or more other generation facilities....

According to Section A 6, "[t]he costs of the facility, other than return on projected construction work in progress and allowance for funds used during construction, shall not be recovered prior to the date a facility constructed by the utility ... begins commercial operation...." Allowance for funds used during construction shall be calculated "utilizing the utility's actual capital structure and overall cost of capital...."

Finally, Section A 6 provides that "[a] utility seeking approval to construct or purchase a generating facility shall demonstrate that it has considered and weighed alternative options, including third-party market alternatives, in its selection process."

Need

We find that the Company has established a need for the additional capacity and energy that the Project would provide. We find that both the Company's assessment of need and the load forecasts employed by Dominion in this proceeding are reasonable.[6]

Energy Efficiency

The Environmental Respondents have asserted in this proceeding that Dominion did not examine reductions in load from increased energy efficiency.[7] We find, however, that in evaluating the need for the proposed Project and in developing its peak demand and energy forecasts, the Company reasonably considered current and future conservation and energy efficiency measures.[8] We further find that increased energy efficiency does not have the potential to defer or satisfy the Company's need for the additional capacity the Project is expected to provide.[9]

Consideration of Alternative Options

Section A 6 provides that a utility seeking approval to construct a generating facility must demonstrate that "it has considered and weighed alternative options, including third-party market alternatives, in its selection process." The Environmental Respondents and the Sierra Club have

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[6] *See, e.g.,* Ex. 4 (Kelly Direct) at 3-12; Ex. 29 (Kelly Rebuttal) at 2-6. We have considered the Environmental Respondents' position that the Company has not demonstrated need for the proposed Project, in part because the Company based its load forecasts on "outdated methods and data." Ex. 19 (Wilson Direct) at 4-10. However we find that the load forecasts employed by Dominion are reasonable and that the Company has demonstrated a need for additional energy and capacity that the Project would provide. We also note that neither Staff nor Consumer Counsel disputed the Company's stated need for energy and capacity. *See* Ex. 21 (Tufaro Direct) at 4-7; Consumer Counsel's Post Hearing Brief at 2 (stating, "Consumer Counsel does not oppose the Company's request to construct and operate the proposed ... [P]roject").

[7] *See* Ex. 19 (Wilson Direct) at 3.

[8] *See, e.g.,* Ex. 21 (Tufaro Direct) at 11; Dominion's Post Hearing Brief at 7; Ex. 4 (Kelly Direct) at 15-16; Ex. 29 (Kelly Rebuttal) at 6-9, 17.

[9] *See, e.g.,* Ex. 30 (Thomas Rebuttal) at 2-3; Ex. 4 (Kelly Direct) at 3-12.

argued that the Commission must reject Dominion's Application because the Company has not properly considered reasonable alternatives.[10]

First, the Environmental Respondents and the Sierra Club argued that Dominion failed to adequately consider third-party alternatives. The parties stated that, although Dominion issued a formal request for proposals ("RFP") to solicit bids from third-party power providers, the RFP included certain onerous, non-standard, and opaque eligibility requirements that discouraged third-parties from submitting bids, limited the scope of generating facilities that could submit bids, and expressed an unwillingness to negotiate terms of purchase power agreements.[11] The parties also argued that the Company failed to evaluate meaningfully and objectively the proposed Project against the bids received in the RFP.[12]

Second, the Environmental Respondents stated that Dominion "not only failed its obligation to consider third-party alternatives, it also failed in its duty to consider self-build options other than Greensville."[13] The Environmental Respondents claimed that the Company failed to consider a number of alternative generating technologies such as solar generation, failed to consider building a solar/gas hybrid facility, and failed to analyze whether choosing a combination of resources, *i.e.*, a "portfolio approach," would be more cost-effective than the proposed Project.[14]

In the Final Order issued in Case No. PUE-2015-00006, we held as follows:

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[10] *See* Ex. 19 (Wilson Direct) at 14-18; Environmental Respondent's Post Hearing Brief at 2-16; Sierra Club's Post Hearing Brief at 13-23.

[11] *See* Sierra Club's Post Hearing Brief at 14-18; Environmental Respondent's Post Hearing Brief at 2-8.

[12] *See* Sierra Club's Post Hearing Brief at 18-23; Environmental Respondent's Post Hearing Brief at 9-11.

[13] Environmental Respondent's Post Hearing Brief at 11.

[14] Ex. 19 (Wilson Direct) at 15-18; Tr. 252-57; Environmental Respondent's Post Hearing Brief at 12-15.

> [t]he statutory requirement that an applicant must demonstrate that third-party market alternatives have been considered and weighed during the applicant's selection process expresses the General Assembly's clear intent that serious and credible efforts must be made to determine whether there are third-party market options available to provide ... power at prices less burdensome to consumers than the applicant's self-build option.[15]

Based on the record in this case, we find that the Company undertook serious and credible efforts to assess the cost and availability of third-party alternatives. The Company issued an RFP and, pursuant to that RFP, the Project was evaluated against 5,020 MW of fully dispatchable, baseload or intermediate generation resources.[16] The Company's evaluation of the RFP found that the proposed Project was more favorable than any third-party alternative that was examined through the RFP process.[17] We find the Company's RFP to be adequate for purposes of this proceeding. Moreover, the Project was also compared to multiple unsolicited offers for solar, wind, landfill gas, and coal resources that were received outside of the RFP.[18]

We further find that the Company undertook serious and credible efforts to compare the Project to potential Company-owned resources. The Company evaluated the Project against numerous dispatchable and non-dispatchable supply-side resources, including renewable resources.[19] The Company also modeled the proposed Project against a portfolio of resources,

[15] *Application of Virginia Electric and Power Company, For approval and certification for the proposed Remington Solar Facility pursuant to §§ 56-46.1 and 56-580 D of the Code of Virginia, and for approval of a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUE-2015-00006, Doc. Con. Cen. No. 151030161, Final Order at 6 (Oct. 20, 2015) (internal citations omitted).

[16] Ex. 29 (Kelly Rebuttal) at 12-13.

[17] *See* Ex. 4 (Kelly Direct) at 18-21; Ex. 21 (Tufaro Direct) at 14-16.

[18] Ex. 29 (Kelly Rebuttal) at 15. The Company also examined renewing several purchase power agreements. *See id.* at 15-16.

[19] Ex. 29 (Kelly Rebuttal) at 17. Dominion testified that it evaluated the Project against numerous dispatchable and non-dispatchable supply-side resources, including "combustion turbines, super critical pulverized coal (with and without carbon sequestration), integrated gasification combined cycle (with and without carbon sequestration), biomass, nuclear, fuel cell, on-shore wind, off-shore wind, and [photovoltaic] solar (with and without battery backup)." *Id.* With regard specifically to renewable resources, we find that the Company adequately considered

and the results of the Company's modeling support the Project as a least-cost option.[20] We find this analysis to be adequate in this proceeding.

In sum, we find, based on the record in this case and for purposes of this proceeding only, that the Company has adequately considered and weighed alternative options, including third-party market alternatives and alternative self-build options (including renewable resource options), in its selection process.[21]

Technology

We find that the Company's choice of technology for the Greensville facility – a 3x1 natural gas-fired combined-cycle plant – is reasonable based on the record herein. As noted by the Company, the 3x1 technology is cost-effective, proven, reliable, and widely used in commercial plants around the world.[22] Once this plant is constructed and in operation in the Commonwealth, it "will operate as one of the most efficient natural gas-fueled power plants in the country...."[23] Between 2019 and 2030, the Project is expected to meet approximately 10% of customers' total energy requirements annually while reducing system-wide fuel expenses.[24]

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renewable alternatives to the Project and the evidence reflects that renewable resources were not cost-competitive with the Greensville County Power Station. *See, e.g., id.* at 6-9, 16-17.

[20] *Id.* at 7-9.

[21] A determination that Dominion adequately considered and weighed alternative options including third-party alternatives in this proceeding does not equate to a determination that the Company's evaluation of alternative options will be appropriate in all future instances. Our findings herein are limited to the specific facts of this proceeding. Under different circumstances, alteration or expansion of the Company's evaluation process, including alteration or expansion of any RFP that Dominion chooses to issue, may be necessary or appropriate to ensure that any proposed self-build option is superior to alternative options.

[22] Ex. 9 (McKinley Direct) at 8.

[23] Ex. 3 (Rogers Direct) at 3.

[24] Ex. 4 (Kelly Direct) at 10.

In addition, we find that this facility is particularly reasonable and prudent in relation to the Company's overall fuel diversity. Specifically, by 2020, natural gas generation is expected to make up approximately 39% of the Company's energy mix, with nuclear at 30%, coal at 19%, and the balance being provided by renewable generation, contracts with non-utility generators ("NUGs"), market purchases, and demand-side management.[25]

Moreover, the Company's choice of a natural gas facility appears prudent given the current natural gas market and forecasted gas prices.[26]

Cost

We find that the estimated capital cost of this Project - $1.33 billion (excluding financing costs) – is reasonable. In addition, the Company has been able to fix approximately 83% of the total Project costs by executing a Turbine Supply Agreement ("TSA") and an Engineering, Procurement and Construction ("EPC") contract.[27] The TSA and EPC contract also provide for performance guarantees, liquidated damages, and on-schedule completion provisions.[28] Dominion has established in this proceeding that the estimated capital costs of the Project, along with the protections negotiated by contract, are reasonable and prudent.

Economic Development

We find that the Project will provide economic benefits to Greensville County, the Southside region, and the Commonwealth. There will be direct and indirect economic benefits related to the construction and operation of the facility, including job creation and increases in

[25] *Id.* at 11.

[26] *See* Ex. 3 (Rogers Direct) at 4; Ex. 10 (Hinson Direct) at 3-11.

[27] *See* Ex. 9 (McKinley Direct) at 16.

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

local and state tax revenues.[29] In addition to local benefits related to construction and operation, most importantly the Project will foster economic development in Virginia by providing reliable and cost-effective electricity supply to meet the growing demand for electric service in the Commonwealth.[30]

Transmission Facilities

We find that the Company's request for approval of the Transmission Interconnection Facilities satisfies the statutory requirements applicable to such facilities if the Project is constructed and placed into service. In such event, the need for the Transmission Interconnection Facilities is not disputed in this record, and the proposed route of the line is reasonable and will minimize adverse impacts.[31]

Environmental Impact

We must consider environmental impact. The relevant statutes, however, do not require the Commission to find any particular level of environmental benefit, or an absence of environmental harm, as a precondition to approval. Rather, the statutes direct that the Commission "shall give consideration to the effect of that facility on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact."[32]

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[29] Ex. 2 (Application) at 11; Ex. 3 (Rogers Direct) at 9-10.

[30] Ex. 2 (Application) at 11.

[31] *See* Ex. 18 (Fisher Direct) at 3-6; Ex. 23 (Cizenski Direct) at Staff Report 8-9, 11; Dominion's Post Hearing Brief at 46-47.

[32] Va. Code § 56-46.1. *See also* Va. Code § 56-580 D (stating that "the Commission shall give consideration to the effect of the facility and associated facilities on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact as provided in § 56-46.1....").

The Department of Environmental Quality ("DEQ") coordinated an environmental review of the proposed Project and submitted a report ("DEQ Report").[33] The DEQ Report summarizes the Project's potential impacts, makes recommendations for minimizing those impacts, and outlines the Company's responsibility for compliance with legal requirements governing environmental protection.[34] The Company did not object to any of the recommendations made by DEQ in its Summary of Findings and Recommendations.[35] Based on the record in this case, we find that the Project will be in compliance with all applicable environmental regulations.

Public Convenience and Necessity

Pursuant to § 56-580 D of the Code, the Commission may only permit the construction and operation of an electrical generating facility if it determines that such generating facility has no material adverse effect upon reliability of electric service, is required by the public convenience and necessity, and is not otherwise contrary to the public interest. The Sierra Club has argued that the Commission must reject the Company's Application because, without additional information on the potential impact that the United States Environmental Protection Agency's recent regulation to control carbon dioxide emissions from existing electric generation units under Section 111(d) of the Clean Air Act ("Clean Power Plan") could have on Virginia, the Commission lacks evidence necessary to determine that the Company's proposal is required by the public convenience and necessity.[36]

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[33] Ex. 24 (DEQ Report).

[34] *Id.*

[35] Ex. 33 (Fisher Rebuttal) at 2.

[36] *See* Sierra Club's Post Hearing Brief at 6-13. The Environmental Respondents also expressed concern that the Company did not test the effect the Project would have on compliance with the Clean Power Plan. *See* Ex. 19 (Wilson Direct) at 13.

While the record in the current proceeding demonstrates that significant uncertainty regarding Clean Power Plan compliance existed at the time the Company filed its Application and will likely continue for some time, the record also states that the Project's carbon intensity is lower than the carbon intensity of Dominion's existing fossil fleet.[37] In addition, the addition of the Project to the Company's current portfolio would effectively displace generation from more carbon-intensive resources, thereby reducing the system-wide carbon intensity.[38] Further, the Company has analyzed the Project using a variety of potential market sensitivities. The results of this analysis show that despite varying market conditions, the Project remains the most prudent option to fill the Company's capacity and energy needs by 2019.[39]

Based on the record developed herein, and in accordance with our findings above, the Commission concludes that the proposed generating facility and associated facilities: (i) will have no material adverse impact upon reliability of electric service; (ii) are required by the public convenience and necessity; and (iii) are not otherwise contrary to the public interest.

Return on Equity

The Commission finds that the fair rate of return on common equity ("ROE") for Rider GV approved herein shall be 9.6%, which becomes effective April 1, 2016. This results in a total revenue requirement for Rider GV, which also becomes effective April 1, 2016, of $40,361,000.

The Commission has recently held that the plain language of Section A 6 allows us to determine the ROE for a Section A 6 RAC – such as Rider GV – in the actual Section A 6 RAC

[37] Ex. 29 (Kelly Rebuttal) at 9.

[38] *Id.*

[39] *Id.* at 11-12.

proceeding.[40] We note that those orders did not address Chapter 6, 2015 Va. Acts of Assembly ("Senate Bill 1349" or "SB 1349"), codified in part as § 56-585.1:1 of the Code,[41] because such statute was not in effect when those respective cases were initiated.[42] The instant Application, however, was filed on July 1, 2015, the effective date of SB 1349. In this regard, Dominion asserts that: (i) prior to SB 1349, the Commission did not have the authority to determine ROE for a Section A 6 RAC in the actual Section A 6 RAC proceeding; (ii) SB 1349 does not give the Commission such authority; and (iii) "[t]hus, Senate Bill 1349 has no bearing on the Commission's authority to set ROE in this case."[43]

Senate Bill 1349 directs the Commission to hold two consolidated proceedings ("Consolidated Proceedings"), one in 2017 and one in 2019, to determine ROE for all of Dominion's Section A 6 RACs:

> Commencing in 2017 and concluding in 2019, the State Corporation Commission, after notice and opportunity for a hearing, shall conduct a proceeding every two years to determine the fair rate of return on common equity to be used by [Dominion] as the general rate of return applicable to rate adjustment clauses under subdivisions A 5 or A 6 of

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[40] *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider B, Biomass Conversions of the Altavista, Hopewell, and Southampton power stations for the rate year commencing April 1, 2016*, Case No. PUE-2015-00058, Doc. Con. Cen. No. 160250199, Final Order (Feb. 29, 2016); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider R, Bear Garden Generating Station For the rate year commencing April 1, 2016*, Case No. PUE-2015-00059, Doc. Con. Cen. No. 160250198, Final Order (Feb. 29, 2016); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider S, Virginia City Hybrid Energy Center*, Case No. PUE-2015-00060, Doc. Con. Cen. No. 160250197, Final Order (Feb. 29, 2016); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider W, Warren County Power Station*, Case No. PUE-2015-00061, Doc. Con. Cen. No. 160250196, Final Order (Feb. 29, 2016).

[41] 2015 Va. Acts Ch. 6 (approved February 24, 2015; effective July 1, 2015) (codified in part as Va. Code § 56-585.1:1).

[42] *See, e.g., Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider W, Warren County Power Station*, Case No. PUE-2015-00061, Doc. Con. Cen. No. 160250196, Final Order at 9 (Feb. 29, 2016).

[43] *See* Dominion's Post Hearing Brief at 50-58.

§ 56-585.1. [Dominion's] filing in such proceedings shall be made on or before March 31 of 2017 and 2019.[44]

Dominion asserts that the General Assembly included the above provision in SB 1349 because the Commission is prohibited from determining ROE for a Section A 6 RAC in an actual Section A 6 RAC case.[45] We disagree. For the reasons set forth in the four orders cited above, the Commission continues to find that the plain language of Code § 56-585.1 A 6 – which explicitly allows the Commission to determine RAC ROEs "from time to time ... pursuant to subdivision 2" – gives the Commission the discretion to determine ROE for a Section A 6 RAC in the actual Section A 6 RAC proceeding. Furthermore, we note that the ROE is part of the cost included in the RAC, and, contrary to Dominion's claim, the statute does not require the Commission to set a rate in the RAC that is above the Commission-determined cost-of-service by using an inflated ROE.

In addition, having found that the plain language is not ambiguous, we do not resort to statutory construction – as sought by Dominion – by looking at SB 1349 to ascertain the plain meaning of Section A 6.[46] Moreover, even if it was appropriate to look at SB 1349 for such purpose, we note that SB 1349 in fact *confirms* the plain reading of Section A 6. That is, in direct contrast to the explicit "from time to time" discretion in Section A 6, Senate Bill 1349

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[44] Va. Code § 56-585.1:1 C 2.

[45] *See* Dominion's Post Hearing Brief at 50-52, 56-58.

[46] *See, e.g., Newberry Station Homeowners Ass'n v. Bd. of Supervisors*, 285 Va. 604, 614 (2013) ("[W]hen the language of an enactment is free from ambiguity, resort to legislative history and extrinsic facts is not permitted because we take the words as written to determine their meaning.") (internal quotes and citation omitted); *Smith v. Commonwealth*, 282 Va. 449, 454 (2011) ("When statutory terms are plain and unambiguous, we apply them according to their plain meaning without resorting to rules of statutory construction.") (citing *Halifax Corp. v. First Union Nat'l Bank*, 262 Va. 91, 99-100 (2001)); *Kummer v. Donak*, 282 Va. 301, 306 (2011) ("Because there is no ambiguity in the applicable statutes, the Kummer children's public policy argument must fail."); *Brown v. Lukhard*, 229 Va. 316, 321 (1985) ("If language is clear and unambiguous, there is no need for construction by the court; the plain meaning and intent of the enactment will be given it.") (citation omitted).

conclusively shows that the General Assembly is quite able – when it chooses – to specify precise biennial dates on which the Commission *must* determine ROE for all Section A 6 RACs.

The Commission will, of course, follow the law and timely conduct required proceedings for all RAC ROEs in the future. In the interim, it is self-evident that we must also set ROEs in RAC cases that are initiated on and after July 1, 2015, but prior to the 2017 Consolidated Proceeding, since *every* RAC must have an ROE. Indeed, Dominion does not contest the fact that we face the present necessity of setting an ROE for Rider GV in the instant case. As explained below, however, the requirements of SB 1349 do not alter the ROE of 9.6% as approved in the instant proceeding, because a resulting ROE of 9.6% is justified under either of the two procedural alternatives available in this case.

Specifically, there are two paths in this proceeding that lead to the same result. Under one path, during SB 1349's Transitional Rate Period, the explicit requirement for the Consolidated Proceedings is interpreted to preempt temporarily the Commission's "from time to time" discretion in Section A 6. In that situation, we find that it is reasonable to use Dominion's most recently approved RAC ROE of 9.6% as determined on February 29, 2016 (in cases that were filed before the effective date of SB 1349), which we found fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital.[47] We further find that it is not reasonable to continue to use Dominion's requested ROE of 10% from 2013, which was set in the Company's 2013 Biennial Review (based on data

[47] *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider B, Biomass Conversions of the Altavista, Hopewell, and Southampton power stations for the rate year commencing April 1, 2016*, Case No. PUE-2015-00058, Doc. Con. Cen. No. 160250199, Final Order at 10-14 (Feb. 29, 2016); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider R, Bear Garden Generating Station For the rate year commencing April 1, 2016*, Case No. PUE-2015-00059, Doc. Con. Cen. No. 160250198, Final Order at 10-14 (Feb. 29, 2016); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider S, Virginia City Hybrid Energy Center*, Case No. PUE-2015-00060, Doc. Con. Cen. No. 160250197, Final Order at 9-13 (Feb. 29, 2016); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider W, Warren County Power Station*, Case No. PUE-2015-00061, Doc. Con. Cen. No. 160250196, Final Order at 9-13 (Feb. 29, 2016).

from several years ago), as opposed to the ROE of 9.6% that was approved just last month (based on an analysis of more recent information).

Following the second path, prior to the 2017 Consolidated Proceeding, the Commission retains the "from time to time" discretion in Section A 6 during SB 1349's Transitional Rate Period and has the authority to determine an ROE based on the facts presented in the instant case. In this situation, we continue to find – based on the record in this proceeding – that a market cost of equity of 9.6% fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital. We find that this ROE is supported by the record in this proceeding (which is consistent with that of the four cases cited above),[48] is fair and reasonable to the Company within the meaning of the Code, permits the attraction of capital on reasonable terms, fairly compensates investors for the risks assumed, enables the Company to maintain its financial integrity, and satisfies all applicable statutory and constitutional standards.[49]

Rider GV

Dominion has calculated the Rider GV rates in accordance with the same methodology used for rates approved by the Commission in several recent cases.[50] Staff found that "there have been no significant changes associated with this proceeding that would necessitate a change

[48] For example, portions of the instant record supporting this factual finding (consistent with the most recent RAC orders) include: Ex. 27 (Oliver ROE Direct); Staff's Post Hearing Brief at 8-10; Tr. 81-84.

[49] See the Final Orders in Case Nos. PUE-2015-00058, -00059, -00060, and -00061 for additional discussion of these concepts.

[50] Ex. 13 (Anderson Direct) at 2; Ex. 21 (Tufaro Direct) at 16-17. *See, e.g., Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider BW, Brunswick County Power Station, for the rate year commencing September 1, 2015*, Case No. PUE-2014-00103, Doc. Con. Cen. No. 150420130, Final Order (Apr. 21, 2015); *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider S, Virginia City Hybrid Energy Center*, Case No. PUE-2014-00051, Doc. Con. Cen. No. 150310313, Final Order (Mar. 12, 2015).

in the methodology used to develop the proposed surcharges."[51] We find that the Company's proposed rate design for Rider GV should be approved.[52]

There is no disagreement between Staff and Dominion with regard to any Project expenditures at this time.[53] The primary difference between Staff's and the Company's Rider GV revenue requirement concerns the appropriate ROE to be used to calculate the Projected Cost Recovery Factor and the AFUDC Cost Recovery Factor.[54] As is discussed above, we find that a revenue requirement of $40,361,000, which incorporates an ROE of 9.6%, effective April 1, 2016, is appropriate and should be approved.

Sunset Provision

As a requirement of our approvals herein, we find that the authority granted by this Final Order shall expire two (2) years from the date hereof if construction of the Greensville County Power Station has not commenced, and that Dominion may petition the Commission for an extension of this sunset provision for good cause shown.

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[51] Ex. 21 (Tufaro Direct) at 19.

[52] The Environmental Respondents have alleged that Dominion's use of winter declining block rates incents customers to use more electricity than they might otherwise use under another policy. Therefore, the Environmental Respondents recommended that the Company continue to explore alternative rate designs. Ex. 19 (Wilson Direct) at 9-10. In its Final Order in Case No. PUE-2015-00035, the Commission directed the Company to analyze certain alternative rate designs and to report on the results of this analysis in future Integrated Resource Plan proceedings. *Commonwealth of Virginia, ex rel., State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUE-2015-00035, Doc. Con. Cen. No. 151250091, Final Order at 14-15 (Dec. 30, 2015).

[53] *See* Dominion's Post Hearing Brief at 48; Ex. 25 (Myers Direct) at 7.

[54] Dominion has calculated a total revenue requirement for Rider GV of $41,643,000 for the April 1, 2016, through March 31, 2017 rate year, while Staff has calculated a total revenue requirement of $39,182,000. *See* Ex. 12 (Propst Direct) 8; Ex. 25 (Myers Direct) at 7-8.

Accordingly, IT IS ORDERED THAT:

(1) Subject to the findings and requirements set forth in this Final Order, Dominion is granted approval and Certificate of Public Convenience and Necessity No. ET-204 to construct and operate the Greensville County Power Station as set forth in this proceeding.

(2) Subject to the findings and requirements set forth in this Final Order, Dominion is granted approval and certificates of public convenience and necessity to construct and operate the Transmission Interconnection Facilities to interconnect the Greensville County Power Station.

(3) Pursuant to the Utility Facilities Act, Chapter 10.1 (§ 56-265.1 *et seq.*) of Title 56 of the Code, the Company is issued the following certificates of public convenience and necessity:

> Certificate No. ET-83h, which authorizes Virginia Electric and Power Company, under the Utility Facilities Act, to operate certificated transmission lines and facilities in Greensville County, all as shown on the map attached to the certificate, and to construct and operate facilities as authorized in Case No. PUE-2015-00075, cancels Certificate No. ET-83g issued to Virginia Electric and Power Company on August 2, 2013, in Case No. PUE-2012-00128.
>
> Certificate No. ET-63f, which authorizes Virginia Electric and Power Company, under the Utility Facilities Act, to operate certificated transmission lines and facilities in Brunswick County, all as shown on the map attached to the certificate, and to construct and operate facilities as authorized in Case No. PUE-2015-00075, cancels Certificate No. ET-67e issued to Virginia Electric and Power Company on August 2, 2013, in Case No. PUE-2012-00128.

(4) The Company's Application for approval of a RAC, designated Rider GV, is granted in part and denied in part as set forth herein.

(5) The Company shall file, within thirty (30) days of the date of this Final Order, a revised Rider GV and supporting workpapers with the Clerk of the Commission and with the Commission's Divisions of Energy Regulation and Utility Accounting and Finance, as necessary to comply with the directives set forth in this Final Order. The Clerk of the Commission shall

retain such filing for public inspection in person and on the Commission's website: http://www.scc.virginia.gov/case.

(6) Rider GV, as approved herein, shall become effective for service rendered on and after April 1, 2016.

(7) The Company shall file its annual Rider GV application on or before July 1st of each year.

(8) This case is dismissed.

DIMITRI, Commissioner, concurring:

I concur in the decision to grant the requested certificates and in the revenue requirement approved for Rider GV in this Final Order. In addition, I would find that SB 1349 cannot impact the Commission's authority in this matter because it violates the plain language of Article IX, Section 2, of the Constitution of Virginia, for the reasons set forth in my separate opinion in Case No. PUE-2015-00027. Indeed, the instant case further illustrates how SB 1349 fixes base rates as discussed in that separate opinion. The evidence in this case shows that Dominion plans to allow certain NUG contracts, currently providing power to customers, to expire while base rates are frozen by SB 1349.[55] The capacity costs associated with these contracts, however, are currently included in those base rates.[56] Thus, as explained by Consumer Counsel, this means that "the Company's base rates will remain inflated" because Dominion (i) will no longer be paying these NUG capacity costs, but (ii) will continue to recover such costs from its customers since base rates are frozen under SB 1349.[57] Based on Dominion's cost estimates, between now and the end of 2019, it will have recovered over $243 million from its customers for NUG

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[55] Consumer Counsel's Post-Hearing Brief at 5-6.

[56] *Id.* at 5; Tr. 107-110.

[57] Consumer Counsel's Post-Hearing Brief at 5-6.

capacity costs that the Company no longer incurs.[58] While other costs and revenues are likely to change up and down during this period and would not be reflected in base rate changes precluded by SB 1349, these NUG costs are known, major cost reductions that will not be passed along to customers.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219. A copy shall also be sent to the Commission's Office of General Counsel and Divisions of Energy Regulation and Utility Accounting and Finance.

[58] Ex. 6 (Virginia Jurisdictional NUG Capacity Costs and Greensville Revenue Requirement).

Attachment 2

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Bureau of Air Quality

DOCUMENT NUMBER: 270-0810-006

TITLE: Guidance for Performing Single Stationary Source Determinations for Oil and Gas Industries

EFFECTIVE DATE: October 6, 2012

AUTHORITY: Act of January 8, 1960, P.L. (1959) 2119, No 787, as amended, known as The Air Pollution Control Act, (35 P.S. § 4001 et seq.)

POLICY: Single source determinations for oil and gas operations arise when a company operates an air contamination source on-site or adjacent to another air contamination source. If the emissions from two or more air contamination sources meet the applicable regulatory criteria, they should be aggregated as a single source for air quality permitting purposes. If the emissions from those air contamination sources are aggregated as a single air contamination source, and reach major source emission thresholds, they would be subject to additional air quality permitting requirements under the Prevention of Significant Deterioration ("PSD"), Non-attainment New Source Review ("NSR") and the Title V Permit programs. The plain language of the regulatory requirements should be followed in making such determinations.

PURPOSE: The purpose of this document is to provide guidance to assist the Department of Environmental Protection's Air Program permitting staff in making single stationary source determinations for the oil and gas industries in Pennsylvania.

APPLICABILITY: This policy applies to case-by-case analyses conducted by DEP's air program permitting staff when determining whether stationary sources at oil and gas facilities should be considered a single source for permitting requirements applicable to air permitting programs including PSD, Non-attainment NSR, and Title V Permits.

DISCLAIMER: The policies and procedures outlined in this guidance are intended to supplement existing requirements. Nothing in the policies or procedures shall affect regulatory requirements.

The policies and procedures herein are not an adjudication or a regulation. There is no intent on the part of DEP to give the rules in these policies that weight or deference. This document establishes the framework within which DEP will exercise its administrative discretion in the future. DEP reserves the discretion to deviate from this policy statement if circumstances warrant.

INTRODUCTION

The purpose of this guidance is to provide assistance to the Department of Environmental Protection's ("Department") air program permitting staff in making single source determinations for the oil and gas industries in Pennsylvania. There are significant gas exploration and extraction activities occurring in the Commonwealth within the Marcellus Shale formation and other formations. As a result, there are permitting issues related as to whether the air emissions from exploration, extraction, or production activities need to be aggregated to determine whether the sources from these emissions qualify as a "major stationary source" or "major facility" for purposes of the PSD, Non-attainment NSR and Title V permitting programs.[1]

APPLICABLE AIR QUALITY PERMITTING REQUIREMENTS

Single source determinations arise when air contamination sources under common control are located on property which is contiguous or adjacent to another air contamination source.[2] If the emissions from two or more air contamination sources meet the applicable regulatory criteria, they should be aggregated as a single source for air quality permitting purposes. If the emissions from the aggregated sources meet or exceed major source emission thresholds, they would be treated as a "single source" subject to additional air quality permitting requirements under the PSD, NSR, and Title V programs. The regulatory permitting requirements in Pennsylvania identify the criteria necessary to make such determinations.

Prevention of Significant Deterioration Regulations[3]

In Pennsylvania, major stationary air contamination sources located in attainment areas are subject to the PSD permit program.[4] Before a person can construct a major stationary source in an attainment area, they must receive a plan approval (preconstruction permit) under the PSD program. Persons seeking to construct and operate such a source in an attainment area in

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[1] A source is subject to Title V if it has the potential to emit 100 tons per year ("TPY") or more of carbon monoxide ("CO"), nitrogen oxides ("NOx"), sulfur oxides ("SOx"), particulate matter of 10 microns or less ("PM-10"), particulate matter of 2.5 microns or less ("PM-2.5"), 50 TPY of volatile organic compounds ("VOCs"), 10 TPY of a single hazardous air pollutant ("HAP"), and 25 TPY of multiple HAPs. In southeastern Pennsylvania, the Title V thresholds for NOx and VOCs are 25 TPY.

[2] "Air contamination source" is defined as "any place, facility or equipment, stationary or mobile, at, from or by reason of which there is emitted into the outdoor atmosphere any air contaminant." 35 P.S. § 4003. "Air contaminant" is defined as "smoke, dust, fume, gas, odor, mist, radioactive substance, vapor, pollen, or any combination thereof." ***Id.***

[3] While the discussion in this section focuses on the PSDprogram, it is also applicable to the Title V program. *See* 61 Fed. Reg. 34202, 34210 (July 1, 1996).

[4] The PSD program applies to sources that have the potential to emit at least 250 TPY of a regulated pollutant, or at least 100 TPY of a regulated pollutant if the source falls within a listed source category. 40 C.F.R. § 52.21(b)(1).

Pennsylvania must comply with the preconstruction permitting requirements under the PSD program.[5]

The federal PSD regulations, which Pennsylvania incorporates by reference in their entirety, define "stationary source" to mean "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant."[6] Moreover, a "building," "structure," "facility," or "installation" is defined as all the pollutant-emitting activities which: (1) belong to the same industrial grouping[7]; and (2) are located on one or more contiguous or adjacent properties; and (3) are under the control of the same person.[8] If two or more air contamination sources are determined to be a single source, under the three-part test of this latter definition, with emissions that collectively meet or exceed the major source thresholds, the sources should be treated as a single air contamination source for PSD and Title V permitting purposes. However, if the three-pronged regulatory criteria for single source determinations are met, all sources should be aggregated irrespective of their separate status as "minor" or "major" air contamination sources.

In the preamble to these regulations, the U.S. Environmental Protection Agency ("EPA") stated that, to be a "source" for the purposes of the PSD program, an activity must: (1) carry out reasonably the purposes of the PSD program; (2) approximate a common sense notion of "plant"; and (3) avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building," "structure," "facility," or "installation."[9] As a result, these additional factors should also be addressed on a case-by-case basis when analyzing whether a group of pollutant-emitting activities (i.e., two or more air contamination sources) should be grouped together as a single air contamination source.

Non-attainment NSR Regulations

In Pennsylvania, major stationary air contamination sources[10] located in non-attainment areas are subject to the non-attainment NSR permit program. The entire Commonwealth is considered a "moderate" ozone nonattainment area for NOx and VOCs because Pennsylvania is a jurisdiction in the Ozone Transport Region established by operation of law under Section 184 of the Clean Air Act.[11] Before a person can construct and operate a major source in a non-attainment area in

[5] *See* 25 Pa. Code, Chapter 127, Subchapter D. The PSD requirements promulgated in 40 C.F.R. Part 52 are adopted in their entirety by the Department and incorporated by reference under this subchapter.
[6] 40 C.F.R. § 52.21(b)(5).
[7] Under this definition, activities are within the same industrial grouping if they share the same two-digit Standard Industrial Classification ("SIC"). Exploration, extraction, or production activities in the oil and natural gas development industry share the same two-digit SIC code – 13.
[8] 40 C.F.R. § 52.21(b)(6).
[9] *See* 45 Fed. Reg. 52676, 52693 (August 7, 1980).
[10] The non-attainment program applies to sources that have the potential to emit at least 100 TPY of a regulated non-attainment pollutant. 42 U.S.C. § 7602(j). These thresholds have been lowered for areas with more acute non-attainment problems. For instance, to 50 TPY for VOC and NOx in serious ozone non-attainment areas, to 25 TPY for severe areas, and 10 TPY for extreme areas. *See generally*, 42 U.S.C. § 7511a.
[11] 42 U.S.C. § 7511c.

Pennsylvania, they must comply with the preconstruction permitting and operating permit requirements under the non-attainment NSR program.[12]

For non-attainment NSR purposes, Pennsylvania defines "facility" to mean "an air contamination source or combination of air contamination sources located on one or more contiguous or adjacent properties and which is owned and operated by the same person under common control."[13] If two or more air contamination sources are determined to be a single source with emissions, which collectively meet or exceed the major source thresholds and the two-part criteria under this definition, they should be treated as a single air contamination source for non-attainment NSR permitting purposes. However, the case-by-case single source determination would apply to all sources irrespective of their separate status as "minor" or "major" air contamination sources.

APPLICATION OF THESE REGULATORY REQUIREMENTS TO NATURAL GAS AIR CONTAMINATION SOURCES IN PENNSYLVANIA

Air quality permitting staff should rely on the three-part regulatory criteria identified above to determine whether emissions from two or more facilities should be aggregated and treated as a single source for air quality permitting purposes. These regulatory criteria are: whether the activities belong to the same industrial grouping; whether the activities are located on one or more contiguous or adjacent properties; and whether the activities are under the control of the same person (or persons under common control).[14] If two or more facilities meet these criteria, they would be treated as a single facility for PSD and Title V permitting purposes. However, for nonattainment NSR applicability determinations in the Commonwealth, the case-by-case determination is a two-part test which considers whether the air contamination source or combination of sources are located on one or more contiguous or adjacent properties and whether the sources are owned or operated by the same person under common control.

Sources belonging to the same industrial grouping

Under the PSD and Title V permitting programs, pollutant-emitting activities are considered to be part of the same industrial grouping if they have the same first two-digit Standard Industrial Classification or SIC code.[15] In addition, a support facility is considered to be part of the same industrial grouping as that of the primary facility it supports even if the support facility has a different two-digit SIC code. Support facilities are typically those which convey, store, or

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[12] *See* 25 Pa. Code, Chapter 127, Subchapter E.

[13] 25 Pa. Code §121.1. The definition "facility" under Section 121.1 applies to the non-attainment NSR permit provisions under Subchapter E.

[14] 40 C.F .R. § 52.21 (b)(6).

[15] *See* 40 CFR Part 52.21(b)(6).

otherwise assist in the production of the principal product." [16] If scenarios exist where the SIC code is different for two sources, staff should determine if a support relationship exists.

However, in defining the source where a potential support relationship exists between two or more facilities in a PSD or attainment area, for PSD applicability purposes, the difference in SIC codes becomes irrelevant. The only factors remaining to be considered are whether the sources or facilities are located on contiguous or adjacent properties and under common control using the common sense notion of what constitutes a plant or single source.

Under non-attainment NSR, Pennsylvania's federally approved definition of "facility" found at 25 Pa. Code, Section 121.1 (relating to definitions) does not include a requirement for sources to have the same SIC code to be part of the same facility. So, here too, the only factors to be considered for non-attainment NSR applicability purposes are whether the facilities are contiguous or adjacent and under common control.

Sources located on one or more contiguous or adjacent properties

Neither Pennsylvania nor federal regulations define the terms “contiguous” or “adjacent” or place any definitive restrictions on how distant two emission units can be and still be considered located on contiguous or adjacent properties for the purposes of a single source determination.

The plain meaning of “contiguous” is – sharing an edge or boundary; touching; neighboring, adjacent, connecting without a break.”[17] “Adjacent” is defined as – “close to; lying near, next to; adjoining.”[18]

These words mean and relate to spatial relationship or spatial distance or proximity. The concept of contiguous or adjacent looks at whether the properties associated with the air contamination source are abutting to, or are close-by, property associated with another air contamination source.

Because of the nature of the oil and gas extraction industry, wells are scattered across a large resource area creating duplicate facilities that perform identical functions. For instance, well production pads and compressor stations are dispersed across a wide area that could encompass many square miles so that the leased properties can be accessed and natural gas can be extracted, compressed, and conveyed via pipeline to a nearby processing facility. Such expansive operations would not generally comport with the “common sense notion of a plant.” Additionally, two aggregate stationary sources located on properties spread throughout a large geographical area would not be consistent with the plain meaning of the terms contiguous or

[16] *See* 45 Fed. Reg. 52695 (August 7, 1980).
[17] *See* Dictionary.com. *The American Heritage Dictionary of the English Language, Fourth Edition*, Houghton Mifflin Co., 2004. http://dictionary.reference.com/browse/contiguous.
[18] *See* Dictionary.com. *The American Heritage Dictionary of the English Language, Fourth Edition*, Houghton Mifflin Co. 2004. http://dictionary.reference.com/browse/adjacent.

adjacent properties. Consequently, only sources that are in close proximity should be considered contiguous or adjacent properties for single source determination purposes.

EPA's nonbinding policy does not include a bright line or numeric standard for determining how far apart activities may be and still be considered "contiguous" or "adjacent."[19] Historically, EPA has stated that it is a case-by-case, fact-specific determination and has made that claim since the promulgation of the PSD regulations on August 7, 1980, and in a number of EPA interpretative letters and guidance documents. EPA guidance generally provides that the determination of whether sources are adjacent is based on the "common sense" notion of source and whether they functionally operate as a single source. In explaining this concept, EPA has noted that whether or not facilities are adjacent depends not only on the "common sense" notion of a source, but also the interdependence of the facilities and is not simply a matter of physical distance between the two facilities.[20]

EPA's non-binding guidance memoranda are merely instructive; they are not dispositive. While interdependence may be considered when conducting a single source determination, the plain meaning of the terms "contiguous" and "adjacent" should be the dispositive factor when determining whether stationary sources are located on contiguous or adjacent properties.

As defined in 40 CFR Section 52.21(b)(5), a stationary source is "any building, structure, facility or installation which emits or may emit a regulated NSR pollutant." These stationary sources can be aggregated when they meet "the common sense notion of a plant." There should be no aggregation when the activities as a group do not fit within the ordinary meaning of "building," "structure," "facility" or "installation."

In applying the "contiguous or adjacent" prong of this criterion, some states have used a quarter-mile rule of thumb.[21] That is, properties located a quarter mile or less apart are considered contiguous or adjacent properties for PSD, Non-attainment NSR and Title V applicability determinations. Properties located beyond this quarter-mile range may only be considered contiguous or adjacent on a case-by-case basis.

A case-by-case determination is needed to determine if sources are considered contiguous or adjacent. The following items should be considered in the analysis: (1) properties located within

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[19] *See* Memo from Pamela Blakely, U.S. EPA Region 5 to Don Smith, Minnesota Pollution Control Agency, March 23, 2010.
[20] *See e.g.,* Memo from Steven C. Riva, U.S. EPA Region 2 to John T. Higgins, New York Department of Environmental Conservation, October 11, 2000.
[21] *See, e.g.*, Texas Commission on Environmental Quality "Definition of Site Guidance," available at http://www.tceq.texas.gov/permitting/air/guidance/titlev/tv_fop_guidance.html; Oklahoma Department of Environmental Quality guidance entitled "Permitting Collocated Facilities," available at http://www.deq.state.ok.us/factsheets/; and Louisiana Department of Environmental Quality guidance entitled "Interpretation of Contiguous for Oil and Gas," available at http://www.deq.state.la.us/portal/tabid/2347/Default.aspx . It should be noted that these guidance documents provide that interdependent properties located more than a quarter mile apart may also be considered contiguous.

a quarter mile are considered contiguous or adjacent; (2) sources within this quarter-mile distance should be aggregated so long as they meet the other two regulatory criteria (same industrial grouping and common control); (3) emission units on two or more separate, but near-by, properties and separated by an intervening railroad, road, or some other obstacle may be considered contiguous or adjacent; (4) facilities should not be “daisy-chained” together to establish a contiguous grouping; and (5) properties located outside a quarter mile may be considered contiguous or adjacent on a case-by-case basis.

The application of the quarter-mile or less rule of thumb takes a "common sense approach" to determining if sources are located on adjacent or contiguous properties and does not aggregate pollutant-emitting activities that as a group would not fit within the ordinary meaning of “building,” “structure,” “facility,” or “installation.” That is, the proximity focus of the analysis should guide the permit reviewer in determining whether two sources should be treated as one plant. Moreover, such an approach would implement the air quality permitting program according to applicable statutory and regulatory requirements.

Sources under the control of the same person

The remaining factor to be considered in defining the source is whether a common control relationship exists between the two facilities. As with the contiguous or adjacent factor, common control is determined on a case-by-case basis and is guided by the general definition of control used by the Securities and Exchange Commission (“SEC”). [22] The SEC defines “control” (including the terms "controlling," "controlled by" and "under common control with") as the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract, or otherwise.[23]

There may be a number of other ways to assist in determining whether a common control relationship exists. First, common control can be established by ownership. Second, common control can be established if an entity such as a corporation has decision-making authority over the operation of a second entity through a contractual agreement or voting interest. If common control is not established by the first two ways, then one should next look at whether there is a contract for service relationship between the two companies or if a support/dependency relationship exists between the two companies in order to determine if a common control relationship exists.

Permit reviewers may also consider the following questions to assist them in determining whether there is common control:

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[22] 45 Fed. Reg. 59874, 59878 (September 11, 1980).
[23] 17 C.F.R. § 240.12b-2.

- Do the facilities share common workforces, plant managers, security forces, corporate executive officers or board executives?
- Will managers or other workers frequently shuttle back and forth to be involved actively in both facilities?
- Do the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?
- Are there any financial arrangements between the two entities?
- Are there any legal or lease agreements between the facilities?
- Are there any contracts for service activities?
- Are there multiple owners of an operation?
- Do the owners have voting or control rights over an operation?

This list is not exhaustive and serves only as a vetting tool for determining “common control” of the air contamination sources. If the owners or operators of a facility can provide information showing that one facility has few significant ties to another facility, then they are most likely separate sources under their own control.

Conclusion

Pennsylvania air quality permitting staff should make single source determination based on the following five-step analysis in determining whether two or more facilities should be treated as a single source for air quality permitting purposes: (1) air emission sources may be treated as a single source for air permitting purposes if they meet the applicable two- or three-part regulatory test; (2) each of the elements must be met in order to treat separate emission units as a single stationary source; (3) while federal guidance may be instructive, it is not dispositive; (4) the aggregation test must be applied on a case-by-case basis to the specific facts of the matter before the agency; and (5) the plain meaning of the terms "contiguous" and "adjacent,” particularly in the context of the “common sense notion of a plant,” and the terms “building,” “structure,” “facility,” or “installation,” are appropriate considerations in the application of the aggregation test.

Finally, properties located a quarter mile or less apart are considered contiguous or adjacent properties for applicability determinations, including those related to the PSD, Non-attainment NSR and Title V programs. Properties located beyond this quarter-mile range may only be considered contiguous or adjacent on a case-by-case basis.

Attachment 3

COMMONWEALTH OF PENNSYLVANIA
ENVIRONMENTAL HEARING BOARD

NATIONAL FUEL GAS MIDSTREAM CORPORATION AND NFG MIDSTREAM TROUT RUN, LLC, Appellants, and SENECA RESOURCES CORPORATION, Intervenor	:	
v.	:	**EHB Docket No. 2013-206-B**
COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION	:	**Issued: December 29, 2015**

A D J U D I C A T I O N*

By Steven C. Beckman, Judge

Synopsis

The Board upholds the Single Source Determination in the GP-5 permit issued by the Department where all three regulatory requirements are satisfied and the pollutant-emitting sources collectively meet the common sense notion of a plant. The Board finds that the Bodine Compressor Station and Well Pad E are each properly classified under Standard Industrial Classification Major Group 13. The Board also finds that the Bodine Compressor Station and Well Pad E fall within the common definition of the term "adjacent." Finally, the Board finds that the Bodine Compressor Station and Well Pad E are under common control due to common corporate ownership and ultimate financial control by that common corporate owner.

Background

This matter involves an appeal by National Fuel Gas Midstream Corporation and NFG Midstream Trout Run, LLC (collectively "Midstream"), and intervenor Seneca Resources

* Concurring Opinion by Judge Labuskes
Concurring Opinion by Judge Mather

Corporation ("Seneca") of an October 10, 2013 letter issued to Midstream by the Department of Environmental Protection ("the Department" or "DEP") authorizing the construction and operation of the Bodine Compressor Station in McIntyre Township, Lycoming County, pursuant to the General Plan Approval and/or General Operating Permit for Natural Gas Compression and/or Processing Facilities ("GP-5 permit" or "the permit"). Midstream and Seneca specifically challenge the Department's single source analysis incorporated into the GP-5 permit that resulted in the aggregation of the emissions from Midstream's Bodine Compressor Station with the emissions from Seneca's Well Pad E. The details of the single source analysis are contained in the Department's Application Review Memo for the Bodine Compressor Station dated October 10, 2013 ("2013 Application Review Memo").

On March 31, 2015, following the submittal of additional information by Midstream, the Department issued a "Re-Evaluation of Single Source Analysis" for the Bodine Compressor Station ("2015 Re-Evaluation Memo"). The 2015 Re-Evaluation Memo updated the Department's single source analysis regarding the SIC code, common control and contiguousness/adjacency three part test that governs single source determinations. The 2015 Re-Evaluation Memo reached the same ultimate conclusion as the 2013 Application Review Memo finding that the Bodine Compressor Station and Well Pad E should be treated as a single source and their air contamination emissions must be aggregated. In reaching the single source determination outlined in the 2013 Application Review Memo and re-affirmed in the 2015 Re-Evaluation Memo, Department staff followed the approach outlined in the Department guidance document entitled "Guidance for Performing Single Stationary Source Determinations for Oil and Gas Industries" dated October 6, 2012 ("2012 Guidance Document").

A three-day hearing was held in this matter from May 12, 2015 through May 14, 2015 at the Board's Northwest Office and Court Facility in Erie, Pennsylvania. Following the hearing, both Midstream and Seneca filed a post-hearing brief on August 3, 2015. The Department filed its post-hearing brief on September 2, 2015, and both Midstream and Seneca filed their post-hearing reply briefs on September 17, 2015. The matter is now ready for decision.

FINDINGS OF FACT

1. On or about August 14, 2013, NFG Midstream Trout Run, LLC, a subsidiary of National Fuel Gas Midstream Corporation applied to the Department for a Pennsylvania General Plan Approval and/or General Operating Permit for Natural Gas Compression and/or Processing Facilities ("GP-5 permit") for the construction and operation of a natural gas compressor facility (the "Bodine Compressor Station" facility) located in McIntyre Township, Lycoming County. (Parties' Joint Stipulation ("Jt. Stip.") No. 1).

2. Midstream's GP-5 permit application states that the purpose of the Bodine Compressor Station facility is to condition, compress, meter, and dehydrate gas from upstream production facilities. (DEP Ex. 7, p. C-33; Hearing Transcript ("T.") 109, 126-127).

3. The GP-5 permit authorizes the construction and operation of air contamination sources that an applicant proposes to use at natural gas compression or processing facilities. (Midstream Exhibit ("Ex.") 5; T. 108).

4. The GP-5 permit defines a natural gas compression and/or processing facility as "[a] facility that produces, compresses and/or processes natural gas, coal bed methane or gob gas starting with dehydration, compression, fractionation and storage." (Midstream Ex. 5; T. 108-09).

5. On October 10, 2013, the Department acknowledged Midstream's coverage under the GP-5 permit for the construction and operation of the air contamination sources at the Bodine Compressor Station described in Midstream's application. (Jt. Stip. No. 2).

6. When reviewing an application for a GP-5 permit, the Department must determine what the "stationary source" is and what the "facility" is in order to compare any aggregated emissions to the emission thresholds established in the Prevention of Significant Deterioration, nonattainment New Source Review, and Title V laws and regulations. (T. 34- 35, 113-114).

7. If the emissions from the stationary source or facility trigger the Prevention of Significant Deterioration, nonattainment New Source Review, or Title V permitting requirements, the stationary source or facility would not qualify for coverage under the GP-5 permit. (T. 113).

8. The Department, in connection with its review of Midstream's application, performed a Single Source Determination and Aggregation Analysis. (Jt. Stip. No. 3).

9. The Department's single source analysis with respect to aggregating the emissions from Well Pad E with the emissions from the Bodine Compressor Station is discussed in an October 10, 2013 Application Review Memo for Midstream's GP-5 application. (Midstream Ex. 1; T. 22-23).

10. The October 10, 2013 Application Review Memo was drafted by Air Quality Engineer John Twardowski, and reviewed and approved by Environmental Program Manager Muhammad Zaman. (Midstream Ex. 1; T. 21, 364).

11. The October 10, 2013 Application Review Memo documents the initial recommendation by the Department's permit reviewing staff that a GP-5 permit be issued for the Bodine Compressor Station facility. (Midstream Ex. 1; T. 31-32).

12. The October 10, 2013 Application Review Memo contains a section entitled "Single Source Analysis." (Midstream Ex. 1; T. 33).

13. As a result of the Single Source Analysis, the Department considered Midstream's Bodine Compressor Station facility and Seneca's upstream exploration and production facilities at Well Pad E to be a single source for air permitting purposes, including the Prevention of Significant Deterioration, nonattainment New Source Review and the Title V permitting programs. (Jt. Stip. No. 4).

14. The combined air pollutant emissions from the air contamination sources at the Bodine Compressor Station and Well Pad E do not exceed the regulatory thresholds for review under Prevention of Significant Deterioration, nonattainment New Source Review, or Title V permitting. (Jt. Stip. No. 5).

15. On February 27, 2015, Midstream provided additional information to the Department relevant to the single source analysis as part of settlement negotiations with respect to this appeal. (Midstream Ex. 3, p. 1).

16. After reviewing and considering that additional information, on March 31, 2015, the Department issued a memorandum entitled "Re-Evaluation of Single Source Analysis" in connection with Midstream's GP-5 permit application for the Bodine Compressor Station. (Midstream Ex. 3).

17. The March 31, 2015 Re-Evaluation Memorandum was drafted by Air Quality Engineer John Twardowski with assistance of counsel, reviewed by Permits Chief David Shimmel, and reviewed and approved by Environmental Program Manager Muhammad Zaman. (Midstream Ex. 3, p. 1; T. 36, 307, 313, 367).

18. The March 31, 2015 Re-Evaluation Memorandum confirms and repeats the initial recommendation by the Department's permit reviewing staff that a GP-5 permit be issued for the Bodine Compressor Station facility, and that the emissions from Well Pad E should be aggregated with the emissions from the Bodine Compressor Station. (Midstream Ex. 3).

19. For purposes of making a single source determination with respect to Prevention of Significant Deterioration and Title V, a group of stationary sources belong to the same industrial grouping if they share the first 2-digits of their Standard Industrial Classification ("SIC") code. (Jt. Stip. No. 23).

20. Seneca's operations at Well Pad E meet the description of SIC Code 1311. (Jt. Stip. No. 22).

21. SIC Major Group 13 is entitled Oil and Gas Extraction and includes establishments primarily engaged in producing crude petroleum and natural gas and further states that pipeline transportation of petroleum, gasoline, and other petroleum products (except crude petroleum field gathering lines) is classified in Transportation and Public Utilities, Major Group 46, and pipeline transportation of natural gas is classified in Electric, Gas, and Sanitary Services, Major Group 49. (Midstream Ex. 21, p. 45, p. 284).

22. SIC code 1311 applies to establishments primarily engaged in operating oil and gas field properties including all activities in the preparation of oil and gas up to the point of shipment from the producing property. (Midstream Ex. 21, p. 45).

23. Midstream listed SIC code 4922 for the Bodine Compressor Station in the GP-5 permit application. (DEP Ex. 7).

24. SIC Major Group 49 is entitled Electric, Gas and Sanitary Services and includes establishments engaged in the generation, transmission, and/or distribution of electricity or gas or steam. (Midstream Ex. 21, p. 284).

25. SIC Code 4922 is entitled Natural Gas Transmission and is for establishments engaged in the transmission and/or storage of natural gas for sale. (Midstream Ex. 21, p. 284).

26. Midstream's operations at the Bodine Compressor Station facility meet the description of SIC Code number 1389 entitled "Oil and Gas Field Services, Not Elsewhere Classified, which applies to, among other things, "gas compressing." (Midstream Ex. 21, p. 46).

27. The edge of the developed property at Seneca's Well Pad E is located 0.24 miles from the fence line of Midstream's Bodine Compressor Station. (T. 61-62, 123, 125).

28. The centroid of Seneca's Well Pad E is approximately 0.30 miles from the centroid of the Bodine Compressor Station. (T. 62, 124).

29. There is an access road between the Bodine Compressor Station and Well Pad E. (T. 129).

30. The Bodine Compressor Station and Well Pad E are connected by a gathering pipeline, which transports natural gas produced from the Well Pad E to the Bodine Compressor Station. (Jt. Stip. No. 7).

31. Well Pad E and the Bodine Compressor Station facility do not share common workforces, plant managers or security forces. (Jt. Stip. No. 24).

32. Well Pad E and the Bodine Compressor Station facility lack a common secure perimeter, common work rules, coordinated operations, common safety requirements, or process equipment. (Midstream Ex. 42; Midstream Ex. 44; DEP Ex. 7, pp. C-35, C-36; T. 434-35).

33. National Fuel Gas Midstream Corporation subsidiaries and Seneca do not share purchasing functions, personnel services, benefit plans, maintenance responsibilities, environmental compliance or remediation responsibilities. (Midstream Ex. 42).

34. Neither Seneca nor its employees have the authority to enter Midstream's facility sites without permission. (Midstream Ex. 42).

35. Midstream employees do not have the authority to enter Seneca's exploration and production facilities without permission. (Midstream Ex. 42).

36. The Bodine Compressor Station facility and Well Pad E are unmanned facilities. (Midstream Ex. 42; Midstream Ex. 44; T. 84).

37. The persons who maintain and service the Bodine Compressor Station are third party contractors retained and directed by Midstream. (Midstream Ex. 42).

38. The intervening land use between the Bodine Compressor Station and Well Pad E is DCNR forestland. (Jt. Stip. No. 9).

39. Well Pad E and the Bodine Compressor Station are not visible from one another because of the intervening topography and land use. (Midstream Ex. 42; Midstream Ex. 44; T. 62-63).

40. Raw gas drilled for and removed from the ground at Well Pad E can be directed either to Bodine Compressor Station facility or to another facility, called the Hagerman facility. (Jt. Stip. No. 10).

41. Seneca is a Pennsylvania corporation established in 1913. (Jt. Stip. No. 11).

42. Seneca is an exploration and production company that explores for, develops and produces oil and natural gas. (Jt. Stip. No. 12).

43. Seneca is a wholly-owned subsidiary of National Fuel Gas Company, a publicly traded holding company organized under the laws of the State of New Jersey. (Jt. Stip. No. 13).

44. NFG Midstream Trout Run, LLC ("NFG Trout Run") is a Pennsylvania limited liability company established in 2010. (Jt. Stip. No. 14).

45. National Fuel Gas Midstream Corporation ("NFG Midstream") is a Pennsylvania corporation established in 2008. (Jt. Stip. No. 15).

46. NFG Trout Run is a subsidiary of NFG Midstream. (Jt. Stip. No. 16).

47. NFG Trout Run engages in "the gathering and processing of production natural gas." (DEP Ex. 7, p. B-2).

48. NFG Midstream and its subsidiaries, including NFG Trout Run, operate in the midstream segment of the natural gas industry. (Jt. Stip. No. 17).

49. NFG Midstream is a wholly-owned subsidiary of the National Fuel Gas Company. (Jt. Stip. No. 18).

50. NFG Midstream's subsidiaries, including NFG Trout Run, gather gas produced by exploration and production companies, like Seneca, and move that gas through their gathering pipelines, compressor stations, interconnect facilities and/or other midstream facilities owned and operated by NFG Midstream's subsidiaries for delivery to interstate pipelines. (Jt. Stip. No. 19).

51. NFG Midstream and its subsidiaries currently gather, process, or transport gas for only Seneca and no other producer. (T. 441).

52. Neither NFG Midstream nor its subsidiaries engage in, or have engaged in, drilling for natural gas or in the production of natural gas. (Midstream Ex. 42).

53. Ronald Tanski is the Chief Executive Officer of National Fuel Gas Company and the Chairman of the Board for both NFG Midstream and Seneca. (Jt. Stip. No. 20).

54. David Bauer is the Treasurer for National Fuel Gas Company, NFG Midstream and Seneca. (Jt. Stip. No. 21).

55. National Fuel Gas Company does not engage in the day-to-day operation of NFG Midstream or its subsidiaries. (Midstream Ex. 42; T. 459).

56. National Fuel Gas Company does not engage in the day-to-day operation of Seneca. (T. 257, 267, 458).

57. Ronald Tanski and David Bauer, on behalf of National Fuel Gas Company, are responsible for reviewing and approving the final budgets and business plans of both Seneca and NFG Midstream. (T. 426-28, 451-53).

58. National Fuel Gas Company presents consolidated financial statements which incorporate the financial statements of its subsidiaries, including Seneca, NFG Midstream and NFG Trout Run. (T. 433).

59. National Fuel Gas Company files a consolidated tax return that reflects the revenues and expenses of its subsidiaries, including Seneca, NFG Midstream and NFG Trout Run. (T. 457).

60. In order to pay dividends and interest on its debt, National Fuel Gas Company relies on interest and dividend payments from its 100% owned subsidiaries, including Seneca, NFG Midstream and NFG Trout Run. (T. 443).

61. All of the funding for the operations of National Fuel Gas Company's subsidiaries is conducted at the parent company level. (T. 443).

62. Seneca and NFG Midstream do not independently issue their own loans. (T. 443-44).

63. The assets of Seneca and NFG Midstream are assets of National Fuel Gas Company. (T. 447).

64. The air contamination sources at issue in this case are considered to be part of National Fuel Gas Company's net investment in property, plant and equipment. (DEP Ex. 2, p. 23; T. 444).

DISCUSSION

Introduction

Midstream and Seneca are challenging the Department's determination that Midstream's Bodine Compressor Station and Seneca's Well Pad E should be treated as a single source for air permitting purposes. This determination was incorporated in the GP-5 permit authorization issued to Midstream. The single source determination conducted by the Department serves two related purposes. The first is to determine whether a natural gas compression and/or gas processing facility is eligible for coverage under the GP-5 permit. Under its specific terms, the GP-5 permit may not be used by a source that is subject to the Prevention of Significant Deterioration ("PSD"), Title V and the nonattainment New Source Review ("NSR") permitting requirements that are triggered when a source meets certain emission thresholds. Therefore, the Department must define the source and determine its emission levels before reaching a decision on an application for coverage under the GP-5 permit. The second purpose involves the emission limits governing ongoing operations at the natural gas compression and/or gas processing facility. The operating emission levels from all sources at the facility must not equal or exceed certain levels specified in the GP-5 permit. Department staff testified during the hearing (and it is stated explicitly in the latest version of the GP-5 permit dated 1/2015) that the emissions limits in the GP-5 permit apply to the emissions from all sources at the natural gas compression and/or gas processing facility, including other sources determined by DEP to be a single source. As such, the single source determination is an integral part of the Department's review and approval/denial of a GP-5 permit.[1]

There is no real dispute between the parties as to the statutory and regulatory framework applicable to determining whether the Bodine Compressor Station and Well Pad E should be treated as a single source. We discuss the statutory and regulatory framework in more detail below, but in order to be considered a single source, the air contamination sources must: 1) belong to the same industrial grouping, 2) be located on one or more contiguous or adjacent properties, and 3) be under the control of the same person (or persons under common control), and, more generally, the sources should meet the common sense notion of a plant. Each part of the three part test must be satisfied before the Department can properly aggregate separate air emission sources into a single source. The Department determined in both its initial review in October 2013 and in the re-evaluation that it conducted in March 2015 that the three part test for aggregation was satisfied and that the Bodine Compressor Station and Well Pad E comport with

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[1] In its post-hearing brief, the Department asserts for the first time that "neither NFG Midstream nor Seneca has proven how they have been aggrieved by this interim permitting decision." (Department's Post-Hearing Brief, p.1). The Department fails to develop this assertion any further in its post-hearing brief. To the extent that the Department's statement can be read to challenge Midstream and/or Seneca's standing to bring this appeal, any standing challenge has been waived. *See Jake v. DEP*, 2014 EHB 38, 60 (issue of standing waived where the Department failed to challenge standing until post-hearing briefing). To the extent that the statement was intended to raise an issue regarding the Board's jurisdiction in this matter, we find that we have jurisdiction. In order to have jurisdiction, there must be a final Department action that adversely affects personal or property rights, privileges, immunities, duties, liabilities or obligations of a person. The approval of coverage under the GP-5 permit is a final permit decision by the Department. At a minimum, Midstream is adversely affected by the issuance of the GP-5 permit incorporating the Department's single source determination because, as a result of the aggregation of the emissions from Well Pad E with the emissions from the Bodine Compressor Station, Midstream must account for the Well Pad E emissions in satisfying the emission limits found in the GP-5 permit. Thus, we have everything that is required to support the Board's jurisdiction in this matter.

the common sense notion of a plant. Midstream and Seneca dispute the Department's determination and contend that the Bodine Compressor Station and Well Pad E fail to satisfy each part of the three part test. Furthermore, they argue that even if the three part test is met, the Bodine Compressor Station and Well Pad E do not satisfy the common sense notion of a plant.

The Board reviews all final Department actions *de novo*. *Warren Sand & Gravel Company v. Department of Environmental Resources*, 341 A.2d 556, 565 (Pa. Cmwlth. 1978). The Board has explained its *de novo* review as follows:

> The Board conducts its trials *de novo*. We must fully consider the case anew and we are not bound by prior determinations made by DEP. Indeed, we are charged to redecide the case based on our *de novo* scope of review. The Commonwealth Court has stated that "*de novo* review involves full consideration of the case anew. The EHB, as reviewing body, is substituted for the prior decision maker, the Department, and redecides the case." *Young v. Department of Environmental Resources*, 600 A.2d 667, 668 Pa. Cmwlth. 1991); *O'Reilly v. Department of Environmental Protection*, 2001 EHB 19, 32. Rather than deferring in any way to findings of fact made by the Department, the Board makes its own factual findings, findings based solely on the evidence of record in the case before it. *See, e.g., Westinghouse Electric Corporation v. Department of Environmental Protection*, 1999 EHB 98, 120 n. 19.

Smedley v. DEP, 2001 EHB 131, 156. Under 25 Pa. Code § 1021.122(a), "[i]t shall generally be the burden of the party asserting the affirmative of the issue to establish it by a preponderance of the evidence." 25 Pa. Code § 1021.122(c) adds that "[a] party appealing an action of the Department shall have the burden of proof … when a party to whom a permit approval or certification is issued protests one or more aspects of its issuance or modification." Since this matter involves an appeal of the authorization of permit coverage issued by the Department, Midstream and Seneca must prove by a preponderance of the evidence that the Department's single source determination regarding Seneca's Well Pad E and Midstream's Bodine Compressor Station that was incorporated into the GP-5 permit is contrary to law or unreasonable.

Regulatory Framework Governing Single Source Determinations

Single source determinations are necessitated by the federal and Pennsylvania regulations implementing the PSD, Title V and the nonattainment NSR permitting programs. The regulatory framework for a single source determination begins with the definition of a "stationary source" found in the federal Clean Air Act ("CAA"). Section 111 of the CAA defines "stationary source" as "any building, structure, facility, or installation which emits or may emit an air pollutant." 42 U.S.C. § 7411(a)(3). In *Alabama Power Company v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), the D.C. Circuit Court found that aggregating the emissions of individual units in a single plant into a single stationary source under the CAA's PSD provisions was permissible. The court, however, rejected an expansive definition of stationary source advocated by EPA and concluded that "EPA cannot treat contiguous and commonly owned units as a single source unless they fit within the four permissible statutory terms" for a stationary source: 1) "building;" 2) "structure;" 3) "facility;" or 4) "installation." *Id.* at 397; 42 U.S.C. § 7411(a)(3). The *Alabama Power* court instructed EPA to define the four statutory terms for "stationary source" in order "to allow an entire plant or other appropriate grouping of industrial activity to be subject as a single unit to PSD, as Congress clearly intended." *Id.*

In response to *Alabama Power*, EPA amended its PSD regulations and specifically amended the definition of "stationary source" to "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant." 40 C.F.R. § 52.21(b)(5). EPA, at the time of the amended PSD regulations, recognized that the *Alabama Power* opinion set boundaries on the components of the stationary source definition such that it must reasonably carry out the purposes of PSD, must approximate the common sense notion of a plant and must avoid aggregating pollutant-emitting activities that as a group would not fit with the ordinary meaning of "building", "structure", "facility" or "installation." 45 FR 52694-95, August 7, 1980. Pursuant to that approach, the amended PSD regulation went on to define "[b]uilding, structure, facility, or installation" as:

> [A]ll of the pollutant-emitting activities which [1] belong to the same industrial grouping, [2] are located on one or more contiguous or adjacent properties, and [3] are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

40 C.F.R. § 52.21(b)(6). The same three-factor analysis contained in the amended PSD regulations was extended to the Title V permitting program. 42. U.S.C. § 7661(2); 40 C.F.R. § 71.2.

Pennsylvania incorporated the federal PSD program in its entirety at 25 Pa. Code § 127.83 but has promulgated its own regulations for the nonattainment NSR and Title V programs. The nonattainment NSR and Title V regulations are found at Subchapters E and G of Chapter 127 of the Pennsylvania Code respectively. In order to treat separate sources of air emissions as a single source under the state regulations governing the PSD and Title V permit programs, the Department must establish that those sources: "[1] belong to the same industrial grouping, [2] are located on one or more contiguous or adjacent properties, and [3] are under the control of the same person (or persons under common control)." 40 C.F.R. § 52.21(b)(6) (defining "facility" for purposes of PSD); 25 Pa. Code § 121.1 (defining "Title V facility"). In order to aggregate sources under the nonattainment NSR program, based on the definition of "facility", the Department must establish that the sources are located on one or more contiguous or adjacent properties and are owned or operated by the same person under common control. 25 Pa. Code § 121.1. The requirement that the sources belong to the same industrial grouping in order to be aggregated does not apply to nonattainment NSR program.

The framework for making a single source determination and aggregating emissions covers all types of industrial facilities and was not specifically designed to address the oil and natural gas industry. Regulators have faced a challenge in applying the framework to the oil and gas industry because of the unique nature and distribution of the facilities and emission sources involved in oil and gas operations. EPA issued a memorandum in 2007 entitled "Source Determinations for the Oil and Gas Industries" intended to guide permitting authorities on single source determinations. The 2007 memorandum was withdrawn by EPA in 2009 and replaced by a memorandum that directed permitting authorities to rely on the three part test set out in the regulations. Just recently, EPA released a proposed rule entitled "Source Determination for Certain Emission Units in the Oil and Natural Gas Sector" attempting once again to clarify certain aspects of the three part test as applied to the oil and gas industry. 80 FR 56579-92, September 18, 2015.

In 2012, in the face of an increase in the number of oil and gas facilities in Pennsylvania related to Marcellus Shale development, the Department released its own guidance document entitled "Guidance for Performing Single Stationary Source Determinations for Oil and Gas Industries." In the 2012 Guidance Document, the Department sets forth the approach its permit staff should follow when making single source determinations involving oil and gas operations. Department staff are instructed to make single source determinations based on the following five-step analysis: (1) air emission sources may be treated as a single source for air permitting purposes if they meet the applicable two-or-three part regulatory test; (2) each of the elements must be met in order to treat separate emission units as a single stationary source; (3) while federal guidance may be instructive, it is not dispositive; (4) the aggregation test must be applied on a case-by-case basis to the specific facts of the matter before the agency; and (5) the plain meaning of the terms "contiguous" and "adjacent," particularly in the context of the "common sense notion of a plant," and the terms "building," "structure," "facility," or "installation," are appropriate considerations in the application of the aggregation test. The 2012 Guidance Document goes further, stating that "properties located a quarter mile or less apart are considered contiguous or adjacent properties for applicability determinations …. Properties located beyond the quarter-mile range may only be considered contiguous or adjacent on a case-by-case basis." The Department offers its standard disclaimer for this guidance document stating that the policies and procedures outlined in the 2012 Guidance Document shall not affect regulatory requirements and are not an adjudication or a regulation. Furthermore, the Department reserves the discretion to deviate from the 2012 Guidance Document if the circumstances under consideration warrant a different approach.

The Board of course is not bound by the Department's guidance document. *See DEP v. Simmons,* 2009 EHB 188 citing *United Refining Co. v. DEP,* 2006 EHB 846 and *Dauphin Meadows v. DEP,* 2001 EHB 521. We also reject the Department's contention that we owe it deference regarding its interpretation of the applicable statutes and regulations. As our prior decisions have made clear, we do not defer to the Department when the Department has failed to adopt a consistent position or has changed its interpretation over time and/or offered a variety of interpretations. *See Tri-State Transfer Co., Inc. v. DEP et al.,* 722 A.2d 1129 (Pa. Cmwlth.

1999); *Waste Management Disposal Services of Pennsylvania, Inc. v. DEP,* 2005 EHB 433; *Brunner, Inc. v. DEP and Beaver Valley Alloy Foundry Company,* 2004 EHB 684; *Environmental & Recycling Services, Inc. v. DEP,* 2002 EHB 461. As is evident by the varying interpretations of the regulations and the three part test that the Department relied on in this matter (i.e. the inconsistencies in the approach between the 2013 Application Review Memo and the 2015 Re-Evaluation Memo, the conflicting testimony of various Department officials during the hearing, and the various approaches to this issue advocated in other single source determinations that have come before the Board), the Department has not consistently applied the regulations and there is no settled approach by the Department to which we owe deference.

Despite not being bound by the 2012 Guidance Document, and without deferring to the Department's interpretation, we agree with significant portions of the five-step analysis set forth by the Department in the 2012 Guidance Document. The Board, along with all of the parties in this matter, agrees that each part of the two or three part regulatory test must be satisfied before the Department can properly aggregate the air emissions from the Bodine Compressor Station and Well Pad E. If even one part of the test is not met, the Department's decision to aggregate the emissions at the Bodine Compressor Station and Well Pad E is improper. We agree that federal guidance is not dispositive and that the Board's decision must be based on the specific facts of the Bodine Compressor Station and Well Pad E situation. Finally, when evaluating whether the Department correctly determined that the emission sources at the Bodine Compressor Station and Well Pad E should be treated as a single source under the three part test, we agree that it is important to keep in mind the plain meaning of the relevant terms and ensure that the ultimate decision supports the common sense notion of a plant and the terms "building," "structure," "facility," or "installation" as used in the "stationary source" definition.

This case of course arises from the application of the identified framework and the Department's stated approach to the actual facts concerning the Bodine Compressor Station and Well Pad E. Following our review of the facts of this matter and applying the statutory and regulatory framework discussed above, we find that the emission sources at the Bodine Compressor Station and Well Pad E are properly aggregated as a single source. As we discuss in more detail below, we have determined that each of the three parts of the test are satisfied, although not necessarily in the manner advocated by the Department. Furthermore, we find that, having met the three part test, the Bodine Compressor Station and Well Pad E satisfy the common sense notion of a plant and reasonably constitute a "facility" as that term is used in the statutes and regulations.

Analysis of the Three Part Test for the Bodine Compressor Station and Well Pad E

SIC Code Determination (Same Industrial Grouping)

A single source determination under the PSD and Title V programs requires that the Department determine the Standard Industrial Classification (SIC) of the pollutant emitting activities. The parties agree that under the PSD and Title V requirements, in order to be considered a single source, the pollutant emitting activities must belong to the same major group (have the same first two digit code) in the Standard Industrial Classification Manual. (Jt. Stip. 23). The parties also agree that Well Pad E is properly identified under SIC code 1311. (Jt. Stip. 22). The parties' dispute is over the proper classification of the Bodine Compressor Station. Midstream contends that the proper SIC code for the Bodine Compressor Station is 4922 and Seneca agrees with Midstream on this point. In the initial single source determination completed in 2013, the Department acknowledged Midstream's use of 4922 for the Bodine Compressor Station but found that there was a support relationship between Well Pad E and the Bodine

Compressor Station that overrode any difference in the SIC code. The Department now contends that the Bodine Compressor Station should be classified under SIC code 1311. If the Department is correct, the first part of the three part test is met because the Bodine Compressor Station and Well Pad E would belong to the same SIC Major Group, Group 13. The Department also maintains its prior position that the alleged support relationship between the Bodine Compressor Station and Well Pad E can override any difference in SIC code if the Board determines that the activities are properly classified under two different SIC codes.

Each of the parties cite to the language of the 1987 Standard Industrial Classification Manual (Midstream Ex. 21) to support its position regarding the proper SIC code for the Bodine Compressor Station. The Department looks to both the general language describing Major Group 13 – Oil and Gas Extraction and the specific language for SIC code 1311 – Crude Petroleum and Natural Gas. The Major Group 13 language relied on by the Department states that it applies to establishments primarily engaged in producing crude petroleum and natural gas and includes activities such as exploration, drilling, oil and gas well operation and maintenance, as well as emulsion breaking and desilting of crude petroleum in the preparation of oil and gas customarily done at the field site. SIC code 1311 covers establishments primarily engaged in operating oil and gas field properties. The Department specifically cites to the language in SIC code 1311 that states that it applies to "all other activities in preparation of oil and gas up to the point of shipment from the producing property." The Department argues that the activities at the Bodine Compressor Station, including the metering, dehydration and compression of the natural gas from Well Pad E, are activities in the preparation of gas up to the point of shipment.

Midstream argues that the Bodine Compressor Station is not involved in any of the activities included in the description of Major Group 13 and instead points to a different section of that description that states that the pipeline transportation of natural gas is properly classified under Major Group 49 – Electric, Gas and Sanitary Services. Midstream further asserts that the Bodine Compressor Station's activities are not included in the description of SIC code 1311 and rejects the Department's reliance on the catchall provision under SIC code 1311 for all other activities in preparation of gas up to the point of shipment from the producing property. Midstream's position is that the activities at the Bodine Compressor Station occur after the shipment of the gas from the producing property and therefore, the specific language of the catchall provision in SIC code 1311 is not satisfied.

Midstream contends that the activities at the Bodine Compressor Station are best classified under Major Group 49 – Electric, Gas and Sanitary Services. Major Group 49 includes establishments engaged in the generation, transmission and/or distribution of electricity, or gas or steam including combinations of any of the three services and also other types of services, such as transportation, communications and refrigeration. The specific SIC code used by Midstream is 4922 which is entitled Natural Gas Transmission and includes establishments engaged in the transmission and/or storage of natural gas for sale. Midstream argues that its activities at Bodine primarily function to condition, meter and compress natural gas for transportation to downstream third-party pipelines and production facilities and that these activities most closely fit SIC code 4922.

The Department's principal argument against the use of SIC code 4922 is that the Bodine Compressor Station does not simply transmit or store natural gas. Instead the Department notes the same activities referenced by Midstream but concludes that these processing activities are not within the description for Major Group 49 or SIC code 4922, which the Department argues are focused on transmission and transportation of natural gas, not gas processing. The Department also makes an extensive argument that Midstream's use of SIC code 4922 is inconsistent with Midstream's statement in its GP-5 permit application that the Bodine Compressor Station is subject to 40 CFR 63, Subpart HH that governs sources that process, upgrade and store natural gas prior to the point that it enters the natural gas transmission or storage source category.

The difficulty in determining the proper SIC code for the Bodine Compressor Station arises principally from two issues, one general issue and one specific to the facts of this case. The first issue is that in determining whether two or more facilities qualify as a single source, the Standard Industrial Classification system is being used for a purpose that is entirely different than the one for which it was developed. The SIC system was developed to classify establishments by the type of economic activity in which they are engaged in order to facilitate the collection, tabulation, presentation and analysis of data collected by various government agencies. Therefore, the SIC system speaks in broad general terms about the types of activities that are included in the categories and attempts to ensure that all economic activity is accounted for in one of the codes. When making a single source determination under air quality regulations, the SIC code is being used to assist the regulator in determining whether various activities satisfy the definition of a stationary source, i.e. a "building, structure, facility or installation." This disconnect between the original purpose of the SIC system and its present use in air permitting decisions like this one creates opportunities for inconsistent application and widely varying legal interpretations like we see between the Department, Midstream and Seneca.

The second issue arises from the particulars of this case. The Bodine Compressor Station, although all within one fenced site, actually consists of various pollutant-emitting activities involving several different types of equipment. These include gas gathering lines, compressor engines, dehydration units, MicroTurbines, tanks and fugitive emission sources. The proper SIC code for the Bodine Compression Station is arguably influenced by which activities and equipment sources one chooses to focus on in determining the SIC code. The Department focuses on the processing activities and equipment at the Bodine Compressor Station in concluding that it fits within the description of SIC code 1311. Midstream focuses more on the gas gathering activity and the overall role of the Bodine Compressor Station in moving gas from the upstream producer to the downstream transmission line. This focus bolsters Midstream's conclusion that SIC code 4922 is the proper classification.

Ultimately, we think that both the Department and Midstream have incorrectly identified the SIC code that should apply to the Bodine Compressor Station. Neither appears to us to be a particularly good fit with the actual activities at the Bodine Compressor Station. As the name implies, the main pollutant-emitting activity at the Bodine Compressor Station is the compression of natural gas. The five compressor engines that were proposed for installation as part of the GP-5 permit application reportedly account for the majority of the potential emissions at the Bodine Compressor Station (83% of NOx, 83% of CO, 78% of VOCs, 53% of HAPs, 0% of Methanol, 60% of Sox, 93% of PM and 75% of CO2e according to the October 10, 2013 Application Review Memo – Midstream Ex. 1.) Because the operation of the compressor engines is the principal pollutant-emitting activity at the Bodine Compressor Station, we think that the proper focus in determining the SIC code for this facility is on the compression of natural gas. In reviewing the SIC manual, we find that the description that best fits the main pollutant-emitting activity at the Bodine Compressor Station is found at SIC code 1389. The 1389 SIC code is entitled Oil and Gas Field Services, Not Elsewhere Classified and is described as establishments primarily engaged in performing oil and gas field services, not elsewhere classified, for others on a contract or fee basis. Among the types of activities described under

SIC code 1389 is the following: "gas compressing, natural gas at the field on a contract basis." As discussed, the major pollutant-emitting activity at the Bodine Compressor Station is gas compression and these services are performed by Midstream pursuant to a contract agreement with Seneca.

The Department makes no reference to SIC code 1389 in its single source determination or in any of its legal filings. Midstream may or may not reference SIC code 1389 in its post-hearing brief. While citing to the pages in the SIC Manual that include the discussion of SIC code 1389, it states "SIC codes 1381, 1382 and 1383 are not applicable because, respectively, Midstream's facilities are not engaged in drilling oil or gas wells, performing exploration services for oil or gas, or performing on-pad oil and gas field services as described." There is no SIC code 1383 so it appears this is intended to be a reference to 1389. In its brief, Midstream adds the term "on-pad" to its paraphrase of the SIC Manual title of Oil and Gas Field Services, Not Elsewhere Classified for SIC code 1389. The term "on-pad" is not used anywhere in the title or description of SIC code 1389. Instead the description of SIC code 1389 speaks of gas compressing at the field level and we do not see any basis for restricting the use of this code to gas compression "on-pad" since the use of the term "field" in the description is clearly intended to cover a broader area than a well pad. The SIC code we determined is appropriate for the Bodine Compressor Station, 1389, is in the same two digit Major Group code as Well Pad E, which the parties stipulated was covered under SIC code 1311. Therefore, we find that the first part of the three part regulatory test for treating Well Pad E and the Bodine Compressor Station as a single source is satisfied.[2]

[2] Because we determined that the first part of the test is met based on the SIC code, we are not required to address the Department's alternative argument that the alleged support relationship between the Bodine Compressor Station and Well Pad E can override any SIC code difference. If we were required to do so, we would likely rule against them on this point. The regulatory language is unambiguous in stating that

Common Control

The second part of the three part test that requires separate sources to be under "common control" in order to be aggregated as a single source is expressed in a slightly different manner in the PSD, Title V and NSR regulations. The PSD regulations discuss "all the pollutant-emitting activities which … are under the control of the same person (or persons under common control)." 40 C.F.R. 52.21(b)(6); 25 Pa. Code § 127.83. Title V regulations speak of "sources … which are under common control of the same person (or persons under common control)." 25 Pa. Code § 121.1 (defining "Title V facility"). Finally, the NSR regulations address the issue as sources that are "owned or operated by the same person under common control. *Id.* (defining "facility"). Despite these slight variations in the regulatory language, the second part of the three part test is generally described as requiring a showing that the air contamination sources are under common control.

None of the relevant air permitting regulations provides a specific definition of "control" or "common control" for use in analyzing the second part of the test in a single source determination. In that determination, EPA and DEP rely on the general definition of "control" used by the Securities and Exchange Commission ("SEC") based on EPA's championing of this definition in its 1980 Preamble to the PSD regulations. We are hesitant to support an approach that originates from a regulatory preamble as opposed to a regulation and, furthermore, relies upon a definition from an entirely different regulatory scheme that was clearly not developed to address the same issues as those addressed by the federal Clean Air Act and Pennsylvania's Air

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the first part of the test requires that the pollutant-emitting activities "belong to the same industrial grouping" and "shall be considered as part of the same industrial grouping if they belong to the same 'Major Group' (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, …." 40 C.F.R. § 52.21(b)(6). We do not agree with the Department's position that it can simply ignore the unambiguous language of the regulation and override any differences in SIC code based on an alleged support relationship.

Pollution Control Act. We think the terms "control" and "common control" are sufficiently clear and unambiguous and should be given their plain meaning, guided by the purposes of the air pollution statutes and regulations, when determining whether pollutant-emitting activities are under the control of the same person or persons under common control.

In the 2013 Application Review Memo, the Department determined that the Bodine Compressor Station and Well Pad E satisfied the common control requirement based on several factors: (1) the common ownership of Seneca and Midstream by their parent company, National Fuel Gas Corporation; (2) a contractual agreement between Seneca and Midstream for gas to be sent to the Bodine Compressor Station and (3) a support/dependency relationship between the Bodine Compressor Station and Well Pad E. In the 2015 Re-Evaluation Memo, the Department determined that common control was established as a result of ownership by a common parent company, National Fuel Gas Company. As a result of this determination, the Department found that there was no need to consider the contractual agreement or the potential support/dependency relationship between the Bodine Compressor Station and Well Pad E in the 2015 Re-Evaluation Memo. The permit reviewer, Mr. Twardowski, testified that he was advised by Ms. Joyce Epps of the Department's Central Office that if common control was established by one of the approaches that the Department relies on, there was no need to go any further in analyzing that issue.

Midstream and Seneca both assert that the common control part of the test must focus on whether a common person or entity controls the air contamination sources and/or pollutant-emitting activities. While acknowledging that they are both subsidiaries of a common parent company, they state that there is no evidence that National Fuel Gas Company exercises any control over the sources or pollutant-emitting activities or the day-to-day operations at the

Bodine Compressor Station and/or Well Pad E. They also assert that Midstream and Seneca are distinct legal entities, with their own separate Board of Directors, By-Laws, Officers, etc. that operate independently of National Fuel Gas Company. Therefore, they contend that the Department was incorrect to rely on common ownership by National Fuel Gas Company to find that there is common control of the Bodine Compressor Station and Well Pad E.

In addressing the Department's additional reasoning for finding common control as spelled out in the 2013 Application Review Memo, Midstream and Seneca argue that the Department cannot rely on the fact that there was a contract for services between Midstream and Seneca or the presence of an alleged support/dependency relationship to satisfy the requirement for common control. They note that it appears that the Department abandoned these additional arguments in the 2015 Re-Evaluation Memo. Even if the Department did not abandon the arguments, they assert that the contract between Midstream and Seneca evidences a commercial relationship but not common control of the nature contemplated by the three part test. They also argue that the use of a support/dependency relationship to support common control is neither legally appropriate nor factually supported in this matter.

In looking at the issue of whether there is sufficient common control to allow two separate sources to be treated as a single source, we find that it is important to keep in mind the purposes for which the determination is undertaken by the regulatory agency. The permit at issue in this matter, the GP-5 permit, and the majority of the regulatory programs in play, specifically PSD and nonattainment NSR, authorize, in part, the initial construction of new air contamination sources. The principal purpose of the single source analysis is to determine whether the proposed new air contamination source or sources will qualify as a minor source or a major source based on whether they meet or exceed certain emission thresholds. Midstream and Seneca's principal arguments regarding the common control issue put the focus on the ongoing operations at the Bodine Compressor Station and Well Pad E. We think that such a focus is too narrow when analyzing whether there is common control. The analysis should include the broader issue of who controls or has the ability to control preconstruction and construction decisions as well as who controls or has the ability to control the ongoing operation of the air contamination sources at the Bodine Compressor Station and Well Pad E.

There is no dispute that National Fuel Gas Company owns both Midstream and Seneca. The parties stipulated that Midstream and Seneca are wholly-owned subsidiaries of National Fuel Gas Company. (Jt. Stips. 13 and 18). There is also no dispute that NFG Midstream Trout Run, LLC, the entity that received approval for coverage under the GP-5 permit, is a subsidiary of National Fuel Gas Midstream Corporation and therefore, ultimately, a subsidiary of National Fuel Gas Company. The issue is whether common ownership of Midstream and Seneca by National Fuel Gas Company is sufficient to demonstrate control of the pollutant-emitting activities and/or sources by National Fuel Gas Company. In finding that ownership was enough, the Department in the 2015 Re-Evaluation Memo noted that: "(1) a number of executive officers are shared among the three corporate entities; (2) National Fuel Gas Company's operations are integrated to such an extent that its different branches are more like different sections of one organization, as opposed to entirely separate organizations; and (3) National Fuel Gas Company owns 100% of both Seneca Resources Corporation and NFG Midstream Trout Run, LLC." The Department stated in the 2015 Re-Evaluation Memo that it had concluded that "those corporate relationships fulfill the SEC definition of 'control' and that, consequently, the activities at Bodine and Well Pad E are under common control."

We conclude that the Bodine Compressor Station and Well Pad E are ultimately under the control and/or common control of the same person, specifically National Fuel Gas Company, as those terms are used in the relevant statutes and regulations. National Fuel Gas Company's control arises from its common ownership of Midstream and Seneca. The Oxford Dictionary defines "control" as "the power to influence or direct people's behavior or the course of events." *Control Definition*, Oxford Dictionaries, http://www.oxforddictionaries.com/us/definition/american_english/control (last visited Dec. 14, 2015). While we agree with the Department that there is common control and that this finding arises from the common ownership by National Fuel Gas Company, we caution that it is not the mere presence of a common ownership interest that demonstrates the necessary control. There must be sufficient information to demonstrate that the common owner has the power to influence or direct the behavior of the entities or the course of events that are relevant to the single source determination. Based on the testimony provided at the hearing, we think there is ample evidence that National Fuel Gas Company has the power to influence and/or direct the behavior of Midstream and Seneca and the course of events with regard to the Bodine Compressor Station and Well Pad E.

The testimony in this case makes it evident that National Fuel Gas Company's control of Midstream and Seneca arises at least in part from the power of the purse. The Department called Mr. David Bauer as a witness at the hearing. Mr. Bauer is the Treasurer for National Fuel Gas Company, Midstream and Seneca. He testified extensively about the financial relationship between the three entities. National Fuel Gas Company owns 100% of the stock of Midstream and 100% of the stock of Seneca. Mr. Bauer explained that Midstream and Seneca implement their own budgets, but those budgets are subject to review by himself and Mr. Ron Tanski, National Fuel Gas Company's CEO, at annual meetings with the subsidiaries. The Department questioned Mr. Bauer about whether he and Mr. Tanski had veto power or final say over the budgets of Midstream and Seneca. Mr. Bauer stated that if there are any disagreements with the proposed budgets presented by Midstream and Seneca, he and the President of the subsidiary would reach an understanding on the budget issue and proceed on that basis. In addition to questions about budgets, Mr. Bauer was asked about his role in the selection of projects or capital investments by Seneca and Midstream. Mr. Bauer stated that the process for deciding on which projects to support with capital investments is similar to the budget process. As described by Mr. Bauer, Seneca would develop and submit a business plan to Mr. Bauer and Mr. Tanski for review and based on their assessment of the plan, Mr. Bauer and Mr. Tanski would determine whether National Fuel Gas Company wanted to commit capital to that business. The same process would be followed in reviewing a business plan for Midstream.

It is clear from Mr. Bauer's testimony that National Fuel Gas Company, through the financial arrangements with its subsidiaries, Midstream and Seneca, has the power to influence the behavior and/or course of events of both Midstream and Seneca vis-à-vis the Bodine Compressor Station and Well Pad E. While the issue was not as fully developed as we would have liked, we have no doubt that the initial construction of both Well Pad E and the Bodine Compressor Station, including all of the air contamination sources located at these sites, would have been subject to the budget and business plan process discussed by Mr. Bauer in his testimony. National Fuel Gas Company's ability to influence the preconstruction and construction decisions that are part of the GP-5 permitting and the PSD and NSR programs is the type of control/common control that satisfies the requirements of this part of the three part test. Although the evidence at the hearing demonstrated that National Fuel Gas Company does not take an active role in day-to-day operations, we also believe that based on its involvement with the financial arrangements of Midstream and Seneca, it could play a more active role in those operations if it so chooses. That too would satisfy our understanding of control since it is the possession of the power to influence or direct the behavior of the parties or the course of events, not the actual exercise of that power that satisfies the requirement for common control.[3]

Contiguous/Adjacent

The third part of the single source analysis involves a determination of whether the relevant properties are contiguous or adjacent. Before we address whether the properties are contiguous or adjacent, we think that the first issue we need to resolve is what property or properties we are looking at for this determination. This issue is more complicated in matters involving the oil and gas industry where the property interests rarely involve the type of the relatively compact property interests more typical in the industrial or manufacturing sector. Instead the property interests in oil and gas matters can be divided in multiple ways and frequently involve facilities that are widely spread across the land. While the relevant property interests in this matter were not as complicated as some, in the hearing, we heard testimony regarding 1) DCNR's property interest in the Loyalsock State Forest which is approximately

[3] Because we determined that the second part of the test is met by National Fuel Gas Company's control of Midstream and Seneca through its common ownership, we are not required to address the two other approaches relied on by the Department in its 2013 Application Review Memo. If we were required to do so, we would support the conclusions reached by Mr. Twardowski in his 2015 review in which he reversed his earlier decisions and determined that the contract for service between Midstream and Seneca was not a basis for finding common control based on the specific terms of the contract and that there was not a support/dependency relationship for purposes of common control because the gas from Well Pad E could be sent to a facility other than the Bodine Compressor Station. In general, we are skeptical about the use of these two approaches to demonstrate common control and caution that the Department should look to the specific terms of the contract or the nature of the relationship to find control and not simply rely on the existence of the contract or relationship as appears to have been the case in the 2013 analysis. Any contract terms relied on by the Department should go beyond the standard business arrangements between entities embodied in an arms-length contract. We think the burden is even higher when asserting common control based on a support/dependency relationship because we think these types of relationships are not uncommon in the business world, (i.e. manufacturer and electric supplier) but rarely rise to the level where the type of control exists that we think is required to satisfy this part of the test.

150,000 acres on which both the Bodine Compressor Station and Well Pad E are located; 2) Seneca's Tract 100 leasehold interest that comprises about 10,000 acres of the Loyalsock State Forest on which Well Pad E is located but not the Bodine Compressor Station; 3) a right of way agreement between DCNR and Seneca to allow for the development of the Bodine Compressor Station off of Tract 100; and 4) the fence line and developed area of the Bodine Compressor Station and Well Pad E.

The property interests considered to be the relevant property for the single source determination may very well be determinative of the third part of the three part regulatory test. For instance, if the relevant property is the Loyalsock State Forest, then both the Bodine Compressor Station and Well Pad E are on the same property. According to the Department's post-hearing brief, this is the position that Mr. Twardowski took in his initial 2013 review. The Department next notes in its post-hearing brief that, based on the additional information presented by Midstream, Mr. Twardowski concluded in his 2015 review that the relevant property was Seneca's Tract 100 leasehold where Well Pad E is located. As a result, he determined that the third part of the test was satisfied because the Bodine Compressor Station is on a contiguous DCNR property that is part of the Loyalsock State Forest.

We find the approach advocated by the Department, adopting either the 150,000 acre Loyalsock State Forest or the 10,000 acre Tract 100 leasehold as the relevant property, is problematic. Such an approach is inconsistent with the idea that one should not aggregate sources that do not fit within the ordinary meaning of "building", "structure", "facility" or "installation." Despite advocating this approach in this matter, we note that the Department rejected defining the relevant property so expansively in the 2013 Application Review Memo. In addition to looking at whether Well Pad E should be aggregated with the Bodine Compressor

Station, the Department also considered another Seneca well, Well Pad M. The Department determined that Well Pad M was not contiguous or adjacent because it was approximately two miles away from the proposed location of the Bodine Compressor Station. It reached this conclusion despite the fact that Well Pad M is located on both the Loyalsock State Forest and on the Track 100 leasehold. This clearly undercuts the positions the Department advocates in its post-hearing brief.

We think that in the oil and gas industry in general, and in this particular matter, the proper way to define the relevant property is by the fence line or developed area of the facility under consideration. This approach is consistent with the regulatory language and the purposes of the permitting programs and avoids a result that would allow the aggregation of sources that were many miles apart but located on a single expansive property such as a state forest. In this matter, the Bodine Compressor Station is contained within a security fence and we find that the fenced in area is the relevant property. In the case of Well Pad E, there is no fence around the facility but there is a clearly visible developed area that defines the relevant property area and its boundary (See Seneca Ex. 19).

Having determined the relevant properties in this matter, we turn our attention to determining whether those two properties are contiguous or adjacent. Since the regulations themselves do not define "contiguous" or "adjacent," we find, and the parties all agree, that the common dictionary definitions of the terms apply. The term "contiguous" means "sharing an edge or boundary; touching; or neighboring." (Department's Post-Hearing Brief, p.26) (citing Midstream's Post-Hearing Brief, p.38). Since Well Pad E and the Bodine Compressor Station are separated by intervening DCNR forestland, it is clear that the properties do not share a common edge or boundary and are not touching or neighboring and are therefore not contiguous.

The question of adjacency requires a more rigorous analysis in this case. The parties agree that the term "adjacent" means "close to; lying near; or next to" and we are comfortable with that definition. Keeping the definition in mind, along with the language and purpose of the relevant statutes and regulations, we think the proper focus is on physical proximity and the proper question for the Board is whether the property where the Bodine Compressor Station is located is nearby the Well Pad E property. The determination of whether two properties are nearby is certainly subjective even when guided by the purposes of the statutes and regulations. In order to address that subjectivity, the Department has adopted a quarter-mile "rule of thumb" when determining if properties are "adjacent" for purposes of a single source determination. Under the rule of thumb, the Department states that properties located within a quarter mile are considered adjacent and properties located outside a quarter mile may be considered adjacent on a case-by-case basis.

Despite the position articulated in the Department's post-hearing brief regarding the relevant property, Mr. Twardowski testified that what actually occurred when he was evaluating whether the properties were adjacent was that he used a map to measure a distance of .24 miles from the edge of Well Pad E to the fence line of the Bodine Compressor Station. (T. 61-62). Seneca and Midstream contend that the proper measurement for purposes of adjacency in this case is .3 miles: the distance between the pollutant-emitting activities on Well Pad E and the Bodine Compressor Station. As is evident from these two arguments, one consideration when attempting to apply the Department's rule of thumb is what is the proper endpoint for measurement between the two properties. Seneca and Midstream contend that we should measure the distance between the pollutant-emitting activities on each respective property, while the Department adopts the view that we should measure from the fence line of each property to determine whether the properties are adjacent. When referencing the adjacency part of the three-part test, the relevant PSD regulations reference "pollutant-emitting activities" that are ***"located on one or more contiguous or adjacent properties***." 40 C.F.R. § 52.21(b)(6) (emphasis added). The other regulations use the same language. The particular phrase used by EPA, and adopted in its entirety by DEP, suggests to us that the proper focus is whether the properties are contiguous or adjacent and not the individual "pollutant-emitting activities." Accordingly, we think that the Department's approach regarding measurement is correct and that the proper points for determining the distance in the adjacency analysis are the nearest fence lines of the developed surface properties or, in the absence of fence lines, the nearest edges of the developed surface properties.

We think it is important to articulate that point but our resolution of that issue does not greatly influence our decision in this particular matter. We find it of little consequence whether the resulting measurement is the .24 miles advocated by the Department or the .3 miles advocated by Midstream and Seneca. The Board, of course, is not bound by the Department's rule of thumb and must reach its own determination. It certainly would be useful if the statutes and regulations contained a bright line rule that stated that properties within a certain distance are adjacent and anything outside that distance is not adjacent. Such a bright line rule does not currently exist and, in the end, the Board is left with the task of determining whether these two properties are sufficiently nearby to be considered adjacent as that term is used in the context of single source determinations.

Seneca and Midstream both argue that the intervening land use between Well Pad E and the Bodine Compressor Station should be a factor in our analysis. They contend that the intervening DCNR forestland evidences a lack of adjacency. Furthermore, Seneca and

Midstream assert that the two properties are not adjacent because the intervening topography prevents the Bodine Compressor Station from being visible from Well Pad E. While factors such as intervening land uses and the visibility of one property from another may play a role in looking at the issue of adjacency, they are far from determinative and in this particular matter, we do not think that they are evidence of a lack of adjacency as asserted by Midstream and Seneca. Having looked at the facts in this matter, we conclude that based on physical proximity, the Bodine Compressor Station property is close enough to the Well Pad E property to constitute "adjacent" properties within the general definition of the term.[4] Therefore, we find that the third part of the test for making a single source determination is satisfied.

Common Sense Notion of a Plant

Finally we turn to the issue of whether Well Pad E and the Bodine Compressor Station comport with the common sense notion of a plant. Both Seneca and Midstream contend that a single source determination is improper where the properties and sources involved do not comport with the common sense notion of a plant. They claim that Well Pad E and the Bodine Compressor Station do not comport with a common sense notion of a plant because they do not share "a secure perimeter, security, work rules, coordinated operations, safety requirements, overall management and process equipment that is proximately located and arranged to produce products." (Midstream Ex. 6, p.19). The Department argues that the concept that the sources must satisfy a common sense notion of a plant is not part of any of the relevant regulations and, therefore, cannot trump the three part regulatory test. Instead, the Department suggests that the

[4] Because we determined the adjacency issue based on the physical proximity of the Bodine Compressor Station and Well Pad E, the Board did not consider the functional interrelatedness of those two sources in deciding this matter and makes no decision at this time on whether functional interrelatedness is a proper consideration when trying to determine whether sources are contiguous or adjacent.

common sense notion of a plant can be used to inform the case-by-case analysis of each of the parts of the three part regulatory test.

The idea of the common sense notion of a plant and the language defining that notion arose out of the D.C. Circuit's *Alabama Power* decision in 1980. EPA discussed that idea later that same year in the preamble of its amended PSD regulations stating:

> In EPA's view, the December opinion of the court in *Alabama Power* sets the following boundaries on the definition of PSD for purposes of the component terms of "source": (1) it must carry out reasonably the purposes of PSD; (2) it must approximate a common sense notion of "plant"; and (3) it must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building," "structure," "facility," or "installation."

45 Fed. Reg. 52676, 52694-95 (Aug. 7, 1980). However, as the Department points out, the concept of a common sense notion of a plant never made it directly in to any of the relevant statutes and regulations and is not a specific part of the three part regulatory test.

We remain skeptical about importing concepts and discussion from regulatory preambles and giving them equal weight with the actual language of the properly promulgated regulations.[5] We agree with the Department that the proper way to think about the common sense notion of the plant is in the context of the requirements of each of the three parts of the regulatory test and the overall definition of a stationary source. As discussed above, we have found that Well Pad E and the Bodine Compressor Station are within the same industrial grouping, under common control, and adjacent to each other; therefore, they collectively satisfy the regulatory definition of a "facility." We do not find the fact that the Bodine Compressor Station and Well Pad E fail to share a "secure perimeter, security, work rules, coordinated operations, safety requirements,

[5] We note that each of the parties relied on EPA's 1980 Preamble as support for their actions and positions at different times in this matter. We disfavor an approach to regulatory matters that elevates language from a regulatory preamble to the status of a regulation itself.

overall management and process equipment that is proximately located and arranged to produce products," is a proper basis to override the regulatory criteria. These common characteristics of a plant do not readily translate to the types of facilities found in oil and gas field operations and, therefore, their absence is not particularly meaningful to our understanding of the common sense notion of a plant in this context. Even if we were to elevate the concept of a common sense notion of a plant to a stand-alone test, we think the facts support that the Bodine Compressor Station and Well Pad E satisfy the common sense notion of a plant.

CONCLUSIONS OF LAW

1. The Environmental Hearing Board has jurisdiction over the parties and subject matter of this proceeding. 35 P.S. § 6021.1313.

2. Department actions are reviewed by this Board *de novo*, meaning that the Board is not bound by the Department's determinations and may make its own findings of fact solely on the record before it. *Warren Sand & Gravel Co., v. DER*, 341 A.2d 556 (Pa. Cmwlth. 1975).

3. Seneca and Midstream must prove by a preponderance of the evidence that the Single Source Determination contained in Midstream's GP-5 was unreasonable, unlawful, or not supported by the facts. 25 Pa. Code § 1021.122(a), (c)(3).

4. In order to treat separate sources of air emissions as a single source under the state regulations governing the PSD and Title V permit programs, the Department must establish that those sources: "[1] belong to the same industrial grouping, [2] are located on one or more contiguous or adjacent properties, and [3] are under the control of the same person (or persons under common control)." 40 C.F.R. § 52.21(b)(6); 25 Pa. Code § 121.1.

5. In order to aggregate sources under the nonattainment NSR program, based on the definition of facility, the Department must establish that the sources are located on one or more

contiguous or adjacent properties and are owned or operated by the same person under common control. 25 Pa. Code § 121.1.

6. The Department's Guidance is not a regulation and the Board is not bound to follow it.

7. Well Pad E and the Bodine Compressor Station belong to the "same industrial grouping" because they are both properly identified under Major Group 13 (Oil and Gas Extraction) in the SIC Manual.

8. Well Pad E and the Bodine Compressor Station fall within the common dictionary definition of the term "adjacent."

9. Because Midstream and Seneca are both wholly-owned subsidiaries of National Fuel Gas Corporation and National Fuel Gas Corporation exercises ultimate financial control over both subsidiaries, Midstream and Seneca are under "common control."

10. Well Pad E and the Bodine Compressor Station fit within the common sense notion of a plant to the extent that they collectively fall within the regulatory definition of a "facility."

11. Seneca and Midstream have not met their burden in this appeal by proving by a preponderance of the evidence that the Department's October 10, 2013 issuance of Midstream's GP-5 permit containing the Single Source Determination was unreasonable, unlawful, or not supported by the facts.

12/29/2015

COMMONWEALTH OF PENNSYLVANIA
ENVIRONMENTAL HEARING BOARD

NATIONAL FUEL GAS MIDSTREAM CORPORATION AND NFG MIDSTREAM TROUT RUN, LLC, Appellants, and SENECA RESOURCES CORPORATION, Intervenor	:	
v.	:	**EHB Docket No. 2013-206-B**
COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION	:	

O R D E R

AND NOW, this 29th day of December, 2015, it is hereby ordered that the appeal of National Fuel Gas Midstream Corporation and NFG Midstream Trout Run, LLC is **dismissed.**

ENVIRONMENTAL HEARING BOARD

s/ Thomas W. Renwand
THOMAS W. RENWAND
Chief Judge and Chairman

s/ Michelle A. Coleman
MICHELLE A. COLEMAN
Judge

s/ Bernard A. Labuskes, Jr.
BERNARD A. LABUSKES, JR.
Judge

s/ Richard P. Mather, Sr.
RICHARD P. MATHER, SR.
Judge

s/ Steven C. Beckman
STEVEN C. BECKMAN
Judge

DATED: December 29, 2015

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NATIONAL FUEL GAS MIDSTREAM CORPORATION AND NFG MIDSTREAM TROUT RUN, LLC, Appellants, AND SENECA RESOURCES CORPORATION, Intervenor	:	
v.	:	**EHB Docket No. 2013-206-B**
COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION	:	

CONCURRING OPINION OF
JUDGE BERNARD A. LABUSKES, JR.

The only issue raised in this appeal was whether the Department correctly applied the three-part aggregation test to the facts related to Midstream's Bodine Compressor Station and Seneca's Well Pad E. That is exactly what we have done and I agree with everything in the Adjudication regarding SIC Codes, control, and adjacency. I write separately to highlight a few things that we have not decided given the narrow question that we have allowed the parties to put before us.

First, all of the parties have assumed that the three-part test must be applied rigidly in this case. The Department came the closest to questioning its wooden application when it argued that the "support relationship" between the compressor station and the well pad justified overriding any difference in SIC codes. *If* the test applies, it does not seem to be appropriate to pick and choose among its parts. However, I am not entirely convinced that the Department had no choice but to apply the test in the first place. The ultimate purpose of the test is to assess whether what appears to be separate sources should actually be treated as a single source, and therefore, included in one permit. If it is a single source, it of course follows that all of the emissions should be added up.

Rather than focus exclusively on the three-part test as the parties have done in this case, I think it would have been better to ask the more basic question, which is whether the compressor station and the well pad belong in one permit. Here, I am not sure that they do, and apparently, the Department agrees because only the compressor station is included in the permit coverage that was ultimately approved. Yet, if the station and well pad constitute a single source, I do not understand why only part of the source is included in the permit.

Adding the missing part of the single source, the well pad, to the permit may have been problematic. Well pads benefit from an exemption, and the general permit in question only covers natural gas compression and/or processing facilities. I am not sure how this plays out, but if the two parts of the single source cannot or should not be included in the permit, why are their emissions being aggregated? Either they constitute a single source or they do not.

By including only part of the single source in the permit, the Department has created a rather odd situation. The permittee's activities in general and emissions in particular going forward will now in part be constrained by the emissions and activities of a party that is not subject to or controlled by the permit – Seneca. The third party's emissions and activities are beyond the scope of the permit, yet those emissions and activities directly affect the permittee. Indeed, Seneca, who would otherwise be exempt, is now effectively being regulated indirectly by a permit. The permittee has no direct control over the third party, so the parent of the permittee, which is not a permittee itself, must apparently control the third party for the benefit of the permittee. If the parent does not do that, will the parent be subject to enforcement action? Since the parent is not a permittee, presumably attempting to enforce the permit against it would require piercing the corporate veil, which is very difficult to do. The Department has placed the compressor station and the well pad in the same bubble for a disembodied aggregation analysis but popped that bubble for what really matters – the permit.

If the Department wanted to impose all of the duties and responsibilities that go along with the permit on the corporate parent and/or Seneca, why not include them in the permit? If the Department was not going to include both the compressor station and well pad in one permit in any event, then why aggregate their emissions?

Whether it turned out that the aggregated emissions exceeded the PSD, NNSR, or Title V thresholds or not, the decision on who to include in the permit is distinct from what permitting requirements apply. A single source should be covered by a single permit.

The issue regarding permitting is also distinct from the common control issue addressed in the Adjudication. My point here is that, if common control justifies treating separate industrial activities as a single source for aggregation purposes, it would seem to justify and indeed require that they be treated as a single source for permitting purposes. There is no record here of any other case where the Department has made a positive single-source determination yet issued the permit to cover only part of that source.

I worry that continued application of the three-part test, particularly in cases such as the one presented here where it does not seem to fit, will continue to result in inconsistent, sometimes result-oriented decisions based on strained analyses dependent upon arbitrary distinctions. Among other things, instead of bringing informed judgment to bear on whether multiple emissions should be covered by the same permit, we are forced to engage in a surrealist debate that only lawyers could love about whether there is "adjacency."

The other point I would like to raise is that the Department has very broad discretion under state law to regulate sources to ensure that they employ best available technology (BAT).

35 P.S. § 4006.6(c). BAT applies to "sources." Sources are defined more broadly under state than federal law. For example, an air contamination source can be a "place." 25 Pa. Code §121.1. The Department's discretion in mandating BAT at sources is not necessarily constrained by the never-ending struggle to define single sources under federal law.[1] Today's Adjudication does not address the Department's authority regarding the application of BAT.

Finally, I agree completely with the Department's argument in its post-hearing brief regarding Article I, Section 27 of the Pennsylvania Constitution. Whether or not it is appropriate to treat multiple sources as one "facility" for purposes of permitting, the Department has the authority pursuant to Article I Section 27 of the Pennsylvania Constitution to ensure that the emissions from the permitted source or sources when considered in the context of other nearby sources will not individually or cumulatively have an adverse impact on the people's right to clean air and the preservation of the natural, scenic, historic, and esthetic values of the environment. Regardless of what the complex regulations governing air quality might otherwise require, the Department is obligated to ensure that reasonable efforts have been made to reduce the environmental incursion of the permitted activity to a minimum, and having done that, ensure that the remaining environmental harms do not clearly outweigh the benefits of the project.

So, in light of all of this, was it appropriate to approve Midstream for coverage under the GP-5 permit? As the Department aptly says in its brief, "NFG Midstream did not appeal the Department's issuance of the General Permit 5 authorization to NFG Trout Run. They only appealed the Department's consideration of the emissions from Seneca's Well Pad E."

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[1] Similarly, NSPS, NESHAPs, and RACT typically apply to emitting equipment irrespective of total emissions of the source at which the equipment is located, although there may be thresholds for individual types of equipment. *See generally* 80 FR 56579-92 (Sep. 18, 2015).

ENVIRONMENTAL HEARING BOARD

s/ Bernard A. Labuskes, Jr.
BERNARD A. LABUSKES, JR.
Judge

NATIONAL FUEL GAS MIDSTREAM CORPORATION AND NFG MIDSTREAM TROUT RUN, LLC, Appellants, AND SENECA RESOURCES CORPORATION, Intervenor	:	
v.	:	**EHB Docket No. 2013-206-B**
COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION	:	

CONCURRING OPINION OF JUDGE RICHARD P. MATHER, SR.

I am in agreement with the majority opinion to dismiss the appeal of National Fuel Gas Midstream Corporation and NFG Midstream Trout Run, LLC. The Appellants have not met their burden to prove that the issuance of Midstream's GP-5 permit containing the Single Source Determination was unreasonable, unlawful or not supported by the facts. Overall, I agree with the vast majority of the discussion in the majority opinion, however, there is one point of caution that I should mention, even though it does not affect my agreement with the majority opinion to dismiss the appeal.

In its majority opinion, the Board rejects the Department's contention that the Board owes deference to the Department's interpretations of the statutes and regulations. In support of this conclusion, the majority opinion generally asserts: "As is evident by varying interpretations of the regulations and the three-part test that the Department relied on in this matter (i.e. the inconsistencies in the approach between the 2013 Application Review Memo and the 2015 Re-Evaluation Memo, the conflicting testimony of various Department officials during the hearing, and the various approaches to this issue advocated in other single source determinations that have come before the Board), the Department has not consistently applied the regulations and there is no settled approach by the Department to which we owe deference." Adjudication at

E-FILED 12/29/2015 PENNSYLVANIA ENVIRONMENTAL HEARING BOARD

page 18. While I am in full agreement with the legal position that the Department is not entitled to deference for its interpretation of a particular regulation where the Department's interpretation of that particular regulation has changed or varied over time, *Pennsylvania School Boards Ass'n, Inc., v. Public School Retirement Board*, 863 A.2d 432 (Pa. 2004) (New interpretation is an abrupt change from prior interpretation and is not entitled to deference) cited in *Rag Cumberland Resources, LP v. Dep't. of Envtl. Prot*., 869 A.2d 1065, 1072, n. 11 (Pa. Cmwlth. 2005.), I raise a cautionary note about the Board's deference discussion for three reasons.

First, the Board's opinion fails to identify any specific Department regulations, any specific Department interpretations of those regulations and any variations or changes in those interpretations. The Board only states that the Department has not "consistently applied the [unidentified] regulations" as the reason to reject the Department's request for deference. I believe more specificity is needed to evaluate a Department claim for deference.

My review of the Department's Post-Hearing Brief indicates that the Department requested deference from the Board regarding its interpretation of the regulatory provisions that establish the "common control" criteria.[2] These regulatory criteria are described in the Department's 2012 Guidance for Performing Single Stationary Source Determinations for Oil and Gas Industries, Document Number 270-0810-006 ("2012 Single Source Guidance"). My review of the Department's 2013 Review memo and the 2015 Re-Evaluation memo on the issue of "common control" does not reveal the Department changed or varied its interpretation of the regulatory criteria establishing "common control." In the 2013 Review memo, the Department

[2] The "common control" criteria is set forth in three different regulations and is applicable in the context of three distinct air quality regulatory programs: Non-Attainment New Source Program and 25 Pa. Code § 121.1 (definition of "air contamination source"), Title V Permitting Program (definition of "facility") and Prevention of Significant Deterioration Program (25 Pa. Code § 127.83 adopting by reference 40 C.F.R. § 52.21(b)(6)).

considered all three bases to establish common control.[3] In the 2015 Re-Evaluation memo the Department simply considered the first basis, ownership, and declined to evaluate the last two bases. I don't believe that this evidence supports a finding that the Department's interpretation of several related regulations containing the "common control" criteria has changed or varied since 2012 when the Department adopted the 2012 Single Source Guidance. 2012 is the critical date when the Department announced its interpretations.

Second, the 2012 Single Source Guidance was adopted by the Department following a public notice and comment period. In 2011, the Department adopted the Single Source Guidance as Interim Final Technical Guidance and published a notice in the Pennsylvania Bulletin in which it requested public comments. 41 Pa. B. 5719 (October 22, 2011). The Department received comments from 366 commentators.[4] Following its review of the comments, the Department adopted the Final Single Source Guidance on October 6, 2012. This Guidance, among other things, contains the Department's interpretations of several regulatory requirements including the three related regulations containing the "common control" criteria. Under the Pennsylvania Commonwealth Documents Law and regulations promulgated by the Joint Committee on Documents, the Department is entitled to set forth regulatory interpretations in guidance documents or statements of policies. See 45 P.S. § 1102; 45 Pa. C.S.A. § 1102; and 25 Pa. Code § 1.4 (definitions of "statement of policy," "guideline" and "interpretations"). I believe that such interpretations are entitled to deference, if one of the exceptions to deference is

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[3] In the 2012 Single Source Guidance, the Department identified three ways to establish common control: 1) ownership, 2) decision-making authority, and 3) support/dependency relationship. Single Source Guidance at page 7.

[4] http://www.portal.state.pa.us/portal/server.pt/document/1424441/aggregation_policy_comment_and_response_document_10-6-2012_pdf_(2)

not applicable.[5] Guidance documents, such as the 2012 Single Source Guidance, that are adopted after a public notice and comment period provide the public and regulated community with advanced notice of a Department regulatory interpretation. The public process whereby the Department announced its regulatory interpretation in the 2012 Single Source Guidance enhances its claim for deference in my view.

Finally, I am hesitant to start down a path of evaluating whether to give deference to Department interpretations of regulations in a general, non-specific manner. Such an approach is similar to an approach suggested by the Department in other matters before the Board to give broad deference to Department decisions applying various regulations, which the Board has already rejected. *Wilson v. DEP*, EHB Docket No. 2013-192-M (Consolidated with 2013-200-M), (Opinion, Aug. 31, 2015). As the Board said in *Wilson v. DEP*:

> To be entitled to deference for a regulatory interpretation, the Department needs to specifically identify the regulatory language in question, and then the Department needs to specifically identify the regulatory interpretation of the specified language. At that point, the Board will be able to determine whether the Department's interpretation is entitled to deference. Deference for a regulatory interpretation is not a blanket to pull over any and all decisions that the Department might make when applying various regulations to a particular situation.

Wilson v. DEP, slip op. at 70. Deference is a question that should be evaluated in the context of a particular regulation and a specific Department interpretation of that identified regulatory language. Here, the Department has identified the regulations containing the "common control"

[5] The Department's reasonable interpretation of the environmental regulations it implements is, as a general rule, entitled to great deference. *Tire Jockey Service, Inc. v. DEP*, 915 A.2d 1165, 1190 (Pa. 2007); *DEP v. North American Refractories Company*, 791 A.2d 461, 466 (Pa. Cmwlth. 2002). There are exceptions to the general rule. For example, an agency's interpretation of a statutory or regulatory provision is not entitled to deference if the interpretation is simply developed in anticipation of litigation or if the interpretation is an abrupt change from an earlier interpretation of the provision. *See e.g., Malt Beverages Distributors Ass'n v. Pa Liquor Control Board.*, 974 A.2d 1144, 1154 (Pa. 2009) (Interpretation developed in anticipation of litigation is not entitled to deference).

criteria and provided an interpretation in its 2012 Single Source Guidance. The Board should have evaluated the Department's request for deference in the context of these specific items.

Notwithstanding my concerns with the Board's discussion of deference to the Department's regulatory interpretations, the Board's opinion reached the same conclusion as the Department regarding application of the "common control" criteria to support the correct decision to dismiss the appeal. I therefore concur with the Board's adjudication, with the limited exception of this discussion about deference to the Department's regulatory interpretation.

ENVIRONMENTAL HEARING BOARD

s/ Richard P. Mather, Sr.
RICHARD P. MATHER, SR.
Judge

Attachment 4

Brunswick Natural Gas - Sulfur Testing

Month-Yr	Date Sampled	Sulfur Content (gr/100 scf)	12-Month Rolling Average* (gr/100 scf)
Nov-15	11/17/2015	0.076	NA
Dec-15	12/8/2015	0.231	NA
Jan-16	1/12/2016	0.1881	NA
Feb-16	2/3/2016	0.429	NA
Mar-16	3/1/2016	0.2112	NA
Apr-16	4/14/2016	0.2244	NA
May-16			NA
Jun-16			NA
Jul-16			NA
Aug-16			NA
Sep-16			NA
Oct-16			0.227
Nov-16			0.257
Dec-16			0.263
Jan-17			0.288
Feb-17			0.218
Mar-17			
Apr-17			

*Condition 9 of the May 13, 2015 PSD permit limits the gas sulfur content to 0.4 gr/100 scf on a 12-month rolling average basis.

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DOMINION VA POWER-FREEMAN
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Report Number : 13071- 153936
Date Reported: 11/24/2015
Date Received: 11/19/2015

Analytical Report

Sample No.: 153936-001 Sample ID Fuel Gas Supply Brunswick County Power Sta. **Date Sampled 11/17/2015 11:15:00 AM**

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Oxygen	0.01	Mol %	GP2261ASTM1945	11/20/2015	KTN
Nitrogen	0.74	Mol %			
Carbon Dioxide	0.31	Mol %			
Methane	94.21	Mol %			
Ethane	4.36	Mol %			
Propane	0.29	Mol %			
Isobutane	0.02	Mol %			
n-Butane	0.03	Mol %			
Isopentane	0.01	Mol %			
n-Pentane	0.01	Mol %			
Hexanes Plus	0.01	Mol %			
Total	100.00	Mol %			
Molar Mass Ratio	0.58531		GP2172ASTM3588		
Relative Density	0.58635				
Compressibility Factor	0.99781				
Gross Heating Value (Dry)	1038.9	BTU/CF (Ideal)			
Gross Heating Value (Dry)	1041.2	BTU/CF (Real)			
Net Heating Value (Dry)	936.8	BTU/CF (Ideal)			
Net Heating Value (Dry)	938.8	BTU/CF (Real)			
Pressure Base	14.696	psia			
Sulfur, Total Volatile	2.3	mg/kg	ASTM D-6667	11/20/2015	CB
Sulfur, Total Volatile	0.076	gr/100SCF	ASTM D-6667	11/20/2015	CB

Approved By:______________________________

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Laboratory Supervisor

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Report Number : 13071- 154159
Date Reported: 12/15/2015
Date Received: 12/10/2015

Analytical Report

Sample No.: 154159-001 Sample ID Natural Gas **Date Sampled 12/8/2015 1:15:00 PM**

Brunswick County Power Sta.

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Oxygen	0.01	Mol %	GP2261ASTM1945	12/14/2015	KTN
Nitrogen	0.72	Mol %			
Carbon Dioxide	0.30	Mol %			
Methane	94.22	Mol %			
Ethane	4.35	Mol %			
Propane	0.30	Mol %			
Isobutane	0.02	Mol %			
n-Butane	0.04	Mol %			
Isopentane	0.01	Mol %			
n-Pentane	0.01	Mol %			
Hexanes Plus	0.02	Mol %			
Total	100.00	Mol %			
Molar Mass Ratio	0.58558		GP2172ASTM3588		
Relative Density	0.58663				
Compressibility Factor	0.99781				
Gross Heating Value (Dry)	1039.9	BTU/CF (Ideal)			
Gross Heating Value (Dry)	1042.2	BTU/CF (Real)			
Net Heating Value (Dry)	937.7	BTU/CF (Ideal)			
Net Heating Value (Dry)	939.8	BTU/CF (Real)			
Pressure Base	14.696	psia			
Sulfur, Total Volatile	7.0	mg/kg	ASTM D-6667	12/15/2015	CB
Sulfur, Total Volatile	0.231	Gr/100SCF	ASTM D-6667	12/15/2015	CB

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Report Number : 13071- 160098
Date Reported: 1/15/2016
Date Received: 1/12/2016

Analytical Report

Sample No.: 160098-001 Sample ID Natural Gas **Date Sampled 1/7/2016 1:07:00 PM**
Brunswick County Power Station

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Oxygen	0.01	Mol %	GP2261ASTM1945	1/12/2016	KTN
Nitrogen	0.56	Mol %			
Carbon Dioxide	0.29	Mol %			
Methane	93.57	Mol %			
Ethane	5.07	Mol %			
Propane	0.39	Mol %			
Isobutane	0.03	Mol %			
n-Butane	0.05	Mol %			
Isopentane	0.01	Mol %			
n-Pentane	0.01	Mol %			
Hexanes Plus	0.01	Mol %			
Total	100.00	Mol %			
Molar Mass Ratio	0.58921		GP2172ASTM3588		
Relative Density	0.59029				
Compressibility Factor	0.99776				
Gross Heating Value (Dry)	1048.5	BTU/CF (Ideal)			
Gross Heating Value (Dry)	1050.9	BTU/CF (Real)			
Net Heating Value (Dry)	945.7	BTU/CF (Ideal)			
Net Heating Value (Dry)	947.8	BTU/CF (Real)			
Pressure Base	14.696	psia			
Sulfur, Total Volatile	0.1881	Gr / 100 SCF	ASTM D-6667	1/13/2016	CB

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Report Number : 13071- 160405
Date Reported: 2/12/2016
Date Received: 2/5/2016

Analytical Report

Sample No.: 160405-001 Sample ID Natural Gas 2-3-16 @ 13:15 Date Sampled
Brunswick County Power Station

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Oxygen	0.01	Mol %	GP2261ASTM1945	2/11/2016	TC
Nitrogen	0.57	Mol %			
Carbon Dioxide	1.08	Mol %			
Methane	94.30	Mol %			
Ethane	3.64	Mol %			
Propane	0.27	Mol %			
Isobutane	0.04	Mol %			
n-Butane	0.04	Mol %			
Isopentane	0.01	Mol %			
n-Pentane	0.01	Mol %			
Hexanes Plus	0.03	Mol %			
Total	100.00	Mol %			
Molar Mass Ratio	0.58932		GP2172ASTM3588		
Relative Density	0.59037				
Compressibility Factor	0.99781				
Gross Heating Value (Dry)	1028.6	BTU/CF (Ideal)			
Gross Heating Value (Dry)	1030.8	BTU/CF (Real)			
Net Heating Value (Dry)	927.3	BTU/CF (Ideal)			
Net Heating Value (Dry)	929.3	BTU/CF (Real)			
Pressure Base	14.696	psia			
Sulfur, Total Volatile	13	mg/kg	ASTM D-6667	2/9/2016	CB
Sulfur, Total Volatile	0.429	Gr / 100 SCF	ASTM D-6667	2/9/2016	CB

Approved By:____________________________

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Report Number : 13071- 160694
Date Reported: 3/8/2016
Date Received: 3/3/2016

Analytical Report

Sample No.: 160694-002 Sample ID Natural Gas 3/1/16 @ 09:12 Brunswick County **Date Sampled**

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Oxygen	0.01	Mol %	GP2261ASTM1945	3/4/2016	KTN
Nitrogen	0.43	Mol %			
Carbon Dioxide	0.27	Mol %			
Methane	92.95	Mol %			
Ethane	5.65	Mol %			
Propane	0.53	Mol %			
Isobutane	0.04	Mol %			
n-Butane	0.08	Mol %			
Isopentane	0.01	Mol %			
n-Pentane	0.01	Mol %			
Hexanes Plus	0.02	Mol %			
Total	100.00	Mol %			
Molar Mass Ratio	0.59349		GP2172ASTM3588		
Relative Density	0.59461				
Compressibility Factor	0.99772				
Gross Heating Value (Dry)	1057.8	BTU/CF (Ideal)			
Gross Heating Value (Dry)	1060.3	BTU/CF (Real)			
Net Heating Value (Dry)	954.3	BTU/CF (Ideal)			
Net Heating Value (Dry)	956.5	BTU/CF (Real)			
Pressure Base	14.696	psia			
Sulfur, Total Volatile	6.4	mg/kg	ASTM D-6667	3/3/2016	CB
Sulfur, Total Volatile	0.2112	Gr / 100 SCF	ASTM D-6667	3/3/2016	CB

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Report Number : 13071- 161186
Date Reported: 4/19/2016
Date Received: 4/14/2016

Analytical Report

Sample No.: 161186-001 Sample ID Natural Gas 4-11-16 @ 3:35 Brunswick County Power Sta. **Date Sampled**

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Oxygen	0.01	Mol %	GP2261ASTM1945	4/16/2016	KTN
Nitrogen	0.44	Mol %			
Carbon Dioxide	0.25	Mol %			
Methane	92.48	Mol %			
Ethane	6.31	Mol %			
Propane	0.39	Mol %			
Isobutane	0.04	Mol %			
n-Butane	0.05	Mol %			
Isopentane	0.01	Mol %			
n-Pentane	0.01	Mol %			
Hexanes Plus	0.01	Mol %			
Total	100.00	Mol %			
Molar Mass Ratio	0.59448		GP2172ASTM3588		
Relative Density	0.59560				
Compressibility Factor	0.99771				
Gross Heating Value (Dry)	1059.8	BTU/CF (Ideal)			
Gross Heating Value (Dry)	1062.2	BTU/CF (Real)			
Net Heating Value (Dry)	956.1	BTU/CF (Ideal)			
Net Heating Value (Dry)	958.3	BTU/CF (Real)			
Pressure Base	14.696	psia			
Sulfur, Total Volatile	6.8	mg/kg	ASTM D-6667	4/15/2016	CB
Sulfur, Total Volatile	0.2244	Gr / 100 SCF	ASTM D-6667	4/15/2016	CB

Approved By:______________________________

Pat Gideons
Laboratory Supervisor

Attachment 5

Table B-13 Hazardous Air Pollutant Emissions

Combustion Turbines

Number of Units:	3	
Maximum Heat Input - CT Gas	3,227	MMBtu/hr (HHV)
Maximum Heat Input - Duct Burner	500	MMBtu/hr (HHV)
Operating Hours, CT on NG with Duct Burner	8,760	hr/yr/CT
Operating Hours, NG - No Duct Burner	8,760	hr/yr

Natural Gas Heating Value: 1,020 Btu/scf (HHV)

VOHAP Efficiency: **35% reduction**

Auxiliary Boilers

Number of Units:	1	
Maximum Heat Input, NG	185.0	MMBtu/hr
Operating Hours, NG	876	hr/yr

Fuel Gas Heaters

	Line 1	Line 2	
Number of Units:	3	3	
Maximum Heat Input	16.1	7.8	MMBtu/hr
Operating Hours	8,760	8,760	hr/yr

Emergency Firewater Pump

Number of Units:	1	
Maximum Heat Input	2.54	MMBtu/hr
Operating Hours	500	hr/yr

Emergency Generator

Number of Units:	1	
Maximum Heat Input	28.8	MMBtu/hr
Operating Hours	500	hr/yr

Propane Emergency Generator

Number of Units:	2	
Maximum Heat Input	1.8	MMBtu/hr
Operating Hours	500	hr/yr

Pollutant	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas	Emission Factor AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion		Emission Factor AP-42 Section Natural Gas Fired 4-Stroke Rich Burn Engines	Emission Factor AP-42 Section 3.3 04/00 - Gasoline and Diesel Industrial Engines (up to	Emission Factor AP-42 Section 3.4 04/00 - Large Stationary Diesel Engines (> 600 HP)	Combustion Turbine Emissions, Emission Rate, 1 Turbine		Auxiliary Boiler Emissions, Emission Rate, 1 Boiler		Fuel Gas Heater Line 1, Emission Rate, 1 Boiler		Fuel Gas Heater Line 2, Emission Rate, 1 Boiler		Emergency Firewater Pump, Emission Rate, 1 Firewater Pump		Emergency Generator, Emission Rate, 1 Generator		Propane Emergency Generator, Emission Rate, 1 Generator		Total - New Sources, Emission Rate, Total	
							Maximum Hourly[b]	Annual[c]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly	Annual
	(lb/MMBtu)	(lb/10^6scf)	(lb/MMBtu)[a]	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
1,1,2,2-Tetrachloroethane				2.53E-05															4.51E-05	1.13E-05	9.02E-05	2.26E-05
1,1,1-Trichloroethane																					0.00E+00	0.00E+00
1,1,2-Trichloroethane				1.53E-05															2.73E-05	6.82E-06	5.46E-05	1.36E-05
1,3-Dichloropropene				1.27E-05															2.26E-05	5.66E-06	4.53E-05	1.13E-05
1,3-Butadiene	4.30E-07			6.63E-04	3.91E-05		9.02E-04	3.95E-03							9.92E-05	2.48E-05			1.18E-03	2.95E-04	5.17E-03	1.25E-02
2-Methylnaphthalene		2.40E-05	2.35E-08				7.65E-06	3.35E-05	4.35E-06	1.91E-06	3.78E-07	1.66E-06	1.84E-07	8.05E-07							2.90E-05	1.10E-04
3-Methylchloranthrene		1.80E-06	1.76E-09				5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08							2.17E-06	8.23E-06
7,12-Dimethylbenz(a)anthracene		1.60E-05	1.57E-08				5.10E-06	2.23E-05	2.90E-06	1.27E-06	2.52E-07	1.10E-06	1.23E-07	5.37E-07							1.93E-05	7.32E-05
Acenaphthene		1.80E-06	1.76E-09		1.42E-06	4.68E-06	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	3.60E-06	9.01E-07	1.35E-04	3.37E-05			1.40E-04	4.28E-05
Acenaphthylene		1.80E-06	1.76E-09		5.06E-06	9.23E-06	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	1.28E-05	3.21E-06	2.66E-04	6.64E-05			2.81E-04	7.79E-05
Acetaldehyde	4.00E-05			2.79E-03	7.67E-04	2.52E-05	8.39E-02	3.68E-01							1.95E-03	4.87E-04	7.25E-04	1.81E-04	4.97E-03	1.24E-03	2.64E-01	1.11E+00
Acrolein	6.40E-06			2.63E-03	9.25E-05	7.88E-06	1.34E-02	5.88E-02							2.35E-04	5.87E-05	2.27E-04	5.67E-05	4.69E-03	1.17E-03	5.01E-02	1.79E-01
Anthracene		2.40E-06	2.35E-09		1.87E-06	1.23E-06	7.65E-07	3.35E-06	4.35E-07	1.91E-07	3.78E-08	1.66E-07	1.84E-08	8.05E-08	4.75E-06	1.19E-06	3.54E-05	8.85E-06			4.30E-05	2.10E-05
Benz(a)anthracene		1.80E-06	1.76E-09		1.68E-06	6.22E-07	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	4.26E-06	1.07E-06	1.79E-05	4.48E-06			2.43E-05	1.38E-05
Benzene	1.20E-05	2.10E-03	2.06E-06	1.58E-03	9.33E-04	7.76E-04	2.58E-02	1.13E-01	3.81E-04	1.67E-04	3.31E-05	1.45E-04	1.61E-05	7.04E-05	2.37E-03	5.92E-04	2.23E-02	5.58E-03	2.82E-03	7.04E-04	1.08E-01	3.48E-01
Benzo(a)pyrene		1.20E-06	1.18E-09		1.88E-07	2.57E-07	3.82E-07	1.67E-06	2.18E-07	9.53E-08	1.89E-08	8.28E-08	9.19E-09	4.03E-08	4.77E-07	1.19E-07	7.40E-06	1.85E-06			9.32E-06	7.46E-06
Benzo(b)flouoranthene		1.80E-06	1.76E-09		9.91E-08	1.11E-06	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	2.52E-07	6.29E-08	3.19E-05	7.99E-06			3.44E-05	1.63E-05
Benzo(g,h,l)perylene		1.20E-06	1.18E-09			5.56E-07	3.82E-07	1.67E-06	2.18E-07	9.53E-08	1.89E-08	8.28E-08	9.19E-09	4.03E-08			1.60E-05	4.00E-06			1.75E-05	9.49E-06
Benzo(k)fluoranthene		1.80E-06	1.76E-09		1.55E-07	2.18E-07	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	3.93E-07	9.83E-08	6.27E-06	1.57E-06			8.84E-06	9.90E-06
Carbon Tetrachloride				1.77E-05															3.16E-05	7.89E-06	6.31E-05	1.58E-05
Chlorobenzene				1.29E-05															2.30E-05	5.75E-06	4.60E-05	1.15E-05
Chloroform				1.37E-05															2.44E-05	6.11E-06	4.88E-05	1.22E-05
Chrysene		1.80E-06	1.76E-09		3.53E-07	1.53E-06	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	8.96E-07	2.24E-07	4.40E-05	1.10E-05			4.71E-05	1.95E-05
Dibenzo(a,h)anthracene		1.20E-06	1.18E-09		5.83E-07	3.46E-07	3.82E-07	1.67E-06	2.18E-07	9.53E-08	1.89E-08	8.28E-08	9.19E-09	4.03E-08	1.48E-06	3.70E-07	9.96E-06	2.49E-06			1.29E-05	8.35E-06
Dichlorobenzene		1.20E-03	1.18E-06				3.82E-04	1.67E-03	2.18E-04	9.53E-05	1.89E-05	8.28E-05	9.19E-06	4.03E-05							1.45E-03	5.49E-03
Ethylbenzene	3.20E-05			2.48E-05			6.71E-02	2.94E-01											4.42E-05	1.11E-05	2.01E-01	8.82E-01
Ethylene Dibromide				2.13E-05															3.80E-05	9.49E-06	7.59E-05	1.90E-05
Fluoranthene		3.00E-06	2.94E-09		7.61E-06	4.03E-06	9.56E-07	4.19E-06	5.44E-07	2.38E-07	4.73E-08	2.07E-07	2.30E-08	1.01E-07	1.93E-05	4.83E-06	1.16E-04	2.90E-05			1.39E-04	4.75E-05
Fluorene		2.80E-06	2.75E-09		2.92E-05	1.28E-05	8.92E-07	3.91E-06	5.08E-07	2.22E-07	4.41E-08	1.93E-07	2.14E-08	9.39E-08	7.41E-05	1.85E-05	3.68E-04	9.21E-05			4.46E-04	1.23E-04
Formaldehyde [f]	2.20E-04	7.50E-02	7.35E-05	2.05E-02	1.18E-03	7.89E-05	4.85E-01	2.13E+00	1.36E-02	5.96E-03	1.18E-03	5.18E-03	5.74E-04	2.52E-03	2.99E-03	7.49E-04	2.27E-03	5.68E-04	3.65E-02	9.14E-03	1.55E+00	6.43E+00
Hexane (<10 MMBtu/hr) [g]		6.30E-03	6.18E-06						1.14E-03	5.00E-04	9.93E-05	4.35E-04	4.83E-05	2.11E-04							1.59E-03	2.44E-03
Hexane (>100 MMBtu/hr) [g]		1.30E-03	1.27E-06				4.14E-04	1.81E-03	2.36E-04	1.03E-04											1.48E-03	5.55E-03
Indeno(1,2,3-cd)pyrene		1.80E-06	1.76E-09		3.75E-07	4.14E-07	5.74E-07	2.51E-06	3.26E-07	1.43E-07	2.84E-08	1.24E-07	1.38E-08	6.04E-08	9.52E-07	2.38E-07	1.19E-05	2.98E-06			1.50E-05	1.14E-05
Methanol				3.06E-03															5.46E-03	1.36E-03	1.09E-02	2.73E-03
Methylene Chloride				4.12E-05															7.34E-05	1.84E-05	1.47E-04	3.67E-05
Naphthalene	1.30E-06	6.10E-04	5.98E-07	9.71E-05	8.48E-05	1.3E-04	2.92E-03	1.28E-02	1.11E-04	4.85E-05	9.61E-06	4.21E-05	4.67E-06	2.05E-05	2.15E-04	5.38E-05	3.74E-03	9.35E-04	1.73E-04	4.33E-05	1.32E-02	3.97E-02
PAHs	2.20E-06			1.41E-04			4.61E-03	2.02E-02											2.51E-04	6.28E-05	1.43E-02	6.08E-02
Phenanathrene		1.70E-05	1.67E-08		2.94E-05	4.08E-05	5.42E-06	2.37E-05	3.08E-06	1.35E-06	2.68E-07	1.17E-06	1.30E-07	5.70E-07	7.46E-05	1.87E-05	1.17E-03	2.94E-04			1.27E-03	3.90E-04
Propylene Oxide	2.90E-05						6.08E-02	2.66E-01													1.82E-01	7.99E-01
Pyrene		5.00E-06	4.90E-09		4.78E-06	3.71E-06	1.59E-06	6.98E-06	9.07E-07	3.97E-07	7.88E-08	3.45E-07	3.83E-08	1.68E-07	1.21E-05	3.03E-06	1.07E-04	2.67E-05			1.25E-04	5.26E-05
Styrene				1.19E-05															2.12E-05	5.30E-06	4.24E-05	1.06E-05
Toluene	1.30E-04	3.40E-03	3.33E-06	5.58E-04	4.09E-04	2.81E-04	2.74E-01	1.20E+00	6.17E-04	2.70E-04	5.36E-05	2.35E-04	2.60E-05	1.14E-04	1.04E-03	2.60E-04	8.09E-03	2.02E-03	9.95E-04	2.49E-04	8.33E-01	3.60E+00
Vinyl Chloride				7.18E-06															1.28E-05	3.20E-06	2.56E-05	6.40E-06
Xylene	6.40E-05				2.85E-04	1.93E-04	1.34E-01	5.88E-01							7.23E-04	1.81E-04	5.55E-03	1.39E-03			4.09E-01	1.77E+00

Table B-13 Hazardous Air Pollutant Emissions

Combustion Turbines

Number of Units:	3	
Maximum Heat Input - CT Gas	3,227	MMBtu/hr (HHV)
Maximum Heat Input - Duct Burner	500	MMBtu/hr (HHV)
Operating Hours, CT on NG with Duct Burner	8,760	hr/yr/CT
Operating Hours, NG - No Duct Burner	8,760	hr/yr

Natural Gas Heating Value: 1,020 Btu/scf (HHV)

VOHAP Efficiency: 35% reduction

Auxiliary Boilers

Number of Units:	1	
Maximum Heat Input, NG	185.0	MMBtu/hr
Operating Hours, NG	876	hr/yr

Fuel Gas Heaters

	Line 1	Line 2	
Number of Units:	3	3	
Maximum Heat Input	16.1	7.8	MMBtu/hr
Operating Hours	8,760	8,760	hr/yr

Emergency Firewater Pump

Number of Units:	1	
Maximum Heat Input	2.54	MMBtu/hr
Operating Hours	500	hr/yr

Emergency Generator

Number of Units:	1	
Maximum Heat Input	28.8	MMBtu/hr
Operating Hours	500	hr/yr

Propane Emergency Generator

Number of Units:	2	
Maximum Heat Input	1.8	MMBtu/hr
Operating Hours	500	hr/yr

							Combustion Turbine Emissions		Auxiliary Boiler Emissions		Fuel Gas Heater Line 1		Fuel Gas Heater Line 2		Emergency Firewater Pump		Emergency Generator		Propane Emergency Generator		Total - New Sources	
Pollutant	Emission Factor	Emission Factor		Emission Factor	Emission Factor	Emission Factor	Emission Rate, 1 Turbine		Emission Rate, 1 Boiler		Emission Rate, 1 Boiler		Emission Rate, 1 Boiler		Emission Rate, 1 Firewater Pump		Emission Rate, 1 Generator		Emission Rate, 1 Generator		Emission Rate, Total	
	AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas	AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion		AP-42 Section Natural Gas Fired 4-Stroke Rich Burn Engines	AP-42 Section 3.3 04/00 - Gasoline and Diesel Industrial Engines (up to	AP-42 Section 3.4 04/00 - Large Stationary Diesel Engines (> 600 HP)	Maximum Hourly[b]	Annual[c]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly	Annual
	(lb/MMBtu)	(lb/10^{6}scf)	(lb/MMBtu)[a]	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Arsenic [h]		2.00E-04	1.96E-07				7.31E-04	3.20E-03	3.63E-05	1.59E-05	3.15E-06	1.38E-05	1.53E-06	6.71E-06							2.24E-03	9.68E-03
Beryllium [h]		1.20E-05	1.18E-08				4.38E-05	1.92E-04	2.18E-06	9.53E-07	1.89E-07	8.28E-07	9.19E-08	4.03E-07							1.35E-04	5.81E-04
Cadmium [h]		1.10E-03	1.08E-06				4.02E-03	1.76E-02	2.00E-04	8.74E-05	1.73E-05	7.59E-05	8.42E-06	3.69E-05							1.23E-02	5.32E-02
Chromium [h]		1.40E-03	1.37E-06				5.12E-03	2.24E-02	2.54E-04	1.11E-04	2.21E-05	9.66E-05	1.07E-05	4.70E-05							1.57E-02	6.78E-02
Cobalt [h]		8.40E-05	8.24E-08				3.07E-04	1.34E-03	1.52E-05	6.67E-06	1.32E-06	5.80E-06	6.43E-07	2.82E-06							9.42E-04	4.07E-03
Lead [h]		5.00E-04	4.90E-07		9.00E-06	9.00E-06	1.83E-03	8.00E-03	9.07E-05	3.97E-05	7.88E-06	3.45E-05	3.83E-06	1.68E-05	2.28E-05	5.71E-06	2.59E-04	6.48E-05			5.89E-03	2.43E-02
Manganese [h]		3.80E-04	3.73E-07				1.39E-03	6.08E-03	6.89E-05	3.02E-05	5.99E-06	2.62E-05	2.91E-06	1.27E-05							4.26E-03	1.84E-02
Mercury [h]		2.60E-04	2.55E-07				9.50E-04	4.16E-03	4.72E-05	2.07E-05	4.10E-06	1.79E-05	1.99E-06	8.72E-06							2.92E-03	1.26E-02
Nickel [h]		2.10E-03	2.06E-06				7.67E-03	3.36E-02	3.81E-04	1.67E-04	3.31E-05	1.45E-04	1.61E-05	7.04E-05							2.35E-02	1.02E-01
Selenium [h]		2.40E-05	2.35E-08				8.77E-05	3.84E-04	4.35E-06	1.91E-06	3.78E-07	1.66E-06	1.84E-07	8.05E-07							2.69E-04	1.16E-03
																				Total HAPs (tpy)	15.53	
																				Max. Single HAP (tpy)	6.43	

Notes:

(a) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf)

(b) For Turbines firing natural gas, Hourly Emission Rate (lb/hr) = [Max Heat Input - CT (MMBtu/hr) * Emission Factor - CT (lb/MMBtu) + Max Heat Input - DB (MMBtu/hr) * Emission Factor - non-CT (lb/MMBtu)] * (1 - % VOHAP Efficiency)

(c) For Turbines firing natural gas, Annual Emission Rate (tpy) = [Max Heat Input - CT (MMBtu/Hr) * 8760 hr/yr * Emission Factor - CT Natural Gas (lb/MMBtu) + Max Heat Input - DB (MMBtu/Hr) * Operating Hours - DB (hr/yr) * Emission Factor - non-CT (lb/MMBtu)] / (2,000 lb/ton) * (1 - % VOHAP Efficiency)

(d) For Boiler/Heaters/Engines, Hourly Emission Rate (lb/hr) = Max Heat Input (MMBtu/Hr) * Emission Factor - non-CT (lb/MMBtu)

(e) For Boilers/ Heaters/ Engines, Annual Emission Rate (ton/yr) = Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * Annual Operation (hr/yr) / 2000 (lb/ton)

(f) 91 ppbvd at 15% O2 based on information provided by Mitsubishi for dry lox NOx combustion.

(g) Emission factors for hexane for natural gas fired external combustion equipment presented in AP-42 Section 1.4 are suspect as it is not consistent with the other organic HAPs presented in Table 1.4-3. Therefore, hexane EFs for natural gas fired external combustion equipment are based on AB 2588 COMBUSTION EMISSION FACTORS, Ventura County APCD.

(h) Combustion turbine emissions of metallic HAPs calculated using non-CT natural gas combustion emission factors for natural gas firing.

Attachment 6

MITSUBISHI ELECTRIC POWER PRODUCTS, INC.
THORN HILL INDUSTRIAL PARK
530 KEYSTONE DRIVE
WARRENDALE, PA 15086-7537, U.S.A.

Phone: (724) 772-2555 Fax: (724) 772-2146
Home Page: www.meppi.com

March 25, 2015

Mr. David Mitchell
Dominion Virginia Power
2400 Grayland Avenue
Richmond, VA 23220

RE: Leak rate of MEPPI breakers

Dear Mr. Mitchell:

All MEPPI SF6 gas circuit breakers comply with IEEE 62271-1, which states required gas tightness levels of 0.5% per year or less.

If you have any questions about this information, please call on me.

Best regards,

Richard Lynn

Richard Lynn
Sales Manager, High Voltage
Gas Circuit Breaker Division
(724) 772-2116

Attachment 7

Request for Proposal

2014 Solicitation for Intermediate or Base Load Power Supply Generation

November 3, 2014

Dominion Virginia Power

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PART I – RFP OVERVIEW

PART II – PROPOSAL EVALUATION

PART III – PROPOSAL SUBMITTALS

PART I – RFP Overview

A. Introduction

Virginia Electric and Power Company, doing business as Dominion Virginia Power in Virginia and Dominion North Carolina Power in North Carolina (the "Company" or "Dominion Virginia Power") is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and North Carolina. The Company, headquartered in Richmond, Virginia, currently serves approximately 2.4 million electric customers located in approximately 30,000 square miles in North Carolina and Virginia. The Company's regulated electric portfolio consists of 19,424 MW of generation capacity, including approximately 1,747 MW of non-utility generator ("NUG") resources, over 6,400 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and more than 57,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in North Carolina, Virginia and West Virginia. In May 2005, the Company became a member of the Regional Transmission Organization PJM Interconnection L.L.C. ("PJM"), the operator of the wholesale electric grid in the Mid- Atlantic region of the United States. As a result, the Company transferred operational control of its transmission assets to PJM.

The Company has a diverse mix of generating resources consisting of Company-owned nuclear, fossil, hydro, pumped storage, biomass and solar facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market.

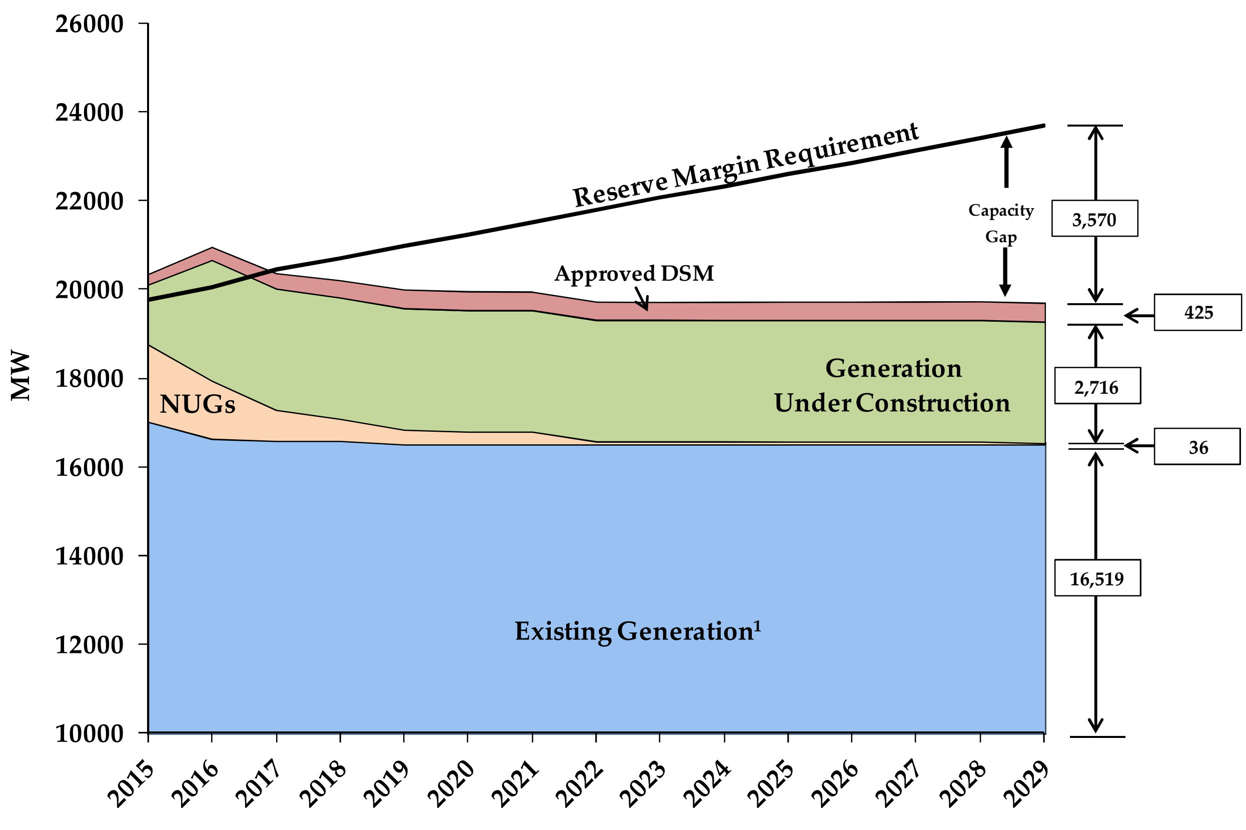
Dominion Virginia Power is a wholly owned subsidiary of Dominion Resources, Inc. ("Dominion") (NYSE: D), one of the nation's largest producers and transporters of energy, with a portfolio of approximately 23,600 MW of generation, 10,900 miles of natural gas transmission, gathering and storage pipeline and 6,400 miles of electric transmission lines. For more information about Dominion, visit the company's website at www.dom.com.

B. Purpose

With this Request for Proposals ("RFP") dated November 3, 2014, Dominion Virginia Power is soliciting proposal(s) (the "Proposal(s)") from bidders ("Bidders") for up to approximately 1,600 MW of intermediate or base load dispatchable summer Unit Firm Capacity (as defined in Section I.C.1, below).

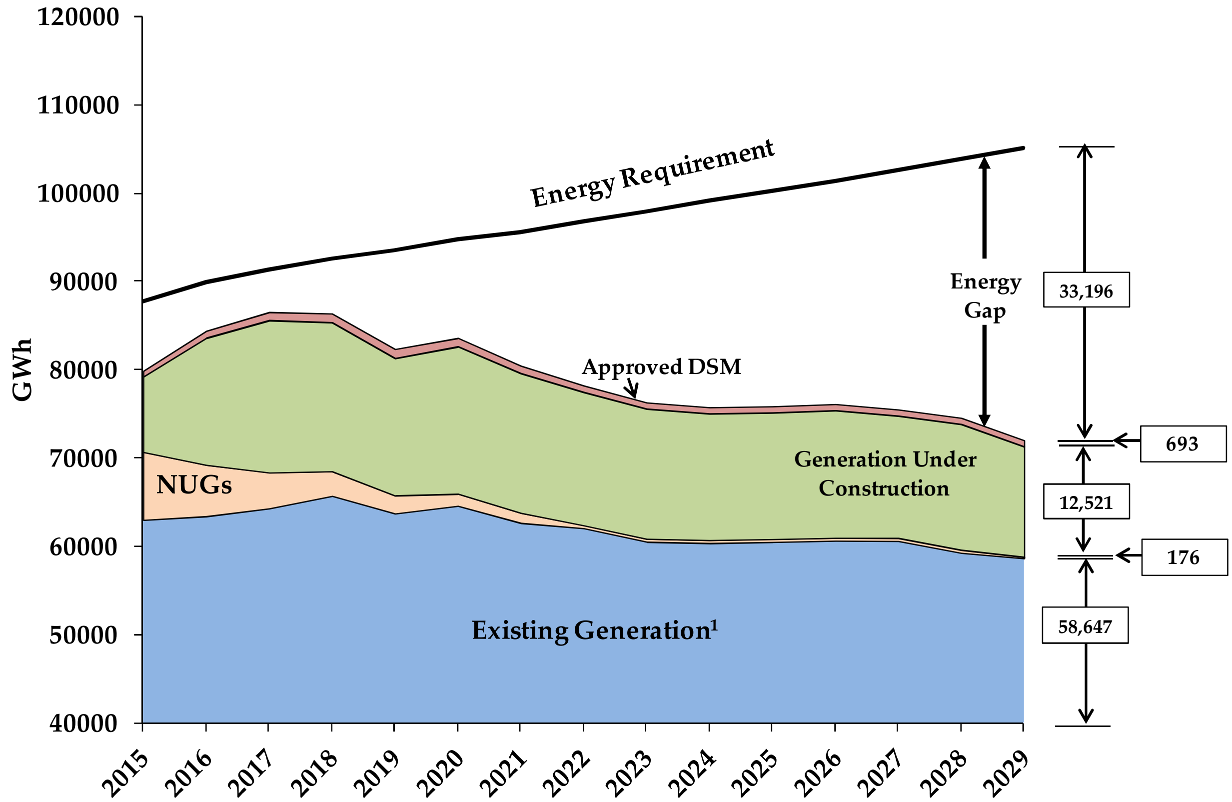
The need for additional generation resources to serve the Company's projected customer load was identified in the Company's 2011-2014 Integrated Resource Plans ("IRPs"). The Company's 2014 IRP is available at www.dom.com/about/integrated-resource-planning.jsp. The IRP is the Company's long-term planning document for meeting future customer needs at the lowest reasonable cost while maintaining reliability and flexibility. In this IRP, the planning process projected a capacity and energy gap between the Company's future generation resources and the projected customer load requirements, as illustrated in Figures 1 and 2. The 2014 IRP selected a new 1,566 MW combined-cycle facility as part of the recommended plan to meet this need. The Company is conducting this RFP to seek third-party proposals in order to fully evaluate and determine the most favorable supply-side option(s) for its customers.

Figure 1 – Current Company Capacity Position (2015-2029)



Note: The values in the boxes represent total capacity in 2029.
1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Figure 2 – Current Company Energy Position (2015-2029)



Note: The values in the boxes represent total energy in 2029.
1) Accounts for unit retirements and rating changes to existing units in the Plan.

C. Scope

All Proposals must conform to the RFP requirements detailed below. Any Proposal not conforming to one or more of the RFP requirements may be eliminated from further consideration. As part of a Proposal, Bidders may offer additional or alternative Proposals with different attributes; however, at least one Proposal submitted by each Bidder must comply with the RFP requirements listed herein.

1. Product

For the purposes of this RFP, "Unit Firm Capacity" is defined as capacity, energy, ancillary services and environmental attributes delivered from a specific new or existing facility. Unit Firm Capacity shall be a fully dispatchable product and the Company shall have the exclusive right to 100% of the net electrical output of the facility from which such fully dispatchable output will be delivered. The Company is seeking base load and intermediate resources only.

2. Term

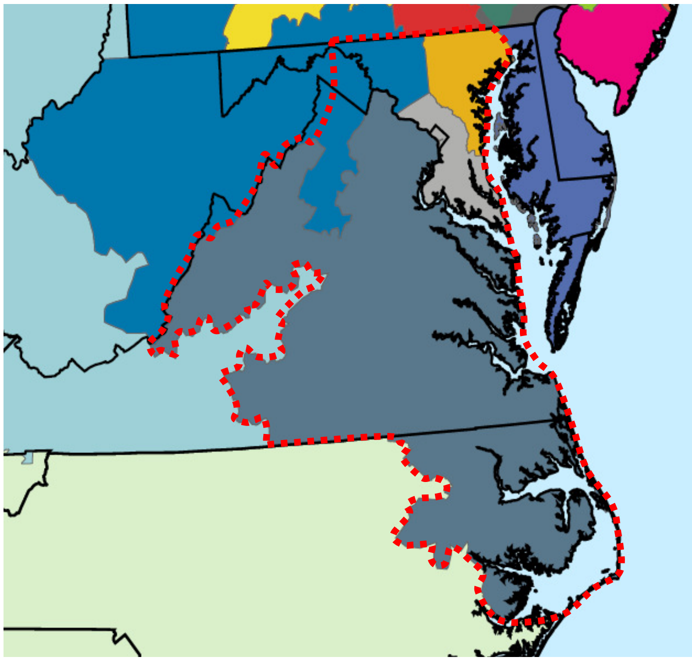
   Bidder may propose any contract delivery term from ten to twenty years, with the delivery of Unit Firm Capacity commencing no earlier than January 1, 2019 and no later than May 31, 2020.

3. Quantity

   The Company is seeking up to approximately 1,600 MW of summer Unit Firm Capacity. Proposals must offer a minimum of 300 MW of summer Unit Firm Capacity. At its sole discretion, the Company may consider Proposals for multiple units which are individually less than 300 MW, but in aggregate total 300 MW or more, if those units are co-located or otherwise closely affiliated.

4. Delivery Point

   The Company will only consider Proposals for facilities located in, and delivering power to, the Company's bulk power transmission system in the PJM Dominion Transmission Zone ("Dom Zone"), or in near proximity to its Dom Zone load, as defined below. The Company will not consider any Proposals for facilities that are not directly interconnected to the PJM transmission system.



Location Requirements for Proposals

This RFP is limited to facilities interconnected to one of the following PJM zones:

- Dominion Zone,
- Baltimore Gas and Electric Company Zone,
- Potomac Electric Power Company Zone, or
- Eastern portion of Allegheny Power Systems Zone.

Additionally, the interconnection point(s) must be electrically east of the terminations of PJM interfaces AEP-DOM, AP South and Black Oak – Bedington.

5. Technology & Fuel Reliability

   All Proposals must utilize an existing, proven technology, with demonstrated reliable generation performance. Proposals must also be supported by a complete and definitive fuel strategy, that a) demonstrates the ability to reliably procure fuel to support Unit Firm Capacity all 365 days of the year and for the full contract term, and b) minimizes any mismatch between the contract price for energy and the Seller's cost of fuel. Proposals must demonstrate the facility has the agreements, assets, or other arrangements necessary to support the fuel strategy. Such fuel strategies may include dual-fuel capabilities, on-site fuel storage, firm fuel transportation agreements from a liquid point, and/or redundant fuel transportation channels.

6. Development Plan

   All Proposals for new facilities must have a well defined and credible development plan for Bidder to complete the development, construction and commissioning of the facility on the proposed timeline. Proposals that are not site-specific or do not currently have land control for the facility site will be disqualified from the evaluation process.

7. Power Purchase Agreement

The Proposal must be accompanied by either (i) an affirmative statement that Bidder is taking no exception to the form of power purchase agreement (the "PPA") provided pursuant to this RFP; or (ii) a fully marked-up PPA reflective of its bid that Bidder deems execution-ready. This is critical for the Company to properly evaluate a Proposal, and to ensure the Company can conclude the RFP process in a timely manner. Any proposed revisions to the PPA must be clearly marked with specific language detailing any such revisions, and the accompanying rationale therefore. Proposals with incomplete PPA revisions, edits and/or accompanying rationale, or that rely on future negotiations to finalize will be deemed non-responsive and subject to rejection by Dominion Virginia Power.

8. Exclusions

The Company is not seeking or accepting demand side management, intermittent, or non-dispatchable resource proposals in this RFP. While these excluded resources are outside the scope of this RFP, the Company may consider these resources outside of this RFP in other existing and future Company-sponsored procurement programs.

The Company will not consider Proposals that have material contingencies, such as for financing.

D. Schedule & Process

1. Key Dates

RFP Announcement & Issuance	November 3, 2014
Intent to Bid Form & Confidentiality Agreement Deadline	November 14, 2014
Bidder Financial Information Deadline	December 5, 2014
Proposal Submittal Date	December 19, 2014
RFP Concluded	March / April 2015

2. Intent to Bid Form and Confidentiality Agreement

All participating Bidders must complete an Intent to Bid Form and execute a Confidentiality Agreement ("CA"). The completed form and signed CA must be emailed to

2014GenRFP@dom.com no later than 5:00 PM EST on November 14, 2014. The Intent to Bid Form and CA can be found on the RFP website at www.dom.com/2014GenRFP. The Company will provide Bidders a confirmation upon receipt of the Intent to Bid Form and CA. Once the CA is received from the participating Bidder, the Company will complete execution of the CA and send a copy of the fully executed CA to Bidder.

After a Bidder has successfully completed and submitted the Intent to Bid Form and CA, the Company will provide access to an electronic data room ("eRoom"), which will contain a form PPA, procedures for Bidder Questions and Company Answers regarding the RFP and the Company's capacity needs, and additional instructions for submitting Bidder financial information and Proposals.

3. Bidder Financial Information

Bidders will be required to provide 2012 (audited), 2013 (audited) and 2014 year-to-date financial information for the Bidder, and, if applicable guarantors and sources of equity funding. Financial Information should include, at a minimum, a Balance Sheet, Statements of Income, and Statements of Cash Flows, with accompanying footnotes. Bidder financial information must be submitted via the eRoom no later than December 5, 2014. More complete instructions for providing Bidder financial information will be made available after submission of Bidder's Intent to Bid Form and signed CA.

4. Proposal Submittal

Bidders must submit Proposal(s) on December 19, 2014, no later than 5:00 PM EST. Proposals must be submitted electronically via the eRoom. The Company will not accept Proposals that are mailed, emailed, or hand delivered. More complete instructions for submitting proposals will be made available after submission of Bidder's Intent to Bid Form and signed CA.

In order to be accepted as complete, Proposals must contain all the documents and data requested in the form and format required, as described in Part III of this RFP document.

5. Expiration of Proposals

Proposals shall expire on the earlier of the time the Company notifies Bidder that its Proposal has been rejected in full or in part, or at midnight on May 3, 2015. All Proposals must remain binding until midnight EST on May 3, 2015.

E. Communications

1. RFP Process Information

In addition to the information and instructions provided in this RFP document, please refer periodically to the RFP website www.dom.com/2014GenRFP for additional information, announcements and updates.

2. Bidder Questions & Answers

The RFP website makes available a list of Frequently Asked Questions with respect to the RFP process. Bidders may also submit questions to the Company concerning this RFP process via email to 2014GenRFP@dom.com. Please note that such questions will not be treated as confidential, and the question and answer may be shared for the benefit of other interested parties via the RFP website.

Please note that under no circumstance should Bidders attempt to contact Company employees directly with any matters related to this RFP process.

3. Company Questions & Answers

Proposals with material omissions will be deemed non-responsive and may be eliminated from consideration by the Company. Note that the Company does not plan to contact Bidders in the event of such non-conforming Proposals prior to elimination.

However, in addition to the information requested from Bidders in this RFP document, the Company may have the need for clarifications or additional information as part of its review of Proposals. In such case, the Company will call or email the designated Bidder contact. Prompt responses to these questions will be required in order to maintain a responsive Proposal.

F. Modifications to RFP

The Company reserves the right to modify this RFP for any reason and at any time. Such changes will be communicated to Bidders who submit a valid Intent to Bid Form.

G. Confidentiality

The Company will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all Proposals submitted, which will be subject to the protections provided under the CA. Bidders should clearly identify each page of information considered confidential or proprietary.

H. Miscellaneous

1. The Company does not intend to negotiate relative to PPA pricing. Bidders are advised to submit their best and final price with their Proposal.

2. The Company may procure more or less than the amount of Unit Firm Capacity solicited in this RFP from one or more Bidders, and Bidders may propose facilities offering all or a portion of the solicited Unit Firm Capacity. Bidders are advised that any contract executed by the Company and any selected Bidder may not be an exclusive contract for the provision of Unit Firm Capacity as described in Section I.C.1. In submitting a Proposal(s), Bidder will be deemed to have acknowledged that the Company may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

3. The Company reserves the right, without qualification and at its sole discretion, to select any Proposal(s) or reject any and all Proposal(s), or waive any formality or technicality in any Proposal(s) received. Bidders who submit Proposal(s) do so without recourse against the Company for either rejection by the Company or failure to execute a power purchase agreement for the purchase of Unit Firm Capacity for any reason.

4. The Company shall not reimburse Bidder and Bidder is responsible for any cost incurred in the preparation or submission of a Proposal(s), in negotiations for a power purchase agreement, and/or any other activity contemplated by the Proposal(s) submitted in connection with this RFP.

5. The information provided in the RFP, or on the Company's RFP website, has been prepared to assist Bidders in evaluating the RFP. It does not purport to contain all the information that may be relevant to Bidder in satisfying its due diligence efforts. The Company makes no representation or warranty, expressed or implied, as to the accuracy, reliability or completeness of the information in the RFP, and shall not be liable for any representation expressed or implied in the RFP or any omissions from the RFP, or any information provided to a bidder by any other source.

6. Bidders should check the Company's RFP website frequently, to ensure it has the latest documentation and information. Neither the Company nor its representatives shall be liable to any Bidder or any of its representatives for any consequences relating to or arising from the Bidder's use of outdated information.

7. Bidder shall hold the Company harmless from all damages and costs, including but not limited to legal costs, in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of the RFP or the award of a bid pursuant to the RFP.

8. The submission of a Proposal to the Company shall constitute Bidder's acknowledgment and acceptance of all the terms, conditions and requirements of this RFP.

9. Bidder shall obtain all licenses and permits that may be required by any governmental body or agency necessary to conduct Bidder's business or to perform hereunder. Bidder's subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

PART II – Proposal Evaluation

A. Evaluation Methodology Overview

1. Overview of Price & Non-Price Methodology

   The Company will review and evaluate Proposals to determine the alternative that provides the lowest reasonable cost while maintaining reliability and flexibility for Dominion Virginia Power customers. This evaluation will be conducted in consecutive steps, as outlined in Section II.B, in order to conduct a thorough but efficient review of Proposals. The Proposals that are selected from the RFP process will be the ones that offer the most favorable combination of the Price Evaluation and Non-Price Evaluation, as described further below.

2. Company Self-build Alternative

   The Company has also developed a self-build alternative, an approximately 1,600 MW combined cycle facility, to meet the Unit Firm Capacity needs identified in this RFP (the "Company Build Option"). The Proposal(s) will be evaluated and compared to the Company Build Option in addition to other Proposals received. The Company Build Option will be finalized prior to the due date of the Proposal(s).

B. Evaluation Process

1. Review for Completeness

   For Proposals received by the submittal deadline, the Company will open and review all responses for completeness and responsiveness. Failure to provide the requested information in accordance with the submittal requirements described in Part III may result in disqualification of the Proposal.

2. Review for Scope Compliance

   The Company will then review Proposals for compliance with the RFP scope as described in Section I.C. Any Proposal not conforming to one or more of the RFP scoping factors may be eliminated from further consideration. As part of a Proposal, Bidder may offer additional or alternative proposals; however, the base Proposal must comply with the RFP scoping factors listed herein.

3. Initial Economic Screening

   Depending upon the number of Proposals that are determined to be complete and that meet scope compliance requirements, the Company may perform an initial economic screening in order to eliminate uneconomic Proposals. This will allow the final evaluation process to focus on the most economic Proposals relative to other Proposals received and the Company Build Option.

4. Detailed Proposal Evaluation

   Dominion Virginia Power will conduct the final review and evaluation of remaining Proposals based on the Price Evaluation and Non-Price Evaluation as described below.

C. Price Evaluation

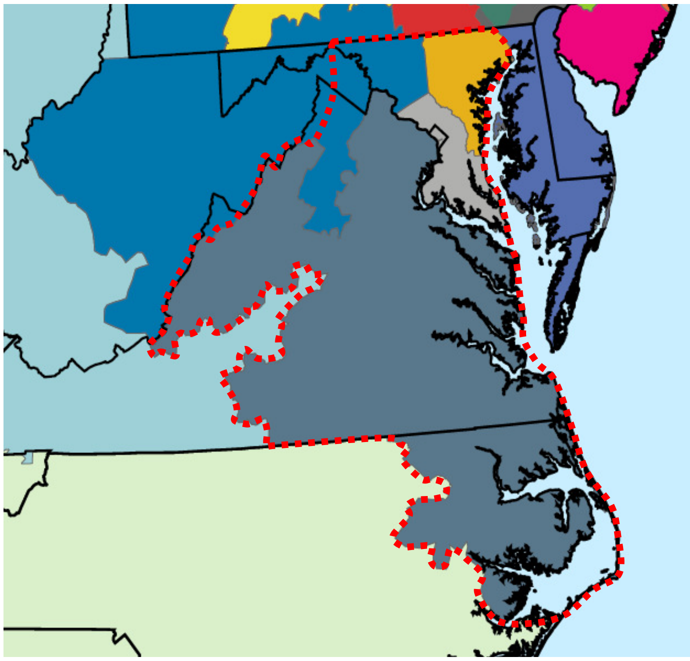
The price evaluation will analyze each Proposal's value to Dominion Virginia Power customers based on the Proposal's pricing, fueling, delivered capacity and energy value, and the operational characteristics. The Company will use generation planning and production cost models to determine the economic value, with the objective of minimizing present value revenue requirements for customers. The price evaluation may also consider factors such as locational differences of each Proposal, regulatory (including environmental) risk, and the integration into the Company's existing system. Depending on the nature of the Proposals, the Company may examine combinations of Proposals, along with the Company's self-build option, to determine the lowest cost future resource plan.

D. Non-Price Evaluation Criteria

1. Facility Location & Market Risk

   The Company strongly prefers Proposals for facilities within PJM Dom Zone. The Company will consider each proposed facility's use of fuels, labor and other resources within Virginia, as well as benefits to industries and communities regardless of the facility's location.

   Facilities located in adjacent PJM Zones, as described below, will be evaluated, but will be considered less favorable compared to facilities located in Dom Zone:



Location Requirements for Proposals

This RFP is limited to facilities interconnected to one of the following PJM zones:

- Dominion Zone,
- Baltimore Gas and Electric Company Zone,
- Potomac Electric Power Company Zone, or
- Eastern portion of Allegheny Power Systems Zone.

Additionally, the interconnection point(s) must be electrically east of the terminations of PJM interfaces AEP-DOM, AP South and Black Oak – Bedington.

2. Experience, Qualifications and Financial Strength

   It is critical that the Company have a high degree of confidence in the Bidder's ability to construct and operate a facility over the term of the PPA. Therefore, a portion of the evaluation will be based on the experience, qualifications and financial strength of the Bidder and other key contributors. Proposals that have well defined roles and responsibilities, supported by the necessary contracts and agreements will also be evaluated more favorably.

3. Development, Permitting and Approvals Risk

   The Company has needs for capacity in the 2019/2020 time period and expects to make commitments in the PJM capacity market based on the selected Proposal. Therefore, the Company will evaluate Proposals based on the risk associated with proposed development plans and the associated PPA contractual commitments. Additionally, plans for significant upgrades to existing facilities that are required to support continued operation for the term of the PPA, will also be evaluated.

Evaluation of development plans will include review of proposed schedule, budget, permitting and approvals. Facilities with advanced and well-defined development plans will be evaluated more favorably. Proposals that are not site-specific or do not currently have land control will be disqualified from the evaluation process.

The Company will not assume any responsibility for the successful development of a proposed facility, and such development schedule, budget, permits and approvals risk will be the sole responsibility of the Bidder.

4. Environmental Risk

The Company will evaluate the risk associated with current, pending and potential future environmental regulations applicable to the Proposal facility.

5. Technical Review of Facility Design, Equipment and Operations

The long-term performance of the proposed facility is critical to providing the intended value and reliability for the Company's customers. The reliability and capabilities of the facility's design, equipment and operations will be evaluated, including:

- Age of equipment
- Reliability of operating history
- Performance guarantees, backed by contractual commitments
- Operating flexibility and cycling capability
- Availability of automatic generation control and voltage control
- Proven equipment and technology from qualified equipment providers
- Appropriate maintenance plan and spare parts inventory
- Operating experience

The Company will also be reviewing the reliability and capabilities of the facility in the context of the PJM Capacity Performance Updated Proposal dated October 7, 2014 as subsequently updated or modified.

6. Fuel Strategy Risk & Flexibility

Proposals should demonstrate a fueling plan to provide fuel availability throughout the year, by having reliable primary fuel transportation and preferably a secondary fuel source (secondary delivery route or on-site storage) for reliability in the event of temporary disruptions to the primary fuel transportation.

Proposals without a reliable fuel strategy will be disqualified. Minimum requirements for a reliable fuel strategy are:

- Fuel strategy is well-defined and supported by necessary contractual arrangements,
- Reliable capability and rights for primary fuel transportation (example: pipeline, rail or water). Such fuel transportation must have full-year firm capacity from origin (or liquid supply point) to plant, and
- Facility fuel cost is closely matched to the variable energy price under the PPA.

The Company strongly prefers proposals that have Secondary fuel supply for reliability (secondary delivery route and/or on-site fuel storage). For gas facilities, such secondary fuel supply should provide for at least three days of operation at full load in the event the facility's primary fuel transportation is disrupted or unavailable. Proposals that have fuel strategies that address longer disruptions to primary fuel, or provide additional fuel optionality may be evaluated more favorably.

The Company will also be reviewing the reliability and capabilities of the fuel strategy in the context of the PJM Capacity Performance Updated Proposal dated October 7, 2014 as subsequently updated or modified.

7. PPA Terms and Conditions

The Company will rely on the PPA terms and conditions to ensure it receives the intended value of the Proposal and to protect Dominion Virginia Power customers from unnecessary risk. Therefore, any PPA submitted must accurately and fully reflect Bidder's Proposal which is critical to the Company's proper evaluation of a Proposal and timely conclusion of the RFP process.

Bidders should assume full risk for the cost and schedule for the development of any new facilities. Proposals that minimize revisions to the Company's form PPA will receive preference in the evaluation process. Additionally, Proposals that provide strong commitments to the operation and performance of the facility, backed by a strong credit package (per Section III.B.12) will be evaluated more favorably.

Proposals that do not include an execution-ready PPA, have incomplete edits and rationale therefore or that rely on future discussions to finalize, will be deemed non-conforming.

8. Key Risk Factors

As the Price Evaluation and Non-Price Evaluation reviews are conducted, certain key risks will be compiled and included in the final evaluation ("Key Risk Factors"). These Key Risk Factors may be unique to a Proposal and while reflected in the Price and Non-Price Evaluation, may be significant enough to independently impact the overall favorability of a Proposal. For example, if there is uncertainty whether a key operating permit/license for a facility can be renewed, jeopardizing the ability of the facility to continue operating, then that risk will also be included as an independent consideration in the final summary evaluation.

PART III – Proposal Submittals

A. Proposal Requirements & General Instructions

Prior to submitting Proposal(s), Bidders will be required to have completed an Intent to Bid Form, executed a Confidentiality Agreement, and provided Bidder financial information by the respective deadlines and in accordance with Section I.D.

Bidders may submit more than one Proposal. For multiple Proposals related to a single facility, Bidders may provide a single Proposal submittal package that clearly identifies the Proposals' differences. For Proposals that are based on different facilities, Bidders should provide a complete and separate proposal submittal package for each Proposal.

Bidders must submit Proposal(s) on December 19, 2014, no later than 5:00 PM EST. Proposals must be submitted electronically via the eRoom. The Company will not accept Proposals that are mailed, emailed, or hand delivered. More complete instructions for submitting Proposals will be made available after submission of Bidder's Intent to Bid Form.

The purpose of these requirements and instructions is to acquire sufficient information from all Bidders that will ensure a uniform and impartial evaluation and ranking of each Proposal(s). For this reason, the Company requires that Bidder complete all applicable items of the Proposal(s) Summary Submittal, Information Form Addendum, PPA, and Additional Requested Documents as described in this Part III.

In order to be accepted as complete, Proposals must contain all the documents and data requested in the form and format required. Any Proposals with material omissions or incomplete responses to the requested items will be deemed non-responsive and may be eliminated from further consideration.

B. Proposal Summary Submittal

Bidder's Proposal Summary must be provided in Microsoft Word or Adobe Acrobat PDF file format, and contain the following information. Please maintain the order and content as listed below to facilitate the review of Proposals.

1. Bidder Name, Contact information and Bidder Affirmation

Proposal(s) must be submitted in the legal name of the actual party or the ultimate "upstream" organizational entity that would be bound by any resulting power purchase agreement with Dominion Virginia Power and authenticated by an officer or other employee who is authorized to bind Bidder to a power purchase agreement based on the Proposal(s).

The first page of the Proposal shall list the Bidder and the Bidder Contact Information (Name, Title, Phone, Email Address, and Mailing Address).

Additionally, it should include the following statement, signed by an authorized representative of Bidder:

"I, _______, am an authorized representative of ____________ ("Bidder") and hereby certify and affirm that: (i) I am authorized to obligate the Bidder to the terms of its Proposal; and (ii) the Bidder's Proposal shall remain binding until May 3, 2015; and (iii) neither Bidder nor any person or entity acting or purporting to act on its behalf or with Bidder has entered into any combination, conspiracy, agreement or other form of collusive arrangement with any person, corporation, partnership or other entity, which directly or indirectly has to any extent lessened competition between the Bidder and any other person or entity for this RFP."

2. Proposal Summary: Please provide a brief summary of the Proposal, including key information on the facility and the PPA. Please highlight any significant unique attributes of the facility relative to similarly situated facilities in the industry.

   Indicate the facility's site location, accompanied by a map(s) of the location. Please designate on map(s) any planned infrastructure upgrades such as electric interconnection route and gas pipeline route.

   If submitting multiple Proposals for a single facility, please clearly identify and summarize each Proposal in a single Summary.

3. Bidder Summary: Please provide a summary of the Bidder. Summary should include:

   a. Ultimate corporate parent entity and relationship to Bidder,

b. Prior experience and qualifications of Bidder as it relates to the execution of the Proposal, and

c. Summary of Bidder's and guarantor's financial strength and capabilities to develop, own and operate the facility identified in the Proposal.

4. Key Contributors Summary: Please provide a summary of the experience and qualifications of other key contributors. Summary should include:

   a. Prior experience and qualifications of any key developers, engineering, procurement and construction contractors, operators, fuel managers, or other key contributors specifically as it relates to the execution of the Proposal;

   b. Summary of the status of contractual relationship with each key contributor;

   c. Key contractual assurances, guarantees, warranties or commitments supporting the Proposal; and

   d. Past experience of Bidder working with each key contributor.

5. Development Plan: For new facilities, or existing facilities requiring material modifications/upgrades, please provide a summary of Bidder's development plan, including:

   a. Key participants: Roles and responsibilities of the companies involved in the design, development, procurement, and construction of the facility.

   b. Description of the facility site and Bidder rights (owned, leased, under option) to such site. Please indicate whether additional land rights are necessary for the development, construction and operation of the facility.

   c. Discussion of the development schedule, and associated risks and risk mitigants for that schedule, including whether there are contract commitments from contractors supporting the proposed schedule. Bidder should be prepared to document and commit to proposed development schedule in the PPA.

   d. Discussion of the financing arrangements, including an overview of the sources of funds, and level of commitment from debt, equity or other investors.

e. Discussion on Permitting, including a list of all required permits, permitting status of each, and key risks to securing necessary future permits approvals.

6. Operating Plan: Please provide a summary of the operating plan for the facility. Such plan should include any third-party roles and responsibilities for operating, maintaining and servicing the facility, including any contractual arrangements currently in place. Please provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

7. Fuel Strategy: Please provide a detailed description of the fuel strategy. Such strategy should: (a) demonstrate the reliable availability of fuel to support Unit Firm Capacity throughout the entire year and for the full contract term, and (b) minimize any mismatch between the PPA price for energy and the Seller's cost of fuel. Provide a summary of the agreements, assets, or other arrangements necessary to support the fuel strategy, and whether the assets and agreements have been secured. Such fuel strategies may include dual-fuel capabilities, on-site fuel storage, firm fuel transportation agreements, and/or redundant fuel transportation channels.

   Additionally, provide a description of any fuel related risks and constraints (seasonal or otherwise), and a description of any fuel related issues that have impacted plant availability in the previous five years.

   To the extent Bidder intends to rely on a third-party fuel manager, please provide a summary of the fuel management company, its experience and qualifications, and any existing agreements in place.

   Bidder should be prepared to document and commit to proposed fuel strategy in the PPA.

8. Environmental Risk: Provide a summary of the facility's existing and planned environmental controls and its plan to comply with current and expected environmental laws and regulations, including air emissions, water intake/discharge, and ash disposal pending and proposed regulations. Note that the cost of compliance with any current or future environmental laws or regulations should be the sole responsibility of Bidder in its Proposal.

9. Legal Proceedings: Provide a summary of all material actions, suits, claims or proceedings (threatened or pending) against Bidder, its Guarantor (if applicable) or involving the

Proposal facility as of the Proposal due date, including those related to employment and labor laws, environmental laws, or contractual disputes for the development, construction, fueling or operation of the facility.

10. Virginia Resources: Provide a description of the expected use of Virginia fuels, manpower and other state resources for the development, construction and operation of the Proposal facility.

11. Economic Impact: Provide a description of the expected benefits to be derived by the industries and communities associated with the development, construction and operation of the Proposal facility.

12. Credit Package: Provide a summary of the proposed credit package (pre-COD and post-COD) to support Bidder's PPA commitments, such as parental guaranties, letters of credit, or other credit support, including amounts/limits. Note that credit support will be required at the time of PPA execution. Such credit package shall provide a minimum of:

    - New Facilities Initial Amount: $120/kW

    - New Facilities post-COD, upon completion of summer & winter demonstrations: $50/kW

    - Existing Facilities: $50/kW

    Letters of credit provided as part of Bidder's credit package must be in form and substance satisfactory to Dominon Virginia Power, drawn upon a financial institution with a minimum senior unsecured (or equivalent) credit rating of A2 and A from Moody's and S&P, respectively and acceptable to Dominion Virginia Power.

    For the Proposal, Bidders may assume that credit packages may utilize guarantees up to credit limits as applicable below. However, such limits will be subject to Dominion Virginia Power's review of individual entities' credit worthiness, with the limit not to exceed the respective percentage of the entities' tangible net worth ("TNW") relative to the lower of their Moody's or Standard and Poor's Senior Unsecured Rating or equivalent:

Rating (S&P and Moody's equivalent)	TNW >= 1 B	TNW < 1 B
AAA / AA+	8%	6%
AA / AA-	7%	5%
A+ / A	6%	4%
A- / BBB+	5%	3%
BBB / BBB-	4%	2%
Below Investment Grade/Unrated	0%	0%

The following table provides a hypothetical example of a Bidder's minimum collateral requirement, assuming a TNW of $1 billion, a 1,600 MW facility, and a new facility initial security amount of $120/kW.

Rating (S&P and Moody's equivalent)	TNW >= 1 B	Required Collateral
AAA / AA+	$ 80,000,000	$ 112,000,000
AA / AA-	$ 70,000,000	$ 122,000,000
A+ / A	$ 60,000,000	$ 132,000,000
A- / BBB+	$ 50,000,000	$ 142,000,000
BBB / BBB-	$ 40,000,000	$ 152,000,000
Below Investment Grade/Unrated	$ -	$ 192,000,000

A Bidder with a rating of "A-" from S&P and "A2" from Moody's will qualify for a maximum unsecured credit of $50 million. The minimum required collateral will be $142 million.

13. Additional Optional Proposals: Please describe any additional Proposals potentially responsive to the RFP, beyond the base Proposal(s) as described above. Evaluation of such offers will be at Dominion Virginia Power's sole discretion, and Dominion Virginia Power will not evaluate any additional Proposals that do not have a fully compliant base Proposal. Furthermore, Dominion Virginia Power reserves the right to include or exclude any additional Proposals in its evaluation process.

C. Information Form Addendum

The Information Form Addendum template can be found on the RFP website at www.dom.com/2014GenRFP. The Proposal's Information Form Addendum should be provided in Microsoft Excel file format, and contain the information requested as applicable to the Proposal. Please maintain the order and format of the worksheets to facilitate the Company's review of the Proposal.

D. PPA

After a Bidder has successfully completed and submitted the Intent to Bid Form and signed CA, the Company will provide access to the eRoom, which will contain the form PPA. The Proposal must be accompanied by either (i) an affirmative statement that Bidder is taking no exception to the form of PPA; or (ii) a fully marked-up, PPA reflective of its bid that Bidder deems execution-ready. This is critical for the Company to properly evaluate a Proposal, and to ensure the Company can conclude the RFP process in a timely manner. Any proposed revisions to the PPA must be clearly marked with specific language detailing any such revision and the accompanying rationale therefore. Proposals with incomplete PPA revisions, edits, and/or accompanying rationale or that rely on future negotiation to finalize will be deemed non-conforming. While proposed revisions to the form PPA may be considered, Proposals which minimize such revisions will receive preference in the evaluation process.

In the case of clause (ii) above, Bidder's Proposal should contain two PPA submittal files. The first should be a file in Microsoft Word or Adobe Acrobat PDF file format that reflects all of the proposed edits to the form PPA, as redline marks. The second should be a file in Microsoft Word format that is a "clean" version, reflecting acceptance of all proposed edits. Reasons or explanations for proposed PPA edits can be included in the text of the PPA documents, or as a separate file.

E. Additional Requested Documents

Bidder shall provide the following documents as separate files in Adobe Acrobat PDF file format.

1. Permits, applications and approvals as listed in Information Form Addendum E.4
2. Key non-fuel contractual arrangements as listed in Information Form Addendum E.5
3. Planned Development and Construction Schedule, which should include:
    a. Permitting activities for each major permit
    b. Certificate of Public Convenience and Necessity ("CPCN") process
    c. PJM Queue Process
    d. Local Approvals, such as conditional use permit

e. Major Equipment Procurement

f. Engineering, Procurement and Construction Bid and Award Process

g. Construction Schedule

h. Commissioning Schedule

i. Commercial Operations Date

4. Heat rate curve(s) for facility (and any supplemental capacity such as duct firing)

Attachment 8

(Slip Opinion)

NOTICE: This opinion is subject to formal revision before publication in the Environmental Administrative Decisions (E.A.D.). Readers are requested to notify the Environmental Appeals Board, U.S. Environmental Protection Agency, Washington, D.C. 20460, of any typographical or other formal errors, in order that corrections may be made before publication.

BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

In re:	)	
La Paloma Energy Center, LLC	)	PSD Appeal No. 13-10
PSD Permit No. TX-1288-GHG	)	

[Decided March 14, 2014]

ORDER DENYING REVIEW

Before Environmental Appeals Judges Catherine R. McCabe, Randolph L. Hill, and Kathie A. Stein.

IN RE LA PALOMA ENERGY CENTER, LLC

PSD Appeal No. 13-10

ORDER DENYING REVIEW

Decided March 14, 2014

Syllabus

Sierra Club petitions the Environmental Appeals Board ("Board") to review a greenhouse gas ("GHG") prevention of significant deterioration permit that Region 6 ("Region") of the United States Environmental Protection Agency ("EPA") issued to the La Paloma Energy Center, LLC ("LPEC") pursuant to Clean Air Act § 165, 42 U.S.C. § 7475. The permit authorizes LPEC to construct and operate a 637- to 735-megawatt natural gas-fired power plant in Harlingen, Texas. Sierra Club challenges the permit's emission limits for greenhouse gases on two grounds, claiming that the Region clearly erred or abused its discretion (1) by failing to base the permitted GHG emission limits for the combined cycle natural gas-fired combustion turbines that will be used at this facility on the energy efficiency of the most efficient of the three turbine models that LPEC identified for potential use at this facility, and (2) by declining to require LPEC to consider adding a solar thermal energy component to the proposed facility in order to further reduce GHG emissions because the Region incorrectly concluded that solar technology would "redefine the source."

Held: The Board denies the petition for review of the Region's final permit decision.

(1) <u>Issue Concerning the Permit's GHG Emission Limits for the Combustion Turbines</u>

> Sierra Club has failed to demonstrate that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the proposed LPEC facility. The Board finds no support in EPA's BACT guidance for Sierra Club's position that the three specific turbine models proposed by LPEC *must* be identified as separate control technologies throughout the Region's five-step analysis. The Region had a rational basis for its determinations that all three of the permitted turbine models are comparably efficient on a performance basis, that the assigned BACT limits are substantially equivalent except for marginal differences attributable to capacity, and that the GHG emission limits for all three turbine models represent BACT for highly efficient combined cycle combustion turbines.

(2) Issue Concerning Region's Conclusion That Solar Technology Would "Redefine the Source"

> Sierra Club has failed to demonstrate that the Region abused its discretion in concluding that adding solar technology to this facility would "redefine the source." Under the circumstances of this case, the business purposes and site-specific constraints described in the administrative record support the Region's conclusion that the addition of supplemental solar power to this facility would constitute redesign of the source.

Before Environmental Appeals Judges Catherine R. McCabe, Randolph L. Hill, and Kathie A. Stein.

Opinion of the Board by Judge Catherine R. McCabe:

I. *STATEMENT OF THE CASE*

Sierra Club filed a timely petition seeking Environmental Appeals Board ("Board") review of a Clean Air Act greenhouse gas ("GHG") prevention of significant deterioration ("PSD") permit, PSD-TX-1288-GHG, that U.S. Environmental Protection Agency ("EPA" or "Agency") Region 6 ("Region") issued to La Paloma Energy Center, LLC ("LPEC") on November 6, 2013. The permit authorizes LPEC to construct and operate a 637- to 735-megawatt ("MW") natural gas-fired power plant in Harlingen, Texas. *See* PSD Permit for Greenhouse Gas Emissions Issued Pursuant to the Requirements at 40 C.F.R. § 52.21 ("Permit") at 1-2 (Nov. 6, 2013) (Administrative Record Index No. ("A.R.") V.01). The petition challenges the permit's emission limits for GHGs on two grounds. Both the Region and LPEC filed responses to the petition. The Board held a status conference/oral argument in this matter on February 12, 2014. For the reasons set forth below, the Board denies the petition for review of the Region's final permit decision.

II. *ISSUES*

This appeal presents the following issues for resolution:

A. Has Sierra Club demonstrated that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the LPEC facility?

B. Has Sierra Club demonstrated that the Region abused its discretion in concluding that adding solar technology to the LPEC facility would "redefine the source?"

III. *STANDARD OF REVIEW*

Section 124.19 of Title 40 of the Code of Federal Regulations governs Board review of a PSD permit. In any appeal from a permit decision issued under part 124, the petitioner bears the burden of demonstrating that review is warranted. *See* 40 C.F.R. § 124.19(a)(4). The Board has discretion to grant or deny review of a permit decision. *See In re Avenal Power Ctr., LLC*, PSD Appeal Nos. 11-03 through 11-05, slip op. at 14-15 (EAB Aug. 18, 2011), 15 E.A.D. ___ (citing Consolidated Permit Regulations, 45 Fed. Reg. 33,290, 33,412 (May 19, 1980)), *appeal docketed sub nom. Sierra Club v. EPA*, No. 11-73342 (9th Cir. Nov. 3, 2011). The Board will deny review of a permit decision unless the petitioner demonstrates that it is based on a clearly erroneous finding of fact or conclusion of law, or involves a matter of policy or exercise of discretion that warrants review. 40 C.F.R. § 124.19(a)(4)(i)(A)-(B). In considering whether to grant or deny review of a permit decision, the Board is guided by the preamble to the regulations authorizing appeal under part 124, in which the Agency stated that the Board's power to grant review "should be only sparingly exercised," and that "most permit conditions should be finally determined at the [permit issuer's] level." 45 Fed. Reg. at 33,412; *see also* Revisions to Procedural Rules Applicable in Permit Appeals, 78 Fed. Reg. 5,280, 5,281 (Jan. 25, 2013).

When evaluating a challenged permit decision for clear error, the Board examines the administrative record that serves as the basis for the permit to determine whether the permit issuer exercised his or her "considered judgment." *See, e.g., In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 191, 224-25 (EAB 2000); *In re Ash Grove Cement Co.*, 7 E.A.D. 387, 417-18 (EAB 1997). The permit issuer must articulate with reasonable clarity the reasons supporting its conclusion and the significance of the crucial facts it relied upon when reaching its conclusion. *E.g., In re Shell Offshore, Inc.*, 13 E.A.D. 357, 386 (EAB 2007). As a whole, the record must demonstrate that the permit issuer "duly considered the issues raised in the comments" and ultimately adopted an approach that "is rational in light of all information in the record." *In re Gov't of D.C. Mun. Separate Storm Sewer Sys.*, 10 E.A.D. 323, 342 (EAB 2002); *accord In re City of Moscow*, 10 E.A.D. 135, 142 (EAB 2001); *In re NE Hub Partners, LP*, 7 E.A.D. 561, 568 (EAB 1998), *review denied sub nom. Penn Fuel Gas, Inc. v. EPA*, 185 F.3d 862 (3d Cir. 1999). Permit issuers therefore must provide sufficient documentation in the record to justify decisions to set less stringent BACT limitations where the record suggests that more stringent levels may be achievable. *In re Pio Pico Energy Ctr.*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 91-97 (EAB Aug. 2, 2013), 16 E.A.D. ___; *accord In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 131 (EAB 1999) ("The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record."). On matters that are fundamentally technical or scientific in nature, the Board typically will defer to a permit issuer's technical expertise and experience, as long as the permit issuer adequately explains its rationale and supports its reasoning in the administrative record. *See In re Dominion Energy Brayton Point, LLC*, 12 E.A.D. 490, 510, 560-62, 645-47, 668, 670-74 (EAB 2006); *see also*, *e.g.*, *In re Russell City Energy Ctr.*, PSD Appeal Nos. 10-01 through 10-05, slip op. at 37-41, 88 (EAB Nov. 18, 2010), 15 E.A.D. ___, *petition denied sub nom. Chabot-Las Positas Cmty. Coll. Dist. v. EPA*, 482 F. App'x 219 (9th Cir. 2012); *NE Hub*, 7 E.A.D. at 570-71.

In reviewing an exercise of discretion by the permitting authority, the Board applies an abuse of discretion standard. *E.g.*, *In re Guam Waterworks Auth.*, NPDES Appeal Nos. 9-15 & 9-16, slip op. at 9 n.7 (EAB Nov. 16, 2011), 15 E.A.D. ___. The Board will uphold a permitting authority's reasonable exercise of discretion if that decision is cogently explained and supported in the record. *See Ash Grove*, 7 E.A.D. at 397 ("[A]cts of discretion must be adequately explained and justified."); *see also Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 48 (1983) ("We have frequently reiterated that an agency must cogently explain why it has exercised its discretion in a given manner * * *.").

IV. *SUMMARY OF DECISION*

For the reasons stated below, the Board concludes that (1) Sierra Club has not demonstrated that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the proposed LPEC facility, and (2) Sierra Club has not demonstrated that the Region abused its discretion in concluding that adding solar technology to this facility would "redefine the source." Accordingly, the Board denies Sierra Club's petition for review.

V. *PROCEDURAL AND FACTUAL HISTORY*

In April 2012, LPEC submitted a GHG PSD permit application to the Region to construct a new natural gas-fired electric generating plant in the City of Harlingen, Texas.[1] *See* U.S. EPA Region 6, Statement of Basis, Draft Greenhouse Gas Prevention of Significant

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[1] In 2011, EPA issued a final rule promulgating a federal implementation plan in Texas that made EPA Region 6 the PSD permitting authority for the pollutant GHGs in the State. *See* Federal Implementation Plan Regarding Texas's PSD Program, 76 Fed. Reg. 25,178 (May 3, 2011) (promulgating 40 C.F.R. § 52.2305). The Texas Commission on Environmental Quality ("TCEQ") is the PSD permitting authority for all other pollutants. *See id*. at 25,179 n.2; SOB at 1. Consequently, in addition to the PSD GHG permit application it submitted to the Region, which is the subject of this appeal, LPEC also submitted a PSD permit application for non-GHG pollutants to TCEQ for the same proposed project. *Id*.

Deterioration Preconstruction Permit for the La Paloma Energy Center, LLC ("SOB") at 1 (Mar. 2013) (A.R. III.03). LPEC revised its application in July 2012.[2] LPEC, PSD GHG Permit Application for a Combined Cycle Power Plant at LPEC, Cameron County, Texas, at 1, 16 (revised July 17, 2012) (A.R. I.03) [hereinafter Revised Application]. LPEC plans to produce electricity to sell to the Electricity Reliability Council of Texas ("ERCOT") power grid. SOB at 5-6. In its application, LPEC stated that the proposed facility would consist of two natural gas-fired combined cycle combustion turbines, each exhausting to a fired heat recovery steam generator to produce steam to drive a shared steam turbine. Revised Application at 1. LPEC explained that, while "final selection of the combustion turbine model would not be made until after the permit was issued," it was considering three models, each producing different maximum baseload power: the General Electric 7FA (183 MW) ("GE turbine"), the Siemens SGT6-5000F(4) (205 MW) ("Siemens 4 turbine"), and the Siemens SGT6-5000F(5) (232 MW) ("Siemens 5 turbine"). *Id*. Combined with the steam turbine's output capacity of approximately 271 MW, the combustion turbines would produce a total generating capacity at this facility of 637, 681, or 735 MW of electricity, depending upon which combustion turbine model is finally selected. *Id*.

The Region issued a draft GHG PSD permit for public comment for 30 days, beginning on March 20, 2013. *See* U.S. EPA Region 6, *Responses to Public Comments* ("RTC") at 3 (Nov. 6, 2013) (A.R. V.02). In the draft permit, the Region specified three different sets of emission limits based on the three potential capacity scenarios. *See* SOB at 16. Sierra Club submitted comments on the draft permit. *See generally* Letter from Travis Ritchie, Sierra Club, to Aimee Wilson, Air Permits Section, U.S. EPA Region 6 (Apr. 19, 2013) ("Sierra Club Comments").

On November 6, 2013, the Region issued its final permitting decision and a document responding to the comments it had received.

[2] LPEC revised its application several times after July 2012. The Board refers to the July 2012 revision in this decision because that is the version the parties submitted and discussed on appeal.

See Permit at 1; RTC at 1. The final permit retained the three different sets of emission limits.[3] Sierra Club filed a timely appeal. Both the Region and LPEC filed responses to the petition. LPEC also filed a Motion to Expedite and Resolve Petition requesting that the Board expedite consideration of this matter and issue a final decision by January 31, 2014. The Board held a status conference/oral argument in this matter on February 12, 2014, at which all parties participated.

VI. *OVERVIEW OF PSD LEGAL REQUIREMENTS AND BACT ANALYSIS*

The PSD provisions of the Clean Air Act govern air pollution in "attainment" areas, where the air quality meets or is cleaner than the national ambient air quality standards, as well as in areas that EPA is unable to classify as either attainment or "non-attainment." CAA §§ 160-69, 42 U.S.C. §§ 7470-79; *accord In re Rockgen Energy Ctr.*, 8 E.A.D. 536, 541 (EAB 1999). The statutory PSD provisions are largely carried out through a regulatory process that requires new major stationary sources in attainment (or unclassifiable) areas, such as the LPEC facility, to obtain preconstruction permits. CAA § 165, 42 U.S.C. § 7475; 40 C.F.R. § 52.21.

The Clean Air Act and Agency PSD regulations require that every proposed PSD permit be subjected to a preconstruction review by the permitting authority, which must include a public hearing with the opportunity for interested persons to comment on the air quality impact of the proposed source, alternatives thereto, control technology, and other appropriate considerations. CAA § 165(a)(2), 42 U.S.C. § 7475(a)(2). New major stationary sources and major modifications of such sources are required to employ the "best available control technology" ("BACT") to minimize emissions of regulated pollutants.

[3] The permit specifies three types of emission limits for each capacity scenario: (1) output rate-based emission limits (pounds of carbon dioxide emitted per megawatt hour of electricity produced (lb CO_2/MWh)); (2) startup limits (lb CO_2/hour); and (3) total annual GHG limits on a mass basis (tons per year). *See* Permit at 7-13; SOB at 16. The parties' arguments in this case focus on the output-based emission limits rather than the other two sets of emission limits.

CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)(2). The statute defines BACT as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition). As the Board explained in *In re Northern Michigan University ("NMU")*, the BACT definition requires permit issuers to "proceed[] on a case-by-case basis, taking a careful and detailed look, attentive to the technology or methods appropriate for the particular facility, [] to seek the result tailor-made for that facility and that pollutant." PSD Appeal No. 08-02, slip op. at 12 (EAB Feb. 18, 2009) (citations and quotations omitted), 14 E.A.D. at ___. The BACT determination results in the selection of an emission limitation representing application of control technology or methods appropriate for the particular facility. *In re Prairie State Generating Co.*, 13 E.A.D. 1, 12 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007); *In re Three Mountain Power, LLC*, 10 E.A.D. 39, 47 (EAB 2001); *In re Knauf Fiber Glass, GMbH*, 8 E.A.D. 121, 128-29 (EAB 1999).

In 1990, EPA issued draft guidance for permitting authorities to use in analyzing PSD requirements (among others) in a consistent and systematic way. *See generally* Office of Air Quality Planning & Standards, U.S. EPA, *New Source Review Workshop Manual* 1 (draft

Oct. 1990) ("*NSR Manual*").[4] The NSR Manual sets forth a "top-down" process for determining BACT for each particular regulated pollutant that is summarized as follows:

> The top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent – or "top" – alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case.

Id. at B.2. Permit issuers apply the top-down method on a case-by-case basis to each permit they evaluate. *See id.* at B.1 (explaining that all BACT analyses are done case-by-case). The NSR Manual's recommended top-down analysis employs five steps:

> Step 1: Identify all available control options with potential application to the source and the targeted pollutant;

[4] Notably, the NSR Manual is not a binding Agency regulation, and consequently strict application of the methodology described in it is not mandatory nor is it the required vehicle for making BACT determinations. *E.g.*, *NMU*, slip op. at 12, 14 E.A.D. at __; *Prairie State*, 13 E.A.D. at 6 n.2; *Knauf*, 8 E.A.D. at 129 n.13. Nevertheless, because it provides a framework for determining BACT that assures adequate consideration of the statutory and regulatory criteria, the NSR Manual has guided state and federal permit issuers, as well as PSD permit applicants, on PSD requirements and policy for years. *E.g.*, *NMU*, slip op. at 12, 14 E.A.D. at __; *In re Cardinal FG Co.*, 12 E.A.D. 153, 162 (EAB 2005); *see also In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 183 (EAB 2000) ("This top-down analysis is not a mandatory methodology, but it is frequently used by permitting authorities to ensure that a defensible BACT determination, involving consideration of all requisite statutory and regulatory criteria, is reached.").

Step 2: Analyze the control options' technical feasibility;

Step 3: Rank feasible options in order of effectiveness;

Step 4: Evaluate the energy, environmental, and economic impacts of the options; and

Step 5: Select a pollutant emission limit achievable by the most effective control option not eliminated in a preceding step.

Id. at B.5-.9.

VII. *ANALYSIS*

This case arises in the relatively new context of PSD permitting authorities' efforts to develop BACT permit limits for GHGs based on energy efficiency. EPA's 2011 GHG Permitting Guidance explains that BACT analysis for GHGs should be conducted in the same manner as it is done for any other regulated pollutant. U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 17 (Mar. 2011). That is, EPA will continue to apply its pre-existing framework for BACT analysis, including the five-step "top-down" analytical method described in the 1990 NSR Manual. *Id.* The GHG Permitting Guidance recognizes that BACT emission limits for GHGs often will need to be based on energy efficiency, as the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-driven pollutants. *Id.* at 21, 29. Accordingly, in this case the Region based the GHG emission limits for LPEC's proposed new power plant on energy-efficient design and other energy efficiency measures that are available for use at this facility.

Sierra Club argues that the Region conducted a faulty BACT analysis and has not gone far enough to assure that the facility will achieve the maximum reduction of GHGs that is required by the Clean Air Act. Specifically, Sierra Club objects that the Region clearly erred or abused its discretion (1) by failing to base the permitted GHG emission limits for the combined cycle natural gas-fired combustion turbines that will be used at this facility on the energy efficiency of the most efficient of the three turbine models that LPEC identified for potential use at this facility, and (2) by declining to require LPEC to consider adding a solar thermal energy component to the proposed facility in order to further reduce GHG emissions. Pet. at 7-29.

For the reasons explained below, the Board concludes that Sierra Club has failed to demonstrate that the Region clearly erred or abused its discretion in its BACT determinations in this case.

A. *The Region Did Not Clearly Err or Abuse its Discretion in Establishing the GHG Permit Limits for the Combustion Turbines at the LPEC Facility*

As explained in Part V above, LPEC has not yet made a final selection of the combustion turbine model it will use at the LPEC facility. LPEC explains that, "[b]ecause the PSD permitting process can take months or years to complete, the project developer generally does not select a particular turbine for a project until the final stages of project development." LPEC Resp. at 8. LPEC further explains that the business considerations affecting its final selection of turbine model include the projected demand for electricity from these units (which informs the amount of generation capacity that is needed) and the turbines' relative efficiency, reliability, and cost. *See id.*; *see also* RTC at 5 (describing factors applicants typically consider in selecting turbines).[5]

The Region accommodated LPEC's desire to retain the flexibility to choose the specific turbine model for its facility at a later stage of the process by specifying separate GHG emission limits in

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[5] *See also NSR Manual* at B.61 (recognizing that, in selecting gas turbine models, a utility typically considers "the peak demand which must be met, efficiency of the gas turbine, reliability requirements, and the experience of the utility with the operation and maintenance service of the particular manufacturer and turbine design").

LPEC's permit for each of the three turbine models under consideration. The permit requires LPEC to submit a permit modification request to the Region once LPEC has selected the final turbine model to eliminate the non-selected models from the permit. Permit at 13. At oral argument, LPEC represented that it has obtained all other necessary permits for construction of the facility and is now prepared to finalize its financing arrangements and construction plans upon EPA's final issuance of the PSD permit under consideration in this matter. Oral Arg. Tr. at 10-11. LPEC further stated that it currently plans to select the GE turbine (the smallest of the three turbine models). *Id*.

Sierra Club argues that the Region failed to conduct a proper BACT analysis in setting the output-based GHG emission limits for the combustion turbines. Sierra Club objects to the Region's establishing "alternate" GHG limits specific to each of the three models, allowing LPEC to select whichever model it chooses after the permit is issued. In Sierra Club's view, the permitted GHG emission limits must be based on the lowest GHG emission limit that any of the three turbine models can achieve, regardless of which model LPEC finally selects. Specifically, Sierra Club argues that the output-based permit limits must be set at the 909.2 lb CO_2 /MWh emission limit that the Region specified for the Siemens 4 turbine. Pet. at 9 & 14 n.5. The output-based permit limits for the Siemens 5 and GE turbines are slightly higher (912.7 and 934.5 lb CO_2/MWh, respectively).[6] Permit at 13.

At the outset, it is important to be clear what is actually at issue in this case. The parties have characterized this case as raising the issue of whether the Region can establish "alternate limits" as BACT for the LPEC combustion turbines. Sierra Club objects that this approach will allow permit applicants essentially to choose their own emission limits.[7]

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[6] In contrast, the GE turbine has the lowest permit limits among the three models for total annual emissions and startup emissions. *See* Permit at 7-13.

[7] Pet. at 3 ("Rather than selecting BACT based on the most efficient turbine that meets the applicant's project purpose, the Region set three different limits and allowed the applicant to choose which would apply depending on which turbine design was (continued...)

The Board does not agree. First, the Region, not LPEC, determined the permit limits here. Second, the permit will be modified to delete any reference to the other turbines once LPEC selects its model. Therefore, only *one* BACT limit ultimately will be permitted for LPEC's combustion turbines. Essentially, the Region has established separate BACT limits for each of three different potential projects to be built.

Sierra Club's arguments, in effect, pose three questions for the Board: (1) whether the permit's GHG emission limit for the Siemens 4 turbine represents BACT, (2) whether the permit limit for the Siemens 5 turbine represents BACT, and (3) whether the permit limit for the GE turbine represents BACT. Because Sierra Club does not question the BACT permit limit for the Siemens 4 turbine, the questions are narrowed to whether the slightly higher output-based GHG permit limits for the Siemens 5 and the GE turbines represent BACT when considered on their own.[8] The GHG emission level that can be achieved by the Siemens 4 turbine is certainly relevant to these questions, but it is not conclusive, as explained below. Thus, the Board need not reach the more general question of whether PSD permits can include "alternate limits" in a single permit.[9]

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[7](...continued)
ultimately installed.").

[8] As noted above, the permit limits for total annual emissions and start-up emissions from the GE turbine are actually lower than the limits for the Siemens 4 turbine.

[9] The parties' use of the phrase "alternate limits" reflects and adds to the confusion caused by the Region's approach to the permit in this case, in allowing LPEC to make its final turbine selection after the permit is issued. Evaluating BACT based on three different design and construction scenarios simultaneously poses challenges for the Region in analyzing and explaining its analysis for each limit properly (and separately). It also poses challenges for members of the public seeking to comment on the proposed permit. Further, this approach complicates the permitting process and makes it more difficult to issue the PSD permit in an expeditious time frame. To avoid these problems, the Board suggests that permitting authorities encourage applicants to make the significant decisions affecting final project design before the permit is issued and ideally before the permit is issued for public comment.

Sierra Club relies most heavily on its argument that the Region erred in conducting its five-step "top-down" BACT analysis (described in Part VI above) to establish the GHG emission limits for the combustion turbines. *See* Pet. at 12-15. The Board finds that Sierra Club has failed to demonstrate clear error in the Region's BACT analysis.

The Region explained its BACT analysis in its Statement of Basis for the draft LPEC permit. SOB at 8-20. In the first step of its analysis, the Region identified combined cycle combustion turbines with "efficient turbine design" as the most energy efficient way to generate electricity from a natural gas fuel source.[10] RTC at 4; *accord* SOB at 8. In Step 2, the Region determined that this technology is technically feasible. SOB at 11. The Region did not conduct a Step 3 ranking analysis of alternatives because it had identified only one technology option for reducing GHG emissions through energy efficiency in the prior steps of the analysis. *Id.* In Step 4 of its analysis, the Region concluded that there are no energy, environmental or economic impediments to the use of combined cycle combustion technology at the LPEC power plant. *Id.* at 12. Finally, in Step 5 of its analysis, the Region based the GHG emission limits on the highest level of pollution control that it considered to be achievable for the combined cycle combustion turbines at the LPEC facility. *Id*. at 13-20.

To assure that the GHG emission limits established in Step 5 of its analysis represent BACT for combined cycle combustion turbines, the Region compared the energy efficiency (as measured by heat rate) and GHG emission rates of the three proposed LPEC turbine models to the heat rates and GHG emission rates that other PSD permitting authorities have accepted as BACT for eight other facilities using combined cycle

[10] The Region also identified carbon capture and sequestration as another technology option for reducing GHG emissions but eliminated that technology from further consideration in Step 4 of its analysis based on economic, energy, and environmental considerations. SOB at 11. Sierra Club does not challenge that determination on this appeal.

combustion technology.[11] *Id*. at 13-14. Permitting authorities typically conduct such a review of comparable sources when assessing appropriate BACT limits. *See NSR Manual* at B.23-24; *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 75-76, 93-97 (EAB Aug. 2, 2013), 16 E.A.D. __. The Region concluded that all three turbine models proposed by LPEC are "highly efficient turbines" and that the GHG emission limits selected by the Region are comparable to the emission limits that have been accepted as BACT by other PSD permitting authorities.[12] SOB at 8 and 17.

Sierra Club does not object to the Region's conclusion that combined cycle combustion turbines represent the best available technology for controlling GHG emissions from the LPEC facility. Nor does it disagree with the Region's conclusion that the heat rates and GHG emission levels of the three turbine models proposed by LPEC are within the range that other PSD permitting authorities have established as BACT for other facilities using combined cycle combustion technology. Sierra Club instead contends that the Region erred by failing to conduct its BACT analysis based on a comparison and ranking of the three specific turbine models proposed by LPEC against each other. *See* Pet. at 13-15. Under Sierra Club's suggested approach, the

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[11] The comparison table provided by the Region in the Statement of Basis expresses the heat rates and GHG emission limits that have been permitted for other facilities using varying measures and operational assumptions. *See* SOB at 13-14. This makes it difficult for readers to compare these limits directly to the limits proposed for the LPEC facility. This presentation presumably reflects differing measures used by the permitting authorities for these other facilities. Nevertheless, the Board encourages permitting authorities to make a greater effort to present and explain their analyses using more consistent measures, by performing the necessary mathematical conversions and obtaining additional information when it is available. Presenting consistent, comparable information is essential for making decisions transparent to the public.

[12] The Region, like other permitting authorities, included a "compliance margin" in the permit limits to allow for design and performance variability and degradation over time of turbine equipment. SOB at 15. These compliance margins, which vary among permitting authorities and specific permits, are included in the emission limits shown in the comparison table. *Id*. at 13-14. Although Sierra Club objected in its public comments that the Region's 12.6% compliance margin in the LPEC permit was excessive, Sierra Club did not raise that objection on this appeal.

Region would identify each turbine model as a separate control technology in Step 1, rank the models against each other in Step 3, and select the model with the lowest GHG emission levels (the Siemens 4) as the basis for the output-based BACT emission limit for all three models in Step 5 of the analysis. *See id*.

The Board finds that Sierra Club's suggested method of analysis is not required as a matter of law or EPA policy. Sierra Club's suggested model-specific approach to Steps 1 and 3 of the BACT analysis is not supported by the language or examples used in the NSR Manual and the GHG Permitting Guidance to describe the five-step analytical method. Both these guidance documents suggest that permitting authorities identify general *types* or *categories* of control technologies in Step 1 and rank them against each other in Step 3 based on the emission reduction levels that are achievable for that type of technology. The guidance does not suggest that the analysis should also identify and rank specific equipment *models* that are available for each type of technology considered. *See GHG Permitting Guidance* at 17-18 ("[T]he top-down process calls for all available control *technologies* for a given pollutant to be identified and ranked in descending order of control effectiveness.") (emphasis added), 29 & F-1 (identifying simple cycle and combined cycle combustion technologies as technology options to consider for GHG emissions from natural gas-fired power plants); *NSR Manual* at B.34 (listing wet scrubbers, carbon absorbers, condensers, incineration, electrostatic precipitators, fabric filters and selective catalytic reduction as examples of technology alternatives to consider in BACT analysis for other types of pollutants), B.57-75 (identifying combined cycle and simple cycle gas turbines as control technologies in Step 1).

Therefore, the Board finds no support in EPA's BACT guidance for Sierra Club's position that the three specific turbine models proposed by LPEC must be identified as separate control technologies in the Region's five-step analysis.

The important question here is whether the Region clearly erred or abused its discretion by failing to base the output-based permit limits for the Siemens 5 and GE turbines on the maximum degree of GHG pollution reduction that is achievable at this facility. The Clean Air Act specifies that permitting authorities are required to make BACT decisions "on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs." CAA § 169, 42 U.S.C. § 7479(3). Consistent with this statutory direction, both the Board and EPA guidance have recognized that permitting authorities have discretion to make the case-by-case determinations necessary to establish BACT limits based on the circumstances of a particular facility. *GHG Permitting Guidance* at 17, 20; *NSR Manual* at B.57.

The GHG Permitting Guidance provides the following guidance for determining case-specific BACT limits:

> In determining the appropriate limit, the permitting authority can consider a range of factors, including the ability of the control option to consistently achieve a certain emissions rate, available data on past performance of the selected technology, and specific circumstances of the specific source under review which might affect the range of performance. *In setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue.*

GHG Permitting Guidance at 44 (emphasis added).

The NSR Manual makes clear that permitting authorities are not expected to consider every possible level of control or to impose the highest possible level of control in all circumstances:

> It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of

> options. Rather, the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.
>
> *** While the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered.
>
> *** In assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review.

NSR Manual at B.23-24.

Similarly, the Board has recognized that permitting authorities are not always required to impose the highest possible level of control efficiency but may take case-specific circumstances into consideration in determining what level of control is achievable for a given source. *See, e.g.*, *In re Russell City Energy Ctr.*, PSD Appeal Nos. 10-01 through 10-05, slip op. at 77-81 (EAB Nov. 18, 2010), 15 E.A.D. ___ (rejecting a "bright line" test of requiring the highest or average level of control that another source has achieved), *petition denied sub nom. Chabot-Las Positas Cmty. Coll. Dist. v. EPA*, 428 F. App'x 219 (9th Cir. 2012); *In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 441 (EAB 2005) ("We recently explained that '[t]he underlying principle of all of these cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology.'" (citing *In re Cardinal FG Co.*, 12 E.A.D. 153, 170 (EAB 2005))); *In re Kendall New Century Redev.*, 11 E.A.D. 40, 53 (EAB 2003) (upholding state permitting authority's decision to establish a BACT emission limit at the top of the range of comparable limits at other facilities, based on case-specific distinctions that *included the size of the combined cycle combustion units*); *In re Steel Dynamics, Inc.*, 9 E.A.D. 740, 760 (EAB 2001) ("Thus, while the guidance instructs permit authorities to evaluate the most effective level of control, it also contemplates that those authorities may exercise their discretion in reviewing less effective levels of control").

In this case, the Region has cited two case-specific reasons for declining to impose the somewhat more stringent output-based GHG emission limit of the Siemens 4 turbine model on the Siemens 5 and GE models: (1) the variation in the models' electric generation capacities and (2) the comparability of the GHG emission rates of all three models. Responding to Sierra Club's public comment that the permit limits should be based solely on the Siemens 4 turbine model, the Region explained:

> EPA has determined that BACT for this facility is combined cycle technology with efficient turbine design, and does not agree that each gas turbine model is a different control technique that must be compared against other models, with one model necessarily being chosen over the others. Because the project is defined by the permit applicant as having a production capacity range of 637-753 megawatts (MW) of gross electrical power, EPA has established alternative sets of BACT limits for combined cycle technology that will apply *based on the capacity of the turbine selected by the applicant from among efficient turbine models that have comparable control efficiencies.*

RTC at 4 (emphasis added).

The Region further explained that the marginal variations in efficiency and output-based GHG emission rates among the three turbine models are attributable to the differences in the models' electric generation capacities. *Id*. at 5 ("If each turbine model is operated at maximum capacity, the Siemens [4 and 5] turbines are marginally more efficient because of their higher capacity."). The Region concluded that the GHG emission limits in the permit should vary with the capacity of the particular model in order to achieve the maximum emission reductions that are achievable for each model.[13] *Id.* ("The approach reflected in the permit ensures that the applicant is required to meet the lowest GHG level that is achievable with the turbine that is optimally sized for the particular capacity that the applicant ultimately selects within the size range specified in the application.").

Sierra Club's petition does not specifically challenge the Region's determination that the GHG emission limits included in the permit represent the lowest emission limits that each of LPEC's three proposed models *can* achieve. Rather, Sierra Club suggests that any of the three models will fulfill LPEC's project purpose, and therefore, the permit's output-based emission limits should be based solely on the most efficient model with the lowest output-based GHG emission rate. Pet. at 7-9. At the same time, Sierra Club explicitly states that it does *not* suggest that the Region should compel LPEC to select the Siemens 4 turbine. *Id*. at 14 n.5. Thus, Sierra Club fails to refute the Region's determination that the GHG output-based emission limits in the permit represent the maximum pollutant reductions that are achievable by each of the three turbine models.[14] The Board will defer to this determination, which is based on the Region's technical judgment. *See In re Indeck-Elwood, LLC*, 13 E.A.D. 126, 161 n.67 (EAB 2006) ("[W]here the views of the permit issuer and the petitioner indicate bona fide differences of expert opinion or judgment on a technical issue, the Board typically will

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[13] The Region noted that, if LPEC ultimately desired to supply power at the lower end of the capacity range for business reasons (as appears to be the case here, *see* Oral Arg. Tr. at 11-15), then the marginal efficiency of the larger turbines "would not necessarily be achieved if the permit applicant is required to" oversize the turbine and operate it "at less than its optimal capacity." RTC at 5-6.

[14] Sierra Club also suggested in its public comments and at oral argument that the each of the turbine models can achieve a lower emission limit because the Region has allowed an overly generous compliance margin for the permit emission limits. *See* Sierra Club Comments at 6-8; Oral Arg. Tr. at 101-02. Sierra Club did not, however, challenge that compliance margin in its Petition. In addition, Sierra Club suggests that there is no dispute "that if the LPEC applies the [Siemens 4] design, it can achieve a lower emission rate per Megawatt hour than the other two turbine designs." Pet. at 9. Sierra Club does not explain, however, how LPEC could "apply" the Siemens 4 design without actually selecting the Siemens 4 turbine.

defer to the permit issuer.") (internal quotations omitted); *In re NE Hub Partners, LP*, 7 E.A.D. 561, 567-68 (EAB 1998) (same), *review denied sub nom. Penn Fuel Gas, Inc. v. EPA*, 185 F.3d 862 (3d Cir. 1999).

The Board also defers to the Region's technical determination that the differences in the GHG emission rates of LPEC's proposed three turbine models are marginal. As noted above, the GHG permit limits for the three models (calculated on a gross output basis) range from 909.2 to 934.5 lb CO_2/MWh, which the Region noted is a variation of only 2.6%. SOB at 16. The range is even narrower when the limits are calculated on a net output basis. *See* RTC at 11 (showing a range from 945.2 to 965.7 lb CO_2/MWh for the three models' BACT limits calculated on a net output basis). The Board calculates the variation in this range as only 2.1%. More significantly, the Region points out that the difference between the output-based emission units for the Siemens 4 turbine and the GE turbine, which LPEC currently plans to select, is only 0.1% when measured on a net output basis.[15] *See* Oral Arg. Tr. at 67 (referring to table in RTC at 11).

The Board concludes, based on this record, that the Region had a rational basis for its determination that all three of the permitted turbine models are "comparably efficient on a performance basis and * * * the assigned BACT limits [are] substantially equivalent except for marginal differences attributable to capacity." Region's Resp. at 5; *accord* RTC at 4-7. In light of their comparable emission levels, the Region takes the position that there is no need to select one of the models over the others in the BACT analysis. RTC at 4-7. The NSR Manual and Board precedent provide some support for this position. The NSR Manual suggests that permitting authorities need not perform a detailed BACT analysis distinguishing between technology alternatives that result

[15] PSD permitting authorities have established BACT limits for GHGs based on both net output and gross output measures. *See* SOB at 13-14 (table); *GHG Permitting Guidance* at 37 (suggesting that net output measures may be preferable for some purposes). During the public comment period, Sierra Club suggested that the LPEC permit limits should be based on net, rather than gross, output. The Region explained its reasons for choosing the gross output measure for this permit, *see* RTC at 10-11, and Sierra Club raises no objection to that choice on this appeal.

in "*essentially equivalent*" or "*identical*" emissions or emission levels with a "*negligible difference*." *NSR Manual* at B.20-21. Citing this provision of the NSR Manual, the Board upheld a permitting authority's decision to eliminate integrated gasification combined cycle ("IGCC") technology from further consideration in the BACT analysis for a coal-fired power plant that was based on a finding that the pollution control efficiency of IGCC technology was comparable to that of another, less expensive technology alternative. *In re Prairie State Generating Co.*, 13 E.A.D. 1, 34-38 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007).

Based on the record in this case, the Board concludes that the Region did not clearly err or abuse its discretion in determining that the GHG emission limits for all three turbine models represent BACT for highly efficient combined cycle combustion turbines, and that the separate emission limits specified for each of the three models will assure that LPEC minimizes GHG emissions from the combustion turbines regardless of which model it selects. The Region duly considered Sierra Club's comments on this issue, and its explanation of its decision is rational in light of all of the information in the record of this case.

If LPEC proceeds with its plan to select the GE turbine, the Board further notes that this turbine model is the smallest of the three models originally proposed by LPEC and, accordingly, has the lowest total annual GHG emission limit (and startup emission limit).[16] Permit at 13. Therefore, LPEC's current choice of turbine should result in the smallest environmental impact from GHG emissions among the three options it first proposed. *See GHG Permitting Guidance* at 46 ("[S]ince the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages.").

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[16] The permit's total annual GHG emission limit for the GE turbine is 1,263,055 tons per year ("TPY") carbon dioxide equivalent ("CO_2e"), compared to limits of 1,417,263 and 1,595,712 TPY CO_2e for the two Siemens turbines. Permit at 7, 9, 11.

B. *Sierra Club Has Not Demonstrated that the Region Abused Its Discretion in Concluding That Adding Solar Technology to the LPEC Facility Would "Redefine the Source"*

The Region did not require LPEC to evaluate solar thermal generating equipment as a potential control option in its BACT analysis for GHGs. *See generally* SOB at 8-11. In commenting on the draft permit, Sierra Club argued that the BACT analysis should have considered the option of solar hybrid technology similar to that used at two other recently permitted facilities. Sierra Club Comments at 18-19; *see also id.* at 11. The Region responded that to do so "would constitute redefining the source." RTC at 21, 37.

On appeal, Sierra Club challenges the Region's conclusion, arguing that, if LPEC used supplemental solar thermal steam, the facility would still be a predominantly gas-fired combined-cycle power plant of the same size and energy production and thus its purpose would not be "redefined." Pet. at 23. Sierra Club also claims that supplemental solar thermal energy in a natural gas combined-cycle generating process is a cleaner production process that has been demonstrated at Palmdale Hybrid Power Project and the Victorville 2 facility and thus should have been considered. *Id*. at 16-20. In its response brief, the Region asserts that it has broad discretion in making "redefining the source" determinations and that, in this case, it properly concluded that a solar preheating option would redefine the source. Region Resp. at 11; *accord* LPEC Resp. at 15.

The Board reviews permitting authorities' determinations that a proposed alternative would "redefine the source" under an abuse of discretion standard. *Russell City*, slip op. at 97, 15 E.A.D. at ___; *In re Desert Rock Energy Co.*, PSD Appeal Nos. 08-03 through 08-06, slip op. at 59, 65, 76-77 (Sept. 24, 2009), 14 E.A.D. at ___. For the following reasons, the Board concludes that Sierra Club has not demonstrated that the Region abused its discretion in this case.

1. *Relevant Legal Principles: Redefining the Design of the Source*

EPA guidance and Board precedent, affirmed by a federal court of appeals, give permitting authorities the discretion to exclude proposed control alternatives that would constitute a "redefinition of the design of the source" from the BACT analysis for that source. *NSR Manual* at B.13*; GHG Permitting Guidance* at 26; *In re Sierra Pacific Indus.*, PSD Appeal Nos. 13-10 through 13-04, slip op. at 59 (EAB July 18, 2013), 16 E.A.D. ___; *In re City of Palmdale*, PSD Appeal No. 11-07, slip op. at 40-42 (EAB Sept. 17, 2012), 15 E.A.D. ___; *Prairie State*, 13 E.A.D. at 15; *In re Knauf Fiberglass, GmbH*, 8 E.A.D. 121, 136 (EAB 1999). If a permitting authority decides that a proposed alternative would constitute a redefinition of the source, it will not list the alternative as a potential control option in Step 1 of its BACT analysis, and that option will not be considered further. *NSR Manual* at B.13.

EPA generally considers proposed changes to an applicant's proposed primary fuel to be a redefinition of the source. *Id*. (building a natural gas-fired electric turbine in lieu of a coal-fired electric generator not required); *Palmdale*, slip op. at 42, 15 E.A.D. at __ (summarizing prior Board cases). The Agency's 2011 GHG guidance acknowledges and reaffirms this principle:

> EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.,* coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating

> unit. Ultimately, however a permitting authority retains the discretion to conduct a broader BACT analysis and to consider changes in the primary fuel in Step 1 of the analysis.

GHG Permitting Guidance at 27-28.

The 2011 guidance distinguishes the above scenario from the situation in which a permit applicant has already proposed use of a secondary fuel type in its project. *Id.* at 28. In the latter circumstance, the guidance provides:

> [W]hen a permit applicant has incorporated a particular fuel into one aspect of the project design (such as startup or auxiliary applications), this suggests that a fuel is "available" to a permit applicant. In such circumstances, greater utilization of a fuel that the applicant is already proposing to use in some aspect of the project design should be listed as an option in Step 1 unless it can be demonstrated that such an option would disrupt the applicant's basic business purpose for the proposed facility.

Id.[17]

The guidance does not explicitly address a third, intermediate option, which is at issue in the present case: whether a *partial* switch or *supplementation* of the primary fuel with a different type of fuel that the applicant did *not* initially propose as a secondary fuel would constitute a redefinition of the source. To address this issue, the Board reviews the

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[17] Board and Agency case law is consistent with this approach. *See, e.g., Sierra Pacific*, slip op. at 62-65, 15 E.A.D. at ___ (discussing whether biomass-natural gas mixes, other than the one the applicant proposed, should have been considered); *Palmdale*, slip op. at 44, 15 E.A.D. at ___ (discussing whether solar power generation beyond that proposed by the applicant should have been considered).

general principles that guide permitting authorities' decisions as to whether a proposed alternative constitutes redefinition of the source.

To determine whether a potential control option would redefine the source, the Board has required permitting authorities to examine first how the applicant defined the proposed facility's "end, object, aim, or purpose," in other words, "the facility's basic design" as described in the application and supporting materials. *Prairie State*, 13 E.A.D. at 22 (footnotes and citations omitted); *accord Sierra Pacific*, slip op. at 59, 15 E.A.D. at ___. The permit issuer then should take a "hard look" at which design elements are "inherent" to the applicant's purpose and which design elements could possibly be altered to achieve pollutant emissions reductions without disrupting the applicant's "basic business purpose" for the proposed facility. *Sierra Pacific*, slip op. at 59, 15 E.A.D. at ___; *Desert Rock*, slip op. at 64, 14 E.A.D. at ___; *Prairie State*, 13 E.A.D. at 23, 26. Additionally, the permit issuer must ensure that the proposed facility design was "derived for reasons independent of air quality permitting." *Prairie State*, 13 E.A.D. at 26; *accord Russell City*, slip op. at 98, 15 E.A.D. at ___; *Desert Rock*, slip op. at 64, 14 E.A.D. at ___.

The Board has cautioned that permitting authorities should not simply dismiss alternative control options, such as cleaner fuels, as constituting redesign, thereby creating an "automatic BACT off-ramp" from further consideration of the option. *NMU*, slip op. at 27, 14 E.A.D. at ___. The Clean Air Act specifies that a BACT determination requires a case-by-case analysis. CAA § 169(3), 42 U.S.C. § 7479(3). Thus, permitting authorities must consider the specific circumstances of the situation presented and explain their decisions in the record. *See, e.g., Sierra Pacific*, slip op. at 60-62, 15 E.A.D. at ___ ; *Palmdale*, slip op. at 45-46, 15 E.A.D. at ___.

In *Sierra Pacific* and *Palmdale*, the Board upheld two permitting decisions by EPA Region 9 rejecting suggestions that applicants' proposed fuel choices be modified to reduce GHG emissions, on the grounds that the suggested changes would redefine the design of those sources under the specific circumstances presented in those cases. *Sierra*

Pacific involved a lumber manufacturing facility that proposed to use a mix of 10% natural gas and 90% biomass (the facility's excess wood waste) to fuel steam turbines at the facility. The Board upheld the Region's determination that requiring a greater use of natural gas or addition of solar power would be inconsistent with the applicant's primary business purpose of burning its excess wood waste. *Sierra Pacific*, slip op. at 60-65, 15 E.A.D. at ___. *Palmdale* involved a new hybrid power plant that the applicant proposed to fuel primarily with natural gas, with a supplemental (10%) solar power component added in order to contribute to the State of California's renewable energy goals. The Board upheld the Region's determinations that an all-solar facility would be inconsistent with the applicant's business purpose of providing a baseload supply of electricity[18] and that, based on the record of that case, there was insufficient space at the proposed site to significantly increase the size of the solar energy component in any event. *Palmdale*, slip op. at 45-49, 15 E.A.D. at ___.

The case-specific justifications for Region 9's "redefining the source" determinations in *Sierra Pacific* and *Palmdale* were essential to the Board's decisions upholding those determinations. The Board did not conclude, as LPEC appears to suggest in the present case, that proposals to add solar power to a power plant fueled primarily by another fuel source always will constitute a redefinition of the source. *See* LPEC Resp. at 19; Oral Arg. Tr. at 49-50.

The Board's *Palmdale* decision makes clear that technical considerations such as space constraints and geography may be considered by permitting authorities in determining whether suggestions to add or increase the use of supplemental solar power would constitute redesign of the source. *See* slip op. at 48-52, 15 E.A.D. at ___. Generally, permitting authorities evaluate issues regarding the technical feasibility of a control technology in Step 2, rather than Step 1, of the BACT analysis. *See NSR Manual* at B.17 (suggesting that permitting

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[18] As explained in *Palmdale*, a baseload power plant is expected to be able to provide a reliable, continuous supply of electricity, at its full capacity, at all times. Slip op. at 45, 15 E.A.D. at ___.

authorities consider the commercial "availability" and "applicability" of a control technology in Step 2 of the five-step BACT analysis). Technical factors such as the availability of space and the physical location of the facility, however, may also inform a permitting authority's decision whether a proposed use of a different fuel would require redesign of the source. In the case of solar power, for example, if the permitting authority concludes that there are space limitations and/or meteorological concerns such that requiring use of solar panels would essentially require relocation of the entire facility, this conclusion clearly would be important to a Step 1 "redefining the design of the source" analysis.

2. *Case-Specific Analysis*

In determining whether Sierra Club has shown that the Region abused its discretion in concluding that use of solar thermal hybrid technology at the LPEC facility would "redefine the source," the Board reviews both the Region's explanation and the administrative record.

The Region explained its conclusion in two of its responses to public comments. *See* RTC at 21, 37 (responses to comments 16 and 27). In both responses, the Region distinguished between the proposed LPEC facility and previous projects in which the applicant had initially proposed a solar hybrid option. *Id*. More particularly, the Region explained:

> While we acknowledge there may be many ways for solar thermal processes to be integrated with a facility that intends to use steam to generate electricity, we believe that requiring such processes in combination with fossil-fuel combustion would represent the merging of distinct and different source types. While Region 9 required 50 MW of solar energy as part of its BACT determination for the Palmdale Hybrid Power Project NGCC facility, the permit applicant in that case had proposed the solar project as part of its project purpose, which included supporting California's goal of

> increasing the percentage of renewable energy in the State. Indeed, Region 9 specifically explained that it incorporated the solar project into its BACT determination not because it was required to do so, but because doing so was compatible with the permit applicant's goals and would therefore not redefine the source * * *.

Id. at 37; *accord id.* at 21. The Region contrasted the situation at the Palmdale facility from the present one, pointing out that, "[h]ere, LPEC did not include a solar energy component as part of its project in its permit application." *Id*. at 37; *accord id.* at 21 (explaining that the applicant "did not include renewable generation in its project purpose"). In its second response, the Region also referred to potential logistical problems with solar usage at this facility, stating that "the commenter has not explained how LPEC might incorporate such a solar component into its project, or even whether it has or can acquire the land necessary to do so, without redefining the source."[19] *Id*. at 37.

The Region's rationale for concluding that adding solar capacity at the LPEC facility would constitute redesign of the source is not as thorough as the Board would expect, nor does it constitute a "hard look." The Region's explanation comes very close to suggesting that adding supplemental solar power generation is always redesign if the applicant does not propose it in the first place. Such a bright line, "automatic BACT off-ramp" approach is not consistent with the NSR Manual, the GHG Permitting Guidance, or Board precedent, all of which suggest that a case-specific assessment of the situation be made in concluding that a proposed control option would redefine a particular source.

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[19] As the Region had stated at the time of the proposed permit, the size of the facility site is, at most, 78 acres. *See* SOB at 29; Jeffrey D. Owens, Intensive Cultural Resources Survey of the Proposed 78-Acre Tract, Harlingen, Cameron County, Texas ("Cultural Resources Survey"), at iii (Dec. 2012) (A.R. II.03); *see also* Revised Application at 15-16 (maps of the site and surrounding area).

Nevertheless, despite the deficiencies in the Region's explanation, under the facts and circumstances of this case, a remand is not necessary and would not lead to a different result. As the Board reiterated in *In re Steel Dynamics, Inc.*, 9 E.A.D. 165 (EAB 2000), to justify a remand, "there must be a compelling reason to believe that the omissions [by the permitting authority] led to an erroneous permit determination – in other words, that [omissions] materially affected the quality of the permit determination." 9 E.A.D. at 191-92 (quoting *In re Mecklenburg Cogeneration Ltd. P'ship*, 3 E.A.D. 492, 494 n.3 (Adm'r 1990)); *accord Palmdale*, slip op. at 48, 15 E.A.D. at ___; *In re Three Mountain Power, LLC,* 10 E.A.D. 39, 55 (EAB 2001). Here, upon review of the administrative record, the Board concludes that there is sufficient evidence to support the Region's conclusion that the supplemental solar option would constitute redesign of the source under the specific circumstances of this case given the business purpose, space limitations, and the specific design requirements of the facility.

The record in this case clearly indicates that it would be logistically difficult for the applicant to incorporate a significant solar component into the facility. The record shows that the site is approximately 78 acres, and at least half of that appears to be utilized by the plant itself and supporting infrastructure. *See* Revised Application at 15-16; *see also* SOB at 29; Cultural Resources Survey at iii; Oral Arg. Tr. at 48-49, 90. As the Board observed in *Palmdale*, generating a significant amount of electric power from solar energy typically requires large acreage for the solar panels. Slip op. at 49, 15 E.A.D. at ___ ("[A] substantial amount of additional acreage would be required to produce a significant amount of additional solar power." (relying on statements of the California Energy Commission)); *accord* Oral Arg. Tr. at 92. For example, in *Palmdale*, the California Energy Commission had estimated that a minimum of eight acres is required to generate one megawatt of electricity. *Palmdale*, slip op. at 49, 15 E.A.D. at ___. Applying this formula to the acreage of the LPEC facility site suggests that very little solar power could be generated there without either significantly expanding the site or relocating the facility.[20]

The record clearly indicates that relocation would be inconsistent with LPEC's basic business purpose. In its application, LPEC summarized the facility's purpose as the generation of 637 to 735 MW "of gross electrical power near the City of Harlingen in an efficient manner while increasing the reliability of the electrical supply for the State of Texas." Revised Application at 11. LPEC further explained that "[p]ipeline natural gas is chosen as the only fuel for the combustion turbines and duct burner systems due to *local availability of fuel and infrastructure* to support delivery of the fuel to the facility in adequate volume and pressure." *Id*. (emphasis added); *accord* Oral Arg. Tr. at 53. The Region also acknowledged this factor to be an important aspect of the proposed facility's design. *See* RTC at 9. LPEC additionally noted that another "[o]ne of the factors in siting the plant is the *availability of reclaimed water* from the City of Harlingen to be used as cooling water at the plant." Revised Application at 11 (emphasis added); *accord* Oral Arg. Tr. at 53. Because the facility is purposely located near reclaimed wastewater and available natural gas lines and associated infrastructure, relocating it would subvert the facility's basic business purpose and design and constitute redesign of the source.

There is also nothing in the record suggesting that LPEC could expand the acreage of the proposed facility in its current location. *See* RTC at 37; Revised Application at 11. Sierra Club has not provided any persuasive evidence or argument indicating otherwise. Sierra Club has merely pointed to two other facilities – Palmdale and Victorville – that have substantially larger acreage that specifically supports their use of solar hybrid technology. *See Palmdale*, slip op. at 49, 15 E.A.D at ___ (explaining that the facility would use approximately 250 acres to

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[20] For example, assuming that a maximum of 39 acres might be available for installation of a solar array at the site (based on the site plan included in the record) and that a minimum of eight acres is needed to generate one megawatt of electricity from solar power, LPEC would be able to produce only five megawatts of electricity from solar power.

generate 50 MW of power using solar technology); LPEC Resp. Ex. EE at 1-1 (City of Victorville, Application for PSD Permit for Victorville 2 Hybrid Power Project (Apr. 2007)) (same).

The Region's decision not to require LPEC to add a solar component to its facility under these circumstances is consistent with prior Board decisions upholding permitting authorities' discretion to reject options that would redefine the source. *See, e.g., Sierra Pacific*, slip op. at 62, 15 E.A.D. at ___ ; *Palmdale*, slip op. at 49-50, 15 E.A.D. at ___; *Russell City*, slip op. at 99-100, 15 E.A.D. at ___ (concluding that permit issuer did not abuse its discretion in determining that dry cooling would redefine the source where facility was initially designed to utilize the city's wastewater, and city transferred land to applicant to allow the facility to be located in that particular location specifically to facilitate use of that wastewater); *Prairie State*, 13 E.A.D. at 28 (concluding that permit issuer's determination that consideration of low-sulfur coal, which would necessarily require use of a fuel source other than the coal at the co-located mine, would require a redefinition of the fundamental purpose or basic design of the proposed mine-mouth facility).

In sum, the business purposes and site-specific constraints described in the administrative record support the Region's conclusion that use of supplemental solar power would constitute redesign of the source under the circumstances of this case.[21] Sierra Club itself, in fact, generally acknowledged that "site-specific considerations" could "preclude the use of solar hybrid technology" at a site in its comments on the draft permit. Sierra Club Comments at 19. Based on the record

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[21] There is also no suggestion in this case that LPEC purposely avoided use of solar hybrid technology in its proposed design to circumvent BACT analysis or air quality permitting requirements, which, as noted above, is another factor that the Board typically considers. *See Prairie State*, 13 E.A.D. at 26. LPEC's site selection was due to the availability of reclaimed wastewater from the City as well as the availability of natural gas and the infrastructure to support efficient and sufficient delivery of the fuel to the proposed facility. *See* RTC at 9; Revised Application at 11. These considerations are clearly related to efficient energy production and do not suggest in any way that the applicant attempted to circumvent Clean Air Act requirements by not including a solar hybrid component in its design.

in this case, the Board concludes that Sierra Club has failed to demonstrate that the Region abused its discretion in concluding that use of solar thermal hybrid technology as a potential control technology for reducing GHG emissions at the facility would "redefine the source."

The Board emphasizes, however, that permitting authorities should include in their Response to Comments a clear and full explanation of any decision to reject comments suggesting the use of a solar component at a proposed facility on the grounds that it would require redefinition of the source. If, as here, a permitting authority's "redefinition of the source" decision is based in part on technical and/or logistical obstacles, it should document the factual basis for its conclusions in the record and explain how the commenter's suggestion would be inconsistent with the facility's basic business purpose (the essential inquiry for a "redefinition of the source" determination). If the permitting authority's decision is based *solely* on technical and/or logistical obstacles to implementing solar options at the proposed facility, the permitting authority should consider whether a Step 2 technical feasibility analysis is needed.

The Board is not suggesting that permitting authorities must perform a full and detailed analysis of all potential solar power options every time a commenter suggests that solar power be considered at a facility. We rejected that suggestion in *Palmdale*, slip op. at 47-48, 15 E.A.D. at ___ (stating that Region was not required to analyze every possible configuration for increasing the solar power component of a proposed power plant in response to a commenter's very vague and general suggestions). The permitting authority may appropriately tailor the level of analysis to the circumstances presented by the case. Further, the scope of a permitting authority's duty to respond to comments suggesting the addition of solar technology is limited to the extent to which the comment is raised. *See Palmdale*, slip op. at 59, 15 E.A.D. at ___; *Knauf,* 8 E.A.D. at 147 (explaining that permit issuer may provide general justifications in its responses where commenters raised issues in a general manner). At a minimum, however, the permitting authority should provide a reasoned response to comments that are fairly raised.[22]

VIII. *CONCLUSION AND ORDER*

For the reasons described above, the Board denies Sierra Club's petition for review of the Region's final permit decision for La Paloma Energy Center, LLC, PSD Permit No. TX-1288-GHG.

So ordered.

[22] See, for example, the explanation that the Region provided in its response brief, explaining why the commenter's suggestion in this case was both logistically unworkable at this site and inconsistent with LPEC's business purpose for the facility. Region Resp. at 12-15. The Region could have provided this explanation at an earlier point in the permitting process by including it in its Response to Comments.

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Order Denying Review in the matter of *La Paloma Energy Center, LLC*, PSD Appeal No. 13-10, were sent to the following persons in the manner indicated:

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Annette Duncan
Secretary

Date: MAR 14 2014

Attachment 9

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
OFFICE OF NEW REACTORS
OFFICE OF NUCLEAR MATERIALS SAFETY AND SAFEGUARDS
WASHINGTON, DC 20555-0001

February 23, 2009

NRC INFORMATION NOTICE 2009-02: BIODIESEL IN FUEL OIL COULD ADVERSELY IMPACT DIESEL ENGINE PERFORMANCE

ADDRESSEES

All holders of operating licenses for nuclear power reactors and fuel cycle facilities, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel; all current and potential applicants for an early site permit, combined license, or standard design certification for a nuclear power plant under the provisions of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants"; all current holders of and potential applicants for construction permits under 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities"; and all licensees and potential applicants for new fuel cycle facilities under 10 CFR Part 70, "Domestic Licensing of Special Nuclear Material."

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert licensees to the potential for diesel fuel oil to contain up to 5-percent biodiesel (B5), which could adversely impact engine performance. The NRC expects recipients to review the information for applicability to their facilities and to consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

On June 19, 2008, the American Society for Testing and Materials (ASTM) International D02 Main Committee approved a revision to the conventional petrodiesel standard specification. The revised standard, ASTM D975-08a, "Standard Specification for Diesel Fuel Oils," now permits No. 2 diesel fuel to contain up to a B5 blend and still be considered the same without labeling the blend. The changes to this standard will take effect within 3 to 5 months after the October 13, 2008, publication date of the final standard. The introduction of biodiesel blends into the No. 2 diesel fuel supply raises potential generic applicability and common-cause failure concerns because of the possibly adverse physical properties associated with biodiesel use in diesel engines including the safety-related emergency diesel generators (EDGs).

Examples of diesel engines providing functions important to safety include EDGs, diesel-driven fire pumps, diesel-driven auxiliary feedwater pumps, diesel-driven essential service water makeup pumps, diesel-driven instrument air compressors, security diesel generators, safeshutdown facility diesel generators, diesel generators for emergency preparedness and response functions, and station blackout diesel generators. The U.S. Department of Energy has stated that biodiesel blends of B5 or less do not cause noticeable differences in performance compared to No. 2 diesel fuel. However, for the reasons discussed below, a B5 blend could be problematic for EDGs and diesel engines that provide functions important to safety.

Cleaning Effect

B5 can have a cleaning effect that loosens accumulated sediment in fuel oil storage tanks that previously stored conventional diesel fuel. This sediment can then plug filters and other equipment in the fuel oil system. To prevent the buildup of this sediment, licensees may take the following actions:

- Clean fuel oil storage tanks before putting B5 in them.
- Add and/or upgrade the filters in the fuel oil system.

Licensees can expect to change and/or clean filters more frequently, especially during the early stages of B5 use.

Water

B5 contains suspended particles of water from the manufacturing process. This water will, in time, fall out of suspension and form "dirty water" in the fuel oil storage tank, which eventually leads to the formation and growth of algae. To prevent the formation of dirty water and the subsequent growth of algae, licensees may take the following actions:

- Use a moisture dispersant and biocide in fuel oil storage tanks containing B5.
- Add a fuel/water separator to the fuel oil system.
- Keep fuel oil storage tanks topped off to minimize in-tank condensation.

Biodegradation

B5 is biodegradable, and the presence of water, heat, oxygen, and other impurities accelerate the degradation of the fuel supply. To avoid damage caused by fuel degradation, licensees may consider not using B5 if it has been stored for an extended period of time (approximately 3 to 6 months or longer).

Material Incompatibility

Brass, bronze, copper, lead, tin, and zinc in tanks and fittings may accelerate the oxidation process of B5, creating fuel insolubles or gels and salts. Licensees should avoid using zinc linings, copper pipes and fittings, and brass regulators with B5.

Licensees should verify that elastomeric materials, such as hoses, gaskets, and O-rings, and their inspection and maintenance, are compatible with B5 and its effects.

Temperature Protection

Biodiesel components have higher cloud points (the temperature at which solid particles start to form, or gel) than standard (petroleum) diesel components. The cloud point also varies considerably with the source of the biodiesel component, which is not specified in B5 blends. Clouding may also combine with suspended particles of water and exacerbate adverse cold temperature concerns. Consequently, licensees should evaluate and ensure adequate low temperature protection for all diesel generator system components.

Housekeeping

Biodiesel is a good solvent. If it is left on a painted surface long enough, it can dissolve certain types of paints. Licensees should check for compatibility with paints they use, and should immediately wipe any B5 spills from painted surfaces.

BACKGROUND

Applicable Regulatory Documents

General Design Criterion 17, “Electric Power Systems,” of Appendix A, “General Design Criteria for Nuclear Power Plants,” to 10 CFR Part 50, requires that onsite and offsite electric power systems be provided to permit the functioning of structures, systems, and components important to safety. In addition, General Design Criterion 17 contains requirements for system capacity, capability, independence, redundancy, availability, testability, and reliability. Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” to 10 CFR Part 50, establishes overall quality assurance requirements for the design, construction, and operation of structures, systems, and components important to safety.

Regulatory Guide (RG) 1.137, “Fuel Oil Systems for Standby Diesel Generators,” Revision 1, issued October 1979, describes a method that the NRC staff finds acceptable for complying with the Commission’s regulations on diesel fuel oil systems for standby diesel generators and assurance of adequate quality of diesel fuel oil. RG 1.137 states that licensees should use Appendix B to American National Standards Institute N195-1976 as a basis for a program to ensure the initial and continuing quality of diesel fuel oil as supplemented by eight additional provisions in RG 1.137 for maintaining the properties and quality of diesel fuel oil.

Related NRC Generic Communications

NRC IN 2006-22, “New Ultra-Low-Sulfur Diesel Fuel Oil Could Adversely Impact Diesel Engine Performance,” dated October 12, 2006, alerts addresses to the potential of new ultra-low-sulfur diesel fuel oil to adversely impact diesel engine performance.

NRC IN 96-67, “Vulnerability of Emergency Diesel Generators to Fuel Oil/Lubricating Oil Incompatibility,” dated December 19, 1996, alerts addressees to a finding that involves the degradation of the power block assembly of two EDGs caused by an incompatibility of the lubricating oil with a low-sulfur-content diesel fuel oil.

NRC IN 94-19, “Emergency Diesel Generator Vulnerability to Failure From Cold Fuel Oil,” dated March 16, 1994, alerts addressees to a safety problem that could lead to the common mode failure of all emergency diesel generator units as a result of temperature-related changes in the fuel oil.

NRC IN 91-46, “Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems,” dated July 18, 1991, alerts addressees to the potential inoperability of multiple EDGs resulting from two common-cause degradations:

(1) degraded diesel fuel oil delivery systems, and

(2) the failure of the licensee to meet technical specification testing requirements intended to detect the potentially degraded quality of the diesel fuel oil stored on site.

NRC Generic Letter 83-26, “Clarification of Surveillance Requirements for Diesel Fuel Impurity Level Tests,” provides licensees with revised surveillance requirements for tests of the impurity level in diesel fuel oil to clearly reflect the relationship between the standard technical specification testing requirements for impurity levels in diesel fuel oil; guidance given in RG 1.137, Revision 1, and American National Standards Institute N195-1976 (ASTM D270, ASTM D975, and ASTM D2274); and the NRC staff review performed in accordance with Section 9.5.4 of NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.”

DISCUSSION

The conventional petrodiesel standard specification, ASTM D975-08a, has been revised to permit No. 2 diesel fuel to contain up to a B5 blend and still be considered the same without labeling the blend. Licensees may start receiving B5 in the near future. As described above, B5 has a number of characteristics that could potentially degrade or render inoperable the associated diesel engine or may create a condition that is inconsistent with current plant design and licensing bases. This B5 issue is of particular concern because it could potentially affect licensee diesel generators that are safety related and/or important to safety, thereby presenting a possible common-mode failure. Licensees can evaluate the potential impacts of B5 and can act to ensure that their plants are consistent with the current design and licensing bases and to prevent the diesels from being rendered inoperable or significantly degraded.

CONTACT

This information notice requires no specific action or written response. Please direct any questions about this matter to the technical contacts listed below.

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Note: NRC generic communications may be found on the NRC public Web site, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

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Attachment 10

Item	Value @ 100% Leak Rate	Value @ 1% Leak Rate
Total Annualized Cost ($/yr)	$75,000	$75,000
CO before Control (ton/yr)	249	249
CO Control (%)	100%	1%
Total CO Controlled (ton/yr)	248.7	2.5
Cost Effectiveness ($/ton)	$302	$30,159

Attachment 11

Combined Cycle Oxidation Catalyst - CO Cost Effectivness for 5 year Life vs. 3 year Life[(a)]
Cost are for One of Three Units

Control Efficiency (%)	85.0	90.0	Incremental

Item	85% Control	90% Control	Incremental Cost	Basis	Source
1) Catalyst Replacement					
Total catalyst replacement cost ($)	$1,162,703	$1,546,395	$1,162,703		
Catalyst Life (yrs)	5	5	3		
Interest Rate (%)	7%	7%	7%		EPA
Captial Recovery Factor	0.2439	0.2439	0.3811	Amortization of Catalyst Replacement Cost	EPA
Annual Cost ($/yr)	$283,572	$377,151	$443,050		
Annualized Catalyst Replacemen Cost ($/yr)	**$283,572**	**$377,151**	**$443,050**		
CO before Control (ton/yr)	**530.3**	**530.3**	**530.3**		
CO Control (%)	**85%**	**90%**	**90%**		
Total CO Controlled (ton/yr)	**450.7**	**477.2**	**477.2**		
Incremental Cost ($/yr)	**$283,572**	**$377,151**	**$159,477**		
Incremental CO Controlled (ton/yr)	**450.7**	**477.2**	**26.5**		
Incremental Cost Effectiveness ($/ton)	**$629**	**$790**	**$6,015**		

(a) This analysis presents the cost differences for 5 year life vs 3 year life not the total oxidation catyst capital or operating cost. These other costs are assumed to be the same for both options so do not affect the incremental cost.

7% interest is form the EPA Cost Control Manual. This interest rate was set by OMB for policy decisions. It is used in BACT analyses for consistency.

<u>Costs not included:</u>

1 - Catalyst disposal costs have not been included

2 - No contingency for price fluxuations of precious metal (platinum) in catalyst

3 - In order to modify the current 85% design, the catalyst vendor has indicated that the CO catalyst system would require some level of redesign to accomodate 90% removal catalyst. The scope of redesign has not been determined and therefore these potential costs have not been accounted for in the 90% case.