BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Implementation of the Alternative	:	Docket No. M-00051865
Energy Portfolio Standards	:	
Act of 2004	:	

COMMENTS OF EXELON CORPORATION RE: THE PENNSYLVANIA PUBLIC UTILITY COMMISSION IMPLEMENTATION OF THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT OF 2004

Exelon Corporation ("Exelon") hereby files this response to the Pennsylvania Public Utility Commission's (the "Commission") "Notice of Technical Conference" for the Implementation of the Alternative Energy Portfolio Standards Act of 2004 (Act 213) (the "Act"), issued on January 7, 2005 and requesting comments regarding the implementation of the Act by January 14, 2005.

I. Introduction

In its Notice of Technical Conference, the Commission has asked interested parties to submit written comments regarding certain areas of interest related to the Act and its implementation. As such, Exelon hereby submits its initial thoughts on the Act and its implementation.

II. Discussion

A. Force Majeure

Force Majeure has been defined in the Act as follows:

> Upon its own initiative or upon request of an Electric Distribution Company or an Electric Generator Supplier, the [Commission], within 60 days, shall determine if alternative energy resources are reasonably available in the marketplace in sufficient quantities for

> the Electric Distribution Companies and Electric Generation Suppliers to meet their obligations for that Reporting Period under this Act. If the Commission determines that Alternative Energy Resources are not reasonably available in sufficient quantities in the marketplace for the Electric Distribution Companies and the Electric Generation Suppliers to meet their obligations under this Act, then the Commission shall modify the underlying obligation of the Electric Distribution Company or Electric Generation Supplier or recommend to the General Assembly that the underlying obligation be eliminated.

The intent of the Force Majeure provision in the Act is to provide the Commission with the ability to forestall non-economic purchases (or payment of non-compliance penalties) due to unfavorable market conditions by entities required to meet the specified portfolio obligations. The Act states that such entities may petition the Commission when renewable demand exceeds renewable supply in the PJM Interconnection, or the Commission may act upon its own initiative in determining market fundamentals (i.e., supply and demand). A determination that demand exceeds supply may result, according to the Force Majeure provision, in a modification of the target percentages in the Act. Another determination may be that, in the absence of the federal production tax credit ("PTC") program, incremental purchases of renewable energy credits associated with certain technologies may be significantly higher than the marginal value of energy. In that instance, the Commission may decide that electric customers should not shoulder the burden of non-economic purchases just to meet the target percentages.[1] Exelon suggests that the Commission determine a reasonable period of advance notice in the event it intends to invoke the Force Majeure provision.

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[1] The recent history of the renewal of the PTC poses a particular concern with respect to Force Majeure – the program has experienced uncertainty each year for the past three (3) years because the renewals have been limited to twelve (12) month periods. Uncertainty has existed each year about whether the program will be renewed.

Although the invoking of the Force Majeure provision may be seen as a rare event, in the context of current market fundamentals (estimated demand based on load forecasts and existing and planned renewable projects) and the perceived sustainability of the federal tax credit program. The Act allows the purchase of renewable energy credits from within PJM, which now includes Illinois and Ohio and soon will include most of Virginia. Therefore, entities required to meet the Act's obligations may draw on a broad supply of renewable energy resources; however, it should be noted that other states' renewable energy laws and RPS requirements will drive competition for available resources within PJM.

Exelon suggests that the Commission design a periodic, data-driven approach to the determination of current and forward market conditions. One approach would be to create an annual report on the state of the renewable energy market, with an opportunity for stakeholder review and comment, that would evaluate how close the market is to exceeding Force Majeure threshold conditions for the current year and future years. In developing such a report, market demand can be determined from the target percentages contained in the renewable energy laws of the various states that compete for the same resources as Pennsylvania. Determination of the marketplace supply will be more complicated, based on available data (See Attachment 1 for source information). Variables that may impact the wide range of forecasts of renewable supply for a Tier I resource like wind include:

- land availability in viable wind resource areas that can be developed
- local and state permitting
- economic transmission access

- fixed-price sales to credit-worthy companies
- the cost of integration of intermittent energy into the regional transmission system

As an alternative to using forecasts of supply and demand conditions for evaluating Force Majeure conditions, the Commission can choose to develop an objective Force Majeure standard. One such standard can be a threshold market price of new construction above which those entities holding the obligation would not have to purchase the renewable energy credits ("RECs") in the year that the threshold price was exceeded. In subsequent years, when the price threshold is not breached, the current-year obligation would have to be satisfied. The threshold could also be developed as a percentage of the underlying forward value of energy in the over-the-counter ("OTC") market, or as a threshold impact on retail rates. The New Mexico commission developed a "reasonable cost threshold" pursuant to the recently enacted renewable standards law that identifies the lower of a two-pronged approach: (1) a rate cap (for example, 1% in 2006, 1.2% in 2007, and so on until the cap is 2.0% in 2011 and beyond); and (2) a maximum cost for each renewable technology (for example, wind is $49/MWh; biomass and geothermal is $63/MWh; and solar is $100/MWh). The Colorado Commission also has developed a threshold based on the impact on retail rates (See generally Attachment 1).

Exelon would appreciate the opportunity to continue to work with the Commission and other stakeholders to develop an appropriate methodology for evaluating Force Majeure conditions.

B. **Alternative compliance payments**

The Commission is required to establish a process for an annual review of the alternative energy market to identify any change in costs associated with the alternative compliance payment program. Exelon would recommend that this review be done in conjunction with the process used for Force Majeure determination and that the timing of such annual review be coordinated to allow for program changes prior to the start of the program year (June 1). Areas of focus for reviewing the costs of the alternative compliance payments are very much aligned with the data required for the Force Majeure review. Specifically, a significant increase in the number of alternative compliance payments or a significant increase in cost may signal a lack of supply and potential Force Majeure conditions.

C. **Deferrals and Cost Recovery**

Section 3(A)(3) of the Act provides that "...any direct or indirect costs for the purchase by electric distribution of resources to comply with this section, including, but not limited to, the purchase of electricity generated from alternative energy sources...shall be recovered on a full and current basis pursuant to an automatic adjustment clause ..." Exelon requests that the Commission provide guidance as to what would be considered a direct or indirect cost and how such costs would be treated during and after the cost recovery period. For example, because demand side management ("DSM") programs qualify as "alternative energy sources" it would be beneficial to include examples of DSM costs associated with each KWH verified reduction eligible for the Section 1307 recovery mechanism.

Additionally, Commission guidance on the following would be beneficial:

(i) Guidelines for determining an appropriate rate of return for deferred costs including method of calculation; and

(ii) Specifics regarding the distinction of voluntarily incurring costs during this deferral period for future recovery vs. the ability to bank alternative energy credits for only a two (2) year period

D. <u>Creation of alternative energy credits program and trading platform</u>

The different markets (e.g. OTC, bilateral) for renewable energy credits have been in existence since approximately early 1998 to support market demand. With the advent of the New Jersey renewable energy portfolio standards ("RPS") law, compliance demand began to develop and is expected to expand significantly with the Pennsylvania and Maryland laws (in addition, Illinois and Delaware have had draft bills). Exelon suggests that the Commission interpret this provision of the Act to mean that the Commission should take actions that provide support to the existing market in order to lower transaction costs and facilitate transactions. A broad goal of the provision should be to enhance liquidity and depth in the renewable markets, because those attributes result in efficiency gains and, over time, lower costs.

A significant contribution to the existing markets would be a Commission-developed registry of qualifying resources. Massachusetts and Connecticut have generator registries, which also interact with the generator information system in Massachusetts (see Attachment 1). The registries make transactions easier because trade confirmations can point to a resource contained in the registry rather than include provisions about what will happen if the resource is not considered qualified during or after the term of the sale and purchase. The registry gives both the buyer and the seller confidence about the transaction.

A separate or newly developed trading platform may be duplicative of a system that PJM has had under development for several years, namely the Generation Attribute Tracking System ("GATS"). The primary objective of GATS, according to the working group concept paper, is to provide PJM members with an "administratively simple, cost-effective means of demonstrating compliance with a variety of state policies and regulations." This objective appears to be congruent with the intent of the Act. Exelon suggests that the Commission meet with the GATS working group to determine if the planned system meets the Commission's requirements.

The definition of an "alternative energy credits program" is unclear, although one interpretation could be a "market," which already exists as described. Exelon does not necessarily see a need for market intervention by the Commission, except to the extent that the Commission provides updated information to market participants. Markets thrive on information, and the renewable markets are to a large degree not transparent (since most trades are bilateral). Reliable information is the clearest path to liquidity and depth. In that spirit, Exelon makes these suggestions:

(i) The Commission, either on its own or in coordination with the Commissions of other PJM states that have renewable procurement laws, should develop a Renewable Energy Annual Report that includes at a minimum reliable information on supply, demand, and prices. Additional helpful information could include technical details (capacity and expected production, location, transmission interconnection points, development and construction status) on completed and planned projects.

(ii) The Commission should develop a website that is devoted to administration of the Act. An example of helpful data on the website would be the generator registry.

(iii) The Commission should draft (with assistance from market intermediaries) a standard trade confirmation for renewable energy credits, or adopt one that is developed by another oversight group such as the EEI. Short of that, the Commission should develop language that can be used in trade confirmations that provides definitions for:

1. A renewable energy credit[2];
2. Eligible facilities or resources;
3. Reporting requirements (generally for the seller) that are compliant with the Commission's requirements; and

(iv) The Commission should work with other Commissions in PJM states that have RPS laws with the goal coordinating information about market conditions.

(v) The Commission should develop an accreditation and tracking program for renewable energy credits generated from demand side management programs.

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[2] For example, Exelon includes the following definition in its trade confirms: **"Renewable Energy Credits"** means any renewable or environmental credits, attributes, or tickets, such as those for greenhouse gas reduction, or the generation of green power or renewable energy, created by any governmental agency and/or independent certification board or created pursuant to private bilateral contracts, in each case generally recognized in the electric power generation industry, and generated by or associated with each MWh of energy produced by the [facility].

E. <u>Portfolio requirements of other states and regional coordination</u>

Three PJM states (New Jersey, Maryland, and Pennsylvania) have adopted RPS statutes over the past several years. While the details of each states' authorizing legislation vary, there are many common issues that would benefit from regional coordination. To promote increased market liquidity and transparency, the renewable market would benefit significantly if the Commission worked toward common protocols and standards for compliance with the Act. Common REC standards would also lower administrative costs for both the regulated community and the regulatory agencies charged with monitoring compliance. The following are examples of common areas of interest that would benefit from regional coordination:

(i) **Common Protocols for "Certifying" Renewable Energy Credits**. Pre-certification of generating units and RECs by a regional body, or state commissions, using common standards may provide a desirable increase in regulatory certainty for electric distribution companies and other retail electric suppliers. However, in the case of non-standardized RECs or generating units, pre-certification might also prove to be administratively burdensome to state agencies and could slow the process of renewable resources deployment across the region if all projects must be pre-certified. To promote early action and support meeting near-term purchase requirements, protocols should also consider standards for RECs developed after legislative dates of enactment, but potentially before all final REC standards are completed.

(ii) **Standard Tracking Systems and Contract Terms**. Market liquidity would be increased, and transaction and REC costs would be lowered, if a standardized contract and REC tracking system were developed for the region. A standardized contract would alleviate the problem of divergent interpretations of provisions regularly used in the renewable energy markets.[3] . A regional registry or clearinghouse could help inform the marketplace regarding available RECs and serve as a repository for banked REC information. Use of the PJM GATS that is currently under development could provide a single platform against which to identify and track renewable energy generation. Such a regional system would also be beneficial in terms of preventing double counting of RECs. Supplemental systems may be required to (i) track renewable generation produced outside of PJM, but sold into the PJM market; and (ii) track Tier II alternative energy sources. Such generation may not be adequately monitored by the GATS system.

(iii) **Compliance Report Filings**. To the extent practicable under implementing laws, compliance filings with state commissions should utilize common standards and protocols. Retail electric suppliers potentially operate across state lines and common standards would reduce administrative complexities and lower compliance costs.

(iv) **Coordinated, Regional Supply Assessments**. With the New Jersey, Maryland and Pennsylvania authorizing legislation contemplating the sourcing of renewable energy and RECs from within PJM, and the potential for surrounding states to supply energy into PJM, it is critical that all states have an integrated understanding regarding how existing, and new, mandates will affect the regional supply of, and construction timeline for, new renewable resources. Other PJM states that adopt RPS requirements will increase demand for regional renewable resources. Regional assessments need to consider the potential for market-based supply and

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[3] Exelon would appreciate methodology with a standardized form of agreement

demand imbalances. Traditional engineering-based cost and deployment analyses could significantly under-estimate actual costs and timelines when non-engineering issues, such as public opposition to specific renewable resource projects (e.g. off shore wind or NIMBY locations) are considered.

(v) **Public Financing and Tax Incentives**. The regional public utility commissions and others may want to jointly support initiatives to assist in the deployment of new renewable resources via initiatives such as asking Congress to extend the federal PTC for a significant period of time into the future to provide more stable, long-term support for new wind projects. Regional loan guarantee programs may be another option.

Finally, the Commission should continue monitoring regulatory developments in states with RPS requirements and work collaboratively with other PJM states on common regulatory elements.

F. Technical Standards for Verification of Demand Side Management

The purpose of this section is to identify issues and provide recommendations with respect to the technical standards for verification of Demand Side Management ("DSM") impacts as such measures are proposed to count toward compliance with the Act.

According to the Act, DSM consists of the management of customer consumption of electricity or demand for electricity through the implementation of:

- energy efficient technologies, management practices, or other strategies....that reduce electricity consumption by those customers (herein referred to as "energy efficiency" or "EE"),

- load management or demand response technologies, management practices or other strategies......that shift load from periods of higher demand to periods of lower demand (herein referred to as "demand-side response" or "DSR"), or
- industrial by-product technologies consisting of the use of a by-product from an industrial process, including the reuse of energy from exhaust gases or other manufacturing by-products that are used in the direct production of electricity at the facility of a customer (herein referred to as "Process By-Products" or "PBP").

Note that an alternative energy credit is measured in units equal to one MWH of electricity from an alternative energy source. Expressing this measure in terms of MWH is significant in that the EE and PBP strategies are typically intended to produce significant units of MWH savings and, in contrast, DSR strategies are more focused on achieving peak MW reductions as opposed to reducing MWH over long periods of time.

(i) **Energy Efficiency**

Since Pennsylvania does not have a history of large-scale EE programs, there is limited experience in terms of formal, independent ex post evaluation of EE programs, and standards or protocols for measuring and verifying ("M&V") the impacts of energy efficiency programs specific to Pennsylvania do not exist. Thus, Pennsylvania is essentially starting from scratch (this is not the case for DSR which will be discussed later).

Other states (e.g. California, New York, New Jersey and Massachusetts) have been managing large-scale EE programs ($135 - $230 million annually) for many years and have devoted significant attention to measuring and verifying the results (including MWH reductions) of their programs.

A fundamental challenge in measuring and verifying impacts of EE programs is to essentially determine what participants in EE programs would have done (in terms of how they use electricity) absent their participation in the program. Details of the specific EE program design influences the methodology for determining the MWH impacts. Meters, sample sizes and the desired degree of accuracy are factors that will impact the cost of measuring and verifying EE impacts. In choosing the methodology it is important to balance the costs of M&V with the benefits in terms of what is required for counting toward the goals set forth in the Act.

In determining the technical standards for measuring EE, the Commission should rely extensively on the experiences of other states and reasonable application of guidelines established by recognized authorities such as the International Performance Measurement and Verification Protocol and the American Society of Heating, Refrigeration and Air-conditioning Engineers (reference provided in Attachment 1). In doing so, care must be taken to avoid overly burdening the cost of EE alternatives with the costs of measuring and verifying impacts.

For purposes of establishing EE credits, a minimum level should be established. Entities seeking credit should be able to demonstrate at least 1 MWH of annual reductions.

(ii) **Demand Side Response**

In contrast to EE, the Commission has significant experience in addressing the measurement of DSR impacts. Pennsylvania utilities have provided DSR programs for several years. Perhaps more significantly, PJM provides a framework for DSR (along with measurement and verification standards) with several programs in which load serving entities and other PJM members participate.

PJM specifies how DSR impacts are to be measured, and participants are compensated based upon the PJM-established standards. Key aspects include:

- The method of verification depends upon the type of program.
- Where available, real time metering can provide the actual reduction measurements.
- Mass-market load management impacts are estimated by the load serving entities (electric distribution companies and electric generation suppliers) seeking to include their programs in the PJM DSR framework. Potential acceptable methods of estimating impacts include using load research data, available industry averages, or engineering estimates.
- Measurement of DSR programs as prescribed in retail tariffs or in the PJM Operating Agreement can serve as a guide for verification. PJM, through its Emergency Load Response Program and its Economic Load Response Program, specifies methods for determining load response for situations where hourly-metered data is available, including establishment of base line usage (Reference Attachment 1).

In determining the technical standards for measuring DSR for the purposes of the Act, Pennsylvania should rely extensively on the experience and proven approaches developed and in place at PJM.

For determining the alternative energy credits provided by a DSR program, due to the peak-focused nature of DSR, the demand reductions must be converted to MWH in order to provide a consistent basis with the MWH metric goal of the Act.

- For real time metered customers this can be established using the baseline usage and the real time usage.
- For mass market customers acceptable methods of estimating reductions include; 1) load research data, 2) available industry averages, 3) engineering estimate, or 4) assumption of the system average load factor.
- As a general matter the burden should be on the load serving entities (electric distribution companies and electric generation suppliers) to show that the method of estimating/conversion is reasonable.

(iii) **Process By-Products**

For industrial by-product technologies consisting of the use of a by-product from an industrial process, including the reuse of energy from exhaust gases or other manufacturing by-products that are used in the direct production of electricity at the facility of a customer, each situation is likely unique and may require a customized approach to measurement and verification. Technical standards should reasonably employ the tools and approaches similar to those described for EE and DSR.

(iv) **Depreciation of Credits**

Credits for DSM should match the useful lives of the respective DSM resource to the extent practicable. Simplifying presumptions should be employed that, while not specifically accurate, protect against the unintended overvaluation of a resource far into the future, and allow for a streamlined process for establishing value.

For EE, there is a diverse array of technologies and programs that vary in terms of how long they maintain their efficiency impacts once implemented or installed. For purposes of simplicity, the Commission should adopt a set of standard lifetimes applicable to the major types of EE programs. An EE application would then be eligible for renewable energy credits based on the savings calculated by an acceptable M&V protocol for a period equal to the standard lifetime, regardless of the actual life of the program.

For DSR, the lifetime should be limited to one year because the nature of DSR programs is to provide peak reduction capability for only one year at a time and must be renewed every year.

For PBP, the nature of the DSM impacts is even more diverse and should be subject to a customized burden of proof. For purposes of determining lifetimes, a simplified standard similar to the one for EE should be employed.

G. <u>Development of technical standards for Interconnection and Net Metering</u>

The Act requires that the Commission convene a stakeholder process to develop rules for interconnection, parallel operation and net metering. Due to the complexity of this task, Exelon recommends that the Commission begin this process immediately in order to develop a consensus rules. The Commission has recently issued an Advanced Notice of Proposed Rulemaking ("ANOPR") on Small Generator Interconnection Standards and Procedures (Docket L-00040168), which will begin the necessary discussion on some of the relevant issues.

PECO Energy Company ("PECO") has already incorporated many of the features identified in the ANOPR as the Company's interconnection standards were revised in 2001 to comply with the Merger Settlement Agreement (Docket A-110550F0147). The revisions to PECO's Interconnection Standards included an expedited review processes for pre-certified generators, simplified application forms and reduction of review fees for simplified interconnections. PECO has also offered a net metering option for qualified renewable generators under 40 KW (PECO Tariff Rate RS) since 2001. In reviewing more recent net metering and interconnection rules approved by states in PJM RTO, PECO offers the following guidance on issues that will need to be addressed during the collaborative process:

(i) **Net Metering Issues**

(1) Appropriate size for renewable installations qualifying for net metering;

(2) Standardized approach to billing practices for net metering applications recognizing that this may be a manual process in most cases;

(3) Clarity on who maintains the rights to RECs created through net metering applications;

(4) Flexibility in net metering language to accommodate different metering systems. For example, use of a single bi-directional meter may not be an option for utilities using AMR systems; and

(5) Recovery of costs associated with non-standard meter installations.

(ii) **Interconnection Issues**

(1) Recognition that generators desiring to interconnect to sell their output on the wholesale market need to comply with applicable PJM and FERC rules;

(2) Fee schedules for reviewing applications should be based on cost;

(3) Timelines for reviewing interconnection applications should be based on standard work practices used in other utility construction work;

(4) Disconnect switch is required to meet safety standards; and

(5) While the need for standardized rules is important, recognition that each utility may require some variance due to unique system designs.

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III. Conclusion

The comments provided by Exelon clearly indicate some of the basic issues that need resolution for successful implementation of the Act. It is evident that the complexity of this task will require significant effort of all stakeholders in the process. In that regard, Exelon will support the Commission in its efforts moving forward in the implementation process.

Respectfully submitted

Dated: January 14, 2005

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Attachment – Reference Material from Exelon the Alternative Energy Portfolio Standards Act of 2004 comments

FORCE MAJEURE

A helpful database for identifying existing resources is maintained by the National Renewable Energy Laboratory ("NREL"), funded by the U.S. Department of Energy, at http://www.nrel.gov/analysis/repis. The database shows existing resources by state and technology. Although NREL updates the information periodically, caution must be exercised with the information because some listed resources may have gone out of operation

Another source of current information is the generator interconnection queue at http://www.pjm.com/planning/project-queues/queues.html. Transmission-related information on planned projects can be found here, but it should not be seen as a definitive source for which projects eventually will be completed (only a small fraction of the planned installed capacity in the queue ever gets built). Notwithstanding the foregoing, helpful information about project ownership, size, substation location, and many other technical details can be found at this site.

Another source for existing and planned wind projects can be found at the website of the American Wind Energy Association at http://www.awea.org/projects/index.html.

Landfill generation project information can be obtained at the website of the Landfill Methane Outreach Program, maintained by the U.S. Environmental Protection Agency at http://www.epa.gov/lmop.

FERC maintains a database of existing and planned hydroelectric projects at http://www.ferc.gov/industries/hydropower/gen-info.asp. A caveat is that the database includes all projects whether they have a chance of moving forward or not.

The Energy Information Administration publishes the Renewable Energy Annual at http://www.eia.doe.gov/cneaf/solar.renewables/page/pubs.html. The Annual contains numerous data tables and other information by technology, fuel, and state.

Information on waste coal generation projects in Pennsylvania can be found at http://www.arippa.org/members_plants.asp.

The U.S. Environmental Protection Agency maintains a database of generation resources at http://www.epa.gov/cleanenergy/egrid/index.htm.

Evolution Markets LLC. Evolution publishes a monthly newsletter at http://www.evomarkets.com/ and a daily newsletter, which is free but requires the creation of an account. Some caution should be exercised in examining the broker market (also called the over-the-counter market) because there is limited liquidity and depth. In other words, most renewable credits trades are done bilaterally at this point

Argus Air Daily at www.argusonline.com contains REC price information

Platts Electric Utility Week at www.platts.com occasionally contains market information on renewables.

http://www.renewableenergyyes.com. Colorado threshold based approach.

MA and CT generation registry info see
http://www.mass.gov/doer/rps/approved.htm and
http://www.dpuc.state.ct.us/CTRPSGeneratorApplication.nsf

Perhaps the most reliable way of staying current on which planned projects will be followed through all the way to completion is periodic contact with all of the market intermediaries in the renewable energy field, including developers, power marketers, energy brokers, transmission owners and operators, consultants, electric distribution companies, and other state commissions. There is no other way to accurately assess market conditions. Such periodic surveys inevitably will yield a wide variety of opinions and solid information, but one can develop an accurate sense over time of market conditions in general, as opposed to precise information on each proposed project.

PORTFOLIO REQUIREMENTS OF OTHER STATES AND REGIONAL COORDINATION

Maryland Regulatory Status and References

Status.

Maryland enacted legislation on July 1, 2004 (requirements start 2006 with 2019 Tier I requirement of 7.5% and Tier II requirement dropping to zero percent from 2.5% in all years of the program preceding 2019); and

The Maryland Public Service Commission must adopt regulations by July 1, 2005.

References.

Maryland Public Service Commission Renewable Energy Portfolio Standards information can be found at:
http://www.psc.state.md.us/psc/electric/rps/home.htm.

Recent documents of interest:

- o Commission Order Case 9019;
- o "Maryland's Renewable Portfolio Legislation: Issues, Options Recommendations Executive Summary", August 13, 2004; and
- o "Maryland's Renewable Portfolio Legislation: Issues, Options Recommendations Report", August 13, 2004.

New Jersey Regulatory Status and References

Status.

N.J.A.C. 14:4-8 Renewable Energy Portfolio Standards rule effective April 19, 2004. Tier I and Tier II requirements starting 2004 with 6.5% requirement by 2008 (3.84% Class I, 2.5% Class II, Solar 0.16%).

The BPU expected to initiate additional rulemaking for post 2008 requirements that may include an increase in Tier I requirements to 20% by 2020.

References.

The BPU Renewable Energy Portfolio Standards information can be found at: http://www.bpu.state.nj.us/home/home.shtml.

Recent documents of interest:

- o "Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard", Edward J. Bloustein School of Planning and Public Policy, Rutgers University, December 8, 2004;
- o December 2004 BPU Commission press release regarding Rutgers study; and
- o "NJ Offshore Wind Energy Feasibility Study", December 2004.

TECHNICAL STANDARDS FOR VERIFICATION OF DEMAND SIDE MANAGEMENT

The International Performance Measurement and Verification Protocol, Inc. ("IPMVP") is a non-profit organization that develops products and services to aid in, among other things, the measurement and verification of energy savings resulting from energy efficiency projects - both retrofits and new construction. (see www.ipmvp.org for information on IPMVP). The IPMVP was founded by the U.S. Department of Energy and the Lawrence Berkley National Laboratories. The IPMVP has published a set of framework documents which provide guidelines for monitoring and measuring energy efficiency programs. Their guidelines are used in California, New York, Texas, and Wisconsin and are also used by the U.S. Department of Defense and the U.S. Department of Energy.

The American Society of Heating, Refrigeration and Air-conditioning Engineers ("ASHRAE") has contributed a more technical work on measuring and verifying energy savings from EE programs in their draft Guideline 14P Measurement of Energy and Demand Savings (see www.ashrae.org for information on ASHRAE).

(Reference: www.pjm.com, Operating Agreement of PJM Interconnection, L.L.C, sheets 142 –166).