Section 13: Addressing Long-Term Challenges

13.0: Overview

Since its 1997 inception, PJM’s RTEP Process has adapted to expanding geographic markets, new and modified market offerings and other growing external and internal influences. 2009 has been no exception. Section 13 discusses emerging RTEP trends based on initiatives within the RTO – stakeholder sphere itself as well from a number of external factors driving RTEP change, depicted in Figure 13.1. Some developments are new, others continue to evolve.

Section 13.1 introduces RTEP impacts based on First Energy Corporation’s decision to integrate their American Transmission Systems, Inc. (ATSI) into PJM by June 2011. ATSI, a subsidiary of First Energy Corporation, owns and controls the transmission system assets of the Toledo Edison Company, Cleveland Electric Illuminating Company, Ohio Edison Company and Pennsylvania Power Company.

Section 13.2 discusses a current Reliability Pricing Model (RPM) issue which is being addressed by PJM stakeholders. In particular, triggers for the development of new Load Deliverability Areas (LDAs) have been developed and discussion by the PJM Planning Committee continues with respect to methodologies which might be used to determine new LDA boundaries.
Section 13.3 summarizes unfolding initiatives to address the RTEP load forecasting and analytical process impacts of Price Responsive Demand (PRD) as enabled by emerging Smart Grid technology in many states in which the PJM RTO operates.

Section 13.4 discusses FERC policy issues which are in progress or contemplated. These include cost allocation for new transmission facilities at or above 500 kV and remaining issues associated with PJM compliance to FERC Order No. 890.

Section 13.5 discusses unfolding renewable portfolio standard (RPS) efforts. A future challenge will be to align these standards into a national framework which would allow the incorporation of RPS into regional planning protocols on a consistent and fair basis.

Section 13.6 discusses sensitivity studies to be performed by PJM as part of its 2010 RTEP process in order to assess the impacts of uncertainty from such factors as RPS initiatives and at-risk generation.

Section 13.7 summarizes PJM’s participation in FERC audit compliance activities from a PJM RTEP process perspective.

ATSI market integration is expected on June 1, 2011. ATSI owns major, high voltage transmission facilities, including approximately 7,100 circuit miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV.

Thirty-five interconnections join ATSI with six neighboring transmission owner zones via high capacity ties with Pennsylvania Electric Company (Penelec), Duquesne Light and Allegheny Power (all current PJM Members), the north through multiple 345 kV high-capacity ties with Michigan utilities (MECS), and to the south through ties with American Electric Power and Dayton Power & Light (both PJM Members). Of these 35 interconnections, 32 tie lines interconnect with PJM Member systems.

Currently, through its affiliation with the Midwest ISO, ATSI plans, operates and maintains its transmission system in accordance with North American Electric Reliability Corporation reliability standards, and applicable regulatory agencies to ensure reliable service to customers.

PJM initiated specific ATSI integration analysis in 2009, similar in scope to that of an annual RTEP cycle of analysis. As part of that analysis, PJM has completed internal reserve margin (IRM) studies with and without ATSI. No change in the IRM has been identified. PJM expects to complete its specific ATSI integration RTEP work in early 2010. Thereafter, and beginning in 2010, ATSI will be fully incorporated into PJM’s annual 2010 RTEP analysis cycle. To that end, PJM has completed expansion of its load forecasting process to incorporate ATSI into the PJM load model. No major impacts on the load forecasting process were encountered.

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*NOTE*

13.2: Creating New LDAs

13.2.0 – Background
In response to a request by the FERC for PJM to review a number of related RPM construct methodology elements, PJM engaged stakeholders in a set of related discussions. One topic of discussion explored the validity of continuing the use of the currently defined 23 LDAs used for load deliverability testing in RTEP and RPM processes. The outcome of those discussions was a stakeholder-supported PJM recommendation to retain the existing 23 LDAs and to pursue development of new LDAs to address persistent transmission constraints.

In looking at future needs, stakeholders discussed the development of triggers which would initiate a review of the need for a new LDA and also for the methodologies that could be used to determine the boundaries of a new LDA.

13.2.1 – New LDA Development Triggers
During 2009, the PJM Planning Committee worked to identify two triggers which would initiate a review of the need for a new LDA.

1. RTEP Market Efficiency Analysis
PJM would utilize existing market efficiency analysis to identify constrained facilities. Facility constraints that are not resolved by an existing approved RTEP upgrade would be identified for further consideration. PJM would evaluate the development of a new LDA when annual market efficiency analysis identifies persistent congestion on a 500 kV or above facility or interface for multiple years beyond the next BRA.

2. RTEP Long Term Planning
PJM would utilize long-term planning analysis to identify potential future constrained facilities or clusters of facilities. Analysis would be updated annually based on approved RTEP upgrades. 500 kV and above facilities that advance more than three years between RTEP cycles would be identified for further consideration. If the driver for a 500 kV facility advancing more than three years is linked to a specific event (e.g. significant generation retirement), further analysis would be required.

The PJM Planning Committee and PJM Markets and Reliability Committee have endorsed PJM Manual 14B language explaining these new LDA development triggers.

13.2.2 – Defining New LDA Boundaries
PJM’s next step is to work with stakeholders to develop a methodology to determine what steps to take once a trigger threshold has been reached. Such methodology will necessarily include exploring how to define the boundaries of a new LDA. For example, one analytical method that is being considered would determine specific busses to be included in the proposed LDA via load bus distribution factors. In addition stakeholders themselves have the option to propose LDA boundaries for PJM and broader stakeholder consideration. The Planning Committee will continue to actively address this topic in 2010.
13.3: Price Responsive Demand and Smart Grid Technology

A number of states and utilities within PJM are pursuing demand response based on dynamic and time-differentiated retail prices and utility investments in Advanced Metering Infrastructure (AMI), often as part of smart grid initiatives. Such developments have the potential to yield significant amounts of Price Responsive Demand (PRD), demand that predictably responds to changes in wholesale prices. Significant levels of Price Responsive Demand would provide substantial benefits. During periods of rising energy costs, it can defer the need for generation investment and delay the need for certain transmission upgrades by slowing the growth in peak demand.

**Smart Grid Technology**

Enabled by smart grid technology, consumers will have the ability to modify their energy consumption behaviors (i.e., demand) as prices change without RTO central dispatch or individual direct RTO market demand reduction bids. Exposure to market prices will have the effect of reducing consumption during high demand periods. These smart meters can both send real-time prices to consumers as well as record the time and amount of electricity used.

**Overall Benefits**

The presence and coordination of PRD are expected to improve reliability both from an operating perspective and planning perspective. A key benefit is the ability to fulfill obligations to achieve Loss of Load Expectation (LOLE) objectives. Essentially, demand reduction from Price Responsive Demand has the real potential to reduce the planning reserves required to meet LOLE based reliability standards. From a planning perspective, other key benefits may potentially also include the following:

- Defer the need for generation investment
- Reduce transmission line losses
- Defer the need for transmission investment
- Reduce environmental impacts

Unlike large customer demand response, mass market Price Responsive Demand is the “macro” sum of responses by hundreds of thousands or millions of consumers. While a single large demand response resource or generating resource may fail to materialize on a given day, the macro response of large numbers of consumers and devices is statistically likely to exhibit less variance.

**PRD and RTEP Process Load Forecasting**

PJM’s Regional Transmission Expansion Planning process and forward resource adequacy planning process are highly dependent on load forecasting. While current load forecasting techniques recognize the impact of economic trends on future regional demand requirements, the impact of Price Responsive Demand enabled by the installation of technologies such as AMI will need to be reflected in PJM’s resource adequacy planning through the development of forecasts that incorporate the firm demand of price responsive loads.

Nonetheless, PJM remains vigilant insofar as the success and benefits of PRD are necessarily predicated on a number of factors including: accurate price signals, actual customer response experience, related forecasting issues and development of Measurement & Verification (M&V) Standards.

PJM will continue in 2010 to engage stakeholders in process and business rule discussions regarding Committed and Uncommitted PRD and their impact on load forecasting and other aspects of PJM’s RTEP process. PJM anticipates finalizing these and a number of other PRD processes and business rules in 2010 through PJM committee stakeholder forums.
**Modeling PRD in RTEP Studies**

RTEP Process reliability analyses will likely require PJM to explore and develop the relationship among load, generator availability and a trigger to invoke PRD in system modeling. Moreover, load deliverability tests would model PRD in a means similar to that currently for Demand Response. Under generator deliverability testing studies and NERC Category C tests, analyses would not likely interrupt PRD.

Given that PJM’s RTEP process also includes market efficiency studies, incorporating PRD impacts will require examining and establishing the relationship between LMP and PRD triggers so as to forecast accurately PRD impacts on modeled load. Doing so will enable PJM to assess the need for new or accelerated transmission upgrades based on market efficiency justification.

Going forward, PRD in PJM’s planning process is expected to evolve over time as PRD quantity grows and experience is gained. This experience will lead to improved understanding of the relationship of price to peak load. Any RTEP Process changes will be developed through PJM’s Planning Committee and Load Analysis Subcommittee stakeholder processes.
13.4: FERC Policy Issues

13.4.0 – Introduction
PJM continues to engage federal regulators and legislative bodies on issues key to PJM’s future success and ability to meet members’ needs. Among the key future challenges with a direct bearing on regional transmission planning are cost allocation and continuing Order No. 890 implementation.

13.4.1 – Unresolved Cost Allocation Issues
On April 19, 2007, the FERC issued orders on cost allocation for new PJM transmission infrastructure. The Order ruled that the costs for 500 kV and above facilities would be allocated on a region-wide basis using the assumption that all retail customers benefit to some degree due to the increased reliability provided by backbone transmission facilities. The cost for facilities energized at voltages below 500 kV would be allocated to those customers who derive the benefits of the upgrade. These are the cost allocation methodologies currently used in PJM.

On August 6, 2009, the 7th Circuit Court of Appeals in Illinois remanded back to FERC for additional consideration its approach to socializing costs across all customers in PJM for transmission facilities operating at or above 500 kV.

In Docket NO. EL05-121-006, the FERC issued an Order dated January 21, 2010 (January 21 Order) establishing a paper hearing procedure on remand of the Seventh Circuit decision. The January 21 Order set a schedule to allow parties to supplement the record in this docket to support FERC’s adoption of a postage stamp cost allocation methodology for new transmission facilities that operate at or above 500 kV.

13.4.2 – Order No. 890 Compliance Follow-up
On February 16, 2007, the FERC issued Order No. 890, which reformed the pro forma open access transmission tariff (OATT) to clarify and expand the obligations of transmission providers to ensure that transmission service is provided on a nondiscriminatory basis. Among other things, Order No. 890 amended the pro forma open access transmission service tariff (OATT) to clarify and expand the obligations of transmission providers to ensure that transmission service is provided on a nondiscriminatory basis. Among other things, Order No. 890 amended the pro forma OATT to require coordinated, open, and transparent planning of transmission systems on both a local and regional level. To implement that requirement, the Commission directed transmission providers to submit a compliance filing containing a new attachment to their OATT (Attachment K) describing a coordinated and regional planning process that complies with the planning principles adopted in Order No. 890.

On August 13, 2008 PJM submitted revisions to its transmission planning process in accordance with this FERC Order. On May 21, 2009 FERC issued an Order accepting PJM’s August 13, 2008 compliance filing. FERC accepted revisions to the PJM Operating Agreement (OA) related to comparability, cost allocation and PJM transmission owner local system planning.

In its May 21 Order, FERC also directed PJM to make an additional compliance filing to address: transmission owner local plans and early stakeholder participation in local planning.

Local Plans
Previous OA revisions provided that each TO must provide PJM with its current Local Plan on a periodic or annual basis or as required by PJM, and, there must be access via the PJM Web site to each transmission owner’s Local Plan, including assumptions and criteria.

FERC directed that the PJM compliance filing include a requirement that the models, criteria and assumptions that each transmission owner uses to develop its Local Plans be provided.

PJM submitted revisions to Schedule 6 of the OA, Sections 1.5.4 (a) and (g) to provide that the models each transmission owner uses in its planning process will be made available, consistent with CEII and existing OA confidentiality restrictions or copyright limitations, in addition to the criteria and assumptions the transmission owner uses in its local planning.

Early Stakeholder Participation
The Commission also found that changes to the OA did not clearly provide for an opportunity for stakeholders to provide early input into Local Plans. The existing process provided for input to Local Plans after they are submitted to PJM.

The Commission ordered a compliance filing to provide the opportunity for stakeholders to review and comment on criteria, assumptions and models used in local planning activities prior
to finalization of the Local Plan and prior to submittal to the Subregional RTEP Committee.

PJM submitted revisions to Schedule 6 of the OA, Sections 1.3 (d) and (f) which would provide the opportunity for stakeholders to review and comment on the criteria, assumptions and models used in local planning activities (i) prior to finalization of the Local Plan, and, (ii) on the Local Plan prior to it being submitted to the Subregional RTEP Committee.
13.5: Integrating Renewable Resources

13.5.0 – Introduction
Initiatives to integrate ever growing amounts of generation powered by renewable resources, continue to unfold at the federal and state levels of government. PJM remains engaged in efforts at each level in order to ensure that planning, operating and market functions remain able to accommodate them.

13.5.1 – FERC Technical Conference

Background
The Governors of New Jersey, Delaware, Maryland and Virginia filed joint comments at the FERC on November 25, 2009, (Docket No. AD09-9-000) expressing concern over PJM’s RTEP process with respect to renewable fuel powered generation, and, more specifically, with respect to development of off-shore wind energy in the Mid-Atlantic region. PJM understands these concerns. In order to pursue public policy objectives such as more aggressive integration of renewable energy projects, PJM has sought further guidance from the FERC regarding the need to expand PJM’s current Commission-approved regional planning protocols and cost allocation methodologies.

March 2, 2009 FERC Technical Conference
The FERC held a Technical Conference on March 2, 2009, with the purpose of identifying the key policy issues associated with planning for the integration of renewable resources into the wholesale electric grid. There is clearly an increased focus, both in Washington, D.C., and at the state level, on the critical role that transmission infrastructure will play in realizing public policy objectives such as energy independence and mitigation of the impact of climate change.

Realization of such objectives will require addressing the fundamental policy question of how much and where transmission should be built and how the costs be should be recovered. PJM believes that guidance from the Commission is essential to addressing whether current transmission planning protocols (as embodied in various tariff provisions) and cost allocation methodologies should be reassessed to include a new set of transmission projects, i.e., those not justified under traditional reliability and economic benefit planning protocols but which are associated with aggressive large scale integration of renewable energy resources.

Naturally, there are a number of key issues associated with the policy changes which would be necessary in order to change the current paradigm with respect to integrating large renewable energy projects into the PJM transmission grid. The role of renewable energy in PJM continues to be significant, especially for wind energy. Currently, there are more than 82,000 megawatts (MW) of new generation or modifications to existing generation being studied or constructed in the PJM region. Of that amount, more than 42,000 MW of wind generation is currently in the study or construction phase of PJM’s interconnection queue.

Wind-powered generation projects cluster in areas with favorable characteristics, such as wind speed, duration and frequency. PJM has a number of such areas, many located far from population centers or in transmission limited areas, potentially driving the need for transmission infrastructure.

Wind facilities coupled with more than 2,500 MW of requests for generation fueled by biomass, hydro, methane, solar and other sources demonstrate the viability of renewable generation in PJM. The PJM market offers developers many potential customers for renewable energy as well as opportunities to sell in the real-time market. Among the questions facing the industry are:

- How to leverage the important role the existing FERC-approved planning processes play today in the integration of renewable resources on to the grid;
- Whether a third set of metrics (in addition to the reliability and economic congestion driven metrics already embodied in PJM’s planning processes) is needed if the Commission’s goal is to drive aggressive integration of renewable resources based on public policy benefits; and
- The policy issues (including trade-offs) associated with any expansion of the current planning process to embrace planning protocols and cost allocation methodologies targeted to the aggressive deployment of new renewable resources on to the grid.
The Commission recognizes that significant additions of variable renewable resources, such as wind, could create challenges for the grid and market operators. Three of the issues raised before the Commission during the Technical Conference were:

**Issue One: How Do We Weigh Various, Sometimes Conflicting, Public Policy Goals?**

In addition to reliability and economic efficiency, should we formally include integration of renewable resources from distant resources into the planning process? If so, should the goal of renewable integration be treated as a co-equal, or even superior to, the goals of (i) reducing congestion on the transmission system or (ii) even building out the grid to solve identified reliability violations?

**Issue Two: How to Best Harmonize Renewable Integration with the Current “Beneficiary Pays” Approach to Generator Interconnection.**

The current generator interconnection paradigm is based upon the concept of identifying and allocating the costs of projects needed to support a project’s interconnection to the queue. Under the current generation interconnection process, the interconnection customer pays for the costs of upgrades it causes. The upgrades are sized to meet the project’s needs as opposed to sized for speculative future generation projects that may later seek interconnection but are not yet in the queue or committed through an interconnection service agreement (ISA). Should we change the paradigm and build the transmission system out to remote areas to support future, undefined renewable projects that will be built only if the system is developed first?

**Issue Three: How Do We Ensure Consistency and Clarity in Cost Allocation Policies?**

Should the Commission seek aggressive integration of new renewable resources? Such a goal will need to be harmonized with the existing patchwork of cost allocation methodologies across the country. Today, PJM itself has three different cost allocation methodologies: (i) an assignment of costs to new interconnecting generators for the costs of system upgrades that were only needed as a result of the specific interconnection request; (ii) socialization of costs for backbone transmission facilities developed pursuant to the existing RTEP criteria; and (iii) for projects below 500 kV, an assignment of costs based on contribution to the need based on DFAX. Of course, large scale backbone projects often span more than one RTO or control area.

Cost allocation for BES transmission lines that cross RTO/ISO boundaries adds yet another dimension of complexity. Thus, on large scale backbone projects, PJM’s three methodologies are multiplied by each transmission provider that is crossed, geometrically increasing the cost allocation policies to be reconciled.

All of these issues, spanning multiple regions, encompassing differing sets of FERC rules governing intra-RTO and inter-RTO planning protocols and cost allocation methodologies will need to be reconciled before aggressive wind integration can successfully proceed.

13.5.2 – Transmission Public Policy

On September 21, 2009 FERC held a Technical Conference on Regional Transmission Planning under Order No. 890, (Docket No. AD09-8-000).

PJM Executives participated in the Conference and asked for further guidance from the Commission regarding working with the states which is needed if the Commission seeks to expand the current Commission-approved regional planning protocols and cost allocation methodologies in order to pursue public policy objectives such as more aggressive integration of renewable energy projects. The development of such criteria would further enable an RTO to move beyond a strict application of a bright-line test and allow the RTO to consider and recommend a project that solves not only reliability issues, but also can take into account economic solutions and public policy objectives. PJM proposed that articulated standards to meet public policy objectives should, at a minimum, address some of the following concerns:
• How applicable renewable portfolio standards (RPS) are to be used as planning parameters in the development of transmission projects. State RPS standards are certainly considered in the present process but the present bright line criteria do not contemplate their serving as drivers per se to grid expansion. Notably, within the PJM region, eight states and the District of Columbia have enacted legislation that sets RPS;

• How much deference should be provided to state and regional needs and goals including consideration of economic development, promotion of local resources, applicable market structures and the reliability needs of the state and region. How should conflicting resource choices be reconciled?;

• How, and over what time period, should the benefits of a particular interregional project be assessed for purposes of interregional allocation of costs;

• How much consideration should be given to potential economies from large-scale interregional transmission projects versus projects focused on delivery of more localized renewable facilities; and

• How to reconcile cost allocation under the interconnection process – which assigns to the interconnection customer the costs of transmission upgrades that are necessary for the interconnection – with a cost allocation policy for regional transmission projects that serve public policy objectives and that may assign costs more broadly.

Even though Congressional action on a national RPS and climate change is pending, there is considerable ground that can be plowed at this point in providing strategic direction for the consideration of public policy imperatives that do not neatly fit within today’s established reliability and economic criteria. PJM is awaiting additional feedback from FERC through their rulemaking process.

13.5.3 – State Based RPS Initiatives
PJM’s footprint encompasses 13 states and the District of Columbia (DC.) Eight states and DC have enacted legislation that sets Renewable Portfolio Standards (RPS). These same jurisdictions have also enacted or are working on Energy Efficiency legislation. The purpose of RPS is to foster development of cost effective demand and markets for renewable energy. These standards and policy incentives are expected to result in significant contributions of clean, environmentally friendly resource development to serve PJM load. Energy Efficiency standards promote moderation in the growth of peak demand and energy.

PJM supports these efforts and is closely monitoring developments to anticipate complementary modifications as may be desirable to markets and transmission planning. This diverse mix of targets and goals among PJM states – reflected in Table 13.1 – raises a broader question regarding the consistency of protocols and methodologies associated with the incorporation of renewable energy projects into the grid, not only in PJM but in other regions of the U.S.

While wind and solar options lead the list of RPS portfolio options, the complete list is extensive and is included in information accessible by following the links below. For example, other options include biomass, fuel cells, hydroelectric and waste coal. Also, notable characteristics of the current rules require that compliance in Pennsylvania and Virginia be satisfied by sources within the RTO, while North Carolina requires 75% from in-state resources and Ohio requires 50% from in-state sources. Additionally, many programs include credit multipliers for specified options and alternative compliance payments.

Additional information and detail regarding the ongoing evolution of the RPS and Energy Efficiency efforts is available online:

• EPA: http://www.epa.gov/chp/state-policy/renewable_fs.html

• EERE: http://www.eere.energy.gov

• DSIRE USA: http://www.dsireusa.org/Index.cfm?EE=0&RE=1
### Table 13.1: RPS Initiatives in PJM States (01/27/10)

**Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States**

<table>
<thead>
<tr>
<th>Regulation or Legislation</th>
<th>Geographic Eligibility</th>
<th>Alternative Compliance Payment (ACP)</th>
<th>Credit Multipliers</th>
<th>RPS Year</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DC</strong></td>
<td>Source must be:</td>
<td>Tier 1 - $50/MWh</td>
<td>a. 120% credits for wind or solar energy before 12/31/2006</td>
<td>2020</td>
<td>Total – 20%</td>
</tr>
<tr>
<td>Bill 15-747 (effective 4/1/2005)</td>
<td>(1) located in the PJM region or in a state that is adjacent to the PJM region; or</td>
<td>Tier 2 - $10/MWh</td>
<td>b. 110% credits for wind or solar energy between 1/1/2007 and 12/31/2009</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bill 17-0492 (effective 10/6/2008)</td>
<td>(2) outside the area described in item (1) but in a control area that is adjacent to the PJM region, if the electricity is delivered into the PJM region.</td>
<td>Solar - $300/MWh in 2007 and 2008, $500/MWh in 2009 thru 2014, declining thereafter.</td>
<td>c. 110% credits for methane from landfill or sewage treatment until 12/31/2009</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>DE</strong></td>
<td>Eligible Energy Resources include energy resources located within or imported into the PJM region.</td>
<td>$25 for 1st deficient year.</td>
<td>a. 300% credit for (1) in-state solar electric or (2) renewable fuel cells installed on or before 12/31/2014.</td>
<td>2019/2020</td>
<td>Total – 20%</td>
</tr>
<tr>
<td>Senate Bill 74 (2005)</td>
<td></td>
<td>$50 for 2nd deficient year.</td>
<td>b. 150% credit for wind energy installations sited in Delaware on or before 12/31/2012.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Senate Bill 19 (2007)</td>
<td></td>
<td>Solar ACP is $250, $300, and $350, respectively.</td>
<td>c. 350% credit for wind energy installations sited off the DE coast on or before 5/31/2017.</td>
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<tr>
<td>Senate Bill 328 enacted 6/28/2008</td>
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<tr>
<td><strong>IL</strong></td>
<td>Eligible resources must be located in IL. If there are insufficient cost-effective in-state resources, resources can be procured from adjoining states, and if these are also not cost-effective, resources can be procured from other regions of the country.</td>
<td>None. Resources must be “cost-effective.”</td>
<td>N/A</td>
<td>2025/2026</td>
<td>25%</td>
</tr>
<tr>
<td>Public Act 095-0481</td>
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<tr>
<td><strong>MD</strong></td>
<td>Source must be:</td>
<td>Tier 1 - $40 / MWh</td>
<td>For generating facilities placed in service after January 1, 2004:</td>
<td>2022</td>
<td>Total – 20%</td>
</tr>
<tr>
<td>HB 1308 / SB 869</td>
<td>(1) located in the PJM region or in a state that is adjacent to the PJM region; or</td>
<td>Tier 2 - $15 / MWh</td>
<td>a. 120% credits for wind energy before 12/31/2005</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SB 595 (2007)</td>
<td>(2) outside the area described in item (1) but in a control area that is adjacent to the PJM region, if the electricity is delivered into the PJM region.</td>
<td>Solar - $450 / MWh in 2008 $400 / MWh in 2009, declining to $50 / MWh in 2023</td>
<td>b. 110% credits for wind energy between 1/1/2008 and 12/31/2008</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HB 375 (2008)</td>
<td></td>
<td></td>
<td>c. 110% credits for methane from landfill or sewage treatment until 12/31/2008</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>MI</strong></td>
<td>Renewable energy credits used to satisfy the renewable energy standards shall be either 1) located anywhere in this state or 2) located outside of this state in the retail electric customer service territory of a utility recognized by the Michigan PSC.</td>
<td>Not applicable for the Renewable Energy Requirement.</td>
<td>Solar receives an additional 2 credits per MWh.</td>
<td>2015</td>
<td>10%</td>
</tr>
<tr>
<td>Public Act 295, (October 6, 2008)</td>
<td></td>
<td></td>
<td>Lesser bonuses awarded for on-peak production, storage, and using in-state labor or equipment.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>NC</strong></td>
<td>Utilities may use unbundled RECs from out-of-state renewable energy facilities to meet up to 25% of the portfolio standard. Qualifying out-of-state facilities are (1) hydroelectric power facilities with a generation capacity up to 10 MW, or (2) renewable energy facilities placed into service on or after January 1, 2007.</td>
<td>None. Recoverable costs are capped.</td>
<td>N/A</td>
<td>2021</td>
<td>12.5%</td>
</tr>
<tr>
<td>SB 3 (August 2007)</td>
<td></td>
<td></td>
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<td></td>
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</tr>
</tbody>
</table>
**Table 13.1: RPS Initiatives in PJM States (01/27/10) (Continued)**

<table>
<thead>
<tr>
<th>Regulation or Legislation</th>
<th>Geographic Eligibility</th>
<th>Alternative Compliance Payment (ACP)</th>
<th>Credit Multipliers</th>
<th>RPS Year</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>NJ N.J.A.C 14:4-8 - NJ Renewable Portfolio Standards Rules (effective April 19, 2004)</td>
<td>Energy shall be generated within or delivered into the PJM region. If the latter, the energy must have been generated at a facility that commenced construction on or after January 1, 2003.</td>
<td>Class I &amp; II (ACP) - $50/MWh Solar (SACP) – was $300/MWh initially. For 2008/2009 it is $711/MWh, declining over eight years to $594 in 2015/16.</td>
<td>N/A</td>
<td>2020/2021</td>
<td>Class I – 20%</td>
</tr>
<tr>
<td>OH SB 221 (May 2008)</td>
<td>At least 50% of the renewable energy requirement must be met by in-state facilities and the remaining 50% with resources that can be shown to be deliverable into the state.</td>
<td>REC - $45/MWh Solar – $450/MWh in 2009, $400 in 2010 and 2011, reduced by $50 every two years thereafter.</td>
<td>N/A</td>
<td>2024</td>
<td>12.5%</td>
</tr>
<tr>
<td>PA Senate Bill 1030 (Printer’s No. 1973) Act 213 HB 1203 (2007) Act 35</td>
<td>Sources located inside the geographical boundaries of this Commonwealth or within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth.</td>
<td>Tier I &amp; Tier II – $45 / MWh Solar – 200% of the average market value for solar RECs sold in the RTO.</td>
<td>N/A</td>
<td>2020/2021</td>
<td>Tier I – 8.0%</td>
</tr>
<tr>
<td>VA SB 1416 (4/2007) SB 718 (3/2008)</td>
<td>Electricity must be generated or purchased in Virginia or in the interconnection region of the regional transmission entity.</td>
<td>None. Voluntary goal. Wind and solar power receive a double credit toward RPS goals.</td>
<td></td>
<td>2022</td>
<td>12%</td>
</tr>
<tr>
<td>WV H.B. 408 (11/20/2009)</td>
<td>Electricity produced must be generated or purchased from a facility in West Virginia or in the PJM Service Territory.</td>
<td>$50/MWh</td>
<td></td>
<td>2025</td>
<td>25%</td>
</tr>
</tbody>
</table>
13.5.4 – Integration of Load Management and RPS

As noted in Section 13.5.3, Energy Efficiency (EE) standards are under development or are already included in RPS programs in a number of PJM states. The status of programs for jurisdictions within PJM are highlighted in Table 13.2. EE standards promote moderation in the growth of peak demand and energy. PJM supports these efforts and is closely monitoring developments to anticipate complementary modifications as may be desirable to markets and transmission planning.
Table 13.2: Energy Efficiency and Demand Response in PJM Jurisdictions (01/27/10)

<table>
<thead>
<tr>
<th>Status of Program</th>
<th>Energy Reduction Goal</th>
<th>Year Reuction Goal Begins</th>
<th>Year Reduction Goal Reached</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC</td>
<td>In FY 2009, the PSC is committed to rendering a decision regarding PEPCO's proposed energy efficiency programs in Formal Case No 945 within 90 days after the close of the record. They will also revise its REPS rules to address the 2008 Act’s higher standards and accelerated schedule than was contained in the 2005 REPS Act.**</td>
<td>DR: Five Demand Side Management programs have been provisionally approved: 1- Residential Lighting &amp; Appliances, 2- Non-Residential Prescriptive Rebate, 3- NR Custom Incentive, 4- NR HVAC Efficiency and 5- NR Building Commissioning. EE: In the 2009 PSC Performance Plan, cited is their Initiative 2.1, which is to begin implementing the clean and affordable energy (CAE) Act of 2008, and to expand the Commission’s programs to increase the public’s awareness of energy efficiency opportunities. ** Part of this includes combining the Heat Smart campaign with an Educated Consumers component.</td>
<td>2009</td>
</tr>
<tr>
<td>DE</td>
<td>Status: Legislation in development. 5-year Energy Plan to be presented to Governor and staff in finalized form by February 2009.</td>
<td>Reduce energy usage 30% by 2015</td>
<td>2009</td>
</tr>
<tr>
<td>KY</td>
<td>Proposed EE plan.</td>
<td>18% reduction of 2025 forecasted demand</td>
<td>N/A</td>
</tr>
<tr>
<td>MI</td>
<td>Status: Legislation enacted - 2008 PA 295 was passed that established renewable portfolio standards (10% by 2015) and required a portion of the renewable resources to be sited in the State.</td>
<td>1% annual energy savings as a percent of prior year’s sales.</td>
<td>2009</td>
</tr>
<tr>
<td>NC</td>
<td>Status: Legislation In Development: Energy Master Plan released on October 22, 2008</td>
<td>EE to meet up-to 25% of RPS in 2011</td>
<td>EE - 2010 thru 2020</td>
</tr>
<tr>
<td>NJ</td>
<td>Status: Legislation enacted. Law Passed 2007 and NCUC issued Order Adopting Final Rules in 2008.</td>
<td>Investor-owned utilities will be required to meet up to 12.5% of their energy needs through renewable energy resources or energy efficiency measures. Rural electric cooperatives and municipal electric suppliers are subject to a 10% REPS requirement.</td>
<td>2007</td>
</tr>
<tr>
<td>OH</td>
<td>Status: Legislation enacted 5/1/08: addresses the expiration of rate caps at the end of 2008 and requirements to cut load via energy efficiency and demand response.</td>
<td>22% energy savings from 2009 levels by 2025; 8% peak reduction by 2018</td>
<td>2009</td>
</tr>
<tr>
<td>PA</td>
<td>Status: Legislation enacted 5/1/08: addresses the expiration of rate caps at the end of 2008 and requirements to cut load via energy efficiency and demand response.</td>
<td>Reduce consumption 3%, peak 4.5% by May 31, 2013 as a percentage of 2009-10 sales.</td>
<td>2011</td>
</tr>
<tr>
<td>WV</td>
<td>H.B. 408 enacted, November 2009</td>
<td>EE &amp; DR earns one (1) credit in the state’s A&amp;RES program</td>
<td>2011</td>
</tr>
</tbody>
</table>
13.6: 2010 RTEP Process Sensitivity Studies

The retool analyses performed in 2009 and the PATH sensitivity studies described Section 8.1 of this report demonstrate the extent to which changing circumstances impact the need to adjust the assumptions used in planning studies and to re-evaluate decisions made as a result of previous planning analyses. PJM continually evaluates system topology, load forecasting data, generation status and other parameters that affect system modeling assumptions. Unforeseen changes to any one of these parameters can introduce significant uncertainty into results.

PJM’s 2010 annual RTEP process will include sensitivity study evaluations related to the uncertainty inherent in key baseline reliability study assumptions, including the following:

- Load growth impacts - such as DR and EE arising out of state RPS initiatives, as described in Section 2.2

- Generation availability and location impacts – such as the growth of generation powered by renewable fuels (also arising out of state RPS initiatives as also described in Section 2.3), unit deactivation, carbon legislation and other factors placing generation “at-risk.”

PJM-wide sensitivity studies will assess the impact of these trends on reliability criteria violations, identified as part of load deliverability and generator deliverability power flow tests. Deliverability analyses themselves are fundamentally related to the balance between load and generation and the transmission capability that joins the two, as described in Section 3.3. The results of sensitivity studies will provide valuable input to ensure that the long-term BES transmission needs of PJM continue to be met.

13.6.1 – Assessing Sensitivity to Load Parameters

PJM’s planning process identifies future system transmission needs based on power flow studies that identify NERC criteria violations. These power flow models incorporate the effect of many system expansion drivers.

Load growth – and the many economic and other factors which impact it – remains a fundamental driver of transmission expansion plans. Comprehensive, current load forecasts are a key component of power flow modeling in transmission expansion studies. Understanding their impact on RTEP analyses is important if they are to yield plans that will continue to ensure reliable system operation and efficient markets.

Demand Response (DR) and Energy Efficiency (EE)

Various state RPS initiatives promote DR and EE programs. Such programs can have the effect of moderating peak demand and energy growth. PJM supports these programs and is closely monitoring developments.

Currently, PJM includes DR and EE values into its RTEP process based on the degree to which such programs clear in RPM auctions and are factored into reliability analyses based on the circumstances under which the programs are expected to be implemented in actual operations. Table 13.3 depicts recent DR and EE auction activity.

Within PJM, DR participation may be price responsive, contractually obligated, or directly controlled. As more experience with these programs is gained, PJM will be better able to assess their impact on energy usage and peak load.

PJM sensitivity studies in 2010 will attempt to provide as assessment bracketing the potential effect of states’ DR and EE programs on reliability criteria violations which drive the need for new transmission.

13.6.2 – Assessing Sensitivity to Generation Parameters

Deliverability studies are also clearly dependent on location and availability of generation. As a result, reliability criteria violations can be either by advanced or delayed depending on such status.

PJM RTEP process experience has demonstrated that the inclusion or exclusion of significant generation resources, particularly those in electrical proximity to constrained transmission facilities, can have a marked impact on the occurrence and timing of projected violations of NERC Reliability Standards. PJM generator sensitivity studies in 2010 will attempt to assess, broadly the impacts of renewable generation under state RPS programs and the impacts of “at risk” generation.
### Table 13.3: Demand Response and Energy Efficiency Impacts (01/27/10)

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid-Atlantic</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Energy Efficiency</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>b. Load Management</td>
<td>2,311</td>
<td>1,863</td>
<td>1,996</td>
<td>1,996</td>
<td>1,996</td>
<td>1,996</td>
</tr>
<tr>
<td>Total Load Management and Energy Efficiency</td>
<td>2,311</td>
<td>1,863</td>
<td>1,996</td>
<td>1,996</td>
<td>1,996</td>
<td>1,996</td>
</tr>
<tr>
<td>Western</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Energy Efficiency</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>b. Load Management</td>
<td>1,403</td>
<td>1,156</td>
<td>1,334</td>
<td>1,334</td>
<td>1,334</td>
<td>1,334</td>
</tr>
<tr>
<td>Total Load Management and Energy Efficiency</td>
<td>1,403</td>
<td>1,156</td>
<td>1,334</td>
<td>1,334</td>
<td>1,334</td>
<td>1,334</td>
</tr>
<tr>
<td>Southern</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Energy Efficiency</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>b. Load Management</td>
<td>28</td>
<td>23</td>
<td>126</td>
<td>126</td>
<td>126</td>
<td>126</td>
</tr>
<tr>
<td>Total Load Management and Energy Efficiency</td>
<td>28</td>
<td>23</td>
<td>126</td>
<td>126</td>
<td>126</td>
<td>126</td>
</tr>
<tr>
<td>PJM RTO</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Energy Efficiency</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Notes: Energy Efficiency values are impacts approved for use in PJM Reliability Pricing Model. At time of publication of the 2009 Load Report, no Energy Efficiency programs have been approved as RPM resources.
**Renewable Generation**

Presently, PJM’s queues include interconnection requests for plants fueled by biomass, hydro, methane, waste, wind and wood. RPS initiatives to integrate ever growing amounts of generation powered by renewable resources continue to unfold at federal and state levels of government. As a result, the role of renewable energy to meet customer needs in PJM continues to grow.

Such resources, however, are often located in areas that pose challenges regarding transmission access to the load centers where their output is most needed. Continued state initiatives based on such standards could lead to substantial development of wind resources in areas best suited to optimize this technology.

**Wind Powered Generation**

Wind generation accounts for more than 38,000 MW currently active in PJM’s interconnection queue. These projects tend to cluster in areas with favorable characteristics, such as wind speed, duration and frequency. PJM has a number of such areas, many in transmission limited areas.

As Map 13.2 shows, wind-powered projects have emerged in several clusters across PJM including a cluster in the Atlantic Ocean shore off the Delmarva Peninsula. The duration and velocity characteristics of prevailing off-shore winds over peak summer periods could improve the availability of energy from such units when needed. PJM’s queues also include requests for interconnection at PJM’s western border – ComEd– from generation further west, including sites in Iowa and South Dakota.

A number of efforts are currently underway within the Eastern Interconnection to examine the impacts of large-scale integration wind-powered generating resources. Among these are the JCSP and EWITS studies, as described in Section 9. To the extent such studies produce results indicating the need for new or expanded BES infrastructure, PJM will study such proposals as part of its 2010 RTEP process to assess their impact on PJM reliability. These PJM RTEP analyses will necessarily evaluate the need for additional BES transmission infrastructure enhancements in PJM in order to accommodate any JCSP and EWITS proposals.

**“At Risk” Generation**

Generation asset owners must consider a number of factors as part of their business case development for an asset’s ongoing economic viability and ability to reap consistent revenue streams. Owners and developers continually evaluate the costs of increased investment to address environmental compliance issues and other needed improvements against anticipated revenues from PJM’s energy, capacity, and ancillary services markets and under existing power purchase agreements. Moreover, age and size of a generation asset are often key factors. Many generators in key locations in PJM are more than 40 years old. Consideration of such business factors drive developer and owner decisions regarding an existing facility’s economic viability, influencing whether a unit will continue to operate.

Generator deactivations alter power flows that often yield transmission line overloads. From an RTEP perspective, generation retirements coupled with steady load growth and challenges faced by new generation have led to the emergence of reliability criteria violations in several areas of PJM.

More recently, RPM activity and RPS initiatives add two additional risk dimensions which generation owners and developers now also consider in their business case development regarding a generating asset’s economic viability:

- A generator that bids into and clears an RPM auction takes on a forward commitment to provide energy in a future planning year from which it will derive a revenue stream. Generation which does not clear an RPM auction is much less certain to derive such revenue streams. Such an outcome may change an asset owner’s decision to continue unit operation, seeking instead to deactivate the unit.

- Pending and future federal and state legislation implementing carbon policies or other pollutant regulations may dramatically affect the disposition of a significant amount of generation within PJM. Generation asset owners may be faced with assessing the impact of additional environmental mitigation expenditures on profits from long-term revenue streams and may be faced with the decision to remain in operation or opt for deactivation instead.

PJM’s 2010 RTEP process will include sensitivity analyses to assess the potential impact of each of these “at-risk” categories on reliability criteria violations and the need for transmission expansion.
Map 13.2: Clustered Wind Generation Projects
13.7: Audit Compliance

PJM’s RTEP process and methodologies, from their inception, have been structured to ensure compliance with established NERC standards. Within this context, PJM can identify reliability criteria violations and determine BES infrastructure needs.

PJM continues preparations begun in 2009 for a compliance audit of North American Electric Reliability Corp. (NERC), ReliabilityFirst (RFC) and SERC reliability standards. The audit is scheduled for February 2010.

The purpose of this independent audit is to assess PJM’s efforts, in terms of procedures, processes and people, to meet its reliability responsibilities in accordance with the requirements applicable to PJM in its registered industry functions. RFC, which will be leading the audit together with SERC, has the authority to recommend and enforce sanctions, including monetary penalties on NERC’s behalf, for cases of non-compliance. A significant focus of the audits will be on PJM’s Planning functions, in addition to PJM Operations and Critical/Cyber Infrastructure Protection (CIP) functions.