Pennsylvania Department of Environmental Protection

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December 13, 2006

Office of Energy and Technology Deployment

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INDEPENDENT REGULATORY REVIEW COMMISSION

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Commonwealth of Pennsylvania
Secretary's Bureau
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Docket No. L-00060180

Proposed Rulemaking Re Implementation of the Alternative Energy Portfolio Standards Act of 2004

Dear Secretary McNulty:

Enclosed please find fifteen (15) copies of the Department of Environmental Protection's comments on the Proposed Rulemaking Order entered July 25, 2006, Regarding Implementation of the Alternative Energy Portfolio Standards Act of 2004.

Respectfully Submitted,

Eric Thumma
Director
Bureau of Energy, Innovations, and Technology Deployment

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SECRETARY'S BUREAU

Enclosures

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Rulemaking Re Implementation of the Alternative Energy Portfolio Standards Act of 2004

Docket No. L-00060180

Introduction

The Pennsylvania Department of Environmental Protection regards the implementation of AEPS in general and this rulemaking specifically as one of the most important policy matters for consideration related to Pennsylvania's electricity market. AEPS is the only policy initiative that actually ensures that new capacity will be added to the electricity system. Its successful implementation will ensure a greater mix of resources, including renewables, which are immune to the type of fuel price fluctuations the current wholesale electricity market has faced. AEPS also promotes distributed generation, which if encouraged in constrained areas can improve system reliability and enhance the economics of the wholesale market. DEP is pleased to be a partner with the Commission in the implementation process and offers these comments on the proposed regulation that we believe will greatly enhance the successful implementation of AEPS and lead to the electricity market benefits described above.

Since Gov. Rendell signed Act 213 of 2004 into law DEP has been working vigorously with alternative energy developers to encourage them to locate projects in Pennsylvania. All of these developers have emphasized the importance of long-term contracting, and clearly defined rules related to cost recovery and the credit market, as prerequisites for their entry into the Commonwealth. While we have been successful in securing Spanish-based Gamesa, one of the world's largest wind energy companies, and

German-based Conergy AG, the world largest solar integrator, there are literally millions of dollars of additional investments waiting to pour into the Commonwealth pending the successful adoption of sound AEPS rules. Our recommendations focus on ensuring that the Pennsylvania alternative energy market created by Act 213 of 2004 meets the expectations of those ready to invest in Pennsylvania's energy future by creating the secure, reliable, and stable alternative energy economy envisioned by the Pennsylvania General Assembly when they passed Senate Bill 1030 of 2004, Pennsylvania's Alternative Energy Portfolio Standard.

We regard the following as the most essential issues for Commission consideration and encourage the Commission to adopt the recommendations presented:

1. Long-term Contracting – the Commission should address long-term contracting for AEPS resources in this rulemaking. (Our comments submitted earlier in other AEPS related dockets indicate that we do not believe it appropriate or prudent for AEPS long-term contracting issues to be delayed until the default service proceeding). The Commission should clarify in this rulemaking that EDCs may enter into long-term contracts with AEPS resources in order to achieve their compliance obligations. We define long-term to include contracts of up to twenty years.
2. Solar-share – The proposed draft does not speak to specific rules related to the solar PV share. This is a critical oversight. The final rule must include a section that speaks specifically to how the solar share will be implemented in Pennsylvania. Pennsylvania's solar share is ambitious, but achievable if the right rules are in place to encourage investor confidence. In order for the Pennsylvania

solar share to be achieved, investors will need certainty that the solar credit system will provide a reliable cash flow to backup their capital investments. Key elements for investor confidence include long-term contracting and cost recovery.

3. Force Majeure – AEPS's mandates should be met through a marketplace of buyers (EDCs and EGSs) and sellers of alternative energy. The introduction of force majeure is meant to be an absolute last resort. As such, this rulemaking should focus on a framework that sets conditions such that a declaration of force majeure is least likely to occur. There is a direct correlation between the possibility of force majeure being invoked and the substance of this rulemaking. The recommendations we are making are designed to ensure that this rulemaking promotes investor, alternative energy developer and EDC and EGS confidence in the alternative energy market, therefore making force majeure less likely. Encouraging investment in the alternative energy market should be the first priority of this rulemaking and is the best defense against the need to invoke any of the force majeure provisions found in the act and the proposed rulemaking.

   Therefore, we believe that more specific regulatory language is necessary to ensure that attempts to invoke force majeure only occur when all market options are exhausted.

4. Recommended Changes to Regulatory Language – In addition to the three preceding priority comments, we provide additional commentary and recommendations on several sections of the proposed rulemaking.

Long-term Contracting

DEP has argued in previous commentary to other AEPS related dockets that the Commission should address the issue of long-term contracts for alternative energy sources in the AEPS rulemaking. There has been some discussion that the Commission will reserve the AEPS long-term contracting issue for the default provider proceeding. We are concerned about this potential approach for a number of reasons. DEP, in concert with the Pennsylvania Department of Community and Economic Development, has been working with numerous alternative energy developers regarding their interest in developing and/or investing in renewable and alternative energy projects in the Commonwealth. The primary barrier to their investment, which we hear continually, is uncertainty regarding their ability to enter into long-term contracts with default providers. This lack of clarity is literally leading to the delay or loss of millions of dollars of investment in the Pennsylvania economy and could impair the ability of EDCs to comply with the requirements of AEPS.

The proposed rule does partly address this concern in the background.

> Because section 2807(e)(3) requires energy procured for default service to be acquired at "prevailing market prices," the Commission interprets 73 P.S. § 1648.3(a)(3) to mean that EDCs should use competitive processes to meet the requirements of § 75.51. However, this interpretation does not preclude the use of long-term, bilateral contracts between an EDC and an alternative energy generator as part of a reasonably balanced portfolio of alternative generation supply resources. The Commission recognizes that EDCs may pursue different strategies to acquire alternative and traditional forms of energy to serve retail customers. For example, an EDC might choose to enter into contracts of varying durations to acquire electricity from traditional energy sources, and at the same time enter into several long term contracts to satisfy its obligations under § 75.51. However, the EDC must still use some type of competitive process to acquire alternative energy in order to demonstrate that retail customers are being provided alternative energy at reasonable rates.

DEP does not believe that the commentary in this background session provides sufficient confidence to EDCs to enter into long-term contracts with AEPS eligible sources. We strongly encourage the Commission to add language in section § 75.51 supportive of EDCs ability to enter into long-term contracts to meet their AEPS obligations. This language should clearly include the following provisions:

- EDCs ability to enter into long-term contracts for electricity and/or alternative energy credits from eligible alternative energy sources. Our discussions with numerous alternative energy developers have indicated that contracts up to 20 years are necessary in order to competitively develop alternative energy projects at the lowest cost.
- EDCs ability to recover the costs of AEPS compliance pursuant to the cost recovery rules found in the act. DEP has engaged on this topic with numerous EDCs who are interested in banking credits and beginning the process of complying with the act. However, uncertainty over cost-recovery, coupled with questions surrounding the validity of long-term contracting, is discouraging them from doing so. The hesitance of EDCs to begin banking credits means that projects, which could be adding capacity to the PJM system and the concomitant benefits are being delayed.

As co-implementers of AEPS, the Commission and DEP have an obligation to promulgate rules that encourage the development of alternative energy sources. Failure to allow for long-term contracting, or to delay that decision until the default service proceeding, will encourage force majeure and/or encourage developers to simply shift their financial resources to states where financing is more readily available because of those states support for long-term contracts.

DEP agrees with the Commission's rulemaking language that EDCs must use a competitive process for procuring alternative energy to meet their compliance obligations. However, we are aware that some EDCs are already entering into bilateral contracts for alternative energy in anticipation of meeting their AEPS compliance obligations. How will the Commission deal with this issue? The commentary language set forth in the proposed regulation recognizes that "…the use of long-term bilateral contracts between an EDC and an alternative energy generator [should not be precluded]".

Clearly, DEP supports early compliance and the banking of AECs and we recognize bilateral contracts are an essential ingredient for achieving this. We believe that this rulemaking should encourage a competitive process, and the early stages of AEPS implementation must allow for bilateral contracts. The Commission should develop a process in this rulemaking by which EDCs may enter into long-term bilateral contracts in order to begin early compliance with AEPS. The Commission, with the aid of the Program Administrator, can evaluate those contracts based on the price of renewable energy in PJM, NYISO and NEISO to determine whether they are "competitive." As AEPS implementation reaches a more mature stage we believe it is possible to go to fully competitive bidding for AEPS compliance, provided the long-term contracting provisions we have outlined above are adopted, however, at this early stage some bilateral contracting will be necessary to jump-start the market, establish market prices, and to encourage banking.

Solar Share

Before addressing our comments and recommendations related to solar share implementation, we note that the proposed rulemaking should include more specific language confirming that the solar percentage mandate in the act applies to all consumer demand. While we believe this was the Commission's intention in the proposed rulemaking as it represents the generally agreed upon intention of the act, we find the proposed rule lacks sufficient clarity on this point. Subsection (b) of §75.51 appears to accidentally prescribe the solar share as a percentage of Tier I sales rather than as percentage of total sales. To address this issue we provide specific recommended language for § 75.51 (b) (1) – (15) and encourage the Commission to adopt this language set forth below:

> For each reporting period, EDCs and EGSs shall acquire alternative energy credits in quantities equal to a percentage of their total retail sales of electricity to all retail electric customers for that reporting period, as measured in MWh. The required quantities of alternative energy credits for each reporting period is identified in the following schedule:
>
> (1) For June 1, 2006, through May 31, 2007: The Tier I requirement is 1.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0013% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 4.2% of all retail sales.

(2) For June 1, 2007, through May 31, 2008: The Tier I requirement is 1.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0013% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 4.2% of all retail sales.

(3) For June 1, 2008, through May 31, 2009: The Tier I requirement is 2% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0013% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 4.2% of all retail sales.

(4) For June 1, 2009, through May 31, 2010: The Tier I requirement is 2.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0013% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 4.2% of all retail sales.

(5) For June 1, 2010, through May 31, 2011: The Tier I requirement is 3% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0203% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 6.2% of all retail sales.

(6) For June 1, 2011, through May 31, 2012: The Tier I requirement is 3.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0203% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 6.2% of all retail sales.

(7) For June 1, 2012, through May 31, 2013: The Tier I requirement is 4% of all retail sales, **WHICH SHALL INCLUDE** the

solar photovoltaic requirement [is] **OF** .0203% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 6.2% of all retail sales.

(8) For June 1, 2013, through May 31, 2014: The Tier I requirement is 4.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0203% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 6.2% of all retail sales.

(9) For June 1, 2014, through May 31, 2015: The Tier I requirement is 5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .0203% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 6.2% of all retail sales.

(10) For June 1, 2015, through May 31, 2016: The Tier I requirement is 5.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .25% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 8.2% of all retail sales.

(11) For June 1, 2016, through May 31, 2017: The Tier I requirement is 6% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .25% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 8.2% of all retail sales.

(12) For June 1, 2017, through May 31, 2018: The Tier I requirement is 6.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .25% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 8.2% of all retail sales.

(13) For June 1, 2018, through May 31, 2019: The Tier I requirement is 7% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .25% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 8.2% of all retail sales.

(14) For June 1, 2019, through May 31, 2020: The Tier I requirement is 7.5% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .25% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 8.2% of all retail sales.

(15) For June 1, 2020, through May 31, 2021, and each successive twelve month period thereafter: The Tier I requirement is 8% of all retail sales, **WHICH SHALL INCLUDE** the solar photovoltaic requirement [is] **OF** .5% of [Tier I] **ALL RETAIL** sales, and the Tier II requirement is 10% of all retail sales.

Pennsylvania's solar share is the second largest mandatory solar PV obligation in the nation. The solar carve out found in the act will require the introduction of between 600 and 900 megawatts of solar PV capacity (depending on capacity factors and technology advancements over the compliance period). Considering that Pennsylvania currently has less than 1 MW of installed solar capacity, Pennsylvania's solar share provides an outstanding opportunity for economic development, but it requires clear rules that encourage solar PV deployment in the Commonwealth.

DEP has been working diligently over the past two years to encourage solar developers and manufacturers to come to Pennsylvania. The recent announcement that

German-based Conergy will locate its renewable financing arm, Voltwerk, in Pennsylvania to be joined by it's solar development subsidiary Sun Technics, is an example of the type of investment that can grow in Pennsylvania through the implementation of AEPS.

Unfortunately, the proposed rulemaking completely fails to provide any guidance or background discussion related to implementation of the act's solar mandate. We strongly encourage the Commission to include a dedicated solar share background discussion and rules in the final rulemaking.

The provisions required to encourage solar PV deployment in Pennsylvania are similar to those discussed in the long-term contracting section above. DEP recommends the inclusion of a solar PV section in the final rulemaking that includes:

- Allowing EDCs to enter into long-term, standardized contracts for electricity and/or alternative energy credits from solar PV for the purpose of AEPS compliance.

  Our discussions with solar developers have concluded that contract lengths of 15 to 20 years are necessary in order to minimize the amortization costs for solar PV installation.

- To encourage early compliance and banking of solar credits the Commission should allow long-term bilateral contracts between EDCs and solar project developers.

  Over time we believe that a fully competitive bid process can be structured, but long-term bilateral contracts will be necessary to jump-start the market.

- Language confirming that EDC cost-recovery for AEPS compliance will be assured for long-term contracts, including bilateral contracts, which EDCs have entered in order to meet their solar share compliance obligation, including for banked credits.

Jump-starting the solar PV market is essential to meeting the act's 2011 requirements. By 2011 we estimate that approximately 20 MW of installed solar PV capacity will be required with a second significant jump to 30 MW in 2012. In order to meet these mandates project deployment and early banking will be absolutely essential, this will not happen without assurances to EDCs that long-term contracting, bilateral contracts and cost-recovery are assured and encouraged through the final rulemaking.

<u>Solar Share Alternative Compliance Payment</u>

Calculating the solar share alternative compliance payment (ACP), while always important, is even more vital in light of the proposed rulemaking's Force Majeure provisions. By setting the ACP for solar at twice the value of a solar alternative energy credit (S-AEC) the legislature clearly sought to encourage EDCs and EGSs to acquire S-AECs instead of seeking alternative compliance options.

In calculating the "market" value of S-AECs it is critical that the Commission not simply analyze the value of S-RECs in other PJM jurisdictions such as New Jersey. For example, in New Jersey, the values of S-RECs are offset, in part, by customer rebates funded through a systems benefit charge. Any calculation of the market value of S-AECs must account not just for price of S-RECs in other jurisdictions, but also any additional subsidies in those jurisdictions.

Consequently, another benefit of allowing bilateral contracts between developers and EDCs early in the compliance period is to develop a "market" value for S-AECs that does not rely on an analysis of other PJM markets.

Force Majeure

The imposition of force majeure must occur only in the most limited circumstances when all other market options have failed. We do not believe the proposed rulemaking sufficiently identifies tests for applying force majeure, nor is the term "good faith," in relation to the *Special Force Majeure* provisions adequately defined.

We recommend the following tests before consideration of any appeal for force majeure:

General Force Majeure

- The Commission, with the aid of the program administrator and DEP, should constantly monitor the status of credits available on the Generation Attributes Tracking System (GATS) or its successor system. The "ramping-up" of AEPS requirements affords the Commission with the opportunity to identify potential future shortfalls in credits for AEPS tiers. Should potential shortages be identified the Commission should require "special solicitations" as part of default service to meet any potential shortfalls before any appeal of force majeure can be made.
- The Commission, with the aid of the program administrator and DEP should constantly monitor compliance with portfolio standard requirements in other states within PJM. Since many states will be relying on alternative and renewable

energy development within PJM to meet their portfolio standard requirements, success in other states will serve as a good signal as to whether a market exists sufficient to meet AEPS mandates.

Special Force Majeure

- The invocation of special force majeure relies heavily on making a determination as to whether an EDC and/or EGS has made a "good faith effort" to comply with the AEPS mandates. Because force majeure should be regarded as an absolute last resort for addressing compliance requirements and because the proposed rulemaking proposes cost recovery for alternative compliance payments when special force majeure is invoked we believe that the requirements for invoking special force majeure must be more clearly defined.
- We propose that the Commission require the following conditions before any request for special force majeure will be considered:
  - Has the EDC or EGS submitted request for proposals (RFPs) for its compliance obligation in advance of its compliance obligation? We recommend that RFPs be let eighteen to twenty four months in advance of an EDC's or EGS's compliance obligation. And related, did bidders submit bids for alternative energy less than the ACP? If so, a request for special force majeure cannot be invoked.
  - Has the EDC or EGS banked credits in advance of its compliance obligation? The Commission should look very skeptically upon requests for special force majeure from mandated entities that did not seek to bank credits during the transition period. In fact, we would regard a failure to

bank credits as means to disqualify a request for special force majeure. An EDC or EGS would need to demonstrate that requests for credits during the transition period could not be met. The Commission should use GATs, and the experience in other EDC territories and portfolio standard states to evaluate any such claims.

<u>Recommended Changes to Regulatory Language</u>

Below are specific changes DEP recommends to language found in the proposed rulemaking in addition to the priority comments we have provided above.

<u>§ 75.51 EDC and EGS obligations</u>

Subsection (a)

The preamble to the proposed regulations indicates that the Commission will not be entertaining comments on whether alternative energy must actually be sold to Pennsylvania customers before the associated alternative energy credit may be separately traded. This is unfortunate because requiring EDCs and EGSs to actually sell alternative energy to Pennsylvania customers is the most direct way of ensuring that Pennsylvanians receive the benefits of AEPS. Benefits they will be paying for.

The Commission's April 28, 2006, Order in *Petition of Pennsylvania Power Company for Approval of Interim POLR Supply Plan*, Docket No. P-00052188, stresses the importance of delivering alternative energy to Pennsylvania customers. The Order also emphasizes the fact that because most states within MISO do not have a renewable portfolio standard statute, "Pennsylvania ratepayers would pay for MISO alternative energy facilities with little or no commensurate economic construction projects in or environmental benefits to them."

Similarly, of the 13 states and the District of Columbia served in whole or part by PJM only 4 (excluding Pennsylvania) have a renewable portfolio standard statute. Therefore, we can expect that Pennsylvania ratepayers will pay for PJM alternative energy facilities with little or no commensurate economic or benefits to them as well. In addition, if Penn Power is successful in its litigation and the Department is not, the burdens on Pennsylvania ratepayers described by the Commission will be fully realized. Requiring alternative energy to be sold to Pennsylvania customers before the associated alternative energy credit may be separately traded is supported by the language of the statute, avoids the Constitutional issues raised by Penn Power and Commissioners Fitzpatrick and Pizzingrilli, and directly promotes the economic and environmental benefits to Pennsylvania ratepayers that the Legislature intended. As such, the proposed regulations should be amended accordingly. This may be accomplished in two different ways. Because subsection (a) requires EDCs and EGSs to purchase "certified" credits it may be most appropriate to amend section 75.54(c) as follows:

> An alternative energy credit may not be certified for a MWh of electricity generation or electricity conservation **IF** that **MWh HAS NOT BEEN SOLD TO OR CONSERVED BY A PENNSLYVANIA RETAIL CUSTOMER OR IF THAT MWH** has already been used to satisfy . . ..

Alternatively, section 75.51(a) could be amended as follows:

EDCs and EGSs shall comply with the act through the acquisition of certified alternative energy credits, each of which shall represent one MWh of qualified alternative electric generation or conservation, whether self generated, purchased along with the electric commodity or separately through a tradable instrument **PROVIDED THAT THE MWh OF QUALIFIED ALTERNATIVE ELECTRIC GENERATION OR CONSERVATION IS FIRST SOLD TO OR CONSERVED BY A PENNSLYVANIA RETAIL CUSTOMER.**

§ 75.52 Fuel and technology standards for alternative energy sources

Subsection (a) (7) – *Biologically derived methane gas*

The proposed regulation includes language that limits the source of methane gas to the anaerobic digestion of organic materials and includes landfill methane gas. Such a limitation is more constrictive than the language of the Act, which states the production of electricity from "biologically derived methane gas, which shall include methane from the anaerobic digestion of organic materials…". The Act did not limit the technology source of biologically derived methane to anaerobic digestion and landfills. DEP encourages the Commission to revise the proposed regulation to be consistent with the language of the Act and recommends that § 75.52 (a) (7) be changed to:

Electricity produced from **BIOLOGICALLY DERIVED** methane, **INCLUDING METHANE** from the anaerobic digestion of organic materials from yard waste, such as grass clippings and leave, food waste, animal waste and sewage sludge. This source also includes landfill methane gas.

Biodiesel – The question has been raised whether the use of biodiesel should be eligible for credits under Tier I of the AEPS. The Department has considered this question very carefully as we believe that biodiesel usage should be encouraged. However, for AEPS purposes we are recommending that biodiesel used in generators for the production of electricity not be considered an eligible AEPS resource.

The definition of biomass energy, found in § 75.52 (a) (6) (i) defines biomass energy to include: "…organic material from a plant that is grown for the purpose of being used to produce electricity…". Biodiesel is generally produced from materials not grown specifically as energy crops. Biodiesel is derived generally from soybeans grown primarily for animal or human consumption purposes or from waste greases. Conceivably the latter could qualify under §75.52 (a) (6) (ii) except that this section refers to "solid nonhazardous, cellulosic materials," which waste greases are not.

Additionally, we do not believe it is in anyway the intention of the act to promote diesel generation. Since biodiesel would typically be blended into conventional diesel at percentages less that 100% biodiesel we strongly caution against provisions that would count biodiesel as an eligible fuel source for AEPS credits. The Department would entertain arguments in the reply comments as to whether generators running on 100% biodiesel should count towards AEPS credits. However, such arguments would also need to confirm limited environmental impacts, and specifically air quality impacts.

At this time, the Department does not consider biodiesel an eligible fuel source for AEPS compliance.

Subsection (b) (2) – *Waste Coal.*

In the preamble to the proposed regulations, the Commission states that it declines to expressly adopt a blanket qualification for waste coal from non-permitted disposal sites because the Act does not provide the Commission with the express authority to expand the scope of the waste coal definition. However, the proposed regulations appear to unnecessarily restrict the ability of facilities that generate electricity from waste coal that was disposed of in non-permitted sites prior to July 31, 1982 to qualify under Tier II.

The definition of waste coal establishes three ways in which a facility can utilize waste coal and obtain Tier II credits. First, the facility combusts waste coal that was disposed of or abandoned prior to July 31, 1982. Second, the facility combusts waste coal that was disposed of in a permitted coal refuse disposal site regardless of when the waste coal was disposed of. Third, other waste coal combustion meeting standards established by regulation. Under the first scenario, any waste coal disposed of prior to July 31, 1982 may be utilized to generate electricity and qualify for Tier II credit – regardless of whether it was disposed of in a permitted site. However, if the waste coal was disposed of after July 31, 1982 it could only utilized to generate electricity and qualify for Tier II credit if the Commission established such an approval process by regulation (under the third scenario).

Waste coal that was disposed of before July 31, 1982 in non-permitted refuse sites creates significant environmental problems in the Commonwealth. Utilizing waste coal from these sites should not be hindered by requiring a case by case determination from the Commission when the Act clearly contemplates equal treatment with permitted disposal sites. There may be however, certain circumstances in which waste coal disposed of in non-permitted sites after July 31, 1982 should qualify under the Act – such as when qualification is necessary to incent the voluntary remediation of a site by a party that had no responsibility in its creation. As such, maintaining an ability to qualify these sites is important. DEP agrees with Commissioner Fitzpatrick that the regulations should set forth the alternate eligibility requirements for these sites. In addition, because the Act requires DEP to verify that alternative energy sources meet the standards specified in section 2 and further clarified in section 75.52 of the proposed regulations, DEP believes that such determinations should be made by the DEP. Therefore, DEP recommends the following changes to the proposed regulation at § 75.52 (b) (2):

> Applicants may petition **THE DEPARTMENT** for waste coal [from] **DISPOSED OF IN** nonpermitted sites **AFTER JULY 31, 1982** to be qualified for alternative energy status. **THE DEPARTMENT MAY APPROVE THE PETITION IF THE APPLICANT DEMONSTRATES THAT THE WASTE COAL IS A THREAT TO PUBLIC HEALTH, SAFETY OR THE ENVIRONMENT, NO ENTITY LIABLE FOR THE DISPOSAL OF THE WASTE COAL EXISTS, THAT THE WASTE COAL HAS NO OTHER ECONOMIC VALUE, AND SUCH APPROVAL IS NECESSARY TO REMEDIATE THE WASTE COAL DISPOSAL SITE.** [The Commission may grant the petitions at its discretion.]

Subsection (b) (4) – *Distributed generation system*

The preamble of the proposed regulations discusses the need for clarification on the scope of the "distributed generation systems" alternative energy source. The Act and the proposed regulation do not define what constitutes "small scale" nor do they specify qualifying technologies and particular fuel types. The Commission states, "at a minimum …this definition would include net-metered and interconnected customer-generators…that utilize Tier II sources." We agree with this minimum but believe it should not be limited to net-metered or interconnected customer-generators. It is possible that a customer-generator could install a distributed generation system that produces electricity in an amount that is consumed wholly on site without being net-metered or interconnected.

For consistency with the Act we suggest that the maximum size of qualified distribute generation systems be limited to not more than 2 MW.

§ 75.54 Alternative energy credit certification

Subsection (e) of this section discusses how alternative energy systems, which rely on more than one fuel source or technology for a portion of their electricity generation shall earn credits. It is the Department's position that this section should be further clarified to identify that such systems will be awarded credits based on the relative heat rates of the alternative fuels used in the system.

The Department concurs with the Commission's proposed language in letter (g) that credits pursuant to AEPS only represent compliance with the act and do not include attributes unrelated to AEPS compliance such as environmental or emissions attributes that may be associated with electricity production.

§ 75.55 Alternative energy credit program administrator.

These sections discuss how the Commission, DEP and the program administrator will work cooperatively to qualify eligible alternative energy systems. Section 7(b) of Act 213 identifies DEP's responsibilities as "...ensur[ing] that all qualified alternative energy sources meet all applicable environmental standards and shall verify that an alternative energy source meets the standards set forth in section 2." However, proposed sections 75.53 and 75.55 do not properly address the roles and functions of the parties for verifying that an alternative energy source meets the standards set forth in section 75.52 and ensuring that qualified alternative energy sources meet all applicable environmental standards.

As the regulations are currently drafted, decisions concerning compliance with environmental standards and conformance with section 75.52 standards are appealable to both the Commission and the Environmental Hearing Board. In addition, the regulations improperly shift much of the burden in qualifying alternative energy systems to DEP. Because the program administrator is charged with the duty to qualify alternative energy systems and DEP is to ensure *qualified* sources meet environmental and section 75.52 standards, the administrator should only refer applications to DEP for a compliance determination if the administrator believes that the alternative energy source does not meet the applicable standards. DEP will then make a final determination of the source's environmental and section 75.52 standards compliance status. Similarly, questions of a qualified alternative energy system's continued compliance with environmental laws and section 75.52 standards should also be referred to DEP for final determination. DEP recommends the following amendments to accomplish these objectives.

§75.53 (f) A facility shall be qualified if [the Department has verified] **IT** is in compliance with applicable environmental regulations, and if it has obtained necessary State and Federal environmental permits for operations.

Delete § 75.53 (g).

Reletter § 75.53 (h) as (g) and revise as follows:

> The Commission may suspend or revoke the alternative system status of a facility [, after notice and opportunity to be heard,] for major environmental violations, **AS DETERMINED BY THE DEPARTMENT.** Major environmental violations shall be defined as those that cause significant harm to the environment or public health and result in a compliance order or penalty **ASSESSMENT.** [assessed by the Department.] Alternative energy credits may not be certified for that facility for a period beginning with the suspension or revocation of alternative energy system status, as evidenced by a formal Commission action, through the time that alternative energy system status is restored.

§75.55 (b) (4) Refer verification of the [application's] **APPLICANT'S** compliance with applicable environmental regulations to the Department **FOR A FINAL DETERMINATION IF THE PROGRAM ADMINISTRATOR CONCLUDES THAT THE APPLICANT MAY NOT BE IN COMPLIANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS. IF THE DEPARTMENT DETERMINES THAT THE APPLICANT IS NOT IN COMPLIANCE WITH APPLICABLE ENVIRONMENTAL REGULATIONS, THE APPLICATION SHALL BE DEEMED TO BE INCOMPLETE AND RETURNED TO THE APPLICANT BY THE DEPARTMENT.**

§75.55 (b) (5) Refer verification of the [application's] **APPLICANT'S** compliance with §75.52 (relating to fuel and technology standards for alternative energy sources) to the Department **FOR A FINAL DETERMINATION IF THE PROGRAM ADMINISTRATOR CONCLUDES THAT THE APPLICANT MAY NOT BE IN COMPLIANCE WITH §75.52. IF THE DEPARTMENT DETERMINES THAT THE APPLICANT IS NOT IN COMPLIANCE WITH §75.52, THE APPLICATION SHALL BE DEEMED TO BE INCOMPLETE AND RETURNED TO THE APPLICANT BY THE DEPARTMENT.**

Delete §75.55 (b) (6) and renumber accordingly

§ 75.60 Alternative energy market integrity

Ensuring that credits from alternative energy sources are only being "consumed" by a single buyer at any point in time is essential for maintaining the integrity of the alternative and renewable energy marketplace. Act 213 recognized this by stating that "…the electric distribution supplier or electric generation company shall not satisfy Pennsylvania's alternative energy portfolio requirements using alternative energy used to satisfy another state's portfolio standard." Similarly, credits sold in the voluntary market – to say a college or university or government entity – should not be eligible to be used for compliance with AEPS, since that credit is already being consumed and has been paid for by that entity. To allow credits acquired and consumed on the voluntary market to count towards AEPS would fundamentally compromise alternative and renewable energy credit markets by allowing a single product to be sold and consumed more than once.

We agree with Commission's language in § 75.60 regarding disclosure of alternative electricity by EDCs and EGSs. Ensuring that retail sales of credits exceeding AEPS requirements must be backed by the appropriate number of verifiable and traceable alternative energy credits is essential to market integrity.

However, we believe additional clarifying language is necessary in the rulemaking to ensure that credits sold to entities without AEPS compliance requirements, such as a college or university purchase in our example above, are then not counted towards an EDCs or EGSs compliance requirement – unless that third-party entity specifically enters into a contractual relationship with EDC or EGS to sell those credits.

We commend the Commission for the work done on this proposed rulemaking and for giving consideration to our comments. We look forward to our continued partnership with the Commission to implement and report on the Alternative Energy Portfolio Standard.