Section 5: Addressing Long-Term Challenges

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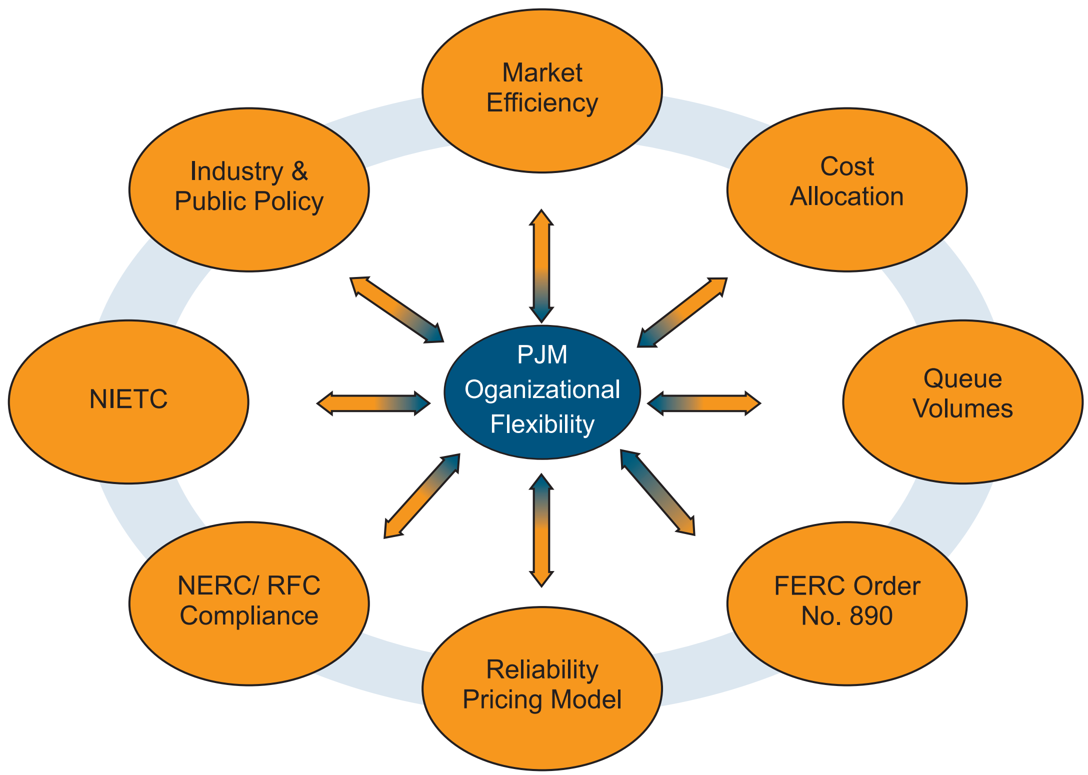
Since its 1997 inception, PJM's RTEP Process has continued to adapt to the needs of an RTO that has experienced expanding geographic markets, market offerings and growing influences from myriad other external and internal factors. **Section 5** discusses emerging RTEP trends based on initiatives within the RTO-stakeholder sphere itself as well from a number of extrinsic factors driving RTEP change.

Section 5.1 examines RTEP process improvements presently underway within PJM as driven by internal PJM and stakeholder initiatives to address identified issues. These process improvements are addressing the following: (1) market efficiency planning procedures; (2) cost allocation procedures; (3) queue request process modifications to address queue back-logs; and, (4) RPM-based LDA considerations within RTEP.

Section 5.2 summarizes extrinsic factors unfolding within the industry that are driving the need for RTEP process changes as well. These include the following: (1) implementation of FERC Order 890 addressing additional process transparency; (2) NERC and RFC initiatives addressing reliability criteria and compliance; (3) DOE approval of the Mid-Atlantic NIETC corridor; and, (4) other specific industry and public policy considerations such as renewable generation portfolio state requirements and Regional Greenhouse Gas Initiative (RGGI) activities.

FIGURE 5.1: Addressing Long-Term Challenges



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5.1: RTEP Process Improvements: PJM RTO / Stakeholder Sphere

5.1.1 – RTEP Market Efficiency Planning

PJM's RTEP process includes the analysis of the economic efficiency of PJM's energy and capacity markets. Most recently, PJM's proposed "bright-line" economic efficiency metric and associated method of determining RTEP market efficiency upgrades was submitted to and is now pending approval by the Federal Energy Regulatory Commission (the Commission.)

Prior to 2006, PJM's RTEP process included an unhedgeable congestion "economic planning" method. In 2006 PJM proposed to enhance the analysis by including evaluation of the eight economic metrics, discussed in the PJM 2006 RTEP, to assess potential projects. In response to stakeholder and Commission direction, PJM significantly clarified and honed its method the result of which is the current "bright-line" proposal, filed by PJM on October 9, 2007 in Docket No. ER07-1474. This method was vetted through PJM's stakeholder process and was supported by a PJM stakeholder sector vote.

PJM's New Market Efficiency Evaluation Method

PJM's current pending proposal is more forward-looking; gives market participants access to both historical information and projections for a 15-year planning horizon; and provides regular evaluation and reevaluation of potential economic-based transmission enhancements. PJM's method also comparably considers DSR programs and generation solutions put forward by the market to be considered as part of PJM's planning process.

Proposed metrics include historic and projected congestion. The historic metrics are gross congestion, unhedgeable congestion, and proration of long-term Auction Revenue Rights. These are posted for all stakeholders regularly to foster development of candidate market efficiency projects. The measure of projected congestion is based on a market analysis of future system conditions performed with a commercially available security constrained, economic dispatch market analysis tool. Market analysis includes congestion and binding constraint results for the current year plus years 1, 4, 7 and 10.

The "Bright-Line" Test

Transmission plans that result from the reliability analysis may also benefit market efficiency. Reliability-based RTEP projects are evaluated to determine if they can be advanced based on market efficiency benefits. Also, the review of historical and projected congestion metrics and other RTEP drivers may suggest new projects or based on market efficiency as the primary driver from combinations of the two.

Candidate upgrades that become market efficiency recommendations will be those facilities that pass PJM's threshold test and "bright-line" economic efficiency test. This test specifies that a proposed solution's savings in the sum of the weighted production cost of energy and capacity plus the weighted load cost of energy and capacity (weighted 70% production cost and 30% load cost) must exceed its projected revenue requirements, on a 15 year present worth basis, by at least 25% (the threshold cost/benefit test.) The result is that projects satisfying this "bright-line" formula will presumptively be included in the RTEP. More information regarding PJM proposals and the Commissions rulings can be found at http://www.pjm.com/documents/ferc.html.

Additional Market Efficiency Metrics

Along with the "bright-line" quantification of the costs and benefits, PJM will also quantify the change in several metrics that more fully describe the candidate project's impacts. This will allow stakeholders to consider projects based on a broader understanding of their merits and to recommend projects that may be appropriate in addition to "bright-line" projects.

At least six metrics will be quantified for each candidate Market Efficiency project. These include quantification of the change in the value of the following, as well as zonal breakdowns, where appropriate to consider doing so:

- **Total PJM Production Cost** – The costs to produce energy to serve load, including fuel, variable operating and maintenance, and environmental costs. These costs will change because the generation dispatch pattern will change with the addition of the proposed transmission upgrade. Production cost changes reflect the cost change associated with a more economically efficient dispatch but may not represent changes in load payments because loads pay the marginal cost of energy.

- **Total PJM Load Payments** – Payments made by loads, determined by multiplying load megawatts by load locational marginal prices at the bus where the load is located. This assumes that loads purchase all of their energy needs from the PJM spot market. It does not include the effect of bilateral contracts or other hedging tools available to loads, as these hedging tools change over time.
- **Total PJM Generator Revenue** – Payments to generators, determined by multiplying generation megawatts by generation locational marginal prices. The difference between total PJM load payments and total PJM generator revenue represents the total system congestion charges.
- **Total PJM FTR Credits** – Measured using currently allocated Auction Revenue Rights (ARR) plus AAR's created by the proposed transmission upgrade to the currently allocated ARRs on a load bus basis.
- **Total PJM Transmission System Losses** – Measured by determining the total system transmission losses with and without the proposed transmission upgrade.
- **Total PJM Capacity Payments** – Measured by comparing the locational capacity payments in a zone, with and without the proposed transmission upgrade.

5.1.2 – Cost Allocation Procedures

PJM cost allocation procedures for transmission expansion upgrades follow the provisions of the PJM Operating Agreement, Schedule 6 and the PJM Open Access Transmission Tariff, Schedule 12.

Generation and Transmission Interconnection

Costs for upgrades specified for generation and transmission interconnection are also allocated according to relative impact based on one of several methods, depending the type of upgrade being pursued: e.g., Load Flow Cost Allocation Method to allocate network upgrades for transmission line expansion plans; Short Circuit Cost Allocation Method for allocation of costs for new circuit breakers, etc. Details on all allocation processes can be found at www.pjm.com, in PJM Manual 14B, "Generation and Interconnection Planning."

Baseline Backbone Transmission Expansion

The FERC issued an order in April 2007 governing the allocation of new transmission in PJM. In summary, the FERC ruled on the following:

- The costs of new facilities operating at 500 kilovolts (kV) or above that are planned through PJM's Regional Transmission Expansion Planning (RTEP) process will be shared across the whole region. This affects both reliability and economic projects. The FERC stated that the broad, regional benefits of such projects justified the sharing of costs region-wide.
- The costs of new RTEP facilities below 500 kV will continue to be funded under PJM's existing approach, "beneficiary pays," in which those benefiting from a new project must pay its costs.
- The costs of existing transmission facilities, as well as new projects initiated by PJM's Transmission Owners, will continue to be allocated on a zonal basis. The FERC found that this approach "reflects the prior investment decisions of the individual transmission owners," adding that the facilities were built primarily "to support load within the individual transmission owners' zones and continue to serve those loads."

Subsequent to April 2007, in accordance the FERC's ruling, PJM and its stakeholders engaged in hearing and settlement talks to define a methodology that implements the "beneficiary pays" approach to cost allocation for new RTEP facilities under 500kV. A proposed settlement was reached and submitted to the FERC in September for its consideration and approval. Hearing procedures on specific aspects of cost allocation regarding merchant transmission continue into 2008.

5.1.3 – Interconnection Request Process Improvements

The PJM request queues contain transmission requests from both merchant transmission and generation interconnections, as well as requests for long-term firm transmission service requests and Upgrade Auction Revenue Right requests. All of these requests require coordination and evaluation by PJM planning staff. In addition, new requests for conversion of expiring, existing generator agreements to Interconnection Service Agreements are a recent significant addition to the request queue study efforts. PJM's generation interconnection queue volume, shown in FIGURE 5.2, is the primary factor that drives queue process workload.

The details of the "T" queue, which closed on January 31, 2008, are illustrative of recent queue activity trends, as shown in TABLE 5.1. The types of requests received are summarized in TABLE 5.2.

A growing trend is clear. After an initial influx of projects into the queues, the market response to adequate reserves was an expected dampening of request activity. Influences that subsequently led to the current increasing trend in queue volume include tightening of reserves, the commencement of the locational capacity markets, merchant transmission entrance into the markets, environmental concerns and public policy incentives encouraging renewable energy alternatives. The backlog effect of queued interconnection requests is being experienced in other RTOs and ISOs as well. The situation in PJM is portrayed in FIGURE 5.3.

FIGURE 5.2 - Generation Interconnection Request Volume

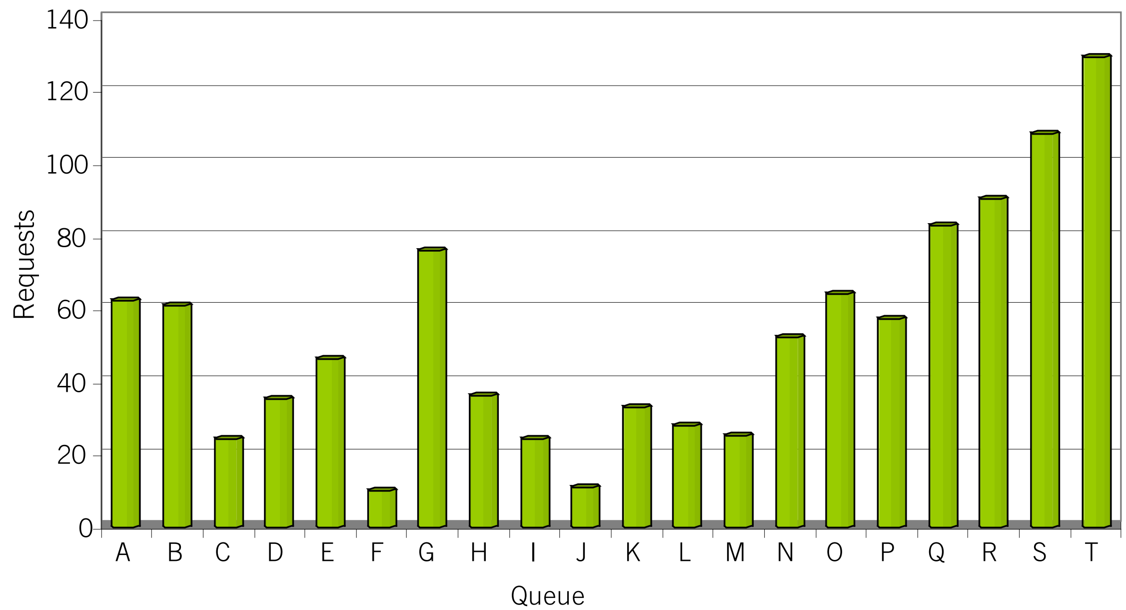


TABLE 5.1: Request Volume Last Weeks of Queue "T"

Queue T Date	Request Volume	Request Type
1/31/2008	28	25 generators, 3 ARRs
1/30/2008	6	all generators
1/29/2008	1	all generators
1/28/2008	6	all generators
1/25/2008	1	all generators
1/24/2008	1	all generators
1/22/2008	1	all generators

Note

Queue T preliminary status as of January 31, 2008

Note

Upgrade Auction Revenue Rights are the rights to auction proceeds resulting from the additional transmission capacity brought about through an upgrade approved through the RTEP. These are a form of Incremental Auction Revenue Rights.

This situation was the subject of a recent Federal Energy Regulatory Commission technical conference. Information regarding PJM's participation in that December 11, 2007 conference can be found at: http://www.pjm.com/documents/ferc/documents/2007-d.html.

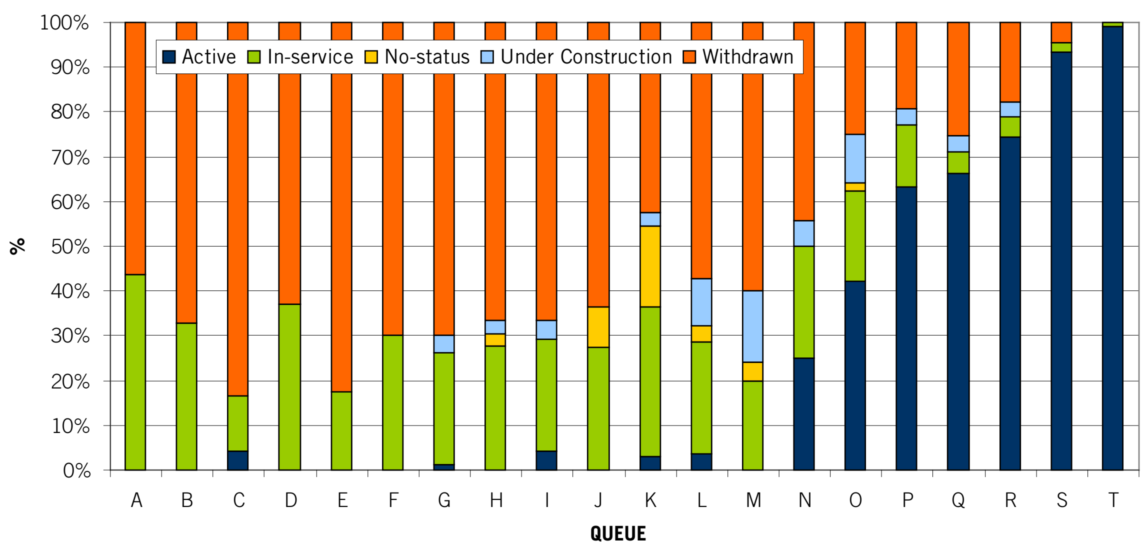
PJM is currently assessing methods to improve the handling of queued requests. For example, the Commission on January 28, 2008, approved for filing PJM's proposal to increase the number of annual queues from two to four beginning with queue "U" on February 1, 2008 (ER08-280-000.) PJM anticipates that as a result of this change, interconnection requests will be more evenly distributed throughout the year. This change should mitigate the large influx of projects just before the queue deadline, currently being experienced, as summarized earlier in TABLE 5.1. Better distribution of workload will help alleviate delays caused when large numbers of studies enter a queue almost simultaneously.

PJM recognizes that the transition to quarterly queues is one step in a process that continues in an ongoing effort to improve timely completion of interconnection evaluations and agreements. Additional short term improvements as well as more comprehensive solutions are continuing to be pursued. For example, in the shorter term, consideration is being given to methods to ease the study burden caused by a customer's right to select an alternate interconnection point. Methods to simplify the allocation of upgrade costs among the projects driving the need for upgrades are also under consideration. During 2008, these and other changes will be considered by PJM through its stakeholder process.

TABLE 5.2: Queue T Request Types (through 1/31/2008)

Request Type	Volume of Requests
Generation Interconnection	129
Long-Term Firm Transmission Service	45
Auction Revenue Rights	3
Merchant Transmission Interconnection	4
Total	181

FIGURE 5.3: Status of Queue Requests



5.1.4 – RPM RTEP Considerations

Locational Deliverability Area (LDA)

The development of the PJM Installed Reserve Margin is based on a critical assumption that the transmission system does not limit the delivery of generating capacity to load during normal or capacity emergency conditions. Locational Deliverability Areas (also referred to as Load Deliverability Areas) (LDA) are electrically cohesive areas defined to test this assumption by determining the ability of the transmission system to deliver energy to an area that is experiencing an internal capacity shortage. Historically the LDAs have been based on the Transmission Owner (TO) service territories and geographic proximity of these territories. This historical perspective results in an LDA for each TO zone in PJM and several combinations of these zones (for example the Southwest Mid-Atlantic LDA is comprised of the TO zones PEPCO and BG&E.) More recently, additional LDA's have been defined for smaller areas within TO zones (such as the Delmarva South area.) These newer areas were defined based on transmission limitations that could disrupt the delivery of emergency capacity to a more localized area of the system. LDA's, through their role in Reliability Pricing Markets and RTEP analyses, provide the locational information and incentives necessary for development of appropriate power system infrastructure. Currently there are twenty three PJM LDA's.

PJM continues to observe transmission system limitations and their impact on the ability of system to provide reliable service to load. In the future new LDA's may be considered as necessary to establish incentives for infrastructure that ensures PJM reliability. Ongoing LDA review is consistent with the changing nature of load responsibility under wholesale and retail access and provides a wider range of information about the performance of the Transmission System as electrical areas of different sizes are evaluated. Nesting small sub-areas into larger areas or combining areas or portions of areas into larger LDA's of PJM helps identify the interrelationships between local and large geographical area deliverability problems. Further review and development work on LDA's will be vetted through the stakeholder process.

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

5.2: RTEP Planning Extrinsic Drivers

Introduction

The PJM planning process is subject to increased influence from external demands. Many of these influences affect requirements and processes that are well established elements of PJM's planning. Addressing the requirements of external factors can increase the volume of planning activities. For example, formalization of well established planning processes, documentation requirements, enhanced opportunities for stakeholder involvement in planning, and regulatory factors in the market place are all examples of recent influences effecting change in the RTEP process. Such external influences provide the opportunity for enhancement of the RTEP planning. This section discusses several effects of extrinsic drivers.

In 2007 the Commission required planning organizations to demonstrate compliance with required planning process enhancements based upon nine planning principles. In response PJM implemented certain enhancements to its planning process. Also, the Reliability*First* Corporation (RFC) and its parent organization the National Electric Reliability Corporation (NERC) continued the development of revised and mandatory reliability standards. These standards significantly augment the process required throughout all phases of PJM's RTEP process. Audits of PJM compliance necessitate organizational focus to manage same and to provide liaison with external parties. Additionally, all phases of PJM's planning must shoulder the added requirements of producing and organizing the evidence of documentation. Finally, several influences are driving efforts toward large interregional transmission studies. These include the United States Department of Energy (DOE) National Interest Electric Transmission Corridors coupled with FERC and NERC discussions of the needs for farther reaching studies that address longer term needs for integration of resources and for enhancement of market efficiencies.

5.2.1 – Implementing the Commission's Order 890

On December 7, 2007 in docket No. OA08-32-000, PJM filed with the Commission revisions to the PJM Operating Agreement in compliance with their Order 890's (the "Order") directives. This landmark Order modified the Commission's Order 888 pro forma OATT to require a transmission provider that is a Regional Transmission Organization (RTO) to submit a Section 206 compliance filing that contains the revised non-rate terms and conditions set forth in the Order. In the alternative the RTO may demonstrate that its existing tariff provisions are consistent with, or superior to, the revised provisions. Among other things, the Order amended the pro forma OATT to require coordinated, open and transparent planning of transmission systems on both a local and regional level. PJM and stakeholders already conduct a compliant planning process filed with the Commission and incorporated in its Operating Agreement (OA) as Schedule 6.

PJM OA Schedule 6 codifies PJM's Regional Transmission Expansion Planning Protocol (Protocol) through which PJM and Stakeholders develop the PJM Regional Transmission Expansion Plan (RTEP.) Nevertheless, PJM has undertaken modifications to its OA and has vetted these revisions through the PJM stakeholder process. These modifications implement continuing improvements to the Protocol. The result is a revised PJM OA Schedule 6 that, together with the associated provisions of the PJM OATT, enhances compliance with the Order 890 planning process reforms.

Stakeholder Enhanced RTEP Participation

A cornerstone of the PJM RTEP process is the stakeholder participation through the PJM Transmission Expansion Advisory Committee (TEAC). Order 890 contains nine (9) planning principles that have a direct bearing on the TEAC process. Specifically, the Order requires that the TEAC RTEP process be coordinated, open, transparent, comparable and also foster information exchange and include economic-based expansion planning.

PJM annually develops its RTEP in a participatory and open transmission planning process with the advice and input of the TEAC. To enhance PJM's compliance with Order 890 principles, PJM has created a new committee, the Subregional RTEP Committee. This new committee increases the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of the planning analyses, violations, and alternative transmission expansions. The Subregional RTEP Committee provides a more local forum for gathering and considering planning issues. Initially the Subregional RTEP committee will convene meetings focusing individually on the PJM Mid-Atlantic, Western and Southern regions. Through these meetings all PJM stakeholders can raise issues, propose solutions or alternatives and initiate additional gatherings as may be necessary. These meetings are open to all stakeholders interested in the issues under consideration. Advance notice and agenda will be provided by PJM and all business is conducted according to PJM TEAC and Committee rules and procedures. Interested parties can access Subregional RTEP Committee planning process information at: http://www.pjm.com/committees/pjm.html.

5.2.2 – New Reliability Initiatives

On January 1, 2007, the North American Electric Reliability Council and the North American Electric Reliability Corporation merged to become the NERC Corporation. The NERC Corporation was certified as the Electric Reliability Organization (ERO) by the Federal Energy Regulatory Commission (Commission) on July 20, 2006.

Pursuant to the Electricity Modernization Act of 2005, which is Title XII, Subtitle A, of the Energy Policy Act of 2005 (EPAct 2005), the ERO must develop mandatory and enforceable reliability standards, which are subject to Commission review and approval. Once approved, the reliability standards may be enforced by the ERO subject to Commission oversight, or the Commission can independently enforce reliability standards.

The Reliability Standards developed by the ERO and approved by the Commission will apply to users, owners and operators of the Bulk-Power system, as set forth in each Reliability Standard. NERC is in the process of developing, approving, and implementing the necessary reliability standards, which include standards applicable to PJM's RTEP process. PJM participates in the stakeholder process of standards development and approval and interprets and implements NERC's evolving mandatory standards as they become effective.

In June of 2007 four mandatory planning reliability standards became effective: TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. These govern the methods and criteria applicable to planning and documenting NERC Bulk Electric System facilities. System normal conditions, loss of a single element, loss of multiple elements and extreme events are addressed. More information regarding these requirements can be found at: http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

As part of its mission to improve the reliability and security of the bulk power system in North America, NERC, audits owners, operators, and users for preparedness and compliance with its standards. PJM, consistent with its continuing compliance with applicable planning criteria, has undertaken an effort to formalize and document compliance with all current, applicable NERC criteria. In addition, PJM continues to evaluate and adjust RTEP process activities to comply with the ongoing evolution of criteria. This compliance culture is being woven into the fabric of PJM's analysis and documentation activities. The current initial "level zero" standards are already under review for modifications. Resulting revised standards which will place further demands on PJM's RTEP process are expected to take effect in 2008. Significant changes to the RTEP planning process necessitated by NERC compliance are presented and discussed at the appropriate PJM Committees.

NOTE

The remaining principles: dispute resolution, planning with interconnected systems, and cost allocation are more ancillary to the development of the RTEP and covered by other OA and OATT provisions. The cost allocation nexus with RTEP is discussed in Section 5.1.2 of this report.

Another significant change in NERC standards affecting RTEP analysis was adopted on May 9, 2007 by the Reliability*First* Board of Directors. (Reliability*First* is the Regional Corporation, that encompasses PJM, to which NERC designates certain of its responsibilities.) Reliability*First* approved a new definition of the Bulk Electric System (BES). Reliability*First* defines the BES as all:

1. Individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher,

2. Lines operated at voltages of 100 kV or higher,

3. Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment).

The Reliability*First* Bulk Electric System excludes:

1. Radial facilities connected to load serving facilities or individual generation resources smaller than 20 MVA or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher, and

2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer); these facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental, and/or other plant restrictions, and

3. All other facilities operated at voltages below 100 kV.

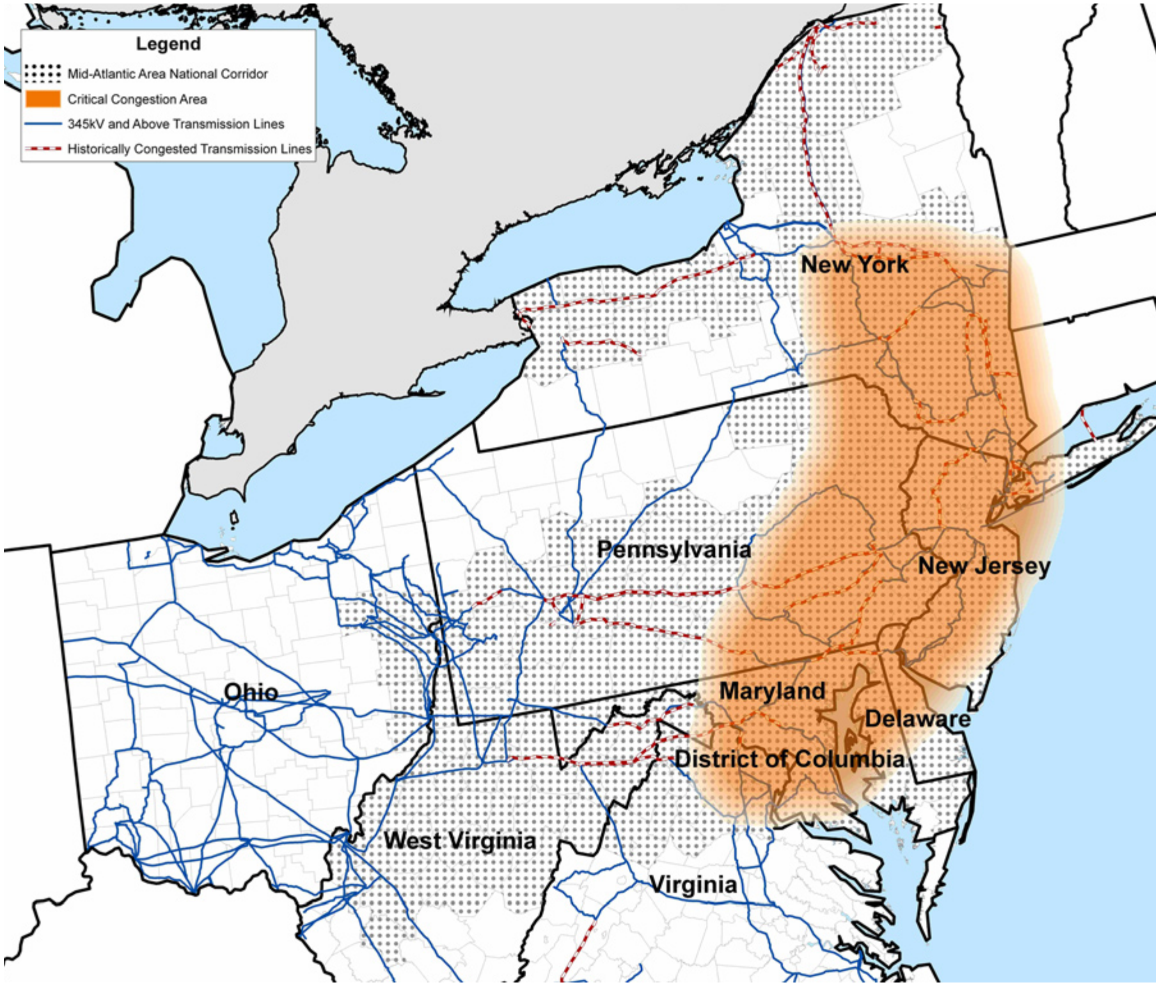
As a result, all planning analyses and planning models are being modified to incorporate additional BES facilities including contingency files and facility monitoring files. These changes are being incorporated into the 2008 planning process. The results of the planning studies including any identification of new violations or upgrades due to the Reliability*First* definition change will be presented to the PJM Board of Managers as additions to the RTEP during the 2008 planning cycle. This will complete PJM's fulfillment of NERC these requirements.

5.2.3 – National Interest Electric Transmission Corridors (NIETC)

PJM initially proposed that the Department of Energy's (DOE's) "National Electric Transmission Congestion Study" designate three National Interest Electric Transmission Corridors (NIETC or National Corridors) within the PJM region: the Allegheny Mountain Corridor, Delaware River Corridor and the Mid-Atlantic Corridor. The 2006 RTEP studies demonstrated that, in the absence of construction of a new, high-voltage transmission circuit (the proposed 502 Junction – Loudoun 500 kV line), NERC and PJM reliability and planning criteria will be violated in 2011. Significantly, these violations occurred in the portion of the PJM system that is within the initially proposed Allegheny Mountain Corridor. The 502 Junction – Loudoun 500 kV line, which remedies these violations, is currently under consideration by various state siting entities including the Virginia State Corporation Commission, the West Virginia Public Service Commission and the Pennsylvania Public Utilities Commission.

Since the release of the 2006 RTEP, DOE has designated a NIETC effectively combining the three proposed National Corridors and a significant portion of New York State into one "Mid-Atlantic Area" Corridor. The scope of the Mid-Atlantic Corridor is presented in MAP 5.1.

MAP 5.1: DOE Mid-Atlantic Area NIETC Corridor



Source: U.S. Department of Energy. Web site: http://nietc.anl.gov, February 6, 2008.

NOTE

The Order designating the Mid-Atlantic Area NIETC became effective on October 5, 2007 and will remain in effect until October 7, 2019 unless rescinded or renewed. On December 3, 2007 the DOE granted requests for rehearing for further consideration of the report and Order that established the Mid-Atlantic Area NIETC. This issue can be tracked by referring to Docket No. 2007-OE-01 at http://nietc.anl.gov/.

PJM's 2007 RTEP cites additional reliability criteria violations during the 2007 to 2022 planning horizon that will not be resolved by the 502 Junction – Loudoun 500 kV line. Rather, the reliability violations, which will require remediation and which are outlined in PJM's 2007 RTEP, are in addition to those previously identified and are also based on the assumption that the 502 Junction – Loudoun line will receive regulatory approval and be energized on time.

Importantly, these violations are expected to occur in the region encompassed by DOE's newly designated draft Mid-Atlantic Area National Corridor. This information demonstrates that in certain areas the need to address transmission constraints has become even more critical since last year's report. In these instances, preserving the reliability of the grid requires a specific remedy starting as early as the year 2012.

The Allegheny Mountain Region and Central Pennsylvania

The 2007 RTEP newly cited reliability issues include overloads of the Mt. Storm – Doubs and Prunytown – Mt. Storm, Harrison – Prunytown, Mt. Storm – Greenland Gap, Greenland Gap – Meadow Brook, and the Loudoun – Pleasant View 500 kV circuits. Further overloads are also observed on the Dooms – Lexington 500 kV circuit and the Bath County – Valley 500 kV circuit from the south. In addition, several 500 kV transmission paths in central Pennsylvania will be overloaded and show reliability criteria violations by as early as 2012. All this is compounded by a number of reliability criteria violations in the Baltimore/ Washington area resulting from the announced retirement of the Benning Road and Buzzard Point generating facilities in 2012.

At this time a combination of upgrades is proposed as the most effective solution to the criteria violation in central Pennsylvania, the Allegheny Mountain region, and the Baltimore/ Washington, D.C. area. These upgrades include the new Amos – Bedington – Kemptown circuit runs approximately 300 miles from the John Amos 765 kV station in West Virginia to a new Kemptown station in Maryland, in an area northwest of the Baltimore – Washington metropolitan area.

Eastern Pennsylvania and Northern New Jersey

In addition, the 2007 RTEP analysis indicates that overloads will occur in the densely networked Northern New Jersey. The main proposal to solve the Northern New Jersey overloads is to build a 500 kV transmission line from the Susquehanna station in northeastern Pennsylvania to the Roseland station in northern New Jersey. The expected in-service date is June, 2012.

Eastern Mid-Atlantic

Another area of long standing concern on the PJM transmission system involves numerous lower voltage transmission violations and long standing transmission limitations to generator operations in the eastern Mid-Atlantic area. This 2007 RTEP has approved the PEPCO Holdings MAPP project (PHI MAPP project), to meet the needs of this area.

The overloads in the Mid-Atlantic Corridor are primarily driven by continuing load growth throughout the region, generation additions in greater proportion in the western portion of the region and generation retirements primarily in the eastern portion of the region.

A Comprehensive Process

The 2007 RTEP has identified transmission as the current proposed solution for these constrained areas, but PJM's planning process is designed to encompass all available alternatives to new transmission. Such alternatives, considered openly on a non-discriminatory basis, include new generation and demand-side response. Notably, these congestion and constraint patterns will continue to be evaluated in light of the PJM markets' strong energy and capacity locational pricing signals intended to drive market proposed alternatives to transmission. Though PJM is constrained to prescribe only transmission solutions through the RTEP, the RTEP process and analysis includes all market-provided solutions to transmission constraints as market participants commit to projects. These market solutions may be proposed in response to the information provided through the PJM regional and subregional planning process, and will be incorporated into the process during the next planning cycle. If these market solutions eliminate the need for a previously identified transmission solution, or enable PJM to propose a more efficient transmission solution in combination with the market solutions, those alternatives will be reflected in changes to the RTEP.

5.2.4 – Industry and Public Policy Considerations

National concern for developing adequate supplies of electric power in an environmentally sound manner has led to state consideration of Renewable Portfolio Standards (RPS). One convenient source for more information on renewable energy standards can be found in the Database of State Incentives for Renewables & Efficiency, which is an ongoing project of the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) funded by the U.S. Department of Energy (http://www.dsireusa.org/). FIGURE 5.4 shows the current status of RPS initiatives across the US.

Wind resources provide one significant option to satisfy RPS requirements. Such resources, however, are often located in areas that pose intensive challenges regarding transmission access to the load centers where their output is most needed. FIGURE 5.5 shows wind resource potential across the US.

Continued state initiatives based on such standards could lead to substantial development of wind resources in areas best suited to optimize this technology. Interregional studies such as current joint efforts discussed in Section 2.9 form the beginning of the conceptual planning that ultimately could prepare for the infrastructure projects that could be needed. This enables RTEP planners to begin to anticipate possible future implications of emergency resource trends.

FIGURE 5.4: Renewable Portfolio Standards - State by State Status (downloaded 2/6/08)

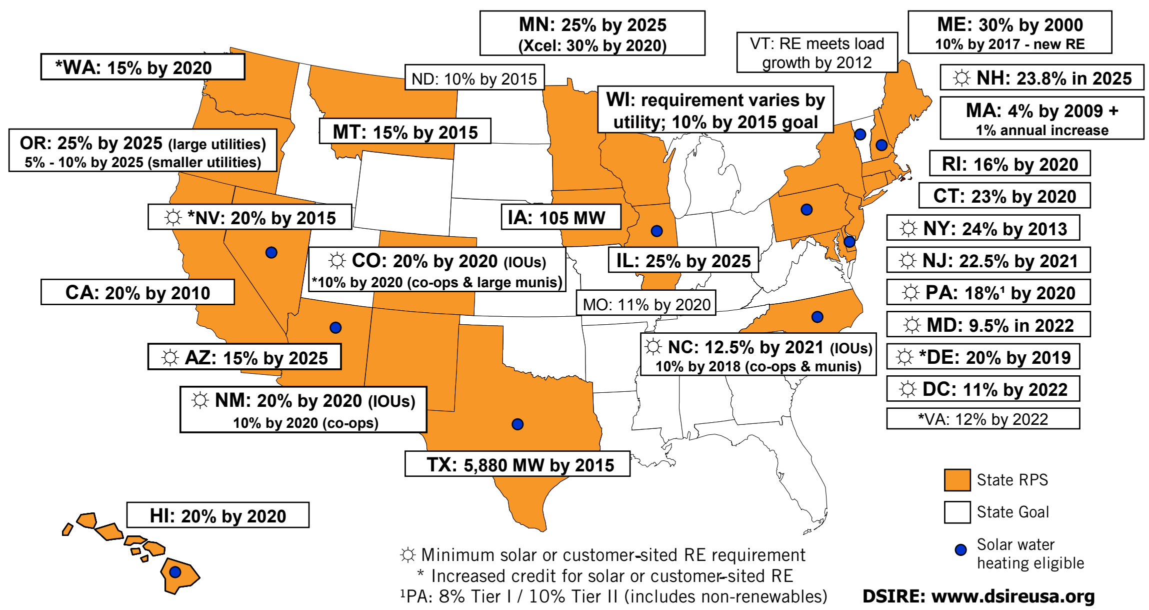
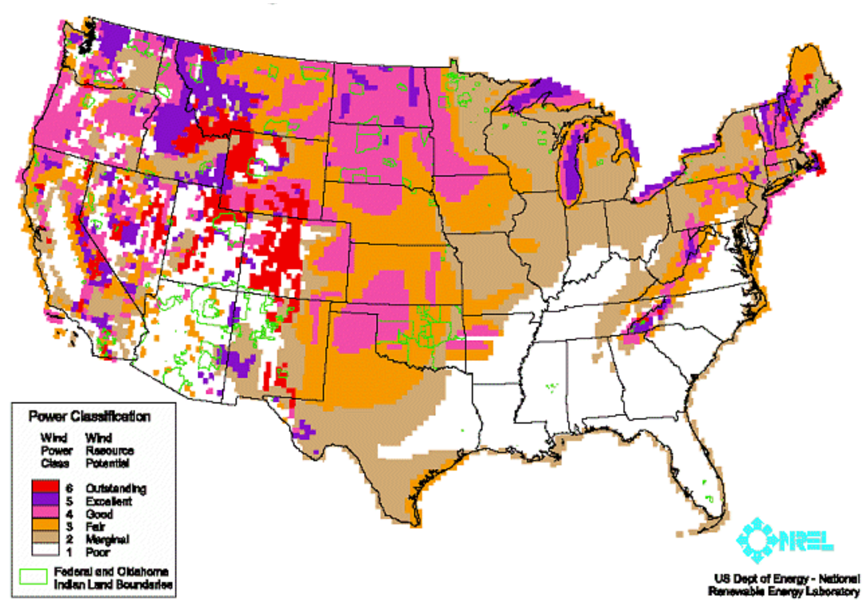


FIGURE 5.5: Wind Resource Potential - U.S. DOE (downloaded 2/6/08)



Interregional Activity

The underpinnings of PJM's interregional planning responsibilities are several joint or coordinated operating arrangements with interconnected transmission providers. Order 890 will significantly further interregional planning efforts. The Order directs transmission planners to take into account a broader view of need when planning transmission expansion. The primary emphasis is to expand the factors considered to include reliability and others. Among these, planning staffs are being urged to consider ways to reduce overall cost to serve native load and integrate new resources on an aggregate basis. This interest in transmission on a larger scale for the purpose of integrating developing resources also appears in NERC's 2007 Long-Term Reliability Assessment: (ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2007.pdf.) NERC cites the challenge of planning adequate infrastructure to anticipate market interest in new wind and nuclear resources. Interregional planning efforts will be especially needed if there is aggressive pursuit of state initiatives for renewable portfolio standards. This Order 890 and NERC increased emphasis in longer term planning has increased industry attention to interregional efforts.

Interregional planning is another significant area in which long-term challenges are being addressed. **Section 2.9** of this report discusses this area in detail.