**BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

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|---|---|---|
| **Carbon Pollution Emission Guidelines** | **:** | |
| **For Existing Stationary Sources** | **:** | **EPA-HQ-OAR-2013-0602** |
| **Electric Utility Generating Units** | **:** | |

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# COMMENTS OF THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

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## COMMENTS OF THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

The Pennsylvania Public Utility Commission (PAPUC) herein files its comments to the U. S. Environmental Protection Agency's (EPA) proposed rule governing Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units pursuant to Section 111(d) of the Clean Air Act (CAA).[1] The Federal Register Notice established a filing date for comments of December 1, 2014.

The PAPUC files these comments in conjunction with comments filed by the PA Department of Environmental Protection (PADEP). The PAPUC also adopts later in its comments specific recommendations made by the Public Utilities Commission of Ohio.

## I. INTEREST OF THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

### A. Regulatory Role

The PAPUC is the regulatory agency of the Commonwealth of Pennsylvania with the responsibility to ensure the provision of safe, adequate and reliable electric distribution service at fair and reasonable rates to all Pennsylvania ratepayers pursuant to the provisions of the Pennsylvania Public Utility Code, 66 Pa. C.S. § 101 *et seq.* A significant part of that obligation is to ensure that electric distribution companies (EDCs), subject to its jurisdiction, have procured or otherwise possess sufficient generation supply to meet their service obligations to the Commonwealth's 12.7 million residents.

[1] *See* Preamble and Proposed Rule at 40 C.F.R. Part 60 published at 79 F R 34830 (June 18, 2014).

The PAPUC was an early and active proponent of the regulatory shift from traditional vertically integrated electricity markets to deregulation of wholesale and retail markets. The PAPUC, pursuant to the Electricity Generation Customer Choice and Competition Act,[2] established one of the first successful retail customer choice programs in the nation. Currently, 38% of Pennsylvania customers participate in the customer choice program.[3] The PAPUC also oversees a vibrant market in alternative energy and energy efficiency by virtue of passage of the Alternative Energy Portfolio Standards (AEPS) Act of 2004[4] and Act 129 of 2008.[5]

Consequently, the PAPUC has an important role in assuring continued electricity supply to jurisdictional EDCs as well as ensuring adequate and reliable service to Pennsylvania electric customers. EPA's proposed CAA 111(d) emissions proposal, if adopted, will heavily impact and change the composition of electric generation into the future which may both reduce the supply of and increase the price of electricity while threatening the reliability of electricity service to the state and the region. On this basis, the PAPUC files its comments at this docket.

### B. Role of PJM

Pennsylvania is part of PJM Interconnection L.L.C. (PJM), the regional transmission organization (RTO), certified by the Federal Energy Regulatory Commission (FERC), to manage the supply of generation and transmission in the 13-state Mid-Atlantic region. PJM is the largest planning authority in the nation.[6] PJM is a critical component of the eastern interconnection comprising 27% of generation, 28% of load and 20% of transmission assets for that region. PJM serves 61 million people and

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[2] Act of December 3, 1997, P.L. 802, No. 138, § 4, effective Jan. 1, 1997 (codified at 66 Pa. C.S. §§ 2801-2812).
[3] http://extranet.papowerswitch.com/stats/PAPowerSwitch-Stats.pdf?/download/PAPowerSwitch-Stats.pdf.
[4] 73 Pa. C.S. § 1648.1 *et seq.* and 66 Pa. C.S. § 2814.
[5] 66 Pa. C.S. § 2806.1.
[6] http://www.pjm.com/~/media/about-pjm/pjm-zones.ashx.

243,417 square miles of territory with a peak load of 165,492 MW, a generating capacity of 183,604 MW and 62,556 miles of transmission lines. In fact, the PJM service area produced 21% of the U.S. gross domestic product in 2012.[7] Pennsylvania is the largest generation source within PJM, the second largest electricity producer in the country behind Texas and is a net exporter of electricity.[8] In 2012, generation located in Pennsylvania produced approximately 223,419,715 MWH of electricity.[9] Pennsylvania electricity production is still heavily coal-based with a growing natural gas component and a significant nuclear component.[10] To put these figures in perspective, Pennsylvania's electricity production by percentage of total and gigawatt-hours for July 2014 consists of the following: coal (6,600 GWH or 34%), nuclear (7,000 GWH or 35%) and natural gas (5,400 GWH or 28%) with the remainder represented by hydroelectric and renewables.[11]

PJM has implemented a centralized capacity market beginning with FERC's approval of the Reliability Pricing Model (RPM) in 2006.[12] PJM procures capacity annually through the Base Residual Auction (BRA) which secures adequate capacity for a three-year forward period. PJM's reasonably successful utilization of both the RPM and BRA mechanisms has resulted in relatively stable electricity prices while attracting sufficient new generation.[13]

PJM's current generation composition is predominantly fossil fuel-based (coal and gas fired generation) with a significant nuclear component and increasing quantities of

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[7] Testimony of Micheal Kormos, Vice President, Operations for PJM Interconnection before the PA Senate Environmental Resources and Energy Committee (June 27, 2014).
[8] http://www.eia.gov/state/?sid=PA.
[9] http://www.eia.gov/electricity/state/pennsylvania/.
[10] http://www.eia.gov/state/?sid=PA#tabs-4.
[11] http://www.eia.gov/state/?sid=PA#tabs-4.
[12] *PJM Interconnection, LLC*, 117 FERC ¶ 61,331 (2006).
[13] *2013 State of the Market Report* prepared by Monitoring Analytics, at 1-2. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume1.pdf.

natural gas combined cycle and renewables such as solar, wind and demand response resources expected in the future.[14] Recently, PJM experienced a significant increase in deactivation of coal-fired generation resources driven largely by environmental regulations and the improved competitiveness of natural gas over coal as a fuel source. Generation deactivations, as of October 1, 2014, amounted to 20,069 MW of generation dating back to 2002 with the majority of retirements since 2011.[15] PJM is also proposing significant future generation deactivations through 2018 of about 12,831 MW.[16] Another factor to be considered is increasing lack of competitiveness of nuclear generation as evidenced by recent BRA results where nuclear facilities did not clear the capacity auction.[17] Finally, PJM, in an effort to improve reliability during extreme weather conditions, is currently developing a new capacity product proposal which will significantly change the nature of capacity products bid into the capacity auction and require greater fuel diversity and security.[18]

### C. Pennsylvania's Energy Profile

Pennsylvania has a diverse energy profile. Pennsylvania energy sources encompass all forms of energy production including nuclear, coal, natural gas, waste-to energy, hydroelectric and renewables.[19]

Pennsylvania is the fourth largest coal producer in the U.S. and produced 68 million tons of coal (bituminous and anthracite) in 2011.[20] The coal industry directly employs about 8,700 employees and indirectly supports about 32,800 jobs such as employment in the state's coal-fired power plants and the railroad industry.[21] Pennsylvania's abundant coal reserves assure decades of reliable, low cost energy for the

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[14] http://www.pjm.com/about-pjm/renewable-dashboard/renewables-today.aspx.
[15] http://www.pjm.com/~/media/planning/gen-retire/generator-deactivations.ashx.
[16] http://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests.ashx.
[17] http://www.rtoinsider.com/exelon-pjm-capacity-mkt/.
[18] *See PJM Capacity Performance Staff Proposal* dated August 20, 2014.
[19] http://www.eia.gov/state/?sid=PA#tabs-3.
[20] http://www.pacoalalliance.com/wp-content/uploads/downloads/2013/03/coal-hard-facts-2012.pdf at 12.
[21] http://www.pacoalalliance.com/wp-content/uploads/downloads/2013/03/coal-hard-facts-2012.pdf at 20.

state and the region. Coal consumption for electric generation in the state was 47,324,852 tons in 2011.[22]

Pennsylvania is also a national leader in the production of natural gas. Natural gas production in the Marcellus region generally exceeded 15 billion cubic feet per day through August 2014.[23] Pennsylvania's Marcellus Region possesses the largest shale gas producing resources in the nation with over 100 rigs currently operating and each rig supporting more than 6 million cubic feet per day in new well production each month. Pennsylvania's annual gross natural gas production, primarily from the Marcellus Shale, exceeded 2 trillion cubic feet in 2012, a 72% increase over 2011 production. Pennsylvania's net energy generation by natural gas amounted to 41,792,165 MWH or 28% of the total generation in 2014.[24]

Nuclear generation also represents a significant portion of Pennsylvania's energy profile. Currently, there are five nuclear generation facilities operating in the state representing 7,000 GWH or 35% of net electricity generation.[25]

Pennsylvania also derives an increasing amount of electric generation from hydro-electric sources and renewables representing 162 GWH and 400 GWH respectively. These figures represent approximately 1.0% and 2.0% of Pennsylvania's electric energy generation.[26]

### D. Pennsylvania's General Policy Positions Regarding The EPA's Proposed CAA

Prior to presenting its comments on specific areas of EPA's Proposed Guidelines, the PAPUC presents its policy position on these guidelines:

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[22] http://www.pacoalalliance.com/wp-content/uploads/downloads/2013/03/coal-hard-facts-2012.pdf at 32.
[23] http://www.eia.gov/todayinenergy/detail.cfm?id=17411.
[24] http://www.eia.gov/state/?sid=PA#tabs-4.
[25] http://www.eia.gov/state/?sid=PA#tabs-4.
[26] http://www.eia.gov/state/?sid=PA#tabs-4.

### 1. EPA's CAA 111(d) Proposal Must Recognize The Need To Maintain Reliability Of The Electric Grid

EPA's proposed CAA Section 111(d) emission standards, if implemented, present potential challenges to the reliability of the electric grid impacting Pennsylvania and the PJM region. EPA's proposed Building Block framework[27] for calculating emissions reductions targets through improved heat rates (BB1) and re-dispatch to natural gas combined cycle (NGCC) units (BB2) will require generators, public utilities, transmission operators and PJM to operate under a significantly different paradigm that emphasizes the dispatch of electricity based on environmental factors as opposed to economic factors that traditionally underlay the wholesale competitive markets. As will be addressed later, the EPA has not given sufficient consideration to the impacts its proposal will have on organized electricity markets and the challenges that the proposal presents to system reliability and the economy.

### 2. EPA's CAA 111(d) Proposal Conflicts With The Federal Power Act's (FPA) And FERC Jurisdiction

CAA Section 111(d) establishes the EPA's authority over the regulation of air emissions by domestic stationary sources.[28] Regulation of wholesale electric markets is governed under the Federal Power Act (FPA).[29] Oversight of the wholesale electric markets is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).[30] FERC regulates the wholesale electric markets by protecting "the integrity of the interstate energy markets."[31] FERC authorized the creation of "regional transmission organizations" (RTO) to oversee certain multistate markets.[32] PJM is the responsible RTO for the Mid-Atlantic region for ensuring the adequacy and reliability of generation and transmission. The EPA's proposed emission plan, through implementation of its building block concept, will require states to develop plans that will fundamentally alter

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[27] For convenience, references to the Building Blocks 1, 2, 3 and 4 will be as BB 1, 2, 3 and 4.
[28] 74 U.S.C. §§ 7401 *et seq.* (as amended).
[29] 16 U.S.C. § 824(b)(1).
[30] *Id.*
[31] *N.J. Bd. of Pub. Utilities v. FERC*, 744 F.3d 74, 81 (3d Cir. 2014).
[32] FERC Order 888-A, 78 FERC ¶ 61,220 (1997).

the composition and cost of generation in the future with disruptive effects on the FERC-regulated electric wholesale markets and on reliability generally.

### 3. EPA's CAA 111(d) Proposal Must Recognize State Jurisdiction Over Renewable Portfolio Standards, Demand Side Resources And Energy Efficiency Programs

Pennsylvania, like many other states, has implemented an aggressive AEPS program for promotion of renewable resources and energy efficiency measures.[33] EPA's proposed CAA Section 111(d) emissions standards purport to regulate renewable energy (RE) resources under BB3 and demand-side/energy efficiency (DS/EE) programs under BB4. As will be addressed later, EPA's proposed targets for both BB3 and BB4 are not credible and will be unattainable given current legislative constraints and structural and economic obstacles to further expansion of RE and DS/EE programs in Pennsylvania. Further, the CAA Section 111(d) BB3 and BB4 requirements constitute an encroachment and interference with state legislative authority.

### 4. EPA Emission Guidelines Should Be Developed In Close Consultation With States

As more fully addressed in the comments of PADEP, the EPA must recognize Pennsylvania's leadership and authority to regulate pollutants within its borders and should ensure preservation of Pennsylvania's discretion in the development and implementation of flexible emission control programs that are consistent with Section 111(d) provisions.[34] The EPA should develop emissions guidelines that provide for maximum flexibility to the states in meeting those guidelines. The emissions guidelines should establish targets, not mandate how to achieve the established targets. Only the states have the authority to design and implement pollution control programs to meet the requirements adopted to regulate carbon dioxide in accordance with CAA Section 111(d), except in areas where the authority has been delegated to a local agency or a state has

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[33] 73 Pa. C.S. § 1648.1 *et seq.*, 66 Pa. C.S. § 2814 and 66 Pa. C.S. § 2806.1.
[34] PADEP Comments at 2.

failed to submit the necessary plan.[35] The EPA claims that its proposed BB methodology gives the states flexibility in achieving the proposed targets. In fact, EPA's BB approach sets fairly aggressive targets for PA which will, in fact, hinder any perceived flexibility.

### 5. CAA Proposed Emission Guidelines Should Address $CO_2$ Emission Reductions From Affected Sources Not Unaffected Sources

Emissions guidelines should establish targets based upon actions that can be taken directly by and at existing sources affected by a CAA Section 111(d) emissions reduction program. This approach is consistent with EPA's previous emissions guidelines promulgated for other source categories under the CAA. The EPA should limit the definition of "best system of emission reduction" (BSER) to actions that can be taken by the affected existing source without redefining the source.[36]

### 6. Emissions Guidelines Should Provide For Emissions Reductions Compared To A Designated Baseline Period

EPA's Section 111(d) proposal relies primarily on 2012 data to set state emission reduction targets for Pennsylvania generation including coal and gas-fired facilities and nuclear generation. By establishing a 2012 base-line period, EPA ignores the emission reduction benefits achieved by generation resources prior to that period. However, the EPA has indicated that, under its plan, carbon dioxide emissions will be reduced by 30% from 2005 levels. [37] The PAPUC urges the EPA to re-examine the appropriate baseline for its proposed emissions standards for fossil fuel generation and utilize 2005 as the baseline instead of 2012. A 2005 baseline would properly capture all of the benefits achieved by: (i) Pennsylvania fossil-fuel generation achieving emission reductions through investments made in coal plant retrofits and environmental compliance activities; (ii) increased deployment of gas-fired generation utilizing domestic natural gas resources; and (iii) uprates of nuclear facilities.

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[35] PADEP Comments at 3.
[36] PADEP Comments at 4.
[37] 79 FR 34832, 34868, Table 7, 34895, Table 8.

### 7. EPA Must Recognize And Account For The Differences Between Regulated And Unregulated Energy Markets

Generators in Pennsylvania participate in a wholesale competitive capacity and energy market subject to the provisions of the FPA, regulation by the FERC and management of PJM. The costs to comply with state plans implementing the CAA Section 111(d) emissions guidelines cannot be directly passed on to the customers in this restructured regulatory scheme. On the other hand, generators participating in a traditional vertically integrated electric market can directly recover the costs of compliance through rates approved by their public utility commission under a traditional rate base/rate of return model. Additionally, the EPA proposal relies on the faulty assumption that all states can require the re-dispatch of natural gas units. That is not the case in Pennsylvania, a restructured state. Any Pennsylvania compliance plan will depend on independently-owned generators abiding by an EPA-mandated re-dispatch plan. Under the PJM market construct, PJM will be required to transform its capacity dispatch model from one based on economic dispatch to a model based on environmental dispatch without economic signals that appropriately account for the value of the EPA proposed environmental conditions. This radical shift will seriously undermine competitive wholesale markets, leading to potentially unjust and unreasonable rates and threatening electric service reliability to Pennsylvania residents and businesses.

### 8. Carbon Pollution And Greenhouse Gases Pose A Serious Threat To Public Health And The Environment

The PAPUC asserts that carbon pollution and greenhouse gases do pose a threat to public health and the environment and that the development of sensible policies is necessary to forestall or prevent the consequences of excess atmospheric carbon dioxide in the future. The EPA has highlighted many of the most cited national and international studies on the impact of climate change in its Preamble. However, sensible policies and regulations for controlling greenhouse gases must also consider the real economic impacts on the individual states that are tasked with implementing the regulations. Moreover, these regulations and policies should also consider the opportunities presented by developing technologies in renewables and energy efficiency that create additional jobs and technological investment. EPA must carefully balance these concerns in its final rulemaking product.

### E. Focus Of PAPUC Comments

The PAPUC provides comments on a narrow number of specific areas raised by the EPA CAA Section 111(d) proposed emissions guidelines as detailed below. The PADEP will file separate comments addressing a broader range of concerns about EPA's proposal. PAPUC comments will address the following areas with Federal Register citations provided:

1. Stakeholder Outreach and Conclusions (79 FR 34845-34848)
2. Legal Basis for EPA's Proposal (79 FR 34844-34845, 34851-34855, 34902-34903, Legal Memorandum).
3. Building Blocks as a Best System of Emission Reduction (BSER) (79 FR 34856-34858).
4. Building Block 1 (79 FR 34859-43862, 34881-34882).
5. Building Block 2 (79 FR 34862-34866, 34882-34883).
6. Building Block 3 (79 FR 34866-34871, 34883-34884).
7. Building Block 4 (79 FR 34871-34875, 34884).
8. State Plans-Selection of a Base Period (79 FR 34918-34919).

## II. COMMENTS

### A. PAPUC Comments On EPA's Legal Authority For The CAA Section 111(d) Proposal

In this section of its comments, the PAPUC addresses EPA's legal justification for the proposed emissions standards and addresses how EPA's legal rationale for establishing its emissions standards fails to consider the inherent conflict with federal energy regulatory policy and structure and the potential for damage to the organized wholesale electric markets. These comments also address EPA's failure to adequately consult with FERC, regional transmission organization (RTOs)/independent system operators, public utilities and state commissions. Finally, the EPA's proposed plan conflicts with Pennsylvania's AEPS and Act 129 standards under which the PAPUC administers programs for RE resources and EE programs. The PAPUC's comments herein specifically address portions of the Preamble at 79 FR 34844-34845, 34851-34855 and 34902-34903 as well as EPA's Legal Memorandum contained in the Technical Service Documents.

### 1. Implementation Of The EPA CAA 111(d) Emissions Standards Conflict With The Federal Power Act And FERC's Responsibility To Regulate Electric Wholesale Markets

#### a. EPA's Legal Basis For The CAA Section 111(d) Emissions Standards

In the Preamble and its Legal Memorandum, the PAPUC understands the EPA to be justifying its proposed emissions guidelines under an expansive interpretation of its authority under the CAA generally and CAA Section 111 specifically. CAA Section 111 establishes mechanisms for controlling emissions of air pollutants from stationary sources. CAA Section 111(b)(1) requires EPA to promulgate a list of categories of stationary sources that the EPA Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[38] Once EPA lists a source category, EPA must, under CAA Section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources in the source category. These standards are known as

[38] CAA Section 111(b)(1)(A).

new source performance standards (NSPS) and they are national requirements that apply directly to the sources subject to them.[39]

Under the EPA's implementing regulations for CAA Section 111(d)(1), the PAPUC understands that the EPA must determine the "best system of emission reduction" (BSER) for the sources, and then apply that best system to determine the required level of emission reduction, which the regulations refer to as the "emissions guideline." Under Section 111(d )(1), the states must then adopt state plans that establish standards of performance and measures that implement and enforce those standards. In the case of an air pollutant that EPA has determined may cause or contribute to endangerment of public health, the states' "standards of performance" must not be less stringent than the EPA's emission guideline. EPA interprets CAA Section 111(d)(1) as granting states the authority, in applying a standard of performance to particular sources, to take into account the source's remaining useful life or other factors.[40]

The state must submit its plan to the EPA for approval. Under CAA Section 111(d) (2), the EPA must approve the state plan if it is "satisfactory." If a state does not submit a plan, the EPA must establish a federal plan for that state. Once a state receives the EPA's approval for its plan, the provisions in the plan becomes federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved state implementation plan (SIP) under CAA section 110.[41]

[39] EPA Legal Memorandum at 1-2; 79 FR 34851-34852. When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA Section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that is not regulated under the CAA section 109 requirements for the national ambient air quality standards (NAAQS) or regulated under the CAA Section 112 requirements for hazardous air pollutants (HAP). In contrast with CAA Section 111(b), which provides for direct federal regulation of new sources, Section 111(d)'s mechanism for regulating existing sources provides that states will submit plans that establish "standards of performance" for the affected sources and that contain other measures to implement and enforce those standards.
[40] EPA Legal Memorandum at 3-4; 79 FR 34852.
[41] EPA Legal Memorandum at 4, 79 FR 34852.

EPA interprets its proposed guidelines as consistent with the requirements of CAA Section 111(d) and the implementing regulations. The EPA interprets the provisions identifying which air pollutants are covered under CAA Section 111(d) to authorize the EPA to regulate $CO_2$ from fossil fuel-fired EGUs. In addition, the EPA recognizes that CAA Section 111(d) applies to sources that, if they were new sources, would be covered under a CAA Section 111(b) rule. In EPA's view, a key step in promulgating requirements under CAA Section 111(d) is determining the BSER. In promulgating the implementing regulations, the EPA explicitly stated that it is authorized to determine BSER for controlling $CO_2$ reductions.[42]

EPA relies on recent Supreme Court decisions in *Massachusetts v. EPA* and *American Electric Power Co. v. Connecticut* wherein the Court held that the "Clean Air Act and the EPA actions it authorizes displaces any federal common law right to seek abatement of carbon-dioxide emissions from fossil-fuel fired power plants." This holding is premised on the Court's understanding that CAA Section 111 applies to $CO_2$ emissions from those sources. EPA also bases its jurisdiction on ambiguities arising from the original drafting in 1990 of CAA Section 111(d) (1)(a)(1). [43]

The PAPUC understands that EPA is proposing two alternative approaches for the BSER. The first alternative identifies the combination of the four building blocks as the BSER. These building blocks include operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate (BB1) and increases in, or retention of, zero- or low-emitting generation, as well as generation, all of which, taken together, displace or avoid the need for generation from

[42] EPA Legal Memorandum at 12-13; 79 FR 34852.
[43] *See* 549 U.S. 497 (2007); 131 S. Ct. 2527, 2537-38 (2011); 79 FR 34853. Given the statutory ambiguity, EPA reasoned it has the authority to regulate greenhouse gases under CAA Section 111(d). In further support, EPA cited *American Electric Power v. Connecticut*, 131 S Ct. 2227, 2237-38 (2011), for the proposition that "the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon-dioxide emissions from fossil fuel-fired power plants." EPA also cites *Massachusetts v. EPA*, 549 U.S. 497 (2007), which held that greenhouse gases, including $CO_2$, are an "air pollutant" under the CAA. EPA Legal Memorandum, p. 20.

the affected EGUs (BB 2, 3, and 4). All of these measures are components of a "system of emission reduction" for the affected EGUs because they either improve the carbon intensity of the affected EGUs in generating electricity or, because of the integrated nature of the electricity grid, they displace or avoid the need for generation from those sources and thereby reduce the emissions from those sources. EPA asserts that these measures may be undertaken by the affected EGUs themselves or by the states.[44] The PAPUC fully comprehends this first alternative.

For the alternative approach for the BSER, the EPA is identifying the "system of emission reduction" as including, in addition to BB1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs. Under this approach, the measures in BBs 2, 3, and 4 would not be components of the system of emission reduction, but instead would serve as bases for quantifying the reduction in emissions resulting from the reduction in generation at affected EGUs. EPA considers this approach as meeting the criteria for being the "best" system because the emission reductions it would achieve, its reasonable cost, its promotion of technological development as well as the reliability of the electricity system would be maintained. [45] The PAPUC does not fully understand this alternative and how it is intended to operate. The PAPUC requests the EPA, in its final rule, to provide better illustrative examples and explanations of how this alternative BSER mechanism should operate.

After determining BSER, the EPA claims it is authorized, under the implementing regulations, as an integral component to setting emission guidelines, to apply the BSER and determine the resulting emission limitation. The EPA is proposing to apply the BSER to the affected EGUs on a statewide basis. In this rulemaking, the EPA terms the resulting emission limitation the state goal. The EPA is

[44] EPA Legal Memorandum at 13-15; 34852-34853.
[45] EPA Legal Memorandum at 15-16; 79 34852-34853.

formulating each state goal as an average emissions rate. The state goals form the EPA's emission guidelines.[46]

EPA then requires each state to develop a plan to achieve an emission performance level that corresponds to the state goal. The state plans must establish standards of performance for the affected EGUs and include measures that implement and enforce those standards under a portfolio approach that imposes requirements on other affected entities -- e.g., renewable energy and demand-side energy efficiency measures -- that would reduce $CO_2$ emissions from the affected EGUs.[47]

In the section that follows, the PAPUC addresses the fundamental failure of EPA to consider the effects of its emissions reduction proposal on the jurisdiction of the FERC as exercised under the Federal Power Act (FPA) and the potential for this proposal, if implemented, to undermine the effective operation of organized wholesale electricity markets.

### b. EPA CAA 111(d) Emissions Standards Conflict With The Federal Power Act And FERC's Responsibility To Regulate Electric Wholesale Markets

The regulation of wholesale electric markets is governed under the Federal Power Act.[48] Oversight of the wholesale electric markets is subject to the jurisdiction of the FERC.[49] FERC's duty is to establish just and reasonable rates.[50] FERC performs this responsibility, not by setting rates directly, but through the establishment of economically-based markets. FERC regulates the wholesale electric markets by protecting "the integrity of the interstate energy markets." [51] Pursuant to its authority

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[46] EPA Legal Memorandum at 16; 79 FR 34853.
[47] EPA Legal Memorandum at 16-17 79 FR 34853-34854.
[48] 16 U.S.C. § 824(b)(1).
[49] *Id.*
[50] 16 U.S.C. § 824(d).
[51] *N.J. Bd. of Pub. Utilities v. FERC,* 744 F.3d 74, 81 (3d Cir. 2014).

under the FPA, FERC authorized the creation of regional transmission organizations (RTO) to oversee certain multistate markets.[52] PJM is the responsible RTO for the Mid-Atlantic region.

PJM employs a collaborative process with its members to establish tariff rules and procedures to ensure markets operate fairly and efficiently.[53] PJM operates both energy and capacity markets. The energy market includes a real-time market that enables PJM to coordinate the purchase and sale of electricity between generators and load-serving entities within the next hour or 24 hours. The capacity market is a forward-looking market that ensures there is enough generating capacity to serve expected electric demand three years in advance. In the capacity market, PJM sets a quota based on how much capacity it predicts will be needed three years in the future and then relies on a Reliability Pricing Model (RPM) to determine the appropriate price per unit of capacity. PJM conducts auctions for new capacity annually for supplies that it projects it will need three years into the future. The auction participants bid to sell capacity for a single year, three years in the future. PJM stacks the bids from lowest to highest and, starting at the bottom, accepts bids until it has acquired sufficient capacity to satisfy its quota.[54]

The highest-priced bid that PJM must accept to meet this quota establishes the market-clearing price. Every generator that bids at or below this level "clears" the market and is paid the clearing price, regardless of the price at which it actually bids. Existing generators are permitted to bid at zero as "price-takers" meaning they agree to sell at whatever the clearing price turns out to be. Both the capacity and energy markets are designed to efficiently allocate supply and demand, a function which has the collateral benefit of incentivizing the construction of new power plants where and when they are needed. Clearing prices occasionally differ based on geographical subdivisions

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[52] FERC Order 888-A, 78 FERC ¶ 61,220 (1997).
[53] *See* http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjms-markets-fact-sheet.ashx.
[54] http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjms-markets-fact-sheet.ashx.

designed by FERC to stimulate new construction by signaling that certain regions are prone to supply shortages.[55]

As these features suggest, the federal markets are the product of a finely-tuned mechanism that attempts to achieve reliable wholesale electric service at just and reasonable rates.[56] FERC rules encourage the construction of new plants and sustain viable, existing plants. FERC rules preclude state regulators from distorting wholesale prices while preserving general state authority over generation sources. FERC rules satisfy short-term demand and ensure sufficient long-term supply. In short, the federal scheme, implemented under the FPA and overseen by the FERC, is carefully calibrated to protect a host of competing interests. The wholesale capacity market construct represents a comprehensive program of regulation that is quite sensitive to external forces.

Additionally, PJM supplies electric power utilizing the concept of economic dispatch.[57] Economic dispatch is defined as: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing the operational limits of generation and transmission facilities." PJM, like most planning authorities, schedules generating units for each hour of the next day's dispatch based on a number of factors including: (i) forecasted load for the next day; (ii) recognition of each generating units operating limits; (iii) recognizing the costs of operation of each generating unit; (iv) analyzing forecasted load and transmission conditions for each area (e.g., a reliability assessment); and (v) monitoring load, generation and interchange flows on the transmission system. This process is complex and requires constant and sophisticated software analysis to ensure that frequency of dispatch is coordinated across the service area.

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[55] *Id.*
[56] *See* 16 U.S.C. § 824(d).
[57] http://www.ferc.gov/eventcalendar/Files/20051110172953-FERC%20Staff%20Presentation.pdf.

EPA's Section CAA 111(d) proposal expands EPA's regulatory authority into areas delegated by statute to the regulatory domain of the FERC as the statutory overseer of wholesale energy markets. FERC's mission is to assist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means.[58] EPA's mission is to protect human health and the environment by issuing and enforcing anti-pollution standards.[59] When establishing a standard of performance for achieving the best system of emission reduction (BSER), EPA must consider the costs of achieving emission reductions as well as the energy requirements. 42 U.S.C. § 7411(a)(1). However, the methods that EPA proposes should not operate in a way that creates obstacles to the reliable functioning of wholesale capacity and energy markets at just and reasonable rates.

It is noteworthy that neither the Preamble nor the Legal Memorandum attempt to reconcile the obvious conflicting directive contained within the EPA proposal and the authority conferred on the FERC under the FPA. EPA's recitation of legal authority (at 79 FR 34844-34845, 34851- 34855, 34902-34903, Legal Memorandum) addresses only the agency's view of its authority under CAA Section 111(d) to establish "standards of performance" and mandate development of "state plans" without examining the ripple effects of those state plans in the larger context of the regulation and functioning of organized electricity markets nor the states' ability to regulates aspects of those markets.

The PAPUC asserts that EPA's proposed CAA emissions reduction plan threatens to undermine the structure of the wholesale electric market by requiring states to develop emission compliance mechanisms that will essentially force planning authorities, such as PJM, to replace economic dispatch with environmental dispatch. By forcing planning authorities to abandon a model based on scheduling and transmitting electricity on the basis of identifying the most cost effective units, the EPA will upend the currently well-

[58] http://www.ferc.gov/about/about.asp.
[59] http://www2.epa.gov/aboutepa/our-mission-and-what-we-do.

functioning and FERC-approved mechanisms that have been the basis for efficiently functioning wholesale electricity markets since deregulation of wholesale electricity was implemented in 1998.

Under EPA's proposal, states will design compliance plans, either individually or in concert with other states, that will largely dictate which forms of generation will or will not be utilized in order to meet specific compliance targets. EPA's proposal will require PJM to fundamentally abandon its current resource procurement process based on securing capacity under the RPM mechanism that procures needed generation at a price that promotes construction and retention of needed generation and will, instead, require PJM to move to a model that selects generation based on environmental drivers that may bear little or no relationship to the economics of wholesale markets.

The FERC has echoed these concerns. Commissioner Clark recently acknowledged that PJM currently allows for non-economic treatment of $SO_2$, $NO_X$ and other emission allowance costs (such as the Regional Greenhouse Gas Initiative (RGGI)).[60] However, there are reasonable limits to shifting from economic to environmental dispatch. As explained by Commissioner Clark, "to go beyond the past practice of allowing incurred costs to be included in economic bids by changing the fundamental market algorithm in the ways some have suggested would be a major change."[61] FERC Commissioner Philip Moeller expressed similar views when he stated that "markets would need to be fundamentally altered and redesigned to implement EPA's proposal to accommodate environmental dispatch…changing from economic to environmental dispatch is truly a fundamental change that would require a complete redesign of markets to include a carbon fee on any resources that emit carbon dioxide."[62]

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[60] Written Statement of Commissioner Tony Clark to the U.S. House Committee on Energy and Commerce at 3 (July 29, 2014).
[61] *Id.*
[62] Written Statement of Commissioner Philip Moeller to the U.S. House Committee on Energy and Commerce at 3 (July 29, 2014).

EPA's proposal will not produce a just and reasonable result insofar as the emissions standards will accelerate the closure of coal-fired generation. Additionally, PJM will be required to accelerate development of NGCC facilities to meet the re-dispatch requirements of BB2 without assurances that the 70% utilization rate under BB2 can be met. Finally, as will be discussed later in PAPUC comments, EPA's proposed standards for attaining the BB3 and BB4 standards for Pennsylvania (PA) are based on errors and lack of understanding of how PA operates its RE and DS/EE programs.

An even broader concern relates to the concept of each of the 13 PJM states developing individual state compliance plans. Because of the diverse characteristics of the 13 states (economic makeup, generation rich vs. generation constrained, states with renewable portfolio standards vs. states without these standards, vertically integrated vs. deregulated state), there is the potential for many irreconcilable differences in emission compliance plans between the states. PJM will ultimately be required to manage the end result of these plans which could negatively impact reliability and affordability.

For example, PA and Ohio, both generation rich exporting states, may differ in their proposals with reference to BB1 and BB2 as compared to other PJM states. PA may seek a more aggressive plan with reference to plant retirements/retrofits and emphasize reliance on more new NGCC generation or limit operating hours of coal-based generation. Ohio may likewise propose a plan that anticipates significant reductions in coal generation and increased reliance on NGCC assets. Meanwhile, MD and NJ, generation-constrained states, may develop a plan that envisions increased deployment of renewables – perhaps unrealistically insofar as both states may have reached limits on market penetration of these assets. Additionally, there are the ongoing retirements of coal plants mandated by other EPA requirements such as Mercury and Air Toxics Standard (MATS), National Ambient Air Quality Standard (NAAQS) as well as the threat of nuclear retirements due to the failure of these plants to clear the capacity auctions.  All of the above could affect system reliability where there is inadequate generation to meet demand in the 13 states of the PJM region.

More specifically, EPA has offered a plan which is flexible, in its view, because it offers the states a variety of means to comply through the four building blocks. However, EPA has designed each of the BBs to be fairly aggressive, on an individual basis, with the overall objective of meeting a set emissions target.  In that regards, EPA puts the states (and the RTO) in a position placing the objective of meeting emissions targets over the objective of meeting system reliability standards.  On this point, EPA has not only exceeded its jurisdiction but placed the nations electric reliability at considerable risk.

PJM will be presented the unenviable task of planning for the future in an environment where there will be less coal-fired generation, increased NGCC generation (assuming adequate natural gas pipeline infrastructure) and uncertainty over the future of renewable energy and DR/EE participation.  An increased likelihood of weather-related impacts and the ongoing regulatory uncertainties of the capacity market will also increase PJM's obligations.

In finalizing these regulations, the EPA must give greater consideration and deference to the role of the FERC, its FPA-imposed authority and the functioning of wholesale capacity markets both in PJM and other planning authorities.  Not to do so will disrupt the well-functioning market constructs that have thus far served the PJM region well in ensuring adequate power supplies at affordable cost.

### c. The EPA Must Adequately Consult With The FERC And The Planning Authorities Before Issuing The Final Rule

The EPA states it did confer with various planning authorities and the FERC as part of a general stakeholder outreach.[63] However, there is no indication that the FERC consultation process was sufficiently detailed to inform the EPA about the FPA and FERC jurisdictional encroachments of the CAA Section 111(d) proposal. Only a limited reference to meetings with FERC appears in the Preamble.[64] Nor is there any indication that FERC was consulted regarding the potential for interference with organized wholesale electric markets from the implementation of the CAA Section 111(d) proposal. Moreover, the EPA's consultation with planning authorities in both regulated and deregulated regions of the country appeared to solicit information that largely conformed to EPA's pre-existing notions regarding the functioning of wholesale electric markets.[65] Finally, EPA's meetings with state public utility commissions and state environmental offices is given scant attention and appears to have been conducted by conference call and collection of state agency literature.[66] While an EPA representative did meet with PAPUC Chairman Robert Powelson, the meeting was very brief, very little consideration was given to the Chairman's concerns and almost none of his questions were adequately answered. It was clear that the intent of the meeting was not to consider Pennsylvania's concerns but simply to "check the box".

EPA's notable exclusion of FERC input into the process was highlighted in recent testimony by FERC Commissioners.[67] While FERC staff met with EPA staff a few times and held a few oral discussions, EPA did not request written advice from FERC and EPA

[63] 79 FR 34845-34848.
[64] 79 FR 34899.
[65] 79 FR 34846, 34880-881, 34899-900.
[66] 79 FR 34846.
[67] 79 FR 34846, 34880-881, 34899-900.

rarely mentions FERC in the text of the Preamble.[68] Nor was any outreach to FERC mentioned in the rulemaking.[69]

FERC Chairwoman Cheryl LaFleur explains in testimony that EPA's rulemaking proposal rests on many assumptions and that EPA did not reach out to FERC staff, who are experts in electric grid reliability to comment on Section 111(d)'s potential effects on reliability.[70] FERC Commissioner Phillip Moeller, who had no consultations with EPA on its proposal prior to publication, contends that EPA is attempting to create national electricity policy, wherein "markets would need to be fundamentally altered and redesigned…to accommodate environmental dispatch" instead of economic dispatch.[71] FERC Commissioner Tony Clark is similarly concerned about "a future jurisdictional train wreck" wherein FERC, an economic and reliability regulatory body, would be forced into "the awkward task of evaluating fundamental wholesale market design changes driven by environmental priorities approved by the EPA."[72] Both Commissioners Clark and Moeller also believe EPA's proposed rule will reorder the jurisdictional relationship between the federal government and the states regarding the regulation of public utilities and state renewable energy and energy efficiency programs.

While EPA's consultation with planning authorities was somewhat more extensive, input from these stakeholders appeared to be more perfunctory and non-specific with little depth or attempt to understand the complexity of the organized

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[68] EPA briefly mentions meeting with FERC on the proposed rule. 79 FR 34899.
[69] Acting Chairman Cheryl LaFleur's Answers to Preliminary Questions, Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives (July 29, 2014). FERC will consider issuing a white paper outlining its advisory role as EPA implements Section 111(d) rule.
[70] *Supra*, FN 64.
[71] Commissioner Philipp Moeller's Answers to Preliminary Questions, Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives (July 29, 2014).
[72] Written Testimony of Commissioner Tony Clark Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives (July 29, 2014).

markets.[73] EPA's summary response to its meetings with the planning authorities was the conclusion: "that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. The EPA believes that any remaining local issues can be managed through standard reliability processes."[74]

The PAPUC asserts that the EPA's efforts to solicit input from critical stakeholders such as the FERC, planning authorities and state agency representatives were insufficient. Electric markets involve complex regulatory constructs where no one entity has authority over all factors that affect the electric markets and system reliability. Before finalizing the rule, EPA should consult with FERC and other stakeholders involved in electric markets to achieve a better understanding of the functioning of the wholesale electric markets and the regulatory processes that this rule will ultimately impact.

#### d. The EPA Proposal Presents A Clear Conflict With State Authority Over Renewable Resources And Energy Efficiency Programs

Pennsylvania, like many other states, has implemented aggressive AEPS and EE programs for promoting renewable resources and energy efficiency measures.[75] EPA's proposed CAA Section 111(d) emissions standards purport to regulate renewable energy and demand-side (RE/DS) resources under BB3 and energy efficiency (EE) programs under BB4 by setting presumptive standards for attainment of renewable resource penetration and EE achievement that would require changes to existing legislation. As will be addressed later in the PAPUC's comments, EPA's proposed targets for both BB3 and BB4 are not credible and will be unattainable given current legislative constraints

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[73] EPA notes that planning authorities offered their assistance to the states in the development of individual compliance plans and also raised concerns regarding how the proposed regulation could impact the reliability of the electric power system. 79 FR 34899.

[74] *See* 79 FR 34900.

[75] 73 Pa. C.S. § 1648.1 *et seq.*, 66 Pa. C.S. § 2814 and 66 Pa. C.S. § 2806.1.

and structural and economic obstacles to further expansion of RE/DS and EE programs in Pennsylvania. Further, the CAA Section 111(d) BB3 and BB4 requirements constitute an encroachment on and interference with state legislative authority. EPA, in effect, establishes a federal mandate over PA renewable energy programs and presents a direct conflict with PA legislation governing RE. EPA should re-examine its approaches to the design of BB3 and BB4 to more sensibly accommodate existing Pennsylvania legislative and PAPUC regulatory mandates for expanding renewable resources and energy efficiency programs.

Pennsylvania's alternative/renewable energy legislation, the Pennsylvania's Alternative Energy Portfolio Standard (AEPS), created by enactment of S.B. 1030 on November 30, 2004, requires each electric distribution company (EDC) and electric generation supplier (EGS) to supply to 18% of its electricity using alternative-energy resources by 2021.

Qualifying resources are divided between Tier 1 and Tier II. The percentage of Tier I (8% with 0.5% from solar), Tier II (10%) and solar alternative energy credits that must be included in sales to retail customers gradually increases over the compliance period.[76]

Pennsylvania energy efficiency standards are governed under Act 129 of 2008 (Act 129). The Act expands the PAPUC's oversight responsibilities for energy efficiency

[76] Tier I sources, as defined at 73 P.S. § 1648.2, include new and existing facilities which produce electricity using the following sources/technologies: photovoltaic energy, solar-thermal energy, wind, low-impact hydro, geothermal, biomass, biologically-derived methane gas, coal-mine methane and fuel cells. Pennsylvania's standard provides for a solar set-aside, mandating a certain percentage of electricity generated by photovoltaics (PV). Currently, PA EDCs must obtain 0.5% of their electric generation from solar sources by 2020.

[76] Tier II sources, as defined at 73 P.S. § 1648.2, include (new and existing) waste coal, distributed generation (DG) systems, demand-side management, large-scale hydro, municipal solid waste, wood pulping and manufacturing byproducts, and integrated gasification combined cycle (IGCC) coal technology.

standards and imposes new requirements on EDCs with the overall goal of reducing energy consumption and demand. [77] Under this legislation, the PAPUC has implemented an energy efficiency and conservation (EE&C) program. Subsequent phases of the Act 129 implementation process will address EDC and default service provider responsibilities; conservation service providers; smart meter technology; time-of-use rates; real-time pricing plans; default service procurement; market misconduct; alternative energy sources; and cost recovery. The PAPUC has aggressively implemented both the AEPS and Act 129 over the past several years and the achievements stemming from these programs are well documented.[78]

The PAPUC asserts that the CAA proposed BB3 and BB4 targets, as currently designed, establish potentially illegal and unenforceable federal mandates on those states that have actively implemented and promoted RE/EE programs. At a minimum, the EPA proposal conflicts with existing state legislative requirements. In the case of PA, EPA has proposed that PA attain a 2029 goal of 9% (interim) and 12% (final) of generation resources from RE from a baseline level of 2% (calculated as of 2012). EPA's alternative scenario establishes PA's 2029 goals of 5% (interim) and 7% (final).[79] Neither goal is attainable under current PAPUC projections as will be addressed later in these comments.

In addition, it is unclear whether EPA would have the authority to mandate a state to adopt RPS or EE standards absent a state including those components in a plan. The EPA avoids this issue by using RE and EE as a means of calculating BSER without mandating specific reductions. However, because of the aggressive targets used in the BSER calculation, it is unclear how PA would met its reduction targets, effectively turning the RE and EE BBs into mandates.

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[77] **House Bill 2200** - Act 129 of 2008 Bill.

[78] http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/act_129_statewide_evaluator_swe_.aspx; http://www.puc.pa.gov/electric/pdf/Act129/SWE_PY4-Q3_Report.pdf.

[79] 79 FR 34868.

## B. PAPUC Comments On Building Blocks As A Best System Of Emission Reduction (BSER)

EPA proposes the scope of the appropriate BSER for reducing $CO_2$ to consist of four building blocks as follows: (1) reductions achievable through improvements in individual EGU emission rates (BB1); (2) EGU $CO_2$ emissions reductions achievable by re-dispatch from affected steam units to unaffected NGCCs (BB2); (3) EGU $CO_2$ emissions reductions achievable by meeting demand for electricity through expanded use of low or zero carbon capacity (RE) (BB3); and (4) expanded use of demand side EE (BB4). EPA proceeds to design two formulations involving these four building blocks. The first formulation involves utilization of each of the four BBs constituting discrete components of the BSER. In the second formulation, measures are taken under BB1 coupled with the use of BBs 2, 3 and 4, not as specific component, but as benchmarks against which reductions under BB1 can be measured.

The PAPUC believes the EPA's four building block concept present serious implementation obstacles for Pennsylvania. First, PADEP has jurisdiction under CAA Section 111(d) *onl*y over the regulation of emissions of "affected sources" that include coal-fired EGUs.[80] PADEP does not have jurisdiction over the re-dispatch of electricity from coal-fired EGUs to non-affected NGCCs. Nor does PADEP exercise direct jurisdiction over renewable resources, nuclear generation or entities providing DS/ EE services within the state. In fact, PADEP has indicated that its compliance plan will primarily rely on achieving compliance through BB1 and that non-affected sources may only be utilized at the discretion of the affected source.[81] PADEP's position suggests that reliance on BBs 2, 3 and 4 may only be considered to the extent the affected sources could achieve compliance through independent agreements with BB 2, 3 and 4 entities either through affiliate agreements or third party contracts.

[80] PADEP Comments at 2.
[81] PADEP Comments at 2.

Before addressing comments to the individual building blocks, the PAPUC must highlight two overall concerns regarding the applicability and implementation of the proposed rule.

First, the PA legislature has enacted both AEPS and Act 129 legislation that governs deployment of renewable energy and EE&C programs in PA. The PA legislature also enacted electric deregulation which was implemented by the PAPUC in 1998. The PAPUC has no jurisdiction over electric EGUs be they coal, gas or nuclear. The PAPUC has no authority to direct the re-dispatch of coal-fired generation to NGCCs. The PAPUC does administer its AEPS program for renewable resources and the Act 129 EE&C programs but is limited in its oversight by the implementing legislation. Any plan developed for PA will require overcoming inherent jurisdictional limitations with regard to both PADEP and the PAPUC, potentially relying upon voluntary cooperation by those parties who would be involved in meeting the BB2, 3 and 4 components. EPA should be cognizant of these important considerations in both the finalization of these regulations and implementation of the state plan for PA. More importantly, the EPA must recognize that PA, like other states, may need legislative approval in order to implement aspects of a CAA compliance program.[82]

Second, the EPA has selected 2012 as the baseline year for implementation of the emissions standards as opposed to an earlier baseline year, such as 2005. EPA also states that the goal of its CAA Section 111(d) proposal is to achieve a 30% reduction of $CO_2$ below 2005 levels.[83] By setting 2012 as the base year for its emission reduction calculations, EPA fails to account for and credit PA for the emissions reductions achieved

[82] Recently, the PA House of Representatives passed a bill captioned the Pennsylvania Greenhouse Gas Deregulation Implementation Act, H.B. 2354 of 2014, which requires any PADEP Section 111(d) compliance plan be submitted to both houses of the PA Legislature for a approval prior to filing with the EPA. *See also*, Act 175 of 2014, *PA Greenhouse Gas Regulation Implementation Act*; http://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=2013&sessInd=0&billBody=H&billTyp=B&billNbr=2354&pn=3898.
[83] 79 FR 34832.

by PA generation facilities from 2005 forward during which time PA-based generation facilities invested heavily in environmental compliance retrofits that achieved significant emissions reductions. EPA should consider resetting the base year for establishing emissions standards from 2012 to 2005.

As a point of reference, EPA has calculated a proposed state goal for PA of 1,179 lbs $CO_2$/net MWh (interim goal) and 1,052 lbs $CO_2$/net MWh (final goal).[84] This would be the goal which PA would be expected to meet under the four BBs.

### C. PAPUC Comments On Building Block 1

The first category of $CO_2$ emission reduction measures, captioned BB1, are designed to reduce the carbon intensity of generation at individual coal-fired steam EGUs by improving heat rates.[85] Although heat rate improvements (HRI) have the potential to reduce $CO_2$ emissions from all types of affected EGUs, the EPA's analysis indicates the potential is significantly greater for coal-fired steam EGUs than for other EGUs. For purposes of determining the best system of emission reduction at this time, the EPA is proposing to base its estimate of $CO_2$ emission reductions from heat rate improvements on coal-fired steam EGUs only. EPA's analysis indicated average $CO_2$ emissions of 1.3 to 6.7 percent could be achieved by coal-fired steam EGUs through adoption of best practices and through equipment upgrades.[86] EPA estimated that $CO_2$ reductions of between 4 and 6 percent from overall heat rate improvements could be achieved on average across the nations' fleet of coal-fired steam EGUs for net costs in a range of \$6-\$12 per ton.[87] EPA's analysis concludes that a total of 6 percent heat rate improvement

[84] 79 FR 34895, Table 8.
[85] Heat rate of an EGU is the amount of fuel energy input needed to produce 1 kWh of net electrical energy output. 79 FR 34859.
[86] 79 FR 34859-34862.
[87] 79 FR 34861; *Technical Support Document: GHG Abatement Measures,* pp. 2-30 through 2-40; The cost attributable to $CO_2$ emission reductions is the net cost to achieve the heat rate improvement after any savings from reduced fuel expense.

can be achieved through a combination of adoption of best practices (4%) and equipment upgrades (2%).

### 1. Coal-Fired Generation In PJM Is Currently Under Severe Stress

Before addressing the merits of EPA's BB1 proposal, the PAPUC must put EPA's proposal in the context of what is the current state of the coal-fired generation fleet in the PJM region. In 2011, PJM published its "*Coal Capacity at Risk for Retirement Report*" which analyzed the potential impacts of the finalized EPA Cross-State Air Pollution Rule (CSAPR) and Proposed National Emissions Standards for Hazardous Air Pollutants (NESHAP). This detailed study applied both physical and economic screens for coal-fired capacity at risk for retirement assuming implementation of CSAPR and NESHAP regulations. PJM concluded that approximately 11,000 MW of a total of 78,000 MW installed capacity was at "high risk" for retirement based on the potential costs of retrofits needed for compliance with CSAPR and NESHAP. An additional 14,000 MW of capacity was at "some risk" due to anticipated compliance costs.[88]

Additionally, PJM detailed approximately 12,381 MW of mostly coal-fired generation is schedule for de-activation through mid-2017 with the majority of these deactivations occurring by mid-2015. The age of these facilities is mostly between 40-60 years.[89] These facilities represent a significant portion of the generation portfolios of major electric suppliers as Dominion, Public Service Electric & Gas & Electric, Jersey Central Power & Light and American Electric Power. This accelerated retirement of coal-fired generation is driven partly by ongoing EPA regulatory requirements but also due to the increased reliance on natural gas fired generation which have rendered older coal generation less competitive in the capacity procurement process.

[88] https://pjm.com/~/media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx at p. v.
[89] http://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests.ashx.

The PAPUC notes that the extreme polar vortex weather event of January 2014 resulted in considerable stress on PJM's generation assets. This event that occurred on January 7-9 resulted in a loss of 22% of generation capacity (including 13,700 MW of coal generation) and severely stressed PJM reserve capability. [90] It is noteworthy that coal generation has the ability to store backup supply on site whereas gas-fired generation does not have onsite storage capability which led to at least some of the issues PA and PJM experienced during the polar vortex.

The PAPUC highlights these statistics as a backdrop to concerns over the impacts of BB1 on the remaining PJM coal generation and the threats it poses to future reliability. Although difficult to assess currently, the import of the EPA BB1 proposal will be the inevitable premature retirement of coal generation facilities, as will be explained below, including facilities wherein significant environmental compliance investment has already occurred with the simultaneous reduction in both generation portfolio diversity and system reliability.

### 2. EPA's Development Of The 6 Percent Heat Rate Improvement (HRI) Factor Is Flawed

A principal component of EPA's BB1 proposal is that a 6 percent HRI that EPA estimates will be achievable as a coal generation fleet average.[91] The PAPUC has examined the EPA's *Technical Support Document, GHG Abatement Measures* that provides the analytical support for EPA's recommended 6 % HRI factor. The PAPUC finds the analysis to be technically thorough but offers some comments and observations.

EPA's analysis relies principally on a 2009 Sargent & Lundy (S&L) Study that examined the efficacy of a variety of HRI methods applied across the entire U.S. coal generation fleet. The S&L Study derived an average cost for HRI in $/kW. EPA's

[90] http://www.pjm.com/~/media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx at 4, 26.
[91] 79 FR 34860.

analysis then reviewed HRI data and applied an assumed average cost of $100/kW, a capital charge rate of 14.3% and a 2020 annual capacity factor of 78% to derive a coal fleet average 2020 net heat rate of 10,450 Btu/kwh and a HRI factor of 6 percent.[92]

The PAPUC notes that EPA's analysis did not rely on site specific information to accurately estimate what percentage of the coal generation fleet has adopted any of the various HRI methods.[93] EPA's analysis did not examine the potential for heat rate reductions either in PA specifically or the PJM region generally. Also, many PA coal-fired generation owners have already made substantial HRI investments prior to 2012 and further reductions may not be possible. [94] While the PAPUC appreciates that this specific information may not be available, there are certain considerations regarding the PJM (and PA-specific) generation fleet that should be considered.

First, EPA's proposal for a 6% HRI is adequate on a national basis but does not take into account state-specific or regional considerations. Regional or state-specific research and data, including HRI methods, should be used as the basis for estimating potential heat rate improvements rather than sole reliance on national averages for all states. States differ widely in the characteristics and operating performance of their generation fleets. Also, there are considerable differences between individual units in terms of age, size, degree of environmental retrofits and HRI methods employed. EPA should solicit this information on regional and state-specific heat rates from state agencies and/or the generators themselves.

A major factor in determining whether or not it is cost effective to undertake heat rate improvements is the average age of a particular generation fleet. PJM has the oldest

[92] 79 FR 34861; *Technical Support Document, GHG Abatement Measures*, at 2-15 through 2-40.
[93] *Technical Support Document, GHG Abatement Measures*, at 2-36.
[94] PADEP Comments at 5.

weighted average fleet age (41 years) of any RTO/ISO.[95] Over the course of the past four decades, these plants have been subject to physical modifications and repairs and have suffered age-related degradation. Many of the modifications have been the addition of emissions controls, which typically have an adverse effect on heat rate. Since initial startup, many units have changed fuel supply and reduced staffing size in order to remain competitive in wholesale markets, increasing operational challenges which create additional potential adverse heat rate effects.

The actual HRI achievable at any generation unit is unit-specific with the maximum HRI improvement depending on the condition and operation of the individual unit. Units where major modifications or replacements of the turbine have been recently completed will have much smaller potential for heat rate improvements, while those units that have not upgraded equipment or have been less well maintained will have a larger potential for heat rate improvement. These latter units, however, may also be at greater risk for retirement insofar as the cost of installing HRI upgrades at this late date may be outweighed by the cost savings from retiring the plant altogether. The costs to improve heat rate are also unit-specific such as the impact of age of the unit, its location and its overall condition including maintenance. Generator plant size also plays a role, as the expenditures are more easily justified for larger units with higher capacity factors.

This concern was highlighted in a 2014 National Coal Council report which noted that some HRI options can have cumulative benefits and a number of measures may work together synergistically to improve heat rate while others may negatively impact reliability. Other combinations of HRI measures may also not be technically or economically feasible. In any case, all HRI measures must be assessed with reference to the specific characteristics of the generation unit and the costs of particular HRI

[95] http://www.powermag.com/americas-aging-generation-fleet/ (January 28, 2013) (citing to SNL Energy) at p. 2.

technology utilized for that unit.[96] The report also has a detailed list of reasons why cited heat rate improvements might not be applicable at a specific power plant. It also includes a list of factors that could lead to an increase in coal power plant heat rates including more operation at partial load, adding more environmental control equipment, switching from once-through to evaporative or air cooling, and switching from bituminous to lower sub-bituminous coal.[97]

The finance requirements of electric generation facilities require that any large investment be justified as contributing toward improved performance as well as profitability. Smaller and/or older units operate less frequently often making a reasonable return on investment difficult to achieve for expensive modifications. These units may have a limited remaining life. Under these circumstances, costly HRI may require a longer time to recover the investment than the facility's useful life.

Investment in HRI may also adversely affect the ability of older coal-fired plants to operate most efficiently. Historically, coal-fired generation was designed to operate optimally in a base load role. With increased reliance on NGCC generation and renewable generation, those older coal plants still operating will be required to engage in more flexible operation such as performing load following, extended low output generation and cycling which can reduce plant efficiency and adversely impact heat rate performance. This was demonstrated in a 2014 study produced by the Electric Power Research Institute (EPRI) "*Range and Applicability of Heat Rate Improvements*" to determine the extent of the efficiency losses associated with increased load following. The report confirmed a substantial loss in heat rate and identified the areas in the plant that suffered with the decreased load stability. Based on those results, the coal units

[96] Reliable &Resilient: The Value of Our Existing Coal Fleet, May 2014, National Coal Council, http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf (see pp. 56-63). The National Coal Council is A Federal Advisory Committee to the U.S. Secretary of Energy.
[97] *Id*. at 60-63.

remaining in service that are no longer base loaded will therefore experience higher (and poorer) heat rates.[98]

PADEP has estimated that PA-based coal-fired units will be forced to operate at less than 20% capacity to meet proposed targets. PADEP also contends that coal-fired units are more efficient when operated close to design loads. Thermal efficiency decreases when operated at loads less than 60% which increases the level of emissions per unit of electricity.[99]

The PAPUC requests that EPA take into consideration in its development of its BB1 proposal: (1) the importance of regional and individual generation facility characteristics in estimating HRI; (2) ability for generation facilities to support investment in HRI equipment; and (3) the impact of regional load factors on HRI.

### 3. EPA's Reliance On Gross Heat Rate Data For Estimating HRI $CO_2$ Mitigation For BB1 Is Inconsistent With The Use Of Net Emissions Accounting Utilized In The State Goals Computation

EPA utilizes gross heat rate data in its calculation of HRI-related improvements.[100] However, EPA later utilizes net emission accounting in the calculation of the state goals computation. Electric industry standards, such as those established by EPRI, require HRI data to be reported on a net generation basis. The use of gross heat generation data for determination of HRI-related $CO_2$ improvements is inconsistent with the use of net generation emission accounting used by EPA in its state goals computation. This "apples and oranges" mismatch may lead to overestimation of the emission mitigation potential. The PAPUC recommends the EPA use a consistent approach for net heat rate estimation and for emissions accounting in the final rule.

[98] EPRI Report 3002003457 (April 2014), *Range and Applicability of Heat Rate Improvements* at 6-1.
[99] PADEP Commets at 5.
[100] 79 FR 34860; EPA used hourly gross heat rate data to assess variability in the hourly gross heat rates of approximately 900 goal-fired generation units.

### D. PAPUC Comments On BB2

EPA's BB2 concept involves reducing emissions by shifting or re-dispatching coal-fired generation to natural gas combined cycle (NGCC) units. EPA's analysis determined that NGCC units can produce 46% more electricity from a given quantity of natural gas than can coal-fired steam generations and that the cost of $CO_2$ reductions from re-dispatch would be approximately $30/metric ton. According to the EPA, average reported availability of NGCC units exceeds 85%. EPA's analysis proposes an average NGCC utilization rate in the range of 65-75% as a reasonable range to be re-dispatched as part of the BSER and recommends a target utilization rate of 70%.[101] For BB2 purposes, only NGCCs in operation after January 8, 2014 may be considered for inclusion in a state BB2 compliance component.

#### 1. EPA's Estimated 70% Utilization Rate For NGCC Plants May Not Be Achievable

The PAPUC has reviewed the EPA's underlying analysis for recommending a 70% utilization rate as a national standard for BB2. The PAPUC is concerned that EPA's analysis does not address whether there will be sufficient other generation units available to handle load-following duties that are currently handled by NGCCs assuming many NGCCs shift to base-load generation. The current PJM generation portfolio relies on nuclear and coal-fired generation for base-load with NGCC generation as a load-following resource. EPA's BB2 proposal envisions NGCC facilities transitioning into more of a base-load role with coal-fired generation assuming more of supplemental supply function. The PAPUC has previously addressed the issue of operational flexibility impacts on coal generation in its BB1 comments. The PAPUC herein reiterates its concern that today's coal-fired generation plants were not designed for and may not be up to the task of a "role reversal" with NGCCs.

[101] 79 Fed. Reg. 34857-34858, 34862-34866; Technical Support Document, *Greenhouse Gas Abatement Measures* at 3-1 through 3-27.

The PAPUC is also concerned that future increased gas prices may render NGCC generation less economic and adequate coal-fired resources may not be available to meet resource adequacy requirements in PJM. The PAPUC contends that PJM's existing coal fleet may not be able to provide adequate flexible operations as most existing coal plants were not originally designed for load following and/or extended low output generation. The PAPUC is also concerned that establishing a dispatch-based mitigation goal that impacts other existing generation types without thorough consideration of the impacts to resource adequacy may significantly degrade reliability. This concern is best exemplified by the experiences in the PJM region during the January 2014 polar vortex event.

As noted previously, a significant percentage of PJM's entire generation portfolio was out of service during that period which included 9,700 MW of gas generation (36% of PJM's total gas generation capacity) due to plant outages and gas supply disruption. Despite these challenging conditions, PJM's robust generation portfolio was able to weather the period without major service outages. The PAPUC is concerned that, under a future scenario where the EPA's BB1 and BB2 proposals have restructured the PJM generation portfolio, there may be significant declines in resource adequacy, reserve margins and less overall flexibility to manage an extreme cold weather event.

#### 2. EPA's BB2 Proposal Fails To Account For The Effects Of Extreme Weather Events On Availability Of NGCC Resources As Well As The Lack Of Electric/Gas Supply Coordination

The PAPUC is concerned that EPA's design of BB2 fails to account for the current expansion of natural gas pipeline capacity (both new pipelines and potential pipeline upgrades) needed to accommodate the increased level of gas-fired generation to support higher levels of re-dispatch at the targeted 70% utilization rates. Nor does the

EPA analysis focus on the undue length of the regulatory approval process for the siting of new pipelines.

EPA relies on EIA and industry publications, primarily INGAA's Midstream Infrastructure Report through 2035, to support its assertion that the industry can currently manage intermittent gas pipeline constraints, relieve bottlenecks and expand capacity.[102] The INGAA Report's principal findings indicate that significant infrastructure will be needed to support growing gas use. The base case assumes $100 per barrel of oil and shows gas prices rising from $4 per MMBtu to an average of $6 per MMBtu in the longer term. The base case projects significant supply development and growth in gas production, primarily from shale resources. Producers are likely to develop shale resources with large quantities of oil and gas, which also have significant needs for new pipeline infrastructure. The base case also projects substantial gas production growth, especially from the Marcellus and Utica shale regions in the northeastern United States and also from other shale regions in the U.S. and Canada. A significant number of gas processing, pipeline, and fractionation facilities will also be required to accommodate growing gas production.[103]

However, as last winter's "polar vortex" demonstrated, pipeline capacity failures during extreme weather conditions and general breakdown of pipeline infrastructure is a continuing reality. On January 8-9, 2014, PJM experienced a 22% forced outage rate during an extreme cold weather event with gas supply failure a major contributing factor.[104] The breakdown of forced outages by primary fuel type shows that natural-gas-fired generators accounted for 47 percent of the unavailable megawatts.[105] The 9,300

[102] 79 FR 34864; EIA *Natural Gas Pipeline Additions in 2011*; INGAA Foundation, *Pipeline and Storage Infrastructure Requirements for a 30 TCF Mar*ket (2004); INGAA Foundation *Midstream Infrastructure through 2035-A Secure Energy Future Report* (2011).
[103] http://www.ingaa.org/File.aspx?id=21498 at 38.
[104] http://www.pjm.com/~/media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.
[105] *Id*. at 24-25.

MW of generation that was unavailable due to natural gas interruptions was a larger amount than PJM reported immediately after January 7.[106] Subsequent to January, PJM worked with generation owners to further validate the outage reasons, and, based on these additional discussions, natural gas issues were found to be larger than initially reported largely due to other generation fuel types being dependent on natural gas and the natural gas infrastructure. An example is a generator that burns oil but that needs natural gas to start up.[107]

On September 30, 2014, the North American Electric Reliability Council (NERC) issued its Report on the Polar Vortex.[108] This Report covered the impacts of the weather events for both the Eastern and Western Interconnections. NERC also highlighted the contribution of gas supply shortfalls as follows:

> One of the largest issues impacting gas-fired generation was the curtailment or interruption of fuel supply. Unlike other fuel sources, natural gas is not typically stored on site. As a result, generators rely on real-time delivery of natural gas from their suppliers. Often, as units are not confident that they will be dispatched, the fuel is obtained on the spot market as an interruptible fuel supply.[109]

EPA's sole reliance on traditional historic EIA and INGAA reports fail to account for the impacts of extreme weather events and the stressors these events place on the system. In its finalization of this rulemaking, the PAPUC urges the EPA to factor into its BB2 analysis a more refined consideration of the impacts of extreme weather events on the ability of gas-fired generation in the PJM region to manage increased dispatch under extreme cold weather events. This would require a closer consultation by EPA with entities such as NERC, INGAA and PJM.

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[106] A second less severe cold weather event occurred from January 22-24, 2014 with a lower albeit still serious forced outage rate.
[107] *Id*. at 26.
[108] http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.
[109] *Id*. at 4.

Additionally, there has been an ongoing issue with the lack of gas electric coordination between interstate gas suppliers and gas-fired electric generation. This issue relates to a fundamental disconnect between how gas pipelines schedule and nominate supplies for delivery customers and how generators schedule available capacity to the wholesale electric markets. This disconnect between the scheduling functions of the two industries has also contributed to supply shortfalls to electric generators during periods of increased system demand. The FERC has an ongoing proceeding to address this issue and is expected to make some general recommendations for further consideration in the near future.[110] The individual RTO/ISOs have undertaken initiatives to resolve these inter-industry issues. The EPA, in its final rule, should examine the impacts of improved gas electric coordination practices in implementing BB2. Further, EPA should consider whether it is prudent to be placing the burden on states to implement BB2 while the gas and electric generation industries are grappling with the need to improve market design issues between the two industries.

### 3. EPA's BB2 Proposal Fails To Consider The Existing Regulatory Delays In Approving Interstate Natural Gas Pipelines By The FERC

EPA has also not considered the time involved into the normal FERC regulatory siting process. Under Section 717f(c) of the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (FERC) is authorized to issue certificates of "public convenience and necessity" for "the construction or extension of any facilities ... for the transportation in interstate commerce of natural gas."[111] Companies seeking to build interstate natural gas pipelines must first obtain certificates of public convenience and necessity from

[110] Docket Nos. RM14-2-000, EL14-22-000, EL14-23-000, EL14-24-000, EL14-25-000, EL14-26-000, EL14-27-000, RP14-442-000. The Commission issued a Notice of Proposed Rulemaking (NOPR) on March 20, 2014 to gather public comments on its proposals to revise the natural gas operating day and scheduling practices used by interstate pipelines to schedule natural gas transportation service for electric generation purposes. The proposed revisions include starting the natural gas operating day earlier, moving the timely nomination cycle later and increasing the number of intra-day nomination opportunities to help shippers adjust their scheduling to reflect changes in demand.
[111] 15 U.S. Code § 717f(c).

FERC.[112] The Energy Policy Act of 2005 (EPAct) designates FERC as the lead agency for coordinating "all applicable Federal authorizations" and for National Environmental Policy Act (NEPA) compliance in reviewing pipeline certificate applications. There are no statutory time limits, however, within which FERC must complete its certificate review process.

The regulatory process for certification of interstate gas pipelines varies depending on whether or not the pipeline developer opts to enter the voluntary pre-filing process before formally applying for a pipeline certificate, pursuant to 18 CFR § 157.21. The pre-filing process involves a set of specific activities including a study of the project sites, stakeholder identification and an open house for affected parties. Concurrently, FERC Staff participates in the open house and publishes, pursuant to 40 CFR § 1508.22, in the Federal Register a Notice of Intent for Preparation of an Environmental Assessment or an Environmental Impact Statement that opens a public comment period. FERC may also consult with stakeholders and hold public meetings and site visits in the proposed project area.[113] The pre-filing process requires a written request to FERC's Office of Energy Projects and commences seven to eight months before the filing of a certificate application.[114]

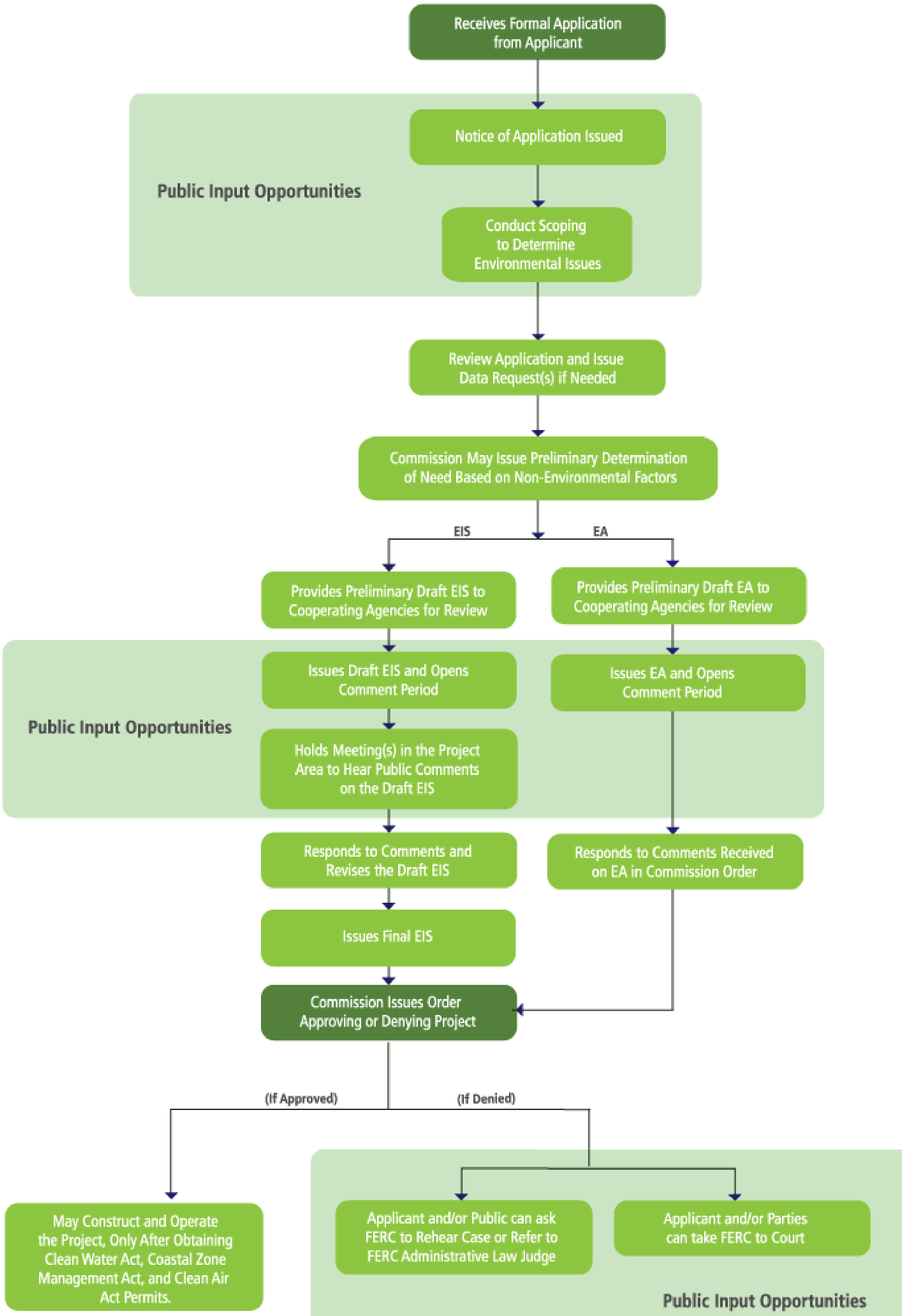
Whether or not the developer participates in the pre-filing process, a developer must formally file an application with FERC in order to receive a certificate of public convenience. This application requires the submission of a description of the pipeline, route maps, construction plans, schedules, lists of other statutory and regulatory

[112] FERC must also approve the abandonment of gas facility use and services. FERC does not have similar siting authority over oil pipelines, nor over natural gas pipelines located entirely within a state's borders not involved in interstate commerce. Siting of oil and *intra*state natural gas pipelines is, instead, variously regulated by the states.
[113] See, Federal Energy Regulatory Commission, "EIS Pre-Filing Environmental Review Process," web page, accessed Sept. 18, 2014, http://www.ferc.gov/help/processes/flow/process-eis.asp.
[114] Federal Energy Regulatory Commission, "Guidance: FERC Staff NEPA Pre-Filing Process for Natural Gas Projects," dated Feb. 10, 2004, http://www.fws.gov/habitatconservation/gas_prefiling_FERC_staff_NEPA_guidance_2004.pdf.

requirements from other agencies, environmental reports analyzing route alternatives and the potential impacts on the environment, cultural and aesthetic resources, geology and land use. If the applicant did not pre-file, FERC then begins the environmental review process that includes many of the same steps of the pre-filing process. In either case, an environmental assessment is typically prepared and a more extensive environmental impact statement is also required where impacts are determined to be significant.[115] FERC's decision whether to grant or deny a pipeline certificate is based on a determination of whether the pipeline would be in the public interest.[116] The complicated regulatory review process for gas pipeline certificates is illustrated below:

[115] See, 40 CFR § 1508.9 (environmental assessment); (42 USC § 4332(c)) (environmental impact statement); Federal Energy Regulatory Commission, "Preparing Environmental Documents," dated Sept. 2008, p. v, http://www.ferc.gov/industries/hydropower/gen-info/guidelines/eaguide.pdf.
[116] Federal Energy Regulatory Commission, *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999) and orders clarifying policy, 90 FERC ¶ 61,128 and 92 FERC ¶ 61,094 (2000).

PROCESSES FOR NATURAL GAS CERTIFICATES
Application Process



The FERC process of pre-filing, filing and review can be lengthy. There are no statutory time limits within which FERC must complete its certificate review process. The pre-filing time frame is between seven and eight months. A review of approved major interstate gas pipeline projects in the Mid-Atlantic region indicates that the average time from filing of the application to issuance of an order is thirteen months.[117] Similarly, major intrastate gas pipeline projects in Pennsylvania alone averaged fourteen months from filing of the application to issuance of an order.[118] Therefore, from pre-filing to receipt of a certificate, a developer spends an average of twenty to twenty-four months solely in the regulatory review process.

The transition to gas-fired generation envisioned in BB2 is intrinsically tied to an increase in construction of pipelines to transport that gas. The PAPUC is concerned that, in setting the $CO_2$ reduction goals in the CAA Section 111(d) proposed rule, the EPA did not sufficiently account for the two-year average time it takes for an application to process through FERC. This is, of course, in addition to the time spent developing a proposal and preparing an application as well as the time for the actual construction of the pipelines themselves. The PAPUC urges the EPA to take pipeline construction timelines into consideration in designing BB2 goals.

[117] Federal Energy Regulatory Commission, "Approved Major Pipeline Projects (2009-Present)," web page, accessed Sept. 18, 2014, http://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp.
[118] *Id.*

## E. PAPUC Comments On Building Block 3

### 1. PA's AEPS Programs

BB3 is defined to include increasing renewable electric generating capacity over time through utilization of state renewable generation targets and factoring in projected annual increases over 2020-2029. EPA considers nuclear generation as a component of BB3. The nuclear component of BB3 includes completion of all nuclear plants under construction coupled with avoiding retirement of six percent of existing nuclear capacity deemed to be "at risk." The PAPUC has examined EPA's BB3 component closely and has identified several defects with regard to its application to PA.[119]

EDCs and EGSs typically meet their AEPS requirements by obtaining, typically through the direct purchase of alternative energy credits (AECs) in amounts corresponding to the percentage of electricity that is required from alternative energy sources. One AEC represents one megawatt hour (MWh) of electricity generated from a qualified alternative energy source and can be purchased separate from the electricity. Credits generated by qualifying facilities located anywhere within PJM can be used for compliance in the year they were generated or in the two subsequent years.[120]

For the 2013 reporting year (June 1, 2012 – May 31, 2013), all EDCs and EGSs complied with the AEPS requirements by retiring the required number of Tier I, Tier II, and Solar AECs needed to meet their obligations.[121] If an EDC or EGS fails to comply with the AEPS requirements, that entity is required to make an alternative compliance

[119] Technical Support Document, *GHG Abatement Measures*, 4-1 through 4-43.
[120] The PAPUC has adopted a 15-year compliance schedule (2007-2021) to implement Pennsylvania's AEPS. The compliance year (CY) for the standard runs from June 1 to May 31 and is followed by a 3-month true-up period.
[121] http://www.puc.pa.gov/electric/pdf/AEPS/AEPS_Ann_Rpt_2013.pdf.
Compliance is based on alternative energy credits (AECs). An AEC is equal to a megawatt-hour of qualified generation and credits are the property of the generator unless expressly transferred. Banking of excess credits is allowed for up to two years, thus an AEC's useful life is three years, the year it was produced and the two subsequent years for which it can be banked. AECs are tracked by the PJM General Attribute Tracking System (GATS).

payment (ACP).[122] ACPs are then directed to the sustainable energy funds for investment into AEPS qualifying project development.

### 2. EPA's Methodology

To estimate the potential RE available for inclusion as part of BSER, EPA developed an RE generation scenario that provides a target for how much of each state's generation can be produced by RE based upon the current goals of leading states in the same region. EPA's proposal assumes each state will grow its RE generation over time towards the target based upon that state's current level of RE.[123]

The method can be summarized as follows. First, the country is divided into regions. Second, an RE generation target level of performance is calculated for each region, based upon averaging all 2020 RPS requirements in that region. Third, an annual growth factor is calculated that would allow the region as a whole to reach the regional RE target in 2029 assuming that RE generation would increase from 2012 levels beginning in 2017. Fourth, the annual growth factor for a given region is applied to individual states' 2012 RE generation to calculate future RE generation in that state from 2017 through 2029, not to exceed a maximum RE generation level equivalent to the regional RE target. Finally, these annual RE generation levels for each state are used to calculate interim and final RE targets for that state.[124]

EPA's methodology results in a PA target RE generation level of 4,459 GWh for 2012, 5,229 GWh for 2017 and projected to reach 35,331 GWh by 2029. As a percentage of generation, these figures translate to 2% for 2012, 2.3% for 2017 and 15.8% by 2029. EPA's proposed targets for RE generation as a percentage of total generation are 9%

[122] The AEPS establishes an alternative compliance payment of $45 per MWh for shortfalls in Tier I and Tier II resources and 200% of the market price for solar AECs.
[123] 79 FR 34866-34867.
[124] http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf at 4.1 and 4.2.

(interim) and 16% (final). EPA's proposed alternate targets for PA are 5% (interim) and 7% (final).[125]

### 3. EPA's BB3 Methodology Fails To Correctly Assign Weight To The Mid-Atlantic States Reflecting Their Unique Generation Characteristics

EPA's BB3 methodology groups states into regions based on NERC designations. PA is located in the East Central Region which also includes DC, DE, MD, NJ, OH, VA and WV.[126] However, the PAPUC has identified several defects with EPA's grouping methodology. First, DC has a state-designated RPS goal of 20% (among the highest) but possesses no fossil generation, limited renewable generation and imports almost all of its power. Inclusion of DC as part of the East Central Group biases the results insofar as it has no traditional generation resources and no emissions. Consequently, there is no in-state generation that would be offset by DC's renewable credits.[127]

Second, the East Central region consists of eight states-six that have adopted RPSs (DE, DC, MD, NJ, OH, PA) and two states (WV, VA) that have not adopted RPS. The PAPUC contends that EPA's method of combining RPSs to derive individual states' renewable targets leads to unfair and distorted conclusion. EPA utilized RPS mandated amounts as the basis for deriving regional targets for the states. EPA's error arises from its computation of regional generation targets by taking the arithmetic average of the six states with RPS programs. This amounts to the sum of 96 divided by 6 to arrive at a regional average of 16%.

In EPA's calculation, however, VA and WV were assigned an effective RE level of 0% but not included in the averaging calculation.[128] Including the values from these

[125] 79 FR 34866-34871, Technical Support Document, *GHG Abatement Measures* at 4-6 through 4-7, 4-22 through 4-25.
[126] 79 FR 34867.
[127] 79 FR 34868.
[128] *Id.*

two states, as would be appropriate, would have produced a lower regional compliance target of 12%. By excluding these two states, that have chosen not to enact RPS targets, EPA penalizes the rest of the region with a higher regional compliance target that translates into higher required targets in the 2020-2029 timeframe. The PAPUC contends that EPA should recalculate its East Central regional compliance targets to correctly reflect only those states that have promoted RE rather than penalizing the region by including states that have not mandated RE resources.

Third, EPA's methodology also ignores the unique qualitative characteristics of each of the states in the region that should influence the setting of targets. For example, PA is a major generation state and net exporter of electricity with a large population and industrial load. MD and DE are far smaller with reference to land areas, population, generation and load but are given equal weight in calculating renewable potential.

Fourth, in order to meet EPA renewable target, PA would need to increase the amount of electricity obtained from renewable resources by a multiple of eight between 2012 and 2030. This multiple exceeds what EPA has assigned to any other state in the East Central with the exception of MD, NJ and OH.[129] Additionally, the eight fold multiple also exceeds the majority of other states' expected targets. This expectation runs counter to evidence from other recognized sources such as National Renewable Energy Laboratory (NREL) that ranks PA at the bottom of the 50 states for potential renewable resource development.[130] The PAPUC questions the logic of EPA's methodology for calculating PA targets given the apparent limited potential for future renewable resource development in the state.

[129] 79 Fed. Reg. 34,868.
[130] NREL, *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis Technical Report* NREL/TP-6A20-51946 (2012).

Fifth, EPA's projected growth rates discriminates against states like PA that have successfully developed state RPS programs. Many states in the Midwest and Great Plains (such as IA, ND, SD) (all located in the EPA North Central Region) have far greater renewable resource potential than PA yet none of these states have enacted RPS programs.[131] The same inconsistency exists when one examines the renewable potential in the South Central Region (comprising states such as KS, NE, OK, AR) that have renewable potential significantly higher than PA but are assigned a target for the region of only 8%.[132] This target compares starkly to the average for the East Central Region of 17%. EPA's proposed method for establishing regional renewable targets, regional annual growth factors and state-specific renewable targets fails to recognize the potential for renewable resource development in these states while imposing unrealistic annual growth rates on PA.

Sixth, EPA's unreasonable high renewable resource targets will require PA ratepayers to pay additional amounts for out-of-state renewable credits which have no benefits to the PA economy and primarily benefit other states in meeting their renewable targets. During the most recent reporting period (June 1, 2012 to May 31, 2013) more than $50 million was expended by PA electric utilities to purchase Tier I credits to meet their RPS requirements. The majority of these credits were purchased from renewable generators from IN and IL.[133] As a result, a significant portion of renewable resources that form the basis for EPA's computation of potential renewable resources to meet future targets derives from out-of-state sources that not only receive the revenues but are benefitted by enhancement of their renewable resource industries including job growth. The EPA must take into account the inherent inequity in the derivation of the PA renewable targets *vis a vis* the burdens placed on other states.

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[131] *Id, supra* note 132.
[132] GHG Abatement Measures TSD, Table 4.5 at p. 4-18.
[133] PAPUC *2013 Annual Report: Annual Energy Portfolio Standards Act of 2004,* Oct. 2014 at 3.

### 4. EPA Methodology Fails To Recognize Credits For Out-Of-State Renewable Sources

Under PA's AEPS program, credits from facilities located anywhere in PJM which includes parts of Illinois, Indiana, Kentucky, Michigan and North Carolina. However, these states are not within the same NERC region as PA under EPA's regional approach. It should be noted that, in the latest AEPS compliance period, 41% of Tier I credits are from states located in regions outside of EPA's East Central region.[134] Consequently, credits received from these states could not be considered in meeting PA's BB3 standard. EPA should consider allowing credits derived from facilities located in these states to be utilized under the BB3 construct to meet the EPA $CO_2$ emissions targets.

The EPA proposes to exclude renewable energy imports into PJM which offset generation within PJM.[135] This exclusion of RE imports penalizes states that have designed their RPS programs so as to include utilization of out-of-state renewables. RE imports into PJM is effectively displacing fossil energy thus lowering GHG emissions as effectively as in-state renewables. EPA should modify its requirements under BB3 to give credit to out-of-state renewables with due consideration paid to avoidance of double counting.

### 5. EPA Methodology Relies On In-State Generation, Not Sales

EPA's BB3 methodology is based on in-state generation rather than sales.[136] This is a particularly polarizing issue for states such as PA that are large net exporters of electricity. While in-state generation does contribute to GHG production, much of this generation is utilized by consumers outside of PA and even outside of the PJM region. States should be accountable for $CO_2$ production only to the extent of what their consumers actually utilize and not be penalized for the electricity use of consumers in other states. PA has no control over the consumption patterns of others outside of their

[134] http://www.puc.pa.gov/electric/pdf/AEPS/AEPS_Ann_Rpt_2013.pdf
[135] 79 FR 34866.
[136] 79 FR 34866-34867.

jurisdiction nor does PA have jurisdiction over the dispatching of generation. EPA should revise its BB3 methodology to reflect state sales as opposed to generation.

### 6. EPA Methodology Fails To Explicitly Recognize All Of The Tier 1 Sources

In determining the 16% target for the PA BB3 goal, EPA only utilized the Tier I resource targets in each state, but did not specifically identify which resources would be acceptable in meeting the target. As referenced previously, PA's Tier I include resources that are not $CO_2$ neutral, such as biologically-derived methane that provide greater than a 1:1 ratio of $CO_2$ reductions. EPA should give consideration to specifically giving credit for the additional reductions associated with the use of these non-$CO_2$ neutral resources. These specific Tier I resources derive their benefit from utilizing biologically or other naturally occurring sources of methane (a more potent GHG) for the production of electricity. The PA AEPS program recognized the value of deriving energy through utilizing methane emissions as an energy source as evidenced by the inclusion of methane-emitting sources in Tier 1. Methane has been determined to be more than 25 times as environmentally destructive than $CO_2$.[137] EPA should modify its BB3 target for PA and all states to specifically recognize the additional $CO_2$ equivalent emissions reductions from these RE sources.

Additionally, the EPA proposes excluding existing hydropower resources from consideration under its BB3 proposal while only including incremental hydropower resources prospectively. [138] The PAPUC agrees with this approach insofar as only generation from incrementally new renewable resources can result in a net decrease of $CO_2$ emissions from the base line. Crediting existing renewable resources that are part of the baseline with lowering CO2 emissions above the baseline is a fallacy; this can only result from incremental generation. This inconsistency suggests that the goals for BB3

[137] http://www.yaleclimateconnections.org/2009/01/common-climate-misconceptions-co-equivalence/.
[138] 79 FR 34869.

should be examined and adjusted accordingly. Only incremental growth in renewable energy, from the baseline year forward, should be considered eligible in meeting the CAA 111(d) goals. Including existing renewable energy that is already "baked in" to the baseline does absolutely nothing towards reducing $CO_2$ emissions below the baseline.

### 7. EPA Methodology Relies On Stale Information

EPA relies largely on a Black & Veatch Report titled *Economic Impacts of Renewable Energy in Pennsylvania* (2004) as the basis for many of its PA-specific recommendations regarding the costs associated with deployment of RE resources. For more up-to-date information, the PAPUC recommends reliance on its annual AEPS/Act 129 Report. The latest report estimates that the cost to meet the 2021 18% AEPS target will be $149.2 million, of which $146 million will be attributed to meeting the 8% Tier I requirement.[139]

### 8. EPA Calculation Of RE Goals For PA Will Require Legislative Changes

The PAPUC contends that the EPA's BB3 proposed targets of 9% (interim) and 16% (final) is unattainable absent legislative changes. Currently, the AEPS target for 2021 is 18% with a cap of 8% and 10% for Tiers I and II respectively. In any event, the current Tier I limit of 8% would need to be doubled by legislation in order for PA to meet the 16% final target level.

### 9. EPA Should Reconsider The 6% Factor In Its Nuclear Proposal

EPA proposes to include nuclear generation as a component of its BB3 proposal. EPA states that nuclear generating capacity facilitates $CO_2$ emission reductions at fossil fuel- fired EGUs by providing carbon-free generation that can replace generation at those EGUs. Re-dispatch to increase nuclear generation, according to EPA, is a technically-viable approach to reduce $CO_2$ emissions from affected EGUs. EPA's proposal rests on

139 http://www.puc.pa.gov/electric/pdf/AEPS/AEPS_Ann_Rpt_2013.pdf.

two assumptions. First, that all five nuclear plants currently under construction in the U.S. will be completed. Second, that 6% of the current nuclear fleet is at risk for retirement and should be preserved with that preserved capacity factored into the state goals for purposes of BB3.[140]

The PAPUC considers the nuclear fleet component in PJM to be a critical element for both reliability and cost stability. Nuclear generation is not as susceptible to the impacts of extreme weather conditions that can affect fuel supply and operational readiness. Nuclear generation also represents a proven source of GHG reduction. In 2013, Pennsylvania ranked third in the country in the production of carbon-free power. Thirty-four percent of the power generated in Pennsylvania in 2012 was produced by nuclear generation. That number is equivalent to nearly 341 million short tons of carbon dioxide emissions avoided through this reliable source of base-load generation.[141]

The PAPUC is also aware that nuclear facilities are under increasing competitive pressure from gas-fired and wind generation. Nuclear facilities have had difficulty in clearing the most recent PJM BRA that procures capacity on a three year forward basis. In the most recent PJM BRA, several Exelon units including Oyster Creek in New Jersey and the Byron and the Quad City units in Illinois failed to clear the auction. Subsequently, industry spokesmen indicated that these factors may force premature retirement of nuclear facilities in the PJM region in advance of normal retirement dates.[142] The EIA has identified nuclear retirements as an issue of concern when coupled with coal plant retirements necessitated by environmental mandates such as the Mercury and Air Toxics Standards (MATS).[143] While changes in the capacity auction process to better recognize the lower cost contributions of nuclear generation may be required, the

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[140] 79 FR 34870-34871.
[141] U.S. EIA at http://www.eia.gov/electricity/data/state/.
[142] http://www.rtoinsider.com/exelon-pjm-capacity-mkt/.
http://www.nytimes.com/2013/06/15/business/energy-environment/aging-nuclear-plants-are-closing-but-for-economic-reasons.html?_r=0.
[143] http://www.eia.gov/forecasts/aeo/power_plant.cfm.

PAPUC contends the EPA should factor the potential impacts of capacity market processes on the future viability of the PJM nuclear fleet (and the nuclear fleets of other planning authorities) in its final version of BB3.

Additionally, EPA's BB3 proposal anticipates continuation of emissions reduction benefits to continue beyond 2030. The PAPUC is concerned that the impact of license expiration of the current nuclear fleet may also impact EPA's BB3 proposal.
A number of PA nuclear facilities are scheduled for operating license expiration by 2030 or shortly thereafter--specifically Limerick Units 1 & 2 (2024/2029); Peach Bottom Units 2 & 3 (2033/2034) and Three Mile Island Unit 1 (2033). Other nuclear facilities in the PJM region are also scheduled for license expiration before or shortly after 2030.[144] By that date, the operating companies may decide not to seek license extensions which may unduly complicate the compliance plans of those states that have factored the continuing operation of those facilities into their BB3 component of the compliance plan. Given the importance of the nuclear generation component to regional reliability and to state emission compliance plans, the EPA should consider the implications of license expirations on its BB3 proposal including increasing the percentage of nuclear plants "at risk" for retirement.

The PAPUC emphatically believes that EPA's 6% at risk estimate is unrealistically conservative given market and licensing risks and EPA should consider increasing its "at risk" percentage to reflect these factors.

### F. PAPUC Comments On Building Block 4

#### 1. EPA's Methodology For Determining EE Standards

EPA's BB4 proposes to incorporate the benefits of state-based demand side energy efficiency (DS/EE) into a comprehensive approach for reducing $CO_2$ emissions. To estimate the potential CO2 reductions at affected EGUs that could be supported by

[144] http://scientech.cwfc.com/company/spokes/PDF/cnpp_2013.pdf at p. 10.

implementation of DS/EE policies as a part of state goals, the EPA developed a "best practices" DS/EE scenario. This analysis is based on a number of successful DS/EE programs in 12 states from 2006 through 2012. EPA's analysis concluded that a 1.5% annual incremental savings rate is a reasonable estimate of the EE policy performance that can be achieved by the states given adequate time.[145]

For the best practices scenario, EPA estimated that each state's annual incremental savings rate increases from its 2012 annual savings rate to a rate of 1.5% over a period of years starting in 2017. The pace at which states are estimated to increase their savings rate level is .2% per year, a rate consistent with past performance and future requirements of the leading third party evaluations. Under the EPA's alternative approach for setting state $CO_2$ reduction goals, the DS/EE requirement uses 1.0% rather than 1.5% annual incremental savings as representative of the best practices level of performance. The pace at which incremental savings increase is relaxed from .2% to .15%.[146]

EPA's reported electricity savings for PA showed a 1.06% incremental savings as a percentage of retail sales in 2012 and a 3.08% cumulative savings as a percentage of retail sales in 2012.[147] Under the 1.5% savings target scenario, PA is required to meet a goal of 4.7% of annual sales by 2020 and 11.7% of annual sales by 2029. At the 1.0% savings target scenario, PA is required to meet a goal of 3.6% of annual sales by 2020 and 6.2% by 2024.[148]

[145] 79 FR 34872.
[146] 79 FR 34873, Table 7.
[147] EPA Technical Service Document, *GHG Abatement Measures*, Table 5-4.
[148] 79 FR 34873, Table 7.

### 2. Summary Of PA's Energy Efficiency Program

The PAPUC is mandated by Act 129 of 2008 to require the seven largest EDCs to implement of energy efficiency and conservation (EE&C) programs.[149] The EE&C program requires each EDC, with at least 100,000 customers, to adopt a plan to reduce energy demand and consumption within its service territory.[150] Each EDC, through its approved plan, was required to reduce electric consumption by May 31, 2011, by at least 1% of its expected consumption for June 1, 2009 through May 31, 2010 base period. By May 31, 2013, the total annual consumption was to be reduced by a minimum of 3% of its expected consumption for the June 1, 2009 through May 31, 2010 base period. Also, by May 31, 2013, each covered EDC's peak demand was to be reduced by a minimum of 4.5% of the EDC's annual system peak demand in the 100 hours of highest demand, measured against the EDC's peak demand during the period of June 1, 2007 through September 30, 2007. All of the EDCs met or exceeded the May 31, 2013 requirements.

As of May 31, 2013 (end of Program Year 4 and Phase I), the seven PA EDCs had collectively saved 5,403,370 MWh per year and 1,540.61 MW of peak demand capacity. These savings are directly attributable to the EE&C programs implemented by the seven EDCs. Individually, all EDCs exceeded their 2013 compliance targets for energy savings and demand reductions as established by the Commission.[151]

At least once every five years, the PAPUC is to evaluate the cost-effectiveness of the program and set additional incremental consumption and peak demand reductions if

[149] 73 Pa. C.S. § 1648.1 (2008); Duquesne Light Company (Duquesne); PECO Energy Company (PECO); PPL Electric Utilities Corporation (PPL); and the FirstEnergy companies – Metropolitan Edison Company (Met-Ed), Pennsylvania Electric Company (Penelec), Pennsylvania Power Company (Penn Power), and West Penn Power Company (West Penn). The PAPUC regulates several smaller electric utilities that are not subject to the Act 129 standards.

[150] http://www.puc.state.pa.us/General/consumer_ed/pdf/13_EnergyRebates.pdf.

[151] General information on the Act 129 program can be found at http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/energy_efficiency_and_conservation_ee_c_program.aspx. http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/electric_distribution_company_act_129_reporting_requirements.aspx.

they are cost-effective. Cost-effectiveness is determined by a total resource cost test, which is a standard test that is met if, over the effective life of each plan, not to exceed 15 years, the net present value of the avoided monetary cost of supplying electricity is greater than the net present value of the monetary cost of energy efficiency conservation measures. This test does not include societal costs or other benefits, such as $CO_2$ reductions.

In 2012, the PAPUC set new incremental targets for consumption reductions that each large EDC must meet by May 31, 2016. These targets range from 1.6% to 2.9%.[152] These targets were based on the cost-effective energy efficiency potential, the costs of the program and the available budget for each EDC. Note that these figures do not represent annual targets but are three-year cumulative reduction requirements. The Commission is currently undertaking the necessary steps to investigate whether the Phase III EE&C program is warranted and what the cost-effective incremental consumption and demand reduction requirements will be, which may extend the program to May 31, 2021.

#### 3. EPA's Assumption Of A 1.5% Annual Incremental Percentage Is Flawed

The PAPUC contends that EPA's 1.5% annual incremental electricity savings as a percentage of retail sales is flawed. The PAPUC points out that the Electric Power Research Institute (EPRI), in a recent published study, "*U.S. Energy Efficiency Potential Through 2035*" indicates an achievable range of annual incremental electricity savings from EE measures to be in the range of 0.5% to 0.7% less than half of EPA's estimate.[153]

In comparing the EPA analysis with PAPUC's current program requirements, the following inconsistencies are revealed: EPA's incremental percentage of 1.5% is essentially double what is required to meet the Act 129 Phase II requirements that are to

[152] The other EDC targets are: Duquesne 2.0%; Met-Ed 2.3%; Penelec 2.2%; Penn Power 2.0%; PPL 2.1%.
[153] EPRI Report 1025477, "*U.S. Energy Efficiency Potential Through 2035*" at vi.

be met in 2016. Early indications of a PAPUC investigation into a Phase III scenario suggests a 0.75% annual incremental reduction which is just slightly above the realized EDC average of 0.72% required in Phase II. PAPUC Staff further adjusted this incremental reduction value taking into account the different baseline years (2012 for EPA and 2009/2010 for Act 129) and the result is an annual adjusted incremental reduction value of 0.74% through 2030. Furthermore, EPA's proposal does not account for the varying levels of energy efficiency potential in each EDC service territory. PAPUC Staff notes that, for Phase II of Act 129, West Penn has a target of 1.6% reduction by the end of the three years, whereas PECO has a 2.9% reduction requirement.

#### 4. EPA Should Credit PA With EE Savings From A 2012 Baseline

EPA's cumulative percentage for PA EE reductions in 2017 is 1.02%.[154] PA's estimated value for 2017 under Act 129 is 5.93%.[155] This higher value for Act 129 considers the reductions attributable to Phases I and II (all prior to the 2012 baseline date) and an assumed annual average incremental reduction value of 0.74% explained previously. PAPUC believes that the EPA should allow PA to be credited with EE reduction benefits back to a 2012 baseline date.

The cumulative percentages for EPA and Act 129 in 2030 are 12.07% and 15.49% respectively.[156] PAPUC estimated EE reductions through 2030 amounts to 19, 327 GWh when starting from baseline year of 2012 projecting forward through 2030 using an incremental annual factor of .74%. [157] This compares to EPA's calculated EE reductions of 19,329 GWh through 2030 utilizing an incremental factor of 1.5%. Thus, the PAPUC-calculated target and the EPA estimates for 2030 are nearly identical. If EPA were not to credit PA with Act 129 EE reductions back to the 2012 baseline then

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[154] Technical Support Document (TSD) for the CAA Section 111(d) Emission Guidelines for Existing Power Plants and PAPUC calculations of PA Act 129 potential.
[155] PAPUC Staff calculation.
[156] PAPUC Staff estimates and calculations.
[157] *Id.*

PA’s cumulative EE reductions (2017 through 2030) would be 10.3% and PA’s associated cumulative GWh reductions would be approximately 14,927, a shortfall of 4,402 GWh. On this point, the PAPUC recommends the EPA allow PA to take credit under BB4 for EE benefits achieved since the baseline year of 2012.

### 5. EPA BB4 Requirements Will Necessitate Changes To PA Quantification, Measurement And Verification Requirements

PA’s Act 129 program employs a State-Wide Evaluator (SWE) that independently audits and verifies EDC compliance with Act 129 requirements. The SWE serves as a third party verifier and auditor of EDC compliance and makes recommendations to the PAPUC at the conclusion of each phase of the program. The SWE engages with the PAPUC, EDCs and EE providers in the development of EM&V protocols. Currently, Act 129 EM&V protocols are developed to track incremental energy efficiency that occurs during a program phase attributable to that program. Baseline standard equipment electric use changes during each phase of the Act 129 program. However, the baseline standard equipment for the EPA proposal would remain constant at the 2012 market penetration assessment.[158]

The PAPUC has determined that new EM&V protocols will need to be developed, along with additional tracking mechanisms, to account for the differences in the equipment baseline in the EPA proposal as well as to account for energy savings beyond the Act 129 program. The EM&V protocols will also have to be modified to include savings obtained from the electric cooperatives and municipal electric authorities if those entities participate. In addition, new tracking mechanisms will have to be developed to track savings associated with building code changes and savings from equipment required to be utilized under the EPA proposal but are not encompassed within the Act 129 program. The EPA, in its final regulations, must allow for time to implement these modifications to PA’s existing Act 129 EE programs.

[158] 79 FR 34872.

### 6. EPA BB4 Requirements Will Necessitate Changes To PA's Act 129 Legislation

Assuming the EPA has the authority to require states to implement EE targets, implementation of EPA's BB4 DS/EE targets would require legislative changes to Act 129 that could conceivably delay implementation of PA's compliance plan. This is especially the case insofar as Act 129 is scheduled to run through May 31, 2016[159] while the EPA requirements continue through 2030 and beyond. Act 129 is the only existing mechanism through which BB4 could be implemented as part of PA's general compliance plan. Also, Act 129 places a spending cap of 2% of EDC annual revenues that may need to be revised in order to achieve EPA's targets. As such, the PAPUC urges the EPA to have some flexibility in allowing PA (and other impacted states) to implement necessary legislative changes that may be required in order to craft a DS/EE BB4 component of its state compliance plan. The EPA should also account for the possibility that state legislatures may not be willing to enact new laws to enforce the EPA's 111(d) mandates.

## G. Selection Of A Base Period

EPA requests comment on the option of selecting a baseline date starting from a specified date prior to the initial plan performance period. EPA states a number of options including 2005.[160] The PAPUC recognizes that EPA has stated that its proposed plan will achieve GHG emissions reductions of 30% below the 2005 level by 2030 if implemented as proposed. However, EPA utilizes the baseline date of 2012 throughout its BB approach. For example, EPA's analysis for BB1 relies on a review of 2012 data for 900 coal generation facilities.[161] Selecting 2012 as a baseline unnecessarily penalizes states, such as PA, that have benefitted from emission reductions from environmental compliance measures taken by coal plant operators since 2005. These measures include

[159] Act 129 requires the PAPUC to assess the cost-effectiveness of the program every five years and set incremental reduction requirements if the program is cost effective. *See*, 66 Pa. C.S. § 2806.1(c) and (d).
[160] 79 FR 34919.
[161] 79 FR 34859.

addition of $SO_2$ and $NO_2$ scrubbers and other upgrades that were designed to improve heat rate and general operating efficiency.

The PAPUC urges the EPA to consider utilizing a 2005 baseline year for the calculation of emissions reductions to be consistent with its stated objective for 30% emissions reductions from a 2005 level by 2030 and to recognize benefits in emissions reductions already achieved by PA generators.

### H. EPA Should Incorporate A Reliability Safety Valve Into the CAA Section 111(d) Proposal

FERC has responsibility under Section 207 of the FPA to address allegations of inadequate service.[162] EPA's Section 111(d) proposal places EPA squarely between the requirements of the FPA and FERC ability to fulfill its statutory duty. This conflict foreshadows the possibility of a generation unit operating under environmental constraints that may need to run more frequently than permitted under the Section 111(d) construct and creates the likelihood that a unit forced to cease operation could be the critical unit needed to prevent a system failure. The PAPUC urges the EPA to consider implementing a reliability safety valve concept as proposed by PJM to ensure that, in time of system stress, critical generation units can be called on to perform even if those units do not meet the technical requirements of environmental dispatch.

### I. Adoption Of Recommendations Of The Public Utilities Commission Of Ohio

PA is similarly situated to Ohio (OH) in the PJM wholesale electric market. Both states have deregulated the retail electric market and both states are net exporters of generation. Both PA and OH have developed shale gas resources that are a dominant fuel source for incumbent generation. Both PA and OH will experience similar negative impacts from the adoption of CAA Section 111(d). Consequently, the PAPUC, in the

[162] 16 U.S.C. § 824(f).

interests of brevity, adopts the following positions as expressed in the comments of the PUCO:

- EPA's proposed implementation schedule does not provide adequate time for changes in state law that may be necessary to accommodate CAA Section 111(d). (PUCO Comments, pp. 17-18).
- EPA's proposed implementation schedule does not provide adequate time for the North American Reliability Council (NERC) to perform necessary reliability analysis on the electric system. (PUCO Comments, pp. 20-21).
- EPA's Section 111(d) proposal is based on a re-dispatch analysis that ignores established dispatch control systems. (PUCO Comments, pp. 24-25).
- EPA's Section 111(d) proposal will create unquantifiable but major cost impacts due to increased capacity pricing. (PUCO Comments, pp. 29-32).
- EPA's BB2 relies on a 70% capacity factor that inappropriately utilizes nameplate capability instead of seasonal capability. (PUCO Comments, pp. 37-38).
- The NERC Reliability Study highlights important reliability challenges associated with BB4. (PUCO Comments, pp. 47-48).

## III. CONCLUSION

The PAPUC appreciates the opportunity to file comments at this docket. The PAPUC cannot emphasize enough the potential negative impact that these proposed regulations pose to the reliability of the PJM transmission system, the function and operation of the PJM wholesale electric market, the cost of electricity to retail customers and the composition of generation in PA and the region. The EPA should also give due consideration to the points raised by the PAPUC, the PADEP and the PUCO (per PAPUC references above) in its finalization of these important regulations.

Respectfully submitted,

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