BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Alternative Energy Portfolio Standards
Technical Conference

Docket No. M-00051865

Comments
On behalf of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company –
The FirstEnergy Operating Companies

January 14, 2004

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Pursuant to the January 7, 2005 Notice of Technical Conference ("Notice"), the FirstEnergy operating companies of Pennsylvania Electric Company, Metropolitan Edison Company, and Pennsylvania Power Company (collectively, "FirstEnergy") submit these preliminary comments regarding the implementation of the Alternative Energy Portfolio Standards ("AEPS") Act of 2004 ("Act").

I. INTRODUCTION[1]

On November 30, 2004, Governor Edward G. Rendell signed into law the Alternative Energy Portfolio Standards Act of 2004 also known as Act 213. The Act provides the Pennsylvania Public Utility Commission ("Commission") and the Pennsylvania Department of Environmental Protection ("DEP") with certain responsibilities associated with implementing AEPS.

The Commission Secretary's Bureau issued a Notice of Technical Conference that identified several areas of the Act that should be focused upon during the meeting. The list of issues covered matters such as (1) force majeure (availability and qualification of eligible alternative energy resources), (2) deferrals and cost recovery, (3) creation of alternative energy credits program and trading platform, (4) alternative compliance payments, (5) portfolio requirements of other states and regional coordination, (6) development of technical standards for verification of energy efficiency and demand side management activities, and proposed depreciation schedules for AEC resulting from such

[1] The FirstEnergy Operating Companies are represented in this Technical Conference discussion by Mr. Kent A. Hatt. Mr. Hatt's work experience and background is detailed in Appendix A to these comments.

measures, (7) development of technical standards for net metering, and (8) development of technical standards for interconnection.

FirstEnergy appreciates the Commission taking the initiative to bring all interested stakeholders together for discussions concerning the implementation of the Act. It is critical that the Commission, when developing regulations and procedures, address legitimate concerns of the various stakeholders and find a proper balance among the various (often competing) interests. FirstEnergy expects to fully participate in the development of the Commission's regulations implementing the Act. However, the breadth of the Act and the short period allotted for the submission of these comments has necessarily limited the ability of FirstEnergy to fully develop and articulate their recommendations on all of the issues that the Commission must consider in implementing the Act. FirstEnergy urges the Commission to continue the open dialogue process that it seems to envision in the January 19, 2005 technical conference by allowing additional comments and/or scheduling further technical conferences as needed on the myriad issues the Act raises.

Moreover, if the objectives contemplated in the Act are to come to fruition, then it must be recognized that least-cost generation sources will not always be utilized in the supply portfolios of electric distribution companies ("EDC's"). The Act, as evidenced by the cost recovery provisions, intends that customers pay in the short run, more than they would have paid, absent the Act, as a trade-off for the development of these markets. It is with these thoughts in mind that FirstEnergy submits its comments.

II. COST RECOVERY & DEFERRALS

As a creature of statute, the Commission can perform only those functions that have been authorized by statute. The Act authorized the Commission to develop regulations that address certain specific aspects of the Act. For example, the Act authorizes the Commission to establish regulations governing the verification and tracking of energy efficiency and demand-side management measures. Section 3 (e) (10), p. 15-16. And within 120 days of the effective date of the Act, the Commission is to develop a depreciation schedule for alternative energy credits created through DSM, energy efficiency and load management technologies, along with standards for tracking and verifying savings from these techniques. Section 3 (e) (11), p. 16. Regarding the issues of deferrals and cost recovery, however, there is very little left to be addressed by the Commission in regulations. The Act already described how costs related to alternative energy sources ("AES") are to be determined, how these costs are to be recovered, and how the recovery mechanism should be structured.

The Act clearly defines the nature of the costs to be recovered, stating, "*All* costs for: (I) the purchase of electricity generated from alternative energy sources, including the costs of the regional transmission organization, in excess of the regional transmission organization[("RTO")] real-time locational marginal pricing [("LMP")], or its successor, at the delivery point of the alternative energy source for the electrical production of the alternative energy sources; and (II) payments for alternative energy credits." Section A (3), p. 9-10 (emphasis added). The Act also defines the types of AESs that come within the scope of the Act. Therefore, if the EDC incurs costs related to the procurement of AES supplies that are defined in the Act, the EDC is entitled to recover these costs, provided that the nature of the costs comes within one of the two cost categories described above. As for verification of these costs, both categories should be easily verifiable. The first cost category is merely a comparison of the difference between the purchase price of AES generation and the corresponding LMP for the period. And the second category of costs will be based on the prices obtained in the alternative energy credit market that is to be developed by the Commission, and which is discussed in more detail in another section of these comments.

The deferral and rate making treatment is also expressly described in the statute. It addresses both the pre- and post-cost recovery period, expressly allowing for the deferral (with carrying charges) of both categories of costs during the cost recovery period as defined in the Act. Section A (3), p. 9-10. This deferral is to be recovered through an automatic adjustment clause within the first year of the expiration of the EDC's cost recovery period. Section A (3), p. 9-10. Both category I and II costs that are incurred after the EDC's cost recovery period are to be fully recovered on a current basis through an automatic adjustment clause. Section A (3), p. 9-10. In light of these provisions, the primary issue to determine regarding deferrals is the interest rate to be used to calculate carrying charges. And, in light of the fact that the AES costs are an external payment for the EDC, FirstEnergy suggests the use of the EDC's overall cost of capital when determining carrying costs.

As for recovery after the deferral period, the Act describes the structure of the recovery mechanism, envisioning a process already developed in 66 PA. C.S. §1307, which deals with sliding scales of rates and adjustments thereto. Section A (3), p. 9-10. Section 1307(b) authorizes the Commission to establish through the rule making process "a mandatory system for the automatic adjustment of their rates by means of a sliding scale…."[2] FirstEnergy recommends a process similar to that described for fuel cost recovery in Section 1307(c). Not only has this process been tried and proven to be effective, many of the stakeholders are familiar with the process.

In light of the foregoing, EDCs should simply submit annual filings in which they propose the kWh charge for the upcoming year. In support of this calculation, the EDC would provide: (1) its actual kWh sales, (2) a reconciliation to projected sales for the same period, (3) the actual costs of AES supplies, and (4) RTO LMP data. All of this is verifiable, leaving no true questions of fact. Rather, as again contemplated in Section 1307, the Commission can verify the accuracy of the proposed AES adjustment through annual audits. *See* §1307(d). With all of this already having been addressed by the Act, no evidentiary hearing would be necessary.

One area of costs that may be overlooked and should be addressed through cost recovery and/or deferred costs is the administrative costs associated with the implementation of AEPS. These administrative costs likely include some of the following: (1) the development, testing, implementation and maintenance of new billing functionality, (2) development, testing and implementation of new programs, transactions, tables and interfaces to procure, store and calculate the data needed to support an alternative energy portfolio, (3) the development, testing and implementation of new programs to track bids, prices, contract information, forecast and transfer of settlement data to PJM (or other designated agent), and (4) the design, coding, testing

[2] This section also calls for reasonable notice and hearing, which will be accomplished during the rule making process.

and implementation of new bill print programs, if needed. These are just of few of the potential administrative costs that should not be overlooked in creating a full scale AEPS.

III. FORCE MAJEURE

At the cornerstone of the Act is the premise that AES resources will be reasonably available in the marketplace. This is demonstrated in the provision of the Act that requires the Commission, "in cooperation with [Pennsylvania's Department of Environmental Protection to] conduct an ongoing alternative energy resources planning assessment…." Section 7, p. 20-21. The Act also authorizes the Commission, either *sua sponte*, or upon a request of an EDC, to assess market conditions to determine "if alternative energy resources are *reasonably available* in the marketplace in *sufficient quantities* for the [EDC] and electric generation suppliers to meet their obligations … under this Act." Section 2, p. 6 (emphasis added). The Act sheds some light on this issue by instructing the Commission, during its market assessment, to consider at a minimum, "… current and operating alternative energy facilities, the potential to add future alternative energy generating capacity, and the conditions of the alternative energy marketplace." Section 7, p. 20 (emphasis added).

In order for the AES market to properly evolve, it is critical that the Commission describe in its regulations the factors that it will consider when determining what constitutes "reasonable availability" and "sufficient quantities". Not only will this assist those who intend to become AES suppliers, by providing them with criteria to consider when assessing market potential, it will also help EDCs in their AES portfolio management by allowing them to appropriately assess vitality of the marketplace. At a minimum, the AES resource supplies and processes for trading and reporting credits must at least be sufficient to allow the EDCs to meet their statutory obligations under the Act or, if not, EDCs must be excused of their obligations pursuant to this Section.

IV. ALTERNATIVE ENERGY CREDITS PROGRAM AND TRADING PLATFORM

Title to Non-Utility Generation AECs

Introduction of new portfolio requirements in other states like New Jersey raised questions related to title and ownership of AECs that may be associated with legacy Non-Utility Generation ("NUG") Purchased Power Agreements ("PPAs"). This is a transitional issue resulting from introduction of potential markets for AEC commodities and PPAs that do not explicitly address attribute title issues.

The Act provides that the Commission is to establish an alternative energy credits program to implement the provisions of the Act. One alternative energy credit is defined as representing one megawatt-hour of qualified alternative energy generation. Because the Act applies to existing alternative energy generation facilities, the issue of the ownership of these credits must be addressed. First, it is important to note that AECs are state-created and thus the state has the power to determine who owns the AECs associated with power purchases from existing non-utility generators ("NUGs"). Pennsylvania customers have been paying the full costs of power purchased usually at above market prices as a result of Commission approved PPAs with NUGs. To the extent that the NUG prices reflected in the PPAs are above market, these costs are recoverable by the utility as stranded costs. Utilities were required to enter into these

PPAs primarily because the characteristics of the facilities enabled them to qualify as QFs and permitted the NUGs to invoke the mandatory purchase obligations of PURPA. In the absence of the state approval of the PPAs under PURPA there would have been no PPAs. A NUG should not receive compensation for the environmental attributes of a QF in addition to the full avoided costs already being paid by the EDC's customers under existing contracts with the NUG facility.

The Act provides that the purchase of electricity generated from alternative energy sources shall be fully recovered as a cost of generation supply. Customers should receive the benefit of the full value of energy already being purchased from NUGs by the EDCs in existing contracts. Failure to permit the EDCs to receive AECs from alternative energy it is already purchasing from NUGs that qualify under Act 213 would simply result in the EDCs having to make up the difference on the open market, including the possibility of purchasing AECs from the same NUGs they are already purchasing power from at above market rates. These additional costs would then be passed onto the EDCs' customers and will result in the customers paying twice. This would be an unjust result for the customers of Pennsylvania.

Consistent with this position, the New Jersey Board of Public Utilities ("BPU") (Docket No. EO04080879) on January 12, 2005, unanimously approved the Attorney General's recommendation that the Renewable Energy Certificates ("REC") (the equivalent of AECs in Pennsylvania) ownership from NUG facilities belong to the purchaser and not the NUG.

The BPU made this finding after it considered extensive comments and reply comments from various stakeholders. After reviewing all the issues, the BPU concluded it was in the public's best interest that under existing NUG agreements, the RECs belonged to the purchasers of the supply.

FirstEnergy urges the Commission to reach the same conclusion for Pennsylvania. Fairness and equity dictate that customers receive the benefit of AECs resulting from the purchase of power under existing, facility-specific NUG contracts with EDCs.

AEC Standards

FirstEnergy has four preliminary comments related to creation of standards and a trading platform for Alternative Energy Credits. These address (1) creation of the new commodity framework itself, (2) regional coordination, (3) creating and funding the administrative model for managing AEC commodities, and (4) transition management strategies.

First, several forms of Alternative Energy Credits sited in the Act are not existing energy commodities and lack definition, certification, tracking and trading standards systems. The framework for all tradable AEC commodities needs to be clarified and should address four elements, some of which are only generally defined in legislation:

1) clear definitions of eligible commodities and of standards accepted to establish AEC quantities,
2) definition of process requirements for documentation, verification and metering of impacts,
3) processes and responsibilities for auditable "cradle to grave" certification and regional tracking for any eligible AEC commodities, and
4) process guidelines for title and ownership of eligible AECs.

Alternative Energy Credits are, by design, a new commodity for commercial trade required by legislation and in order for a market to develop , the support and credibility of the Commonwealth, will be essential. Standards and business rules related to these processes will be the focus of commercial transactions without much history. The framework will need to develop and should leverage existing institutions and infrastructure to the extent practicable, such as the PJM tracking and trading processes.

Second, AEC processes should ultimately be coordinated on a regional basis. Additional thoughts on this issue will be discussed in more detail in another section of these comments.

Third, the commission's approval of an independent entity to serve as the alternative energy credits program administrator is of critical importance. An overview of the administrative model related to the new process, describing the powers and responsibilities of the new administrator and of the agencies it may manage (e.g. for AEC certification, tracking and reporting) should be proposed for comment and suggestions in the proceeding. How costs associated with the administrator or related agents are funded must also be established.

Fourth, the legislated requirements for <u>new</u> process development and administration for the Commission and DEP are too ambitious. Timely implementation should be possible where processes and commodities exist today (e.g. for energy commodities or the PJM Load Response and Active Load Management programs). Additional AECs that are not adequately defined should be phased in following prudent development. If implemented in haste, actions could result in additional costs and harm to the credibility of commodities and portfolio initiatives. Considerable work is needed to identify and address milestones and transition issues related to the implementation of the legislated processes.

Having said that, one basis for Force Majeure should be failure on the part of the State or its recognized agents to develop, test and establish the technical, procedural and legal underpinnings for AEC commodities as described above in sufficient time for suppliers to meet the requirements.

V. ALTERNATIVE COMPLIANCE PAYMENTS

The Act provides for an alternative compliance payment in the event that the Commission determines that an EDC or EGS has failed to comply with the Act. Furthermore, the Act dictates that alternative compliance payments shall be paid into a special fund of the Pennsylvania Sustainable Energy Board. These funds are to be used in the development of new projects.

Fundamentally, the Act passed the General Assembly in order to encourage the use and development of alternative energy. But, the Act fails to address the recovery of alternative compliance payments although, as mentioned above, the funds will be used to foster continued expansion of the alternative energy market. FirstEnergy encourages the Commission to permit cost recovery of alternative compliance payments so long as the EDC takes reasonable efforts to comply with the Act.

VI. PORTFOLIO REQUIREMENTS OF OTHER STATES AND REGIONAL COORDINATION

As stated above, FirstEnergy supports regional coordination; however, numerous states are contemplating portfolio standards. Pennsylvania should coordinate with other states (e.g. through the Mid-Atlantic Demand Response Initiative/MADRI) and PJM to develop consistent regional standards and processes for certifying, registering and tracking eligible AEC commodities. Ultimately, standards should be regional, and utilize a common process for registration of AECs and a regional tracking/trading agent such as PJM to preclude double counting, and enable consistent clearing for approved AEC commodity transactions. Serious consideration should be given to the PJM Generation Attributes Tracking System (GATS) as a regional AEC tracking agency, particularly for renewable credits.

It is important to note that Penn Power is a member of the Midwest Independent System Operator ("MISO"). The language in the Act is clear that the Commission and DEP should recognize energy derived from AES within the service territory of any regional transmission organization ("RTO") that manages the transmission system in any part of the Commonwealth. Section 4, p. 18-19. Although it is too premature to state accurately, Penn Power may use resources located in MISO to fulfill their alternative energy requirements.

VII. TECHNICAL STANDARDS FOR VERIFICATION OF ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT ACTIVITIES

FirstEnergy has four preliminary recommendations relative to establishing standards and a depreciation schedule for AECs from energy efficiency, load management and demand-side management measures (DSM-AECs).

First, Pennsylvania should leverage existing regional standards for demand-response products, such as the PJM Load Response and Active Load Management programs. As with recommendations for AECs in general, Pennsylvania should align with other states (e.g. through the Mid-Atlantic Demand Response Initiative/MADRI) and PJM to develop consistent regional standards and processes for demand-side commodities. Ultimately, standards should be regional, and utilize a common process for registration of AECs and a regional tracking/trading agent such as PJM to preclude double counting, and enable consistent clearing for approved AEC commodity transactions.

Second, the Standards should provide a framework for tradable DSM-AEC commodities, addressing four elements suggested for AECs in general:

- clear definitions of eligible "measures" or "technologies" and of protocols used to determine energy and peak load impacts, including technology-specific schedules for measure lives and depreciation,
- process requirements for documentation, verification and measurement of impacts,
- processes and responsibilities for auditable "cradle to grave" documentation, certification and regional tracking for any eligible DSM-AECs commodity, and

➢ process guidelines for title and ownership of eligible DSM-AECs.

Several existing commodities and processes for demand response have been defined through an open PJM membership process that includes many Pennsylvania stakeholders, and can provide a model framework for other tradable DSM commodities. Additional AECs that are not adequately defined should be phased in following prudent development.

Third, to provide demonstrable and timely compliance with legislation, standards should be established to enable rapid implementation of DSM-AECs for commodities that are defined and tradable today using standards that fit the framework described above. Given the broad scope of the legislative language, the Standards should require development and resolution of the above four framework elements before enabling other DSM-AECs. The standards should allow sufficient time for prudent development and phasing in new commodities deemed to be appropriate and ready for trade.

By definition, "All qualifying alternative energy systems must include a qualifying meter to record the cumulative electric production to verify the advanced energy credit value." Section A (3) (e) (3) p 13. The PJM Load Response programs meet this standard. Standards for energy conservation programs will need to be developed.

Commodities eligible for certification and tracking of energy efficiency AECs should be carefully and specifically defined. This task will not be easy or straightforward. Any commodity to be traded should have demonstrable substance, credibility, and impact on market values for energy and capacity. In general, with the exception of the PJM Load Response programs, standards for such commodities are not defined in the mid-Atlantic region, and FirstEnergy is not aware of any national standards that approach the needed framework. The International Performance Measurement & Verification Protocol (http://www.ipmvp.org) is useful as a reference guideline for performance-based programs (which generally require some form of support using metered data), and offers a generic framework for different types of quantifying efficiency savings with examples. The NJ BPU approved a stipulation governing measurement protocols for performance-based energy conservation programs in 1993[3] and more recently approved "protocols" for reporting estimates of energy and demand impacts resulting from non-performance-based energy efficiency measures (http://www.bpu.state.nj.us/wwwroot/cleanEnergy/EO04080894_20041223.pdf). Texas utilities have developed standards for performance-based programs for retrofit applications (http://www.aepefficiency.com/cisop/downloads/Sec3-04.pdf) and for new construction (http://www.aepefficiency.com/cisop/downloads/Sec4-04.pdf). Comparison of these protocols illustrates a wide range of approaches. While useful, none of these protocols provides a framework addressing the four elements of a clear standard as outlined above.

If the Commission wishes to implement efficiency AECs more quickly, it should consider allowing recognition of claims in advance of final resolution as part of an interim transition and implementation strategy for the new processes.

Fourth, with respect to metering requirements and depreciation schedules, protocols used for certification of DSM-AECs should specify a conservation measure or technology-specific depreciation schedule that is consistent with the measurement plan. Depreciation schedules should preclude value beyond the life of the measure or

[3] In the Matter of Measurement of Energy, Demand and Capacity Savings under New Jersey Utility Demand Side Management Plans Pursuant to N.J.A.C. 14:12 ET SEQ. (Dockets EE92020102,

technology, and should consider the credibility of the measurement and verification protocol associated with the load reduction impact for each measure or technology. Protocols that do not require annual measurement should reflect average energy impacts over the stipulated life of the measure or technology.

Fifth and finally, Pennsylvania must establish DSM-AECs for tradable demand response commodities. However, provisions should be added to consider waivers or some form of credits for accomplishment of non-tradable demand-response impacts that align with Pennsylvania's demand-response goals. For example, energy savings have been well-documented for income-eligible customers under Universal Service programs that should qualify. The load impact associated with customers on real-time pricing or TOU rates will be difficult or impossible to measure, but meeting such goals should have value and should somehow "count" toward meeting Pennsylvania's portfolio goals without a commodity trade.

VIII. INTERCONNECTION STANDARDS

The Commission, prior to the passage of the Act, issued an Advanced Notice of Proposed Rulemaking (ANOPR) and the development of Interconnection Standards. The ANOPR did not include or address the issue of Net Metering, and we believe that is the appropriate course to take. It is fundamental that net metering should be considered separately from interconnection standards. Interconnection is a technical and safety issue. It should be strictly limited in scope to operational and safety parameters and the appropriate allocation of costs associated with the interconnection of distributed

EE92020103, EE92020104 and EE92020105)

generation resources (DG). Conversely, the financial issues related to net metering are paramount and represent the business rules between the parties related to the transfer of energy and its associated value and is not otherwise directly related to the interconnection issue. With the exception of NJ, all of the existing standards referenced in the ANOPR (as well as Ohio) do not incorporate net metering requirements in their interconnection standards; nor should Pennsylvania.

Interconnection Issues

The Commission in its ANOPR for the development of an interconnection standard directed the parties to review existing standards such as those identified in the ANOPR and identify preferences and comment on the merits of the standards. Although these comments are preliminary, there are two primary elements of the Interconnection issue that need to be addressed: (1) the specific technical requirements necessary to insure a safe & reliable electrical distribution system, and (2) the procedural and cost recovery aspects of the interconnection process.

Technical

Each of the existing state standards is primarily based on IEEE 1547 with few exceptions. IEEE 1547 is intended to provide minimum technical requirements for interconnection. The Commonwealth should adopt 1547 as the standard and should not deviate from the requirements of the standard in any way, which diminishes the integrity, reliability and safety of the interconnection intended by the standard. For example, all generation systems must have a readily accessible, outdoor and lockable disconnect switch in order to ensure safety of workers and the public as well as to timely prevent potential damage to the distribution system. IEEE 1547 provides for the requirement of this switch where the EDC deems it necessary. Only NJ has pre-empted the EDC's ability to enforce this important safety requirement.

Islanding (the ability to generate while the system is down) should not be permitted at this time. There are no national standards for allowing a DG to export power in the event of a utility outage. IEEE 1547 does not allow unintentional islanding and provides that a DG cease to energize the system within 2 seconds of the formation of an island. IEEE 1547 recognizes the lack of any standard for intentional islanding and provides that this topic is under consideration for future revisions to the Standard.

If any screening process for automatic approval of pre-certified DG is utilized at all, it should be limited to small inverter-based systems and should not include larger inverter based systems or, more importantly, rotating equipment systems, which should always be subject to a full review process, including system impact study. In the event of a fault, rotating equipment has the potential to generate five to seven times its full load rating and which can cause damage to the distribution system and customer equipment.

In general, we submit that IEEE 1547 should control and form the basis for the technical requirements for interconnection and parallel operation of DG and when revised should supersede or modify any previously approved technical requirements.

Procedural/Cost Recovery

Review times must be reasonable and adequate to ensure safety and reliability of the system. Review times should recognize a basic difference between small inverter-based generators and larger capacity inverters as well as rotating equipment systems. The potential impact of rotating systems on the safety and reliability of the EDC system can be substantial. Time limitations on the application review process should never result in a “deemed approval”. This represents a serious potential safety concern. Due to the complexity of electric distribution systems, variable conditions and differences between EDC systems, it is necessary that EDCs be able to adequately evaluate systems through a thorough review. Nothing should limit the ability of the EDC to conduct a thorough review and require that the generator meet specific requirements to ensure safety, system control, and reliability.

Threshold application fees should be required for all applications with an incremental cost over some specified size. (e.g., $350 minimum, increased by $5 per kW for systems larger than 50 kW). The minimum fees will help prevent the EDCs from being inundated with frivolous applications and allow the EDCs to recover some of the costs of a high-level, preliminary feasibility study. Interconnection study fees should be recovered in all cases and should be based upon reasonable costs, including overheads but excluding profit. Construction and upgrade costs should be borne by the interconnection service customer, i.e., those costs incurred by the EDC to upgrade its distribution system in order to accommodate the interconnection service customer. Additionally, any required periodic inspection and routine maintenance performed by the EDC should also be performed at the interconnection service customer’s cost.

A standardized interconnection agreement format should be based upon the PJM model. However, contract modifications for larger systems requiring additional protective equipment, including dealing with such issues as: short circuit duty, voltage regulation and power factor correction and other similar impacts on the distribution grid should be expressly permitted. Insurance and indemnification should be included in every interconnection agreement.

VIII. NET METERING STANDARDS

As stated above, we believe it is more appropriate that net metering issues be considered separately from technical interconnection standards. It is notable that with only one exception, New Jersey, the existing state interconnection standards do not also articulate the rules for net metering. Nonetheless, when the net metering issue is addressed the following concerns should be considered and addressed.

- Many of the EDCs in the Commonwealth have existing tariff provisions for net metering of small renewable DG. In many cases, these provisions are a result of restructuring. Unless there is a mechanism for full and current cost recovery, any changes to the existing net metering requirements need to be postponed to the end of any existing rate cap periods.
- There are existing tariff provisions (i.e. existing PURPA provisions) for treatment of other than small renewable DG provided for in the existing net metering provisions.
- There should be a MW cap on total allowable net metering.
- Operational coordination with PJM for larger loads must be required.
- Reasonable limitation should be placed upon the size of the generation system so as not to create a new regulatory structure for bringing generation on-line, but instead to fulfill the originally intended purpose of encouraging small renewable distributed generation.
- Generators should be compensated at a wholesale rate level and not at retail for power placed into system.

- Cost recovery of lost transimission and distribution revenues or any other costs not recovered from the DG customer should be provided to the EDCs through a simplified mechanism such as SBC or annual, reconcilable mechanism such as 1307E.
- Net metering DG facilities should be limited in size to the energy requirements of the host.

X. SUMMARY

In response to the Commission's initiative to seek input regarding the implementation Act 213, it is the position of the FirstEnergy Operating Companies that the PUC should coordinate efforts on a regional basis and continue to seek comments from interested parties in order to promote an alternative energy market that is viable and fair to all stakeholders.

Met-Ed, Penelec and Penn Power thank the Commission for an opportunity to present comments in this technical conference and look forward to continued participation as this important issue moves forward.

APPENDIX A

Education and Work Experience
of
Kent A. Hatt

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Mr. Hatt is employed as Senior Consultant -- Rates and Regulatory Affairs for the Pennsylvania Rate Department of FirstEnergy Service Corp. FirstEnergy Corp is the registered holding company of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec") and Pennsylvania Power Company ("Penn Power"). Mr. Hatt is responsible for the development, coordination and preparation of regulatory information pertaining to Met-Ed, Penelec and Penn Power as well as rate-related matters before the Pennsylvania Public Utility Commission ("PUC" or "Commission"). He is also responsible for the administration of the Companies' tariffs, development of retail electric rates and rules and regulations ensuring uniform administration and interpretation.

Mr. Hatt graduated from Bloomsburg State University in 1983 with a Bachelor of Science degree in Business Management and St. Joseph's University in 1997 with a Masters in Business Administration degree. He has over twenty years of experience with Met-Ed/GPU Energy/FirstEnergy Corp.

Mr. Hatt's most recent work experience has included the preparation of testimony regarding supply procurement for the JCP&L Deferred Balances Filing before the New

Jersey Board of Public Utilities at Docket No. ER02080507. As part of his responsibilities as Manager-Tariff Administration & Supplier Services for GPU Energy, he prepared and submitted ratemaking testimony in proceedings held before the PUC in 2001 at Docket Nos. P-00001860 and P-00001861, concerning the impact of escalating competitive electricity market costs on Met-Ed and Penelec in their role as provider of last resort ("POLR"). He also worked on implementation of deregulation initiatives as well as providing support to Electric Generation Suppliers.