Synapse
Energy Economics, Inc.

PJM System Planning

Enhancements for the 21st Century

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AUTHORS

Paul Peterson, Vladlena Sabodash, Matthew Wittenstein & Doug Hurley

485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

Executive Summary

PJM, as the regional transmission operator (RTO) for a broad swath of the Mid-Atlantic and Midwest, is responsible for planning to ensure "efficient, reliable, and non-discriminatory transmission service" throughout the area it serves.[1] To do so, PJM will increasingly have to contend with significant, public-policy-driven changes in the power sector.

Falling electricity demand and proliferating mandates to integrate demand management, energy efficiency, and renewable resources into the power supply will alter PJM's load forecasts and reliability needs. Simultaneously, a wave of coal-fired power plant retirements, driven by necessary environmental protection rules and market changes, will require PJM to nimbly address significant shifts in available generation in order to avoid costly "reliability must-run" agreements with plants which would otherwise retire.

The Federal Energy Regulatory Commission (FERC) will likely issue a final order in 2011 which will mandate consideration of these public policy impacts on reliability.[2] PJM is ahead of the curve, and is already in the process of developing planning reforms through its Regional Planning Process Task Force (RPPTF). To further that effort, this report identifies key areas for reform, with a particular focus on managing coal-fired power plant retirements.

Consistent with PJM's proposals now before the RPPTF, we recommend that PJM focus on improvements in three areas: forecasting and stress testing, assessment of at-risk generation, and reliability solutions.

Improved Forecasting and Stress Testing

The load forecast drives PJM's reliability analysis, so it must be as accurate as possible. Public policy mandates and goals need to be accounted for in the load forecast, as they can significantly shift its conclusions. If PJM's load forecast is too high, it may lead PJM to conclude that it needs more generation or transmission for reliability purposes than is actually the case.

The link between economic growth and increases in electricity demand is weakening as energy efficiency measures spread through the system. As a result, PJM's load forecast will be biased high if it does not take these changes into account. Indeed, full implementation of just state energy efficiency programs would reduce peak load forecasts in 2025 by nearly 10,000 MW.

When these savings are combined with growing interest in demand-side resources—14,000 MW of which cleared the last capacity auction—the peak load forecast may well flatten or diminish over time.

Growing renewable resources—often located in areas without previous generation—will also alter the topology and needs of the transmission system.

The upshot is that PJM should incorporate state and federal efficiency, demand-management, and renewable portfolio standards into its load forecast, modeling such policies at 100% of their mandates, and running sensitivities both above and below these values to account for possible variation.

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[1] 18 C.F.R. § 35.34(k)(7).
[2] *See* 75 Fed. Reg. 37,884 (June 30, 2010) (proposed rule).

PJM should also carefully review how it translates its load forecast into reliability analyses by considering the efficacy of its “stress testing” approaches in this changed context. In essence, PJM should ensure that its models fully account for demand-side resources and other measures which may be reducing stress on the system, and generation projects which may address reliability needs.

Improved Assessment of At-Risk Generation

As EPA and the states work to improve public health by reducing coal-fired power plant pollution through a series of legally mandated rulemakings, operators of some plants are likely to opt to shut down some coal capacity and replace it with cleaner resources. PJM estimates that between 14,000 and 17,000 MW of smaller, older coal power plants lack pollution controls which EPA may require. A substantial number of these plants, and perhaps others, may retire.

Yet, PJM’s tariff now requires generators to give PJM only 90 days’ notice before they retire—and PJM is supposed to respond with a reliability analysis in just 30 days.[3] This notice period is unacceptably short, especially in this period of major potential retirements, and will lead to expensive must-run agreements while PJM scrambles to conduct reliability analyses. Generators make retirement decisions more than 90 days in advance, and PJM, as well as ratepayers in its region, deserves to know these decisions in advance to allow for cost-effective retirement planning.

We recommend that PJM extend its required notice period to at least three years—the same timeframe used for capacity market auctions—to provide adequate lead time to design and implement any necessary reliability upgrades. To supplement this enhanced notification period, PJM might also consider developing incentives for companies to provide earlier notice, or disincentives (such as less favorable must-run agreement terms) for companies that provide only short notice.

As well as enhancing its notice requirements, PJM should work to enhance its internal, independent modeling capacity to develop screens for plants that are clearly at risk and likely to retire. Ample publicly available data can be used to identify older, less-efficient plants, and those without necessary pollution controls. Indeed, PJM’s own capacity auction can be used to identify plants that repeatedly fail to sell their capacity.

Although generators may have some legitimate concerns with PJM’s own retirement screenings, these concerns must be counter-balanced by the strong ratepayer interest in avoiding costly must-run agreements and rushed reliability projects. Whether through improved notice requirements, improved screening analyses, or some combination, PJM must be able to plan for retirements with lead-times far greater than the 90 days now granted in its tariff.

Improved Reliability Solutions

Not every coal plant retirement will cause a reliability problem, and not every reliability problem will require expensive and time-consuming major transmission upgrades. PJM should review its upgrade-selection process to ensure that it is able to generate, and consider, a wide range of possible reliability solutions so that it can identify the most cost-effective option.

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[3] PJM OATT §§ 113 *et seq*.

Opening the process more fully to stakeholders and the public is one effective way of developing a useful range of alternatives. New York ISO's "request for proposal" process, which allows market participants and others to come forward with possible market-based and regulated solutions, provides a useful model for PJM.

These solutions, importantly, should explicitly include analysis of small, local, transmission upgrades, larger transmission alternatives, and "non-transmission alternatives" such as demand-side resources, which would reduce load and hence address a reliability problem. Including such alternatives, as NY ISO already does, will help PJM identify the lower-cost solutions quickly and effectively.

Public policy goals are driving a cleaner and more efficient power sector, which will be less dependent on dirty, coal-fired power stations and more able to integrate cleaner resources. PJM has the opportunity, and the obligation, to effectively manage this transition and its impacts on the bulk power system.

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1. Introduction

In this report, we review PJM's transmission planning processes and recommend enhancements to address new technologies, resources, and public policies. We identify and discuss some of the key 21st-century issues and trends that will need to be accounted for in planning for a reliable and efficient electric grid, for PJM or any other power pool. We address these issues and develop our recommendations in light of PJM's own efforts to gain stakeholder support for significant planning changes it is proposing. We support many of the changes to system planning that PJM proposes. For some elements of the straw proposal, we think PJM can do even more than they have suggested.

Our recommendations cover three broad categories:

- **Improve forecasting**: Develop better estimates of the likely impacts of a whole range of elements that affect the forecasts that are used as inputs to reliability testing and modeling of the bulk power system. These elements include, but are not limited to, load forecasts, energy efficiency forecasts, the impacts of demand response resources, retail advanced metering programs, renewable portfolio standards, feed-in tariffs, customer-based distributed generation, and other state and federal policies and regulations. When modeling the system, PJM needs to avoid overly conservative assumptions that bias results toward large new transmission lines.
- **Assess at-risk resources**: Expand PJM's current efforts to identify at-risk generation to address the likely impacts of new EPA regulations on an aging, uneconomic fleet of specific resources (much of it coal-fired generation). Develop screens and thresholds that will allow PJM to proactively address both near-term and long-term impacts of a significant quantity of retirements over the next several years. Early identification of solutions to potential reliability violations due to retirements is essential to avoid uneconomic and costly reliability contracts (for resources that PJM cannot allow to retire).
- **Expand Reliability Solutions**: Develop analytical tools and revise tariff and cost allocation rules to allow for solutions to reliability violations that are composed of transmission upgrades, new supply resources, or demand resources, or any combination thereof. Particular attention needs to be paid to low-cost upgrades to the smaller lines of the bulk power system that may be able to delay, or avoid entirely, large new transmission lines.

Enhancements to the planning processes will provide PJM with additional analytical tools to better assess future bulk power system needs and to target investments in resources and infrastructure in the most economical manner. A robust 21st-century planning process will help ensure that the safe, reliable operation of the bulk power system will continue, consistent with the requirements of state and federal policies, while achieving just and reasonable rates without undue discrimination. When environmental impacts are considered, support for these enhancements makes even more sense.

2. Background

In this section, we show how PJM's planning process is already being challenged by public policy drivers, including, most fundamentally, the delinking of economic growth from electricity demand. A falling load forecast, for instance, led PJM to conclude (after considerable advocacy) that a massive transmission upgrade, the PATH project, will not be needed for some time. The PATH story, alone, indicates a need to improve PJM's transmission planning process, a need which is further underlined by PJM's recent need to use "must run" agreements to manage two coal-fired power plants. Happily, PJM and the FERC are moving forward with reforms.

A. Traditional Planning and the Changing Power Sector

Transmission planning has traditionally been an occupation for transmission engineers, power system planners, and design professionals who have substantial expertise in all issues related to the generation, flow, transmission, distribution, and use of electricity. They have developed sophisticated systems to control and account for the electrical flow from energized wires. The bulk power systems that most of us can blissfully ignore are engineering marvels. Control areas are essentially a single big machine with interconnected parts that literally hum along 24 hours a day, each and every day.

These machines, such as the PJM Interconnection (PJM), have evolved over the years to become more internally and externally integrated. Large geographic areas pool their resources to improve efficiency through economies of scale, avoided redundancy, and competitive markets for procuring electrical services. The planning processes for these bulk power system machines has historically focused on projecting future energy demand and peak loads, assessing known resources and assumed additions, and running models to see if the poles and wires could support all the necessary transactions between resources and loads. Over time, forecasting peak load and annual energy demand became a standardized, predictable exercise, with the largest uncertainty being daily and seasonal weather variations.

However, many of the historical certainties related to system planning are much less certain today.

1. Decoupling Electricity Demand and Economic Growth

The core historical trend that is driving the need to reform bulk power system planning is the decoupling of electricity use from economic growth, as the two figures below illustrate.

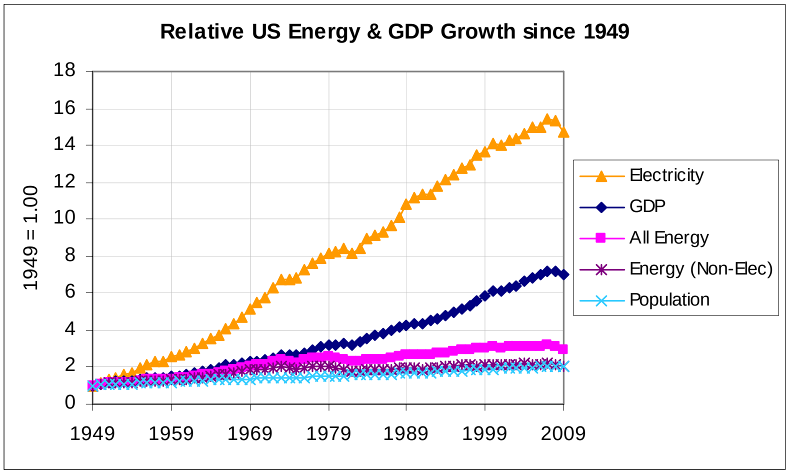

Figure 1. Relative U.S. Energy & GDP Growth since 1949

Figure 1 shows that historical constant load growth in electricity consumption has been slowing since the mid-1970s. Taking the two 30-year periods shown on the graph, during the first 30 years (1949-1979), electricity consumption increased by a factor of four. Over the next 30 years (1979-2009) electricity consumption increased by a factor of two.[4] This change in annual growth rates roughly coincides with the increase in commodity fuel costs since the first oil embargo in 1973. Partly as a response to prices and partly as a result of specific programs and policies, energy use and electricity consumption growth rates are starting to flatten. As a consequence, energy intensity values improve as less energy (and electricity) is needed to produce a unit of gross domestic product (GDP).

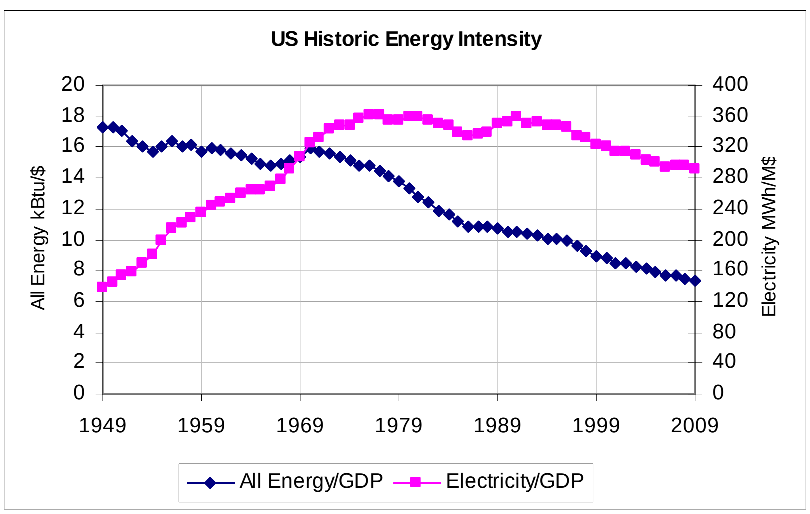

Figure 2. U.S. Historic Energy Intensity

[4] Later, in Section 4, we will show how recent trends will slow the growth in electricity consumption even more.

Figure 2 illustrates this improving trend by comparing the amount of energy we consume with the quantity of goods we produce. Energy intensity (the measure of how much energy is needed to produce a widget, heat a building, and so on) has been improving under both the "all energy" metric and the "electricity only" metric. An improvement in energy intensity helps insulate our entire economy from future price shocks in commodity fuels (oil, coal, gas, uranium, etc.) because the ripple effect of the commodity price increase is muted. If we are able to use less energy in our production of goods, our buildings, our vehicles and so on, an increase in commodity fuel prices has less of a compounding drag effect on the overall economy and personal incomes.[5]

These improvements in energy consumption and energy intensity remove some of the urgency that transmission planning processes have historically tried to address. The planning procedures and criteria that evolved during the last half of the 20th century were developed to respond to constant, rapid load growth. Economic recessions were never anticipated in planning forecasts; electrical load grew every year at a straight-line defined rate into infinity. Economic growth meant even more rapid growth in electrical consumption. Initially developed as "light companies," electric utilities became refrigeration, heating, cooling, and, most recently, entertainment providers (via electronic devices such as televisions and computers). Over-estimating load growth and over-sizing transmission infrastructure were really only issues of timing. If load growth slackened due to poor economic conditions and the planned transmission upgrade seemed a bit excessive upon completion, there was no need for recrimination. In a few years, load growth would bounce back and the "unnecessary" or "oversized" upgrade would be just what was needed.

That time has passed. It is critically important that transmission planners recognize the new trends in technology and resources for bulk power system planning. If they do not, they will over-estimate electrical demand and related reliability needs, resulting in an over-built and overly expensive transmission system. They also need planning models that can respond flexibly to other system changes—such as retiring generators or new demand and renewable resources.

Indeed, the old transmission paradigm may be eroded even more quickly as more direct public policies kick in. These trends of increasing efficiency and renewable resources are occurring without an explicit carbon price adder that would only act to accelerate these trends. Nor do these historical trends fully reflect recent efforts to accelerate them through government policies on efficiency programs, demand response implementation, targeted renewable and distributed generation resource additions, more rigorous air and water standards to safeguard our health, and nascent efforts to deal with greenhouse gases. The old bromide that transmission system upgrades not necessary today will be essential in a few years may need to be revised to: transmission upgrades that are not essential today may not be needed for many, many more [redacted].

[5] A simple example is an employee at an automobile factory. Using less energy to manufacture a car makes the car price less dependent on energy prices. If the car is also more fuel efficient in operation, the worker (assuming he purchases the car) will be impacted less by an increase in gasoline prices. If the worker's home is made more efficient with a comprehensive energy retrofit, the worker's annual heating, cooling, and overall electricity costs will be less volatile if energy prices increase. In sum, the worker may need less of a pay increase (due to transportation and home energy savings) when energy prices rise and the automobile company will have more competitive products to sell at home and abroad. As energy intensity values decrease, there are multiple beneficial economic impacts.

2. Other Technological and Policy Changes Further Alter the Traditional Paradigm

Other shifts further challenge traditional notions of transmission planning. These changes, which are driven both by public policy and by market-based innovation, include major state and federal initiatives that will significantly alter resources available to transmission operators. These policy initiatives will directly or indirectly impact traditional planning assumptions regarding future loads, existing and new resources, and the system infrastructure needed to support these developments while ensuring a reliable grid. Such policies include renewable portfolio standards and energy efficiency programs.

They also include, most notably, major EPA initiatives to address air emissions, water quality, and waste disposal for fossil generation (as well as industrial fossil uses). These new regulations, long-mandated by statute but also long-delayed, will impose long-deferred pollution control costs on certain classes of generation. Based on industry estimates, many generators may decide that it is uneconomic to upgrade and operate a substantial number of their coal units, and choose to transition to cleaner energy sources rather than invest in pollution control equipment at these facilities. The national estimates vary substantially, but a quantity of between 20 to 80 gigawatts (GW) of coal generation could be affected. The EPA is rolling out draft rules throughout 2011, which are expected to be in effect in the 2014 to 2015 timeframe. This near-term wave of likely coal retirements presents PJM, and other grid operators, with a major planning challenge, which is qualitatively different from the sporadic retirements PJM previously addressed.

These major changes are complemented by many other shifts, including:

- A greater technical ability for customer loads to vary and market incentives to control and sell those variations as a balancing service.
- Incentives for improved efficiency in all electrical uses, including industrial equipment and appliances, heating and cooling, lighting, and electronics.
- Growing market share for small-scale power generation, which in some circumstances is directly subsidized through government policies; these resources are often seen and modeled as reduced demand because they are behind a customer's meter and are a substitute for grid electricity.
- Growing use of variable energy resources such as wind, solar, and tides that are capable of providing substantial amounts of clean electricity, but which have a different, and possibly greater, need for balancing resources than traditional fossil and nuclear generation.

There is also an explosion of new technology to monitor, measure, coordinate, and aggregate all of the changes above and make the bulk power system a more dynamic interaction of variable loads and variable generation. These technology enhancements may be in the form of chips in appliances, lighting, and motors; new software applications to control and coordinate those chips; enhanced customer meters that directly communicate with the distribution utility; enhancements to both transmission and distribution system information and control technologies; control technology for major energy uses; and other applications not yet developed.

3. FERC Recognizes the Need for Change

FERC's recent rulemaking on transmission planning and cost allocation includes a proposed rule that would require planning authorities, such as PJM, to include assessments of the impact of state and federal policies on future upgrades to the bulk power system. These impacts are so substantial, according to FERC's proposed rule, that addressing them is necessary to fulfill an RTO's basic obligation to provide for just and reasonable rates.[6]

Specifically, FERC stated:

> [W]e propose to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by State or Federal laws or regulations that may drive transmission needs. After consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by State or Federal laws or regulations… [W]e propose to require each public utility transmission provider to coordinate with its customers and other stakeholders to identify public policy requirements established by state or federal laws or regulations that are appropriate to include in its local and regional transmission policies."[7]

The Commission is expected to issue an Order with the final rule language later this year.

Thus, rather than the old approach of continued expansion of the system to keep up with escalating demand, the urgency today is to develop processes to model the bulk power system over a range of new, dynamic parameters (variable loads, alternative resources, and new technologies) to identify the critical infrastructure enhancements that need to be made to accommodate the likely futures that our policy decisions will produce. There will be much less certainty to this type of system planning: straight line growth rates will be replaced by ranges of growth; stressing the system will need to account for a more dynamic electric machine than the current static snapshot; and committing to large-scale transmission facilities based on predictions of future loads and resources will require more robust analyses. The cost-effectiveness of traditional transmission solutions needs to be re-examined in light of new resources and technologies that can support alternative solutions.

B. The PATH Project Demonstrates the Need for Reform

Issues associated with the PATH project underscore the need for PJM to enhance its planning procedures to include the impacts of new technologies, resources, and policies in order to provide better forecasts of future system needs and better tools to analyze potential solutions.

The Potomac Appalachian Transmission Highline (PATH) is a joint venture of American Electric Power (AEP) and Allegheny Energy to build a 765-kV, 275-mile transmission project from the Amos Substation located in Putnam County, West Virginia, to the proposed Kemptown substation in Frederick County, Maryland. Although PJM initially believed that PATH was soon necessary for reliability, a lower load forecast ultimately demonstrated otherwise.

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[6] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Docket No. RM10-23; 75 Fed. Reg. 37,884 37,893 ¶ 63 (June 30, 2010).
[7] *Id.*, at ¶ 64-65.

In December of 2007, PATH LLC filed a proposal to be included in the PJM Open Access Transmission Tariff (OATT) to implement a transmission cost of service formula rate and incentive rate authorizations for the PATH project.[8] PJM's reliability analysis for the 2007 Regional Transmission Expansion Plan (RTEP), its annual regional transmission plan, determined that the year of need for the PATH upgrade was 2013. The PJM Board approved the inclusion of the 765-kV PATH line in the 2007 RTEP in November of 2007 to resolve violations of national and local standards for reliable operation of the region's transmission system.[9]

After the 2007 RTEP, PJM continued to identify the need for the proposed PATH project in every subsequent annual Regional Transmission Expansion Plan (RTEP), including the most recent 2010 RTEP. However, a re-evaluation by PJM in December of 2009 showed that the year of need for PATH had moved beyond 2014.[10] PJM specifically referenced analyses based on demand response resources that had cleared the May 2009 BRA (for delivery in power year 2012 – 2013) as a significant factor in moving the date of need beyond 2014. The 2009 RTEP (published in February of 2010) still had a date of need of 2014 for PATH. In the 2010 RTEP, the date of need is stated as 2015.

In connection with a Virginia State Corporation Commission proceeding reviewing the need for PATH, PJM was ordered to conduct a series of analyses based on the most recent economic forecasts, demand response commitments, and new generation resources in the queue. When PJM re-evaluated the PATH project in early 2011 based on a new load forecast received in late 2010, preliminary results revealed that the expected reliability violations that necessitated the PATH project "have moved several years into the future."[11] Based on these findings, on February 28, 2011, PJM directed sponsoring Transmission Owners to suspend their development efforts on the PATH project while PJM conducts its rigorous analysis of the potential need for PATH. This directive, however, did not require cancelation of the PATH project. The 2010 RTEP (published in February of 2011) still shows a date of need of 2015 for the PATH project. [12]

Table 1 shows the annual RTEPs, their dates of publication, and the status of PATH. We have also noted the two re-evaluations that led to changes to the "date of need" for PATH.

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[8] Potomac-Appalachian Transmission Highline, LLC, Request for Hearing. Docket No. ER08-386-000; Potomac-Appalachian Transmission Highline, LLC, Update on Status of Project Docket No. ER08-386-000, March 7, 2011.

[9] PATH Press Release, February 28, 2011, "PATH Seeks to Withdraw Applications for Electric Transmission Project. Regional grid operator directs suspension of PATH project."

[10] PJM Steven Herling letter to PATH, Inc. December 28, 2009.

[11] Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers. Planning for Transmission in the 21st Century. February 28, 2011; Potomac-Appalachian Transmission Highline, LLC, Update on Status of Project Docket No. ER08-386-000, March 7, 2011.

[12] PJM presentation to TEAC on Market Efficiency Analyses, May 12, 2011, slide 3, shows no need for PATH out to 2025.

Table 1. PJM PATH Analysis History

	Published	PATH	Date of Need
RTEP 07	Feb. 2008	√	2013
RTEP 08	Feb. 2009	√	2013
RTEP 09	Feb. 2010	√	2014
VA Commission request to re-evaluate Dec 4, 2009	Dec. 28, 2009	√	2015
RTEP 10 approved by PJM Board in November 2010	Feb. 2011	√	2015
PJM revised loads Dec 2010 and new generation Jan 2011	Feb. 28, 2011	suspended	2018-2025

The PATH story and timeline illustrate three important lessons for 21st-century planning processes. First, the year of need was very sensitive to assumptions about future loads, demand resources, and the interconnection of new generation. The 2009 capacity auction results (with a large quantity of demand response resources clearing) were not a surprise to many stakeholders, but caught PJM planners off-guard. The 2010 changes to the load forecast were also not a surprise to some stakeholders who closely monitor economic trends.[13] The result of these inputs that shifted the PATH project's year of need at least five years into the future demonstrates the need for better forecasting approaches for all of the many inputs into the power flow models.

The second important lesson is the need for a continuous planning process that frequently updates the analyses. Although it took some prodding from a Virginia Hearing Officer, PJM ultimately responded to the new information by revising the inputs to its models and re-evaluating the results from earlier analyses. Re-evaluations are particularly important when the number of variables in the power flow models increase and when the variables themselves are uncertain. As discussed earlier, new types of resources, policy initiatives, and technology changes are contributing to this expansion of inputs and their unpredictability.

The third important lesson that the PATH example provides is the need for PJM to consider timing issues related to its RTEP reports. PJM's 2010 RTEP, published in early 2011, is based on a load forecast from 2009. It does not include capacity auction results from May 2010. In these respects, the 2010 RTEP was one to two years out of date when it was published. PJM addressed this issue for the 2010 RTEP by placing numerous "green boxes" in relevant sections of the report. The green boxes were used to reflect the revised load forecast and the fact that PATH construction

[13] Direct Testimony of James F. Wilson on behalf of Commission Staff, Case No. PUE-2009-00043, December 8, 2009, before the Virginia State Corporation Commission

has been halted, even while much of the regular text in the 2010 RTEP discusses how the planning process shows that PATH is still needed by 2015.

C. The Coming Wave of Coal Plant Retirements and RMR Contracts

Just as the PATH experience demonstrates that PJM's process for identifying transmission solutions needs improvement in the face of changing demand, PJM's experience with coal power plant retirements raises serious concerns about the existing system's ability to accommodate these retirements cost-effectively. The two issues are linked: If PJM over-estimates the need for transmission solutions to address reliability problems, including problems caused by generator retirements, it will be less able to accommodate retirements on short notice.

1. Issues with RMR Contracts

PJM requires generators to give only 90 days' notice before they retire—and requires PJM staff to respond with a reliability analysis within 30 days. These timelines are prohibitively short; PJM will struggle to produce a meaningful analysis in that period, and will certainly be unable to implement any reliability solution. The result, all too often, will be reliability must run (RMR) contracts, paying to keep plants open while PJM works to resolve any reliability issues.[14] In those cases, the units retained for reliability are allowed to receive compensation at above-market prices to support their continued operation as RMR units. Importantly, an RMR contract may be used even if generators provide more than the required 90-day notice to PJM—but the odds of such contracts increase as the notice period shrinks.

RMR contracts generally impose extra costs on consumers who must support the continued operation of these uneconomic units. They thus divert ratepayer resources away from initiatives that provide long-term, more cost-effective solutions in order to manage a reliability problem in the short-term.

RMR units also impair the functioning of competitive markets. The impairment occurs because RMR units are not allowed to set the clearing price in the energy market (that is, they are price-takers) even though their RMR payments may be higher than the clearing price. The RMR costs are generally socialized to all market participants purchasing power in the energy market as an uplift charge. Uplift charges usually distort the pricing signals that the market clearing price is supposed to provide. The RMR units could be displacing units that have less costly offers, but which are still higher than the clearing price. But for the system constraints that required the RMR contract in the first place, those other units would be dispatched instead of the more costly RMR unit and provide a more accurate and efficient clearing price value.

In 2003, FERC emphasized the detrimental effect of RMR contracts in an Order responding to RMR contracts in New England (the Devon case).[15] The Commission stated:

> "RMR contracts suppress market-clearing prices, increase uplift payments, and make it difficult for new generators to profitably enter the market . . . [E]xpensive generators under RMR contracts receive greater revenues than new entrants, who would receive lower

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[14] The severity of the reliability violations can influence the length and terms of the RMR agreement.
[15] Docket No. ER03-563, April 25, 2003, at ¶29. The Devon case and the RMR agreements associated with it were the direct precursors to the Forward Capacity Market settlement agreement reached in 2006 between New England stakeholders and ISO New England.

revenues from the suppressed spot market price. In short, extensive use of RMR contracts undermines effective market performance. In addition, suppressed market clearing prices further erode the ability of other generators to earn competitive revenues in the market and increase the likelihood that additional units will also require RMR agreements to remain profitable."

The size and severity of the RMR impacts helped persuade the Commission to reject ISO New England's then existing capacity market structure and order the development of an alternative market design.

2. Existing RMR Contracts in PJM

Two Exelon plants in the PJM footprint in Pennsylvania demonstrate the damaging effects of the excess costs caused by RMR agreements.

Cromby Unit No. 2 (Cromby) is a 201-MW peaking unit running on either natural gas or fuel oil, and Eddystone Unit No. 2 (Eddystone) is a 309-MW coal unit. Both units are operated by Exelon Corporation. Both of these units failed to clear in the PJM capacity auctions for the 2011/2012 and 2012/2013 delivery years.[16] On December 9, 2009, Exelon provided notice to PJM of its intention to deactivate Cromby and Eddystone, effective May 31, 2011. Exelon explained that its deactivation decision was based on the uneconomic continued operation of the units due to their age and the costly investment needed to meet environmental regulations.[17]

PJM conducted a deactivation study and concluded that Cromby and Eddystone were needed beyond their requested deactivation date for reliability purposes, pending the completion of transmission upgrades. According to PJM, Cromby is needed through May 31, 2012 and Eddystone is needed through December 31, 2013.[18]

Exelon agreed to continue operation of Cromby and Eddystone in return for an RMR agreement. On June 9, 2010, Exelon filed a proposed RMR rate schedule according to which Exelon would recover its costs of operating Cromby and Eddystone beyond May 31, 2011 through a three-part cost of service rate. The three parts include a monthly fixed-cost component to recover capital and fixed costs through a traditional cost of service mechanism, a project investment tracker mechanism to recover Exelon's actual investment costs associated with emissions controls, and a variable cost reimbursement mechanism to recover Exelon's variable fuel, emissions, chemicals, auxiliary power, and incremental insurance costs.

Exelon's proposed cost of service rate is based on an annual revenue requirement of $31.7 million for Cromby and $96.6 million for Eddystone.[19] There is no certainty that the Commission will approve the requested annual recovery for each of these units.[20] Nonetheless, all the payments

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[16] Those auctions occurred in May 2008 and 2009, respectively.
[17] FERC Docket No. ER10-1418-000, Order Accepting and Suspending Tariff Filing, Subject to Refund and Establishing Hearing and Settlement Procedures at ¶ 4, Issued September 16, 2010. Available at: http://www.ferc.gov/whats-new/comm-meet/2010/091610/E-11.pdf
[18] *Id.*, at ¶ 5.
[19] *Id.*, at ¶ 9. The Cromby value of 31.7 million includes $154,053 requested for the Cromby Diesel unit, a small diesel generator that is used to start the larger Cromby unit.
[20] *Id.*, at ¶ 22. One contested issue in the proceeding is the amortization of investments over the remaining life of the units. The PJM Market Monitor has requested more information to justify the 36 month and 24 month

ultimately approved can be considered excessive costs. Because neither unit cleared PJM's capacity auctions for the 2011/2012 or 2012/2013 delivery years, neither unit is providing a capacity service through PJM's capacity market. PJM has purchased other units in those auctions to satisfy its capacity requirement. Pursuant to the RMR operating agreement for these two units, they are both prohibited from participating in any future PJM capacity auctions.[21]

Even without evaluating energy market uplift costs, these two units impose excessive costs on consumers because consumers have purchased all the necessary capacity through the PJM capacity market **and** they will pay the full RMR contract costs for the Cromby and Eddystone units. These RMR contract costs could be entirely avoided if the units retired. PJM is optimistic that transmission upgrades will allow Cromby to retire in May of 2012 and Eddystone to retire in December of 2013, but the operating agreement allows for additional RMR payments (terms to be determined) if either unit is still needed. Table 4 below shows the excess cost to consumers for the Fixed Cost portion if the proposed recovery is approved by the FERC.[22] The excess costs do not include the "project investment tracker" costs, which are unknown at this time.

Table 2. RMR Payments to Cromby 2 and Eddystone 2

Unit	2011/2012	2012/2013	2013/2014	3-Yr Total
Cromby 2	$31,548,701	-	-	$31,548,701
Eddystone 2	$96,577,979	$96,577,979	$48,288,990	$241,444,948
			Total	**$272,993,649**

This is just the beginning: As noted in the Exelon presentation cited in this report that identified likely retirements of its coal units, Exelon anticipates the economical retirement of 11 GW of its coal plants in PJM.

Given the much larger quantities of resources that may seek deactivation in the coming years due to EPA's efforts to reduce the unhealthy impacts of fossil fuel generation, PJM needs better planning criteria to identify these at-risk resources and develop least-cost solutions. Cromby and Eddystone represent less than 5% of the uneconomic resources that Exelon alone may retire.[23] Without improvements to the planning process, PJM (and other planning authorities) will have little choice but to enter into RMR agreements with more and more resources. As demonstrated by the Cromby and Eddystone examples, these RMR agreements are likely to impose substantial

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depreciation schedules for Cromby and Eddystone respectively. It is that uncertainty (how long the plant will operate) that contributes to the controversy about the appropriate annual dollar recovery to charge to consumers.

[21] *Operating Procedures for Cromby Generating Station Unit No. 2 and Eddystone Generating Station Unit No. 2 as Required for Reliability*, May 27, 2010 at page 3, section 2.b. Available at: http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/must-run-operating-procedures.ashx.

[22] These are "excess costs" because consumers are already paying for all the necessary capacity to replace these units, and any energy production (if the units are ever needed to run) will be separately compensated through the variable component of the RMR agreement.

[23] Exelon presentation by President Chris Crane to EEI Financial Conference, November 2010, slide 4, states that approximately 11,000 MW of coal units in the PJM footprint subject to new EPA regulations could retire.

excessive costs on consumers until the necessary infrastructure improvements can be implemented to allow the retirement of the units.

D. The EIPC Process

Many state regulators and industry stakeholders are beginning to address the challenges associated with the shifts away from traditional transmission planning.

In particular, the Eastern Interconnection Planning Collaborative (EIPC) received DOE funding to consider future electric system resources and transmission infrastructure options for 2030. It involves market participants and other stakeholders from 40 states with a special role in the process for state regulators as the Eastern Interconnection States Planning Committee (EISPC). The Stakeholder Steering Committee is composed of 29 delegates who participate in a collaborative decision-making process. The Steering Committee is supported by caucuses of additional representatives from all segments of the electric power industry: generators, transmission owners, marketers, alternative resource providers, municipal utilities, end user organizations, environmental organizations, RTOs, and state regulators. Through three primary working groups (2020 Rollup, Modeling, and Scenario Planning) the EIPC effort will analyze a wide variety of future combinations of resources and policies.

The EIPC goal is to evaluate eight resource futures with nine sensitivities each (a total of 72 different analyses). Ultimately, the Steering Committee will select three alternative build-out scenarios for 2030 based on the modeling results. The resource futures and sensitivities cover federal and state policy options, a wide range of fuel prices, large renewable development, a nuclear renaissance, a low carbon future, a carbon-sequestered coal future, and many other potential developments. The 2020 Rollup process revealed that the dozen or so large planning authorities in the eastern interconnection have very different approaches, use different assumptions, and produce results that are difficult to compare and reconcile between one region and another. The EIPC process is almost to the halfway point of the work funded by DOE. The Regional Rollup is finished, the decisions on resource futures to model have been made, and the modeling results for three of the futures are well underway.

In its interconnection-wide process, EIPC is addressing some of the same issues raised in this report that are under discussion in the PJM stakeholder process (see next section).[24] Because PJM is the largest RTO in the eastern interconnection and has a major role in the EIPC process, it is possible, perhaps likely, that the resolution of some issues and the development of new analytical tools in the EIPC collaboration could be transferable to PJM's planning processes.

E. PJM Planning Process Reforms

To address numerous planning issues, including those raised by the PATH project and reliability must run contracts, PJM initiated a stakeholder process in June of 2010 to consider reforms to its planning process. The Regional Planning Process Task Force (RPPTF) was chartered to review PJM's planning process and criteria in order to develop recommendations for appropriate changes to refer to the PJM voting committees. Several PJM presentations to the RPPTF have stated that

[24] The common issues include how to estimate future loads, the impact of state and federal policies that address demand resources, renewables, carbon reductions, and clean air/water rules.

this effort is a priority established by the PJM Board and that the Board is fully committed to file proposed changes with the FERC by the end of December 2011.

In March of 2011, PJM provided a straw proposal, addressing possibilities for integrating public policy into transmission planning, for stakeholders to consider. The purpose of the straw proposal is to set out some initial options and invite comments from PJM stakeholders. In Section 5 we discuss the Regional Planning Process Task Force process in more detail. In general, we find the RPPTF very encouraging: it demonstrates the seriousness with which PJM takes the challenges before it. Many of the recommendations we make later in this report amplify proposals already presented in the RPPTF straw proposal.

3. Overview of PJM's Transmission Planning Practices

To provide context for our recommendations in this report, we briefly review how PJM's transmission process works now.

PJM uses a comprehensive transmission planning process that produces an annual report (Regional Transmission Expansion Plan, or RTEP). The yearly RTEP report is essentially an update of the previous RTEP to reflect changes that have occurred (including changes to load forecasts, generation additions or retirements, new transmission projects, new rules and regulations, etc.). The planning process is governed by sections of the PJM OATT, Operating Agreement, Manuals and other documents. In this section we provide an overview of PJM's planning process with references to the appropriate controlling documents.[25]

PJM uses the Figure 3 graphic to represent the RTEP transmission planning process and some recent proposed modifications. Each box identifies a key part of the overall RTEP process, which moves essentially from an initial baseline reliability analysis through identification of potential upgrades, and ranking of those upgrades, followed by overall testing for compliance with basic reliability standards with those upgrades in place, before the cycle starts again. The middle two boxes, Market Efficiency Analysis and Public Policy Analysis, represent PJM's proposal for sensitivity analyses that would feed into a process to optimize RTEP upgrades (the Public Policy Analysis, of course, would be new). The optimization process is not entirely new, but PJM is proposing new elements that might go into that optimization process such as upgrades for reliability retirements, upgrades for a critical mass of projects, or upgrades as part of a "cluster review" to enable the delivery of renewable energy resources.

[25] Most of this section is covered by Manual 14B

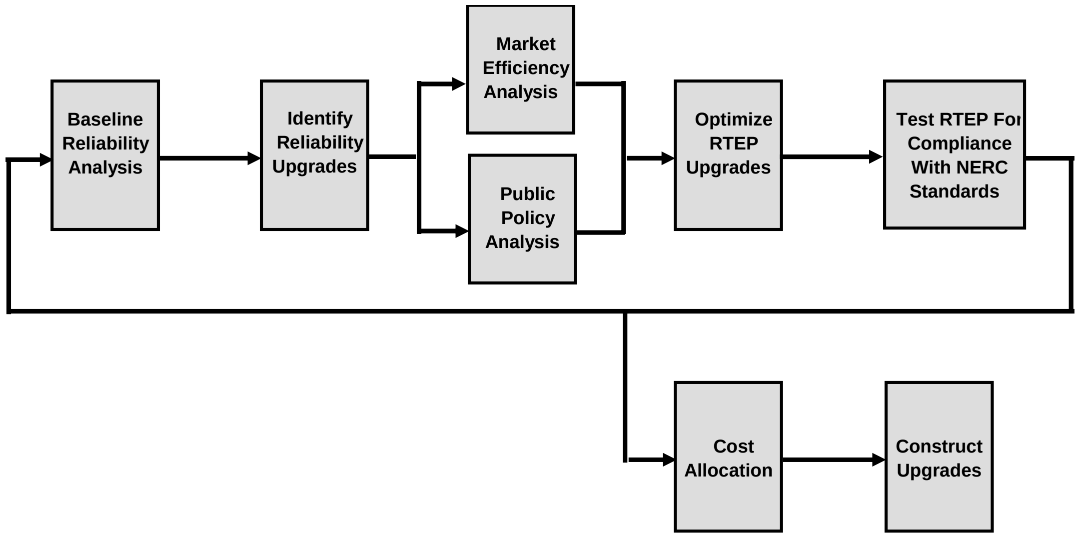

Figure 3. PJM RTEP Process

PJM uses the Figure 4 graphic to represent the fundamental issues that system planning processes try to address. There is a window of time, sometimes short and sometimes long, before reliability violations actually occur. The goal of the system planning process is to identify the potential violations, estimate the timeframe to address them, and then develop and implement solutions before the reliability violations occur, or, second best, before they become severe. PJM relies on a specific violation by a specific date (a "bright line" test) to trigger an analysis of options and the selection of a solution. This effort to find a bright line violation selects a point on a continuum of growing certainty that a reliability violation will occur, as the graphic shows.

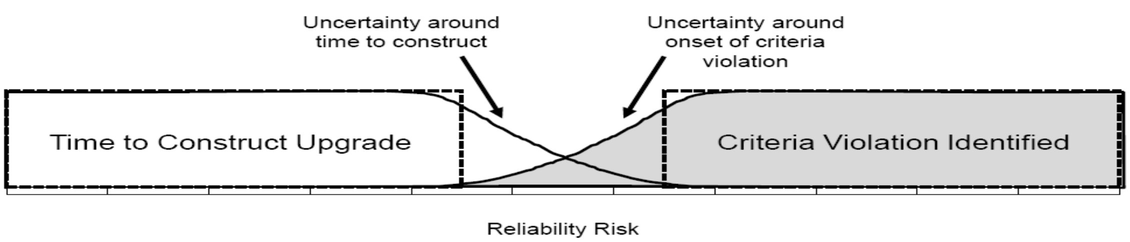

Figure 4. Uncertainty in System Planning

It is helpful to think of Figure 3 as representing all the processes that PJM proposes to utilize in order to address the uncertainty shown in Figure 4.[26] The first step in transmission planning is to establish a baseline analysis of existing system conditions. This analysis uses annually updated load forecasts, committed resources, and firm transmission service requests to test the ability of

[26] PJM has developed numerous variations of these two graphics to illustrate options for the RTEP planning process in materials for the RPPTF. We have included several of them in Appendix A.

the currently planned system to satisfy all applicable planning standards (NERC, regional reliability standards, PJM reliability standards, PJM design standards, and Nuclear Licensee requirements). The baseline analysis will identify system enhancements needed to meet reliability and other standards. The baseline analysis also serves as the starting point for evaluating any proposed additions of new generation or merchant transmission projects.[27]

The annual baseline update provides the platform for expanding the reliability analysis over a 15-year period. Maintaining a safe and reliable system that meets the needs of its transmission customers is PJM's most fundamental responsibility. To meet that responsibility, PJM develops a near-term (5y) analysis based on power-flow modeling. PJM then uses the five year results to produce a long-term (15y) reliability analysis.[28] Each overall analysis consists of multiple steps that utilize specific criteria applicable to each step.[29]

PJM annually conducts extensive power flow modeling of its transmission system for the five-year-out reliability analysis, and later points in time up to fifteen years out (through extrapolation). All the analyses are designed to identify reliability violations[30] and suggest transmission solutions to resolve those violations. The analysis process does not explicitly seek out least-cost solutions to reliability concerns, but rather is focused on determining the transmission solutions that resolve the identified reliability violations. PJM is cognizant of the importance (and potential economic benefit) of demand-side and supply-side alternatives for resolving reliability violations, but consistently notes that its ability to authorize reliability solutions is limited to transmission, and not demand-side and supply-side options.

The modeling process includes analysis of existing and certain proposed generation availability to help inform the expected value of generation within local deliverability areas (LDAs) used in the modeling process. It also requires load inputs (primarily peak load values) and a defined transmission topology. Load inputs include, to a limited extent, the effect of peak load reduction arising from energy efficiency programs; and to a less limiting extent, the effect of peak load reduction arising from demand response programs. Defining transmission topology includes accounting for planned and approved transmission system reinforcements expected to occur over the near-term (5y) period.

PJM stresses its transmission system through this modeling process. PJM chooses input parameters that reflect underlying assumptions about load, generation, and the transmission delivery system that exists or will exist in the relevant year. The primary focus is the five-year window, e.g., the recently completed 2010 RTEP process focused on the requirements to meet reliability criteria for 2015, using 2015 inputs for load, generation, and transmission topology.

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[27] Manual 14B at p. 23-24

[28] A power flow analyses uses a model with specific assumptions about loads, generation, and transmission. PJM uses the five-year power flow model results to extrapolate results for the longer-term analysis (years 6-15). PJM does not do power flow modeling for years 6-15.

[29] Id., at 24

[30] A reliability violation in general is a violation of NERC reliability criteria, and represents an indication that the transmission system will not be able to reliability deliver power to load under certain defined circumstances. These circumstances usually represent extreme and/or contingency conditions, as defined through input parameters to the power flow models. Common reliability violations that require mitigation include thermal overloading of lines or transformers, and voltage collapse. The violations occur within the modeling process.

Two of the primary power flow tests conducted by PJM to assess reliability requirements are the Load Deliverability test and the Generation Deliverability test.[31] The results of these tests indicate where and when thermal reliability violations are anticipated on the PJM system. Along with an assessment of voltage violations under designated planning criteria, these tests make up the core of PJM's baseline reliability assessment. As a result of these tests, PJM proposes transmission system improvements to resolve the reliability violations. This is the process PJM used, for example, to determine the reliability need for several recent large transmission projects.[32]

The input parameters used with these tests will determine the extent to which the output of the tests indicates reliability violations that require upgrades to the transmission system. To the extent that load input parameters do not reflect the full complement of energy efficiency and demand side resources, the tests will overstate the need for new transmission resources. Similarly, to the extent the tests do not adequately consider the availability of generation resources in PJM regions that historically require transmission support to import power during peak times, the tests will overstate the need for transmission resources. If the tests use a transmission topology that does not include certain transmission system elements that may be in place, the results will again overstate the need for new transmission system resources. While the converse is also true—transmission needs will be underestimated if load is too low, or (e.g.) eastern PJM generation assumptions are too high—in practice our experience is that PJM uses input assumptions that in general are conservative, i.e., would be more likely to result in an overstatement of transmission need than an understatement of transmission need.

A. Near-Term Analysis

The near-term reliability analysis identifies criteria violations based on iterative contingency analyses that model the bulk power system under a variety of conditions.[33] The contingency analyses will identify various violations or near-violations that will be addressed through short-term remedies or referred to the long-term analysis process for more robust solutions. Since each new RTEP analysis is fundamentally an update of prior RTEP analyses, PJM is able to closely monitor near-term violations and account for changes to the resource mix (additions or retirements) as well as the impact of transmission upgrades in making those assessments. If needed, PJM will issue "addendums" to its current-year RTEP reports at any time throughout the year.[34]

PJM's near-term reliability analysis process is comprised of seven steps:

1. A reference power flow case that uses annually updated information as inputs for a reliability analysis mode. The inputs include assumptions about current loads, installed resources, transmission and generation maintenance schedules, system topology, and firm transactions. Capacity auction results will be used to specify the amount and location of resources for the purposes of the modeling; resources that do not clear the PJM capacity market auction for the relevant years are not included in the models.

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[31] These are described in detail in PJM's Manual 14B, "PJM Region Transmission Planning Process". Current revision 17, dated April 13, 2011.
[32] Those large lines included TRAIL Susquehanna-Roseland, and PATH.
[33] For the methodology for determining system operating limits see Attachment F to Manual 14B.
[34] The PATH line was re-evaluated under this procedure; see Section 2.B of this Report.

2. A thermal analysis is done to ensure that line ratings are not exceeded under both normal (prior to a contingency) and emergency (after a contingency) situations. This analysis is based on a 50-50 load forecast which is then stressed with the loss of first one, and then a second, facility.[35]

3. A voltage analysis is done that uses the same contingency analyses as the thermal analysis to evaluate voltage changes due to the contingencies. A variety of transmission elements are held constant during the contingencies to determine violations for voltage drop and for absolute voltage level criteria violations. All violations are recorded and categorized as to type and cause.

4. A load deliverability thermal analysis is used to determine transfer limits within the PJM system. The goal is to have sufficient transfer capability to allow the delivery of adequate quantities of generation to each load zone under extreme weather (90-10) load conditions. The evaluation criteria for violations is no more than "one event failure in 25 years," a higher standard than the "one event failure in 10 years" that is used to evaluate generation reliability violations.[36]

5. A load deliverability voltage analysis uses a similar procedure as the thermal analysis to identify voltage violations. The specific voltage tests are the same as those used for the baseline voltage analysis.[37]

6. A generation deliverability test is used to ensure that the transmission system can deliver generation resources to defined areas under peak load conditions. This ability is measured under the same (N-1) and (N-1-1) contingencies as used for the baseline thermal analysis.[38]

7. A baseline stability analysis is conducted on an individual generator basis as part of each generator's interconnection study. On an annual basis, PJM reviews the stability impacts of roughly one-third of all generators, thereby achieving a full evaluation of all generation units every three years. The analysis includes a system evaluation under light load conditions, typically the most challenging and severe from a transient stability perspective. The analysis also includes an evaluation of the system under summer 50-50 peak load conditions.

The combination of these seven separate analyses is all included in the near-term analysis section of the RTEP. These analyses cover the current year plus five additional years.

B. Long Term Reliability Review

PJM conducts a longer term reliability review over a 15-year planning horizon and tests its assumptions with two power flow models: current year plus 15 years and current year plus 10 years. These power flow models identify reliability issues beyond the five-year baseline analysis. For violations that require solutions that may need to be implemented more than five years in

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[35] The 50-50 load forecast represents a 50% probability of a peak load. The removal of facilities is usually referenced as (N-1) and (N-1-1) conditions.
[36] Id., at 27 and Attachment C.
[37] Id. N-1 and N-1-1 describe two variations of the base case model. N-1 is the base case (N) with a single element removed (a transmission line or generator). N-1-1 is the sequential removal of two elements with an opportunity for the system operators to reconfigure the system in-between the two contingencies. A simultaneous loss of two elements is represented as N-2.
[38] Id. At 28 and Attachment C

advance, PJM can start to evaluate solutions. For violations that can be remedied in less than five years, PJM includes them in the appropriate baseline analysis for future RTEP reports.

Much of the longer term analyses utilize the same criteria as the near-term reliability analyses. The load deliverability analysis uses the 90-10 load forecast to provide a test of extreme weather. The generator deliverability analysis uses the 50-50 load forecast to review system performance over all peak hours.

PJM also performs market efficiency analyses with a variety of sensitivities to test for possible system enhancements that will improve overall market efficiency. The criteria and procedures for conducting these analyses are detailed in the Operating Agreement and Manual 14B. PJM's overall approach to sensitivity analyses is being evaluated in the current RPPTF meetings (next section) as part of PJM's effort to include public policy goals/rules in the long-term planning process. However, the ability of these analyses to actually impact decisions on future system enhancements is limited. The most recent RTEP states:

> "While sensitivity studies are contemplated in the RTEP, public policy issues such as those discussed in this section are not specifically identified in the Operating Agreement as transmission drivers and have not, therefore been considered actionable within the context of RTEP. *Only the results of PJM's bright-line test, performed in accordance with PJM's written procedures have been sufficient to support PJM's continued direction to construct transmission projects* such as PATH and MAPP.[39] [*emphasis added*]"

Despite the limitations of the sensitivity analyses, PJM remains committed to expanding and improving upon these analyses as a mechanism for evaluating public policy impacts.

4. Enhancements to PJM Transmission Planning

With this background, we turn to our recommendations. PJM has recognized that its current transmission planning procedures and criteria need enhancements to address the challenges of the 21st-century electric grid. In this section we identify three critical areas for improvements:

- Forecasting and Stress Testing
- At-Risk Generation
- Integrated Solutions

Importantly, PJM is already actively investigating many of the issues and approaches we discuss below. As noted in the background section, the Regional Policy Planning Task Force is considering a straw proposal that addresses improvements to PJM's forecasting approach, considers various ways to model at-risk generation retirements, and determines possible triggers for action by PJM and stakeholder groups to address any reliability violations PJM identifies. Thus, the enhancements discussed below could usefully be integrated into the straw proposal.

[39] 2010 RTEP, Section 4.0.5 at p.74.

A. Improved Forecasting and Stress Testing

As economic growth becomes steadily less dependent upon ever-growing electrical demands, and public policies integrate new resources into the mix, load forecasting and stress testing must evolve accordingly. We recommend that PJM ensure that its load forecast carefully account for these changes, including fairly valuing efficiency and demand-side measures that reduce overall demand, and new renewable and distributed resources that alter system planning needs. These are not small changes: Indeed, state policies designed to increase energy efficiency, if fully implemented, would alone reduce projected demand below PJM's current estimate by nearly 10,000 MW. PJM's stress testing approach in its reliability modeling should reflect these changes.

In this section, we address changes to load forecasting, to forecasts that address new resources, and to the underlying stress testing of the system.

1. Load Forecasting

Historically, load forecasts have varied slightly from year to year to reflect short-term economic trends such as periods of growth and recession, and long-term trends in energy intensity and technology. As we have discussed above, and as the PATH experience indicates, the historic association between economic activity and electricity demand is weakening, necessitating significant improvements to load forecasting.

PJM has relied on econometric forecasts for its load forecast estimates for several years.[40] PJM's recent experience with the slow economic recovery from the 2008 recession has called into question the usefulness of the primary econometric model PJM has relied upon in recent years. The model assumed a rebound to pre-recession levels of electricity consumption. The pace and size of the rebound has been much slower and smaller based on the actual data on peak loads and energy consumption. A report produced by ITRON documents the variations between different econometric models and suggests reasons why each model's forecasts have produced the divergent results.[41]

Part of what is occurring is a long downward de-coupling of economic activity from increased energy consumption. In Section 2.A we noted that the historical linkage between economic growth and increased demand for electricity was strong. Except for daily weather variations and economic cycles over several years, load forecasts projecting growth have generally been accurate; although, as noted in Section 2.A, demand projections have gradually outpaced actual measured demand.[42] Today, this relationship is becoming steadily more tenuous. There are many new components of economic growth that are not linked to increased consumption of electricity. For example, improved efficiency standards for lighting fixtures and appliances increasingly allow these basic necessities to be installed without increasing demand. New construction practices

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[40] An "econometric" forecast relies on various economic indicators to project electricity demand from trends in the economy as a whole. The other option for forecasting loads is to rely on estimates from each load-serving entity and then aggregating all the individual forecasts into a system forecast (with adjustments for non-coincident peaks and other factors). A concern with the aggregating loads approach is the consistency and the comparability of the data from numerous different load-serving entities.

[41] *Review of PJM Peak Forecasting Models,* Itron Inc., September 2010.

[42] Daily weather variations have a significant impact on overall system reliability as well as hourly operational challenges for system operators. Economic cycles have usually produced short-term reductions in consumption and then a rebound to previous long term growth rates.

allow for similar benefits. Cost-effective construction practices today can produce buildings that have a “net-zero” energy consumption. This can be achieved through the installation of power producing elements, such as combined heat and power heating/cooling systems, and photovoltaic systems, in combination with maximum insulation and air control features.

PJM should run sensitivities on the load forecasts to capture the relative impacts of variations in economic growth, energy efficiency investments, and the development of demand response and renewable resources. While uncertainty about the economic recovery and the implementation of state and federal policies may persist for years, PJM needs to develop the procedures for doing such an analysis. Energy efficiency and demand response products are important resources for PJM to address in this context. We discuss them in turn, recommending that PJM fully include these resources in its baseline load modeling.[43]

a. Energy Efficiency

Daily weather variations have a significant impact on overall system reliability as well as hourly operational challenges for system operators. Economic cycles have usually produced short-term reductions in consumption and then a rebound to previous long term growth rates.

PJM’s current approach for consideration of the impact of energy efficiency (EE) programs in the RTEP baseline reliability analysis is to include the EE resources that clear in its annual capacity auction for delivery three years in the future. PJM is considering modifications to this process because PJM knows that this approach does not reflect EE investments beyond the three-year capacity market horizon. In addition, there is substantial evidence that not all EE resources are offered into the annual capacity auctions. Uncertainty about precise program achievements three years in advance, the complexities of participating in annual capacity auctions, and the need to satisfy PJM measurement and verification (M&V) protocols all create barriers to maximum EE participation.

PJM has estimated the likely EE resources available based on current state program goals in the PJM footprint through 2025.[44] Figure 5 compares the Base Forecast to EE quantities from the annual capacity auctions (the dotted line just below the top line) and the EE quantities that PJM estimates that the state programs could deliver (the lower red line). The difference in 2025 is close to 10,000 MW. This is a 7 to 8 percent reduction in peak load—equivalent to the generation output of many power plants—that might defer reliability violations for multiple years.

[43] It is important to specify the purpose for which a particular load forecast is developed. A load forecast to establish quantities of capacity to be purchased in the annual RPM capacity auction is different from a load forecast for committing resources in the day-ahead energy market. For the capacity market, supply and demand resources can all contribute to meeting the anticipated annual summer peak load. For the day-ahead energy market, the load forecast needs to anticipate the quantity of resources needed each hour to match anticipated changes in load; for these purposes, passive demand resources need to be netted from the load estimates. And a significantly different load forecast would be used to dispatch the system in real-time as operators make moment to moment adjustments to match generation and load levels. A load forecast for system planning purposes will be distinct from other load forecasts. PJM should develop procedures to tailor load forecasts for the explicit purposes that they are intended to address. For planning purposes, this will require detailing all the assumptions that go into each load forecast such as baseline demand growth rates, the impacts of energy efficiency and demand response resources on those growth rates, the installation of distributed generation resources including combined heat and power facilities, and the impacts of variable renewable resources such as wind and solar.

[44] RTEP 2010, Sec. 4.1.3 at p. 77.

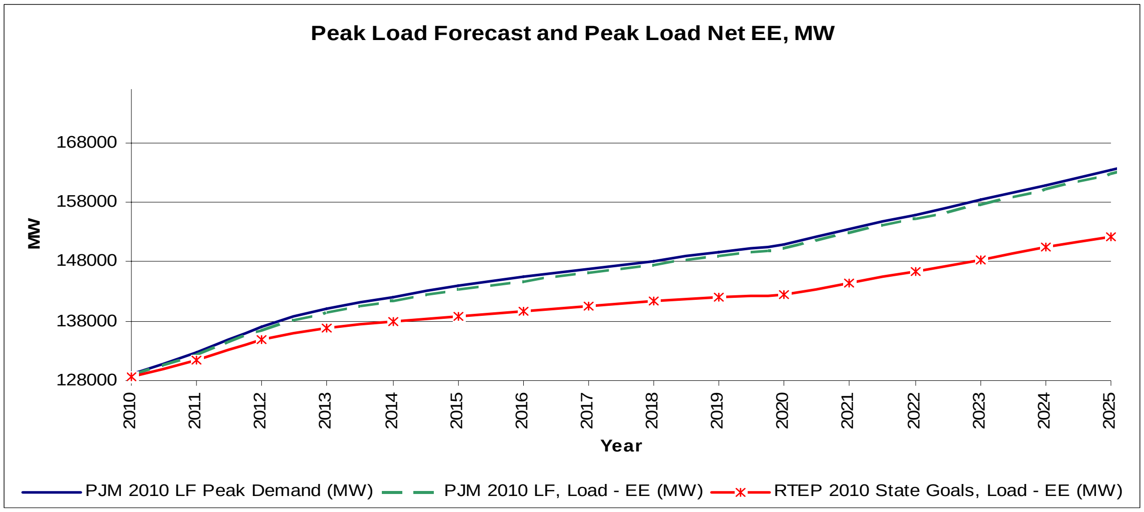

Figure 5. Peak Load Forecast and Peak Load Net EE, MW

Figure 6 (below) shows the same three lines as Figure 5 and then adds in current New England energy efficiency resources that participate in the capacity market (~1% annual energy reduction) projected to 2025 and MISO-states estimated average energy efficiency resources (~1.4% annual energy reduction). The MISO energy efficiency estimates reduce PJM's 2025 peak by 20,000 MW. If a "best practices" rate (~2% annual energy reduction) is applied, peak loads start diminishing in 2017.[45]

[45] See Appendix B for details on this analysis and a graph with the 2% annual savings value.

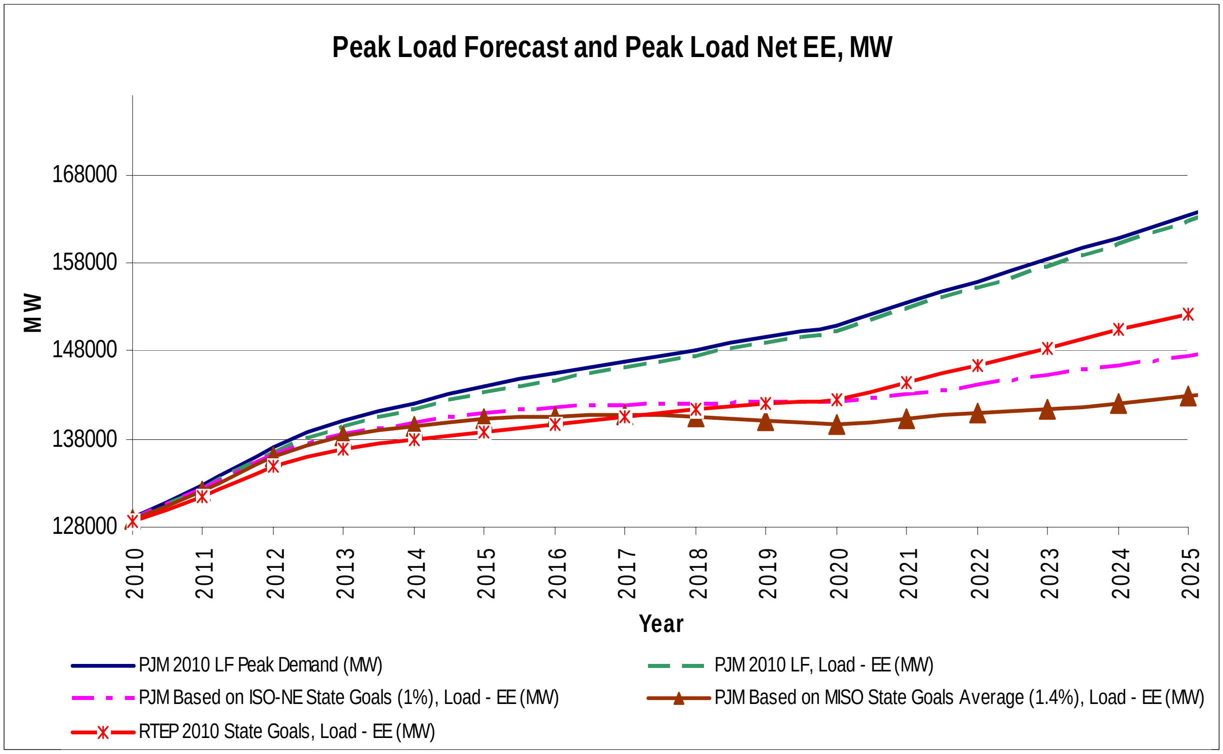

Figure 6. Peak Load Forecast and Peak Load Net EE, MW

PJM should account for the effect of *all* anticipated energy efficiency when estimating peak load inputs to the power flow modeling used in the determination of baseline reliability requirements.

Yet even these PJM estimates may understate the impact of cost-effective energy efficiency investments. Some efficiency gains may be achieved through codes and standards. One of the best examples is the discontinuation of the sale of most incandescent bulbs, to be replaced with compact fluorescents and light emitting diodes (LEDs). Similar impacts may come from appliance standards and new construction codes. These efficiency gains will impact load forecasts by reducing peak loads. They will also impact power flow models by lowering annual energy consumption over a wide range of hours.

The impacts of state energy efficiency policies alone can produce significant reductions for planning models. PJM should include the effect of 100% compliance with these policies in its baseline modeling, with sensitivities above and below those values to account for uncertainty.

b. Demand Response

The ability of system loads to vary their demand has been increasing at an accelerating rate. As a result, demand response resources have been providing reliability benefits as capacity resources for several years through RTO/ISO programs with increased participation each year. Demand response resources may soon be providing substantial quantities of daily energy reductions through direct wholesale energy market participation.[46]

Demand response resources (active demand resources) participate as capacity resources in PJM.[47] The most recent capacity auction shows the continuation of annual growth for these resources.

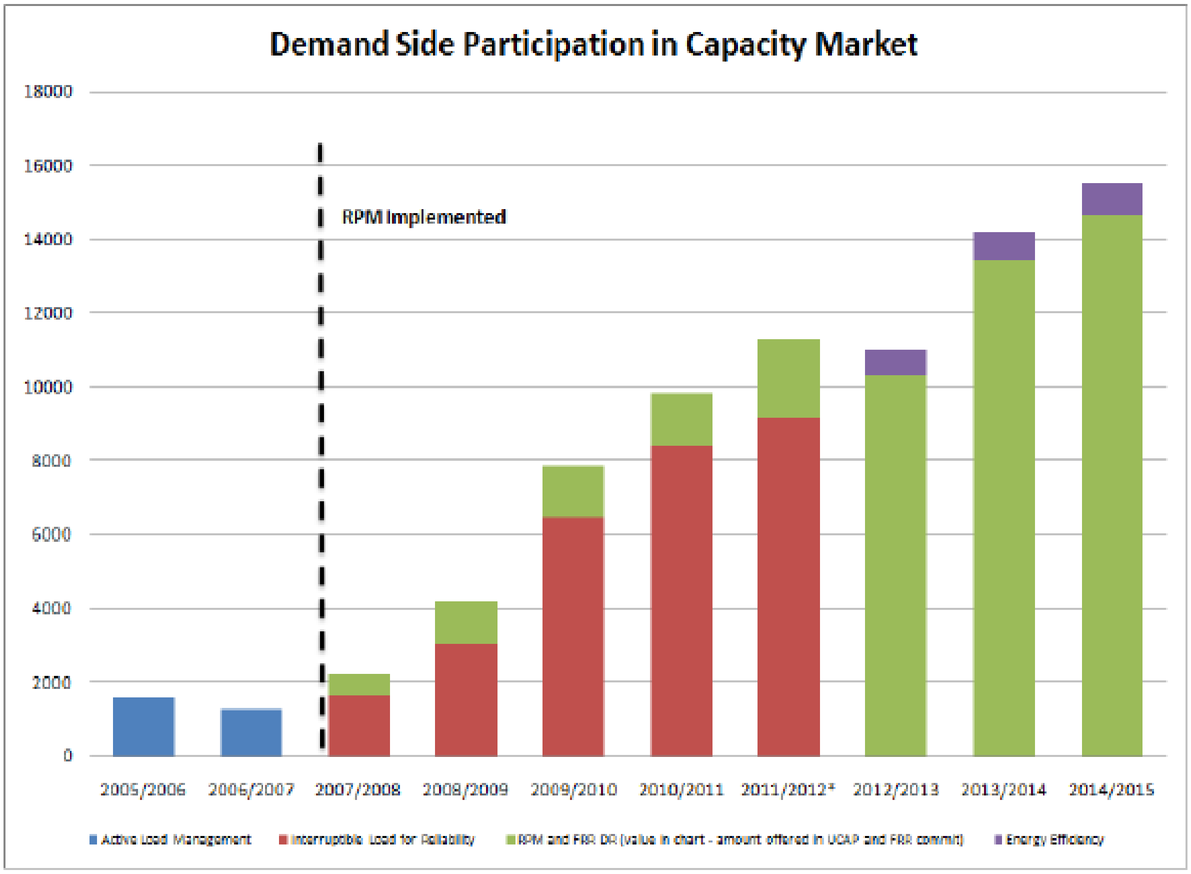

Figure 7. Demand Side Participation in Capacity Market

The recent 2014 – 2015 auction included over 15,000 MW of offers from demand response resources, with a little over 14,000 MW cleared. This was a 20% increase over the prior auction.[48] This auction was also the first one in which demand response resources could select three

[46] Order No. 745, RM10-17-000, March 15, 2011. *See*, ¶ 1, 2, 6, and 8-10.

[47] There is a lot of confusion in the literature between “demand response” and “demand resources”. We use “demand resources” to refer to all resources on the customer side of the meter. Active demand resources are resources that can be turned on or turned off (such as customer demand response in the form of back-up generation or interruptions of cooling systems). Passive demand resources are resources that are automatically on (such as energy efficiency measures and PV solar systems).

[48] PJM 2014-2015 RPM Base Residual Auction Results, May 13, 2011.

different commitment levels that are designed to give PJM greater flexibility in the use of demand response resources to balance system conditions.[49]

It is interesting to compare this quantity of cleared demand response resources for delivery in the 2014 – 2015 power year to the table in the 2010 RTEP that shows PJM's estimates of state-sponsored demand response programs. In that table, PJM estimates 6,943 MW for 2015, up from an initial estimate of 3,001 MW for 2010. Based on Figure 7, the actual quantity of demand response resources cleared in the recent capacity auction for delivery in 2015 is over 14,000 MW, and the quantity that cleared for delivery in 2010 was almost 10,000 MW.[50] While the estimates of state goals for DR in the 2010 RTEP may be correct, those state goals do not represent all the demand resources that will be available based on the RPM auction results.

Demand response resources are particularly useful during times of system peak, including both seasonal and daily peaks. PJM has begun a process of differentiating demand response resources based on their availability to system operators.[51] This is a key element of a more interactive bulk power system because it provides PJM greater flexibility to dispatch demand response resources more frequently.[52] PJM should fully incorporate the impact of *all* demand response resources into the peak load estimates used in the reliability modeling.[53] PJM currently includes a significant amount of demand response resources in the load forecast estimate used in the load deliverability test. However, such resources are not included in the generation deliverability test analysis of the transmission system.

Two new trends may have substantial impacts on future system demands for electricity. The first is the participation of demand response resources in day-ahead and real-time energy markets. Demand response resources' participation in the energy markets was provided a major boost with a recent Order from the FERC that resolved a major controversy over appropriate compensation for demand reductions in favor of demand response providers.[54] The contested issue was whether or not demand response providers should be paid the same energy market payment (the locational marginal price, or LMP) that is paid to generators; FERC determined that a full LMP payment was appropriate for demand response resources that can provide the same balancing service as generation.

The second new trend is the development of new retail rates based on advanced metering installations. These advanced meters can provide direct real-time price signals and encourage utility customers to enroll in dynamic rate programs that charge consumers based on hourly, or

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[49] Id at p. 7.

[50] RTEP 2010 Table 4.1, p 77. This is a good example of how policy goals may understate the total quantity of resources that may be available.

[51] *See,* FERC Docket No.ER11-2288, Order of January 31, 2011 and 2014/2015 RPM Base Residual Auction Results, May 13, 2011 at pp.7 and 26.

[52] PJM's previous protocol for dispatching demand response resources was based on a day-ahead notification to demand response providers that they might be dispatched. The new protocols will allow PJM to dispatch some demand response resources based on real-time conditions without prior notification (similar to generation resources).

[53] In addition, individual electric distribution companies (EDCs) and load serving entities (LSEs) within PJM are required to provide PJM estimated load drops, of which DSR may be a part, for the development of the PJM load forecast. This peak load forecast is then used in the development of RTEP power flow models and to that extent impacts the assessment of future system conditions that drive the need for new transmission to meet load-serving responsibilities.

[54] Order No. 745, March 15, 2011.

even more granular, prices. When high load hours reflect higher prices, customers will have an incentive to either defer electricity consumption to later low-priced hours or install efficiency measures that reduce consumption during those peak hours. Notably, Washington, DC is expected to have nearly 100% of residence meters replaced with smart meters by the end of 2011. A robust planning process needs to be able to model these changes and reflect their impacts.

Going forward, PJM needs to develop information on how these demand resources perform and their impacts on hourly system energy flows. With that information, PJM can develop inputs to the planning models to reflect the performance of these resources in future system topography at different quantities of participation.

2. New Generation Resources

To effectively manage the system, as well as account for changes in demand, PJM must consider the addition of resources driven by public policies, including renewable portfolio standards, feed-in tariffs, and efforts to promote distributed generation.

a. Renewable Portfolio Standards

Renewable portfolio standards (RPS) have been adopted by many PJM member-states. Although there are some differences between the state RPS rules regarding the specific types of renewable resources that qualify and the quantities of each that are sought, all the RPS rules require an increasing proportion of resources used to meet customer electricity needs to include specific, qualified renewable resources.

Utility-scale wind resources, likely to represent the bulk of resources installed to meet state RPS requirements, should be modeled as interconnected resources at the appropriate voltage level. Wind resources will have a different effect on the modeled PJM transmission system depending upon the choice of injection voltage used by PJM in its modeling. For example, initial indications are that PJM is planning to model the presence of significant amounts of western PJM wind resources at 345, 500, and 765 kV injection points.[55] Wind resources, however, are likely to be connected to the PJM system in many cases at lower voltage levels, including 115, 138, and 230 kV. Since the total amount of resources anticipated to meet state RPS levels is close to 30,000 MW by 2020,[56] it is critical that the models correctly characterize the injection voltage levels of these resources to properly gauge the effect they have on underlying baseline reliability needs. If PJM models these RPS resources on higher voltage lines than the resource actually uses, PJM may propose different and more expensive transmission upgrades than the upgrades that are actually required.

One of the challenges for PJM planners is to track programs, such as New Jersey's solar PV program for small-scale solar. To date, over 300 MW of solar PV has been installed at 8,000 locations.[57] Solar PV is a passive resource that can be modeled as a reduction to load during daylight hours. Although a variable resource on a day-to-day basis, solar PV's performance is

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[55] See the May 12 and April 15, 2011 Reliability Analysis Updates presented by PJM at the TEAC meetings.
[56] Cite to 2010 RTEP, Section 4.1 at p. 75.
[57] NJ Board of Public Utilities new release, April 12, 2011

predictable when adjusted for daily sunlight intensity. PJM needs to know the size and the precise location of solar PV installations in order to model their impact on the overall system.

Most important, however, is for PJM to model the full effect of state RPS objectives in order to capture the growth of these resources over time. To do so, PJM should include these resources in its baseline models at 100% of their required value, and model sensitivities above and below those values.

b. Feed in Tariffs

In addition to RPS rules, some states have developed specific quantity targets for certain renewables through a mechanism called a “feed-in tariff “(FiT) to acquire those quantities. A feed-in tariff typically sets an annual quantity of MW and invites entities to provide bids for the cost of acquiring a specific quantity. The auction entity will then select the lowest bids up to the annual quantity amount, or limit the bids based on a pre-determined threshold of the maximum it will pay (or a combination of these approaches). The rationale is that after a year or so of accepting high bids that the bids will get lower and lower as the technology approaches commercial feasibility. Some feed-in tariffs have these conditions completely spelled out; others leave some discretion with the auction or regulatory entity that oversees the FiT program.

For planning purposes, PJM needs to account for the quantities that these FiTs will procure and the likelihood that after the FiT program ends that additional quantities will be available each year into the future as commercial feasibility is reached.

c. Distributed Generation

PJM needs to incorporate customer-based resources that displace a portion, or all, of that customer’s annual consumption of electricity into its planning processes. Today, these customer resources include combined heat and power (CHP), small wind turbines, PV solar arrays, bio-mass, and fossil generation.

PJM needs to develop a mechanism for tracking the installation of these resources, some of which may be implemented to meet state RPS or FiT programs.[58] PJM will also need to estimate the impacts of these resources on both peak energy demand and overall energy consumption. The output from customer-owned resources behind their meters will provide even more refinements to future load estimates. These resources may also be able to provide critical balancing functions to deal with local reliability issues as renewable portfolio standards (RPS) and feed-in tariffs mature and evolve over time. The total quantity of customer resources (that look like demand reductions to PJM) needs to be specifically addressed. PJM’s analysis tools will also need to address storage and load-shifting technologies for larger customers that appear on the system as peak load reductions and off-peak consumption.

PJM’s baseline reliability modeling processes should appropriately accommodate the technical characteristics of anticipated generation resources, including distributed generation at customer locations. Distributed generation is best modeled as a reduction to load, given the limited ability of PJM to model supply resources at distribution system levels. PJM recently changed its initial

[58] PJM will need to ensure that overlaps between RPS, FiT, and DG resources are resolved when developing specific inputs for its reliability modeling runs

intention to model solar PV as a supply-side injection, and instead is planning to model it as a load reduction.[59]

3. Enhancements to Stress Testing

To properly value these demand reductions and new resources, PJM will have to alter its basic stress testing approaches. We recommend, in particular, that PJM:

- Reduce the peak load values used in the load deliverability and generation deliverability tests to account for additional energy efficiency resources. Currently, PJM only includes energy efficiency peak load reductions that have cleared the most recent RPM base residual auction. However, there are identifiable utility or state programs that currently capture peak load reductions from energy efficiency resources, yet are not considered when modifying peak load with cleared RPM resources. These resources are no less real than those resources that have cleared the RPM auctions.
- Reduce the peak load values used in the load deliverability and generation deliverability tests to account for additional demand response resources. Currently, PJM only includes demand response resources that have cleared the most recent RPM base residual auction. When PJM projects demand response resources in future years (beyond the horizon of the delivery year associated with the most recently completed RPM base residual auction) PJM limits the quantity to only those demand response resources that cleared the last RPM auction. However, RPM base residual auction results show that there have been significant year-over-year increases in the availability of these resources. In addition, PJM needs to develop mechanisms to track price responsive demand that may participate through utility smart meter programs or through participation in day-ahead and real-time energy markets.
- Modify the generation delivery tests to include available demand response resources to reduce loading in the power flow model. Currently, demand response resources are limited to reducing peak loading in the load deliverability tests only. Generation deliverability tests, while not designed to test extreme loading conditions like the load deliverability test does, nonetheless presume a capacity deficiency, or capacity emergency, in the areas to which generation is to be delivered.[60] Thus, at least some portion of faster-acting demand response resources available in those capacity-deficient areas should be used in the model when testing generation deliverability.
- Modify the level of new resources that can be considered in the power flow modeling to account for generation units that have completed a feasibility study agreement (FSA). Currently, only those units that reach the Interconnection Service Agreement (ISA) stage of the queue process are used as sources for mitigation of potential reliability violations. While it is reasonable to be cautious in considering which units in the queue process may be speculative, the current “hard” threshold of an ISA is overly restrictive. Some new generation projects can have dramatic impacts on reliability violations. They may warrant inclusion in some modeling runs to provide PJM with a better understanding of the

[59] As noted by PJM at its TEAC meeting, May 12, 2011.
[60] Manual 14B, Generation Deliverability section.

possible solutions to reliability violations that occur when the resource is not included.[61] Including such resources is particularly important, even on a case-by-case basis, when modeling large-scale, expensive transmission upgrades.

- More carefully analyze, and consider for inclusion in the baseline transmission topology used in the reliability tests, resources that are available to mitigate voltage violations. Reactive power resources such as SVCs and other devices can remedy voltage violations at lower costs than new transmission facility resources. These are frequently “no regrets” upgrades that solve low-level transmission and distribution issues while also alleviating the need or scope of larger projects.

B. At-Risk Generation

Properly forecasting demand reductions and new resources is crucial to providing a foundation for analyzing the retirement of a significant amount of existing coal-fired generation. Accurate forecasts that incorporate current trends and policies are likely to show that many retirements do not produce reliability problems, and for those that do, the reliability violations may be less severe, or, at least, produce only limited reliability problems. Nonetheless, the reliability issues that do occur must be addressed.

To manage these issues economically, PJM must navigate with care. First, and most obvious, PJM must dramatically improve its notification and analysis requirements to ensure that it receives sufficient notice of retirements to put reliability solutions in place expeditiously, eliminating, or, at least, limiting, the use of “reliability must run” contracts. Second, PJM must carefully weigh the solutions it picks to avoid overbuilding or unnecessary upgrades in response to potential problems. Enhancing the transparency of, and expanding notice requirements for, the entire retirement planning and response process will help address both issues.

1. The Magnitude of Coming Retirements

PJM has been considering the issue of at-risk generation as part of its planning process, and has identified between 14,000 and 17,000 MW of at-risk generation. The 2010 RTEP states:

> At-risk generators face the real possibility of deactivation given the economic impacts of such factors as increasing operating costs associated with unit age (some more than 40 years old) and changing environmental policy, particularly with regard to carbon emissions and water quality. . . .In addition to the risk from public policy and aging units, a potential at-risk indicator is a plant’s inability to clear an RPM auction given its costs compared to other resources offered into the auction.[62]

PJM is continuing its efforts, noted in the 2010 RTEP, to develop a process to identify and evaluate at-risk generation. We have included recent PJM estimates of the coal units at risk in the PJM footprint in Appendix C and summarized those estimates in Table 3. As the table shows, a large number of small, old coal power plants lack required pollution controls; as a result, their

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[61] The PATH project analyses excluded a Virginia facility with an FSA in RTEP analyses until it had achieved ISA status for the 2011 RTEP analyses. Including that resource, along with the load forecast and demand response resource changes, significantly reduced the size and number of future violations in the preliminary 2011 RTEP modeling runs. PJM TEAC presentation March 10, 2011, slides 8 and 18

[62] RTEP 2010, Exec. Summary at 6.

operators may well choose to retire them, and replace them with cleaner resources, rather than make investments to upgrade these antiquated, uneconomic units.

Table 3. PJM estimates of at-risk coal generation for the PJM footprint

Environmental Controls	MW of summer coal capacity, Coal > 40 years, < 400 MW
Without necessary SO_2 controls	16,830
Without necessary SO_2 and NO_x controls	14,680
Without necessary mercury controls	14,806
Using once through cooling	17,157

The key issue is the pace of potential unit retirements and the need for system enhancements, in some or all cases, in order to allow retirement while maintaining reliability standards. If units are needed for reliability and not allowed to retire, as in the cases of the Cromby and Eddystone units discussed above, they are eligible for reliability contracts that pay a unit based on its costs, not on its successful competition in PJM's energy, reserves, and capacity markets. The cost for these units is "out-of-market" compensation that is collected as an uplift charge that is difficult to estimate in advance; but the bottom line is that, whatever the charge, ratepayers pick up the bill to keep these plants running.[63] The market distortions from reliability contracts (for essential units that are otherwise too expensive) become more severe as more and more units qualify as reliability must run (or must-be-available) units.

In the 2010 RTEP, PJM notes that generator deactivations can alter power flows in ways that produce overloads. PJM states its concern that:

> 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.[64]

It is interesting to note that the trends described earlier regarding reductions in load growth due to the 2008 recession and the impacts of state efficiency programs will help accommodate, rather than exacerbate, generation retirements. Likewise, renewable portfolio standards and feed-in tariffs will provide new generation resources. And greater demand response participation in all wholesale markets will be available to reduce peaks loads that previously required the retired generation. A robust transmission planning process will evaluate these trends and use them to

[63] Out-of-market uplift costs are detrimental to efficient markets. Not only do they create unpredictable daily costs for all providers, they also depress the stated clearing prices. This is because reliability units displace other units that would have been selected at higher offers than the cleared units; reliability units by definition are not allowed to set the clearing price.
[64] 2010 RTEP, Section 2.4, p.43.

maintain a reliable system while lowering costs and reducing damage to air, water, and land resources.

In the past two years, numerous studies have evaluated the potential impact of proposed EPA enhancements to existing rules governing air, water, and waste issues associated with fossil-fueled generation, particularly coal-fired facilities. Some of these estimates are from financial and investment institutions, others are from industry participants. Some studies only looked at one or two specific EPA regulations while other studies examined a large number of upcoming changes. We provide these estimates as a reasonable range of expectations and to document that the potential for retirement is a well-known and evaluated issue.[65]

Figure 8 provides a summary of several studies. There is consensus among the various estimates that unit owners will opt to retire ~60 GW of coal plants rather than upgrade them to comply with modern pollution control requirements. This represents about 17% of the current fleet of coal units (~340 GW) and is consistent with the Exelon estimates of PJM fleet retirements of 14.6% (11 GW out of a total of 75 GW).[66]

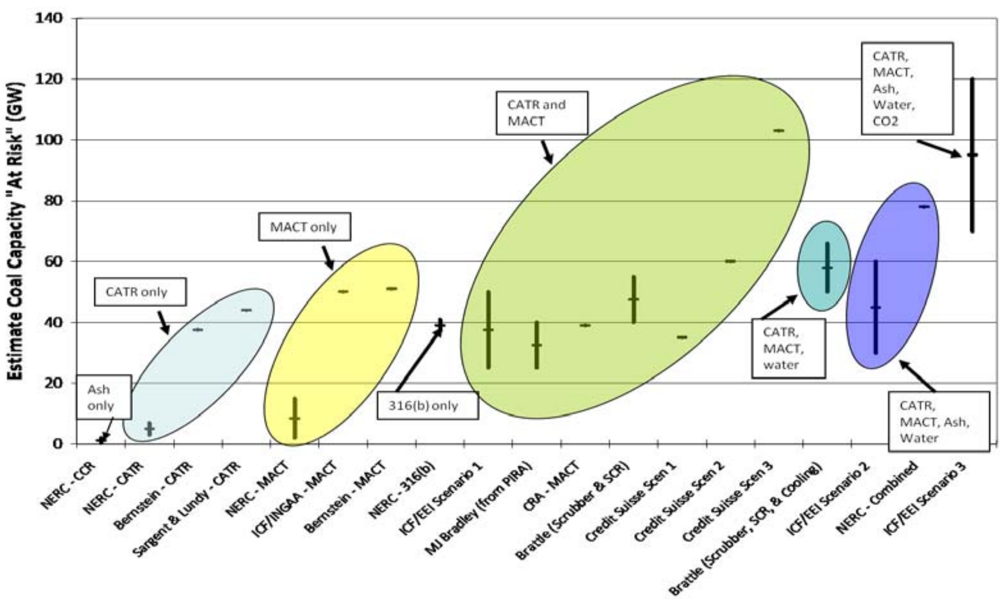

Figure 8. Generation Capacity (GW) Retired Due to EPA Rules, by Study and Scenario

If the Exelon estimate of about 15% (11,000 MW) of coal retirements and the PJM estimate of 14,000 MW are close to what actually occurs, PJM will have a substantial challenge to evaluate and accommodate those retirements over the next several years. If PJM's planning processes are

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65 There have been concerns expressed about the need to mask the identity of units that may face retirement pressures. In light of the extensive publicity about this issue and utility obligations to their investors, the listing of a unit as a potential retiree is not really news. A decision to retire a specific unit on a specific date may warrant confidential treatment.

66 Since these estimates were made, some of the draft rules have been released. Early analysis suggests that the compliance options are less severe than originally thought and the total quantity of retirements may be reduced. However, there is still substantial uncertainty about the overall economic health of many of these coal resources regardless of the EPA regulations.

unable to develop solutions for these retirements in a timely manner, then the likely alternative is retention of the units under special reliability contracts.

These contracts have the potential to significantly increase costs to all consumers since reliability contracts pay a premium over market prices for the specified generation units. Moreover, the out-of-market payments to the reliability units act to depress market prices for all other generation and dampen the market price signals for new generation construction. [67]

2. Recommendation on Retirement Notification and Analysis

The magnitude of these retirements poses a major challenge to PJM transmission planners and a threat to ratepayers if PJM does not have sufficient time to identify and swiftly implement cost-effective reliability solutions. PJM's existing retirement notification provision of 90 days is fundamentally inadequate for this task, and PJM does not yet have formal procedures it can use to integrate its own retirement predictions into system planning. Without reform, the result will be costly RMR contracts, while PJMJ struggles to identify and implement reliability solutions.

PJM can, and should, address this problem. Whatever else it does, PJM should begin by expanding its notice requirements. PJM should also enhance its own ability to model retirements, and act upon the results of that modeling.

a. Enhancements to the Tariff's Notice Provision

As we have noted above, PJM's tariff allows generators to provide a minimum of 90 days' notice before they retire, and obligates PJM to decide within 30 days whether the retiring unit is needed for reliability purposes. These short time periods bear no relation to either the timeline of a generators' retirement decision (which will generally be made many months before a unit retires) or to the time PJM needs to conduct a thorough reliability analysis and to select and implement any necessary solutions.

If these provisions remain unchanged, the coming retirements will badly stress PJM staff resources and, worse, ratepayer resources. Retirement requests are evaluated on a queue basis that is established by the date of their notification to PJM. The queue analysis for retirements is similar to the queue for interconnection requests. These sequential analyses for retirement create a similar burden on PJM as interconnection requests: they require significant commitments of people and time. If PJM determines that specific units are needed for the reliable operation of the system, PJM is obligated to develop individual compensation agreements to retain each unit. The short notice time, and short time to develop solutions, biases the system towards repeated use of RMR contracts to buy time for a more thorough analysis and the development of a permanent solution.

This arrangement distorts the market and harms ratepayers. It should not continue. PJM should expand the notification requirements in its OATT to better align with market realities and, in particular, with the three-year forward capacity market based on PJM's Reliability Pricing Model

[67] This is precisely the situation in New England that led to the Devon complaint in 2002. Generation units with reliability agreements were operated throughout Connecticut (a constrained load pocket) with the uplift assigned to Connecticut consumers and the rest of the New England market place experiencing low energy prices. The Devon complaint ultimately led to the creation of the Forward Capacity Market (FCM) in New England. FERC Docket No. ER03-563, et al.

(RPM).[68] The annual RPM auctions provide a three-year advance notice of capacity revenues for all resources that clear the annual RPM Base Residual Auction. A parallel three-year retirement notice would be a reasonable change. The ability of a unit to clear the annual capacity auctions will be a major factor in the unit owner's economic evaluation decision to retire or to make investments to allow continued operation. PJM might also consider developing a sliding-scale notice requirement, in which generators that provided later notice would receive relatively less favorable RMR contract terms.

Such improvements are entirely consistent with PJM's obligation to ensure "efficient, reliable, and non-discriminatory transmission service" throughout the area it serves. These improvements would remove the existing system's dangerous bias towards RMR contracts as stopgaps, which consumes resources that would be better spent on more permanent system upgrades.[69] Requiring generators to provide adequate notice, rather than benefitting from RMR contracts that could be avoided or minimized with sufficient lead time, serves PJM's ultimate obligation to maintain just and reasonable rates for the public it serves.

b. Screens Based on RPM and MMU Data

With or without an explicit expansion of the retirement notice requirement to three years, PJM may be able to use information from the annual capacity auction, and supplemental auctions, to screen units and establish thresholds for use in the planning process. PJM has included a discussion of at-risk units since the 2007 RTEP and provided screens based on age, size, and fuel-type since 2009. In the last several months, PJM has developed estimates of resources affected by proposed EPA regulations.[70] Additional screens could be developed for resources that are receiving insufficient market payments to meet annual revenue requirements; resources that have not proposed any capital improvements to comply with EPA regulations; resources with low capacity factors or high heat rates (which indicate that they are inefficient and little-used); and resources that fail to clear in RPM auctions.

This modeling, of course, is particularly crucial if PJM does not expand its notice requirement: If PJM must wait until 90 days before a retirement to begin planning, it will be badly behind the curve. Owners of at-risk resources are understandably uncomfortable with published lists and screening results that indicate concerns about the continued economic operation of their units, but these concerns are counter-balanced by ratepayers' strong interest in effective system planning, which must include accounting for the potential retirement of thousands of MW of coal units. Moreover, as discussed above, there is already considerable public information available that the new EPA regulations and pre-existing economic issues (age, size, efficiency, etc.) will make the continued operation of many coal units doubtful. PJM need not, and should not, refuse to consider such public information—which is already being used by market analysts and others to inform

[68] The 90-day notice requirement and related matters were the subject of a FERC decision in 2004. In that order the Commission determined that PJM's offer mitigation rules needed to be modified to ensure that units that had their energy bids mitigated (lowered) due to market power concerns be allowed greater levels of cost recovery to avoid premature retirements. This decision was prior to the approval of a settlement regarding PJM's modifications to its capacity market designs based on the Reliability Pricing Model (RPM) in late 2006. PJM has credited the new RPM capacity construct with providing sufficient additional revenues to some resources to both defer retirement decisions and to rescind some earlier requests for retirements. Order of May 6, 2004, in Docket No. EL03-236-000.
[69] 18 C.F.R. § 35.34(k)(7).
[70] PJMJ Presentation to Transmission Expansion Advisory Committee (TEAC), May 12, 2011. See Appendix C

retirement projections. The fact that PJM is conducting an analysis of specific units as part of its planning process does not reveal anything about these old, small, high heat-rate resources that is not already publicly available. Some of the details of PJM's analysis may need to be protected as commercially sensitive information, but PJM's planning analysis does not say anything definitive about whether a particular unit will or will not retire. Thus, while PJM should respond to unit owners' concerns, and may develop ways to shield some portions of its analyses, it must still go forward to address this pressing system-wide concern.[71]

PJM is already collecting much of the data it needs to make robust retirement predictions; remaining data is generally in the public domain. The PJM RPPTF straw proposal, for instance, has already proposed removing plants that fail to clear the capacity auction two years in a row from baseline reliability modeling. PJM can supplement this useful recommendation with further analysis, as we next describe.

i. Sources of Economic Data

PJM collects information sufficient to allow it to understand the retirement incentives for units in the system, and this information, unsurprisingly, indicates that substantial retirements are likely.

Starting in 2009, PJM State of the Market Reports (SOM) added a subsection on the Actual Net Revenue and Avoidable Cost Recovery analysis in addition to their regular Net Revenue subsection of the Section 3 "Energy Market", Part 2, of the SOM. In 2009 and 2010, PJM's SOMs provided analyses of actual net revenues, avoidable costs, and statistics on the avoidable cost recovery rates from energy, ancillary and capacity markets revenue for selected technologies in the analyzed years 2009 and 2010, respectively. In addition, the 2009 SOM provided some comparative statistics on the avoidable cost recovery rates for 2007 and 2008 years, as compared to 2009.

In the electricity markets terminology, avoidable costs are the costs which must be paid each year in order to keep a unit operating. The relationship between a unit's annual avoidable costs and actual net revenues is a criterion for continued future operation: it is rational to continue a unit's operation if it is covering its avoidable costs and therefore contributing to covering fixed costs. If avoidable costs are not covered and not expected to be covered, it is not rational to continue a unit's operation, and it is logical to retire the unit. This comparison is also a signal of the units in PJM that are at risk of retirement.

Avoidable costs, however, can also include annualized fixed costs of investments required to maintain a unit as a capacity resource; these can include avoidable project investment recovery (APIR) costs. Since existing APIR are sunk costs, they are ignored in a rational decision about retirement. Therefore, we should be careful interpreting results of avoidable costs and actual net revenues comparison.

PJM's analysis provides comparison of avoidable costs to actual net revenues from energy and ancillary markets, to actual net revenues from capacity markets, and both. Depending on the

[71] PJM has recently suggested an approach for modeling at-risk resources at the Local Delivery Area (LDA) level that would reduce the MW of resources in the LDA by a fixed amount of at-risk resources without identifying any specific units. This would provide PJM with a high-level assessment for each LDA of certain reliability issues; the high-level assessment would indicate which LDAs needed more detailed modeling. RPPTF discussion May 25, 2011.

generation technology, avoidable costs, capital expenditures and operating costs per MWh, different units depend on revenues from energy, ancillary services, and capacity markets to a different extent.[72] Since coal units have significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, their profitability relies more heavily on energy and ancillary market revenues.

SOM considers two classes of coal units: sub-critical coal and super critical coal. Table 4 below provides a comparison of the avoidable cost recovery rates for selected technologies, including two types of coal, for the period of 2007-2010.

Table 4. Proportion of Units Recovering Avoidable Costs from Energy and Ancillary Markets as Well as Total Markets for Calendar Years 2007 Through 2010[73]

Technology	2007		2008		2009		2010	
	Full Recovery From Energy Markets	Full Recovery From Capacity Markets	Full Recovery From Energy Markets	Full Recovery From Capacity Markets	Full Recovery From Energy Markets	Full Recovery From Capacity Markets	Full Recovery From Energy Markets	Full Recovery From Capacity Markets
CC – Two One Frame F Technology	74%	90%	74%	100%	83%	100%	93%	100%
CC – Third Generation Aero	45%	79%	41%	100%	16%	100%	32%	100%
CC – Third Generation Frame F	47%	100%	48%	100%	25%	100%	62%	100%
Nuclear	100%	100%	100%	100%	93%	100%	100%	100%
Sub-Critical Coal	**93%**	**95%**	**85%**	**95%**	**30%**	**75%**	**52%**	**82%**
Super Critical Coal	**98%**	**100%**	**100%**	**100%**	**35%**	**82%**	**50%**	**82%**

[72] Base load power plants run many, many hours and earn most of their revenue form the energy market. Peaking units run just a few hours a year and earn most of their revenue from the capacity market. Some resources can qualify for ancillary services payments (from reserves, balancing, and black-start markets).

[73] Data for 2007 and 2008 are collected from the PJM 2009 SOM; data for 2009 and 2010 are collected from the PJM 2009 SOM. Data for 2009 varies in the two SOMs.

Coal units, profitability of which relies heavily on the revenues from energy and ancillary markets, recovered their avoidable costs almost in full from energy and ancillary markets in 2007 and 2008; then recovery rate from energy and ancillary markets dropped significantly to 30-35% in 2009 and increased only slightly to 50-52% in 2010. In 2009 and 2010, 18 to 25% of all coal units didn't recover their full avoidable costs even after their capacity revenues were considered.

Such significant drop in recovery rates can be explained by the fact that in 2009 electricity prices decreased more significantly than did the delivered prices of coal, and, as a result, energy net revenues for coal units went down significantly. In 2010, despite higher loads and overall higher price levels relative to the operating costs, some coal-fired units in PJM still did not fully recovered their avoidable costs even with capacity revenues.

Both 2009 and 2010 SOMs compared characteristics of the subset of coal units with less than 100 percent avoidable cost recovery to those with full recovery. Table 5 below provides the summary of the comparisons from both reports.

Table 5. Comparison of Coal Units with Less than 100 Percent Avoidable Cost Recovery and Full Cost Recovery

Characteristic	2009		2010	
	<100% Recovery	Full Recovery	<100% Recovery	Full Recovery
Total Installed Capacity (MW)	11,250	N/A	6,769	37,808
Average Size (MW)	73.1	N/A, but greater than 73.1	225.6	282.1
Average Age (Years)	N/A	N/A	50	40
Heat Rate	10,500 Btu/kWh	N/A, but lower than 10,500 Btu/kWh	11,430 Btu/kWh	10,870 Btu/kWh
Average Operating Costs	$54.58/MWh	N/A, but lower than $54.58/MWh	$43.08/MWh	$29.92/MWh
Average Run Hours (Hours)	N/A	N/A	3,847	6,505
Location	89% of these units in MAAC		~85% in unconstrained LDA associated with lower cap and energy revenues[74]	

[74] According to the PJM 2009 SOM, "Approximately 85 percent of the coal units that did not cover avoidable costs cleared in the unconstrained RTO LDA for the period, representing the AEP, AP, ComEd, DAY, DLCO and Dominion Control Zones while only 15 percent were located in EMAAC or SWMAAC LDAs. The zones associated with the RTO LDA receive lower capacity revenues and generally lower energy revenues compared to the EMAAC and SWMAAC LDA control zones." (Section 3, Part 2, p. 176)

As shown in Table 4, coal units that did not recover their full avoidable costs are smaller, older, and less efficient units that run less often and operate as mid-merit or even peaking units, with the majority of them located in unconstrained zones.

As mentioned before, for some units annual avoidable costs also include APIR, which is a sunk cost and should not be considered in retirement decision. Those units that do not fully recover their avoidable costs but have APIR included in their cost calculation may be at lower risk of retirement, but still should be flagged as potential at-risk for retirement units. If total annual markets revenues continue to be lower than annual avoidable costs for units with and without APIR included, retirement becomes an economically rational decision.

ii. Additional Screens

We propose additional screens that PJM could use for assessing at-risk resources. PJM's current screens of age, fuel, technology type, and compliance with new EPA regulations are good initial screens. A screen based on market revenues would help identify resources that are economically stressed, even if they are compliant with the new EPA regulations or even if they are less than 40 years old. Other data worth evaluating are the heat-rate and annual capacity factors of individual units. A unit with a high heat-rate (which demonstrates an inefficiency of converting fuel to electricity) and a low annual capacity factor (the percentage of hours that the unit runs) provides a strong indication that the unit is not financially viable.[75] Much of this information is currently provided by the MMU on an aggregated basis in the SOM and could be provided to PJM on a plant-specific basis for use in modeling runs for planning purposes. A screen based on capital investments by at-risk resources to comply with EPA regulations in order to continue to operate would provide PJM with important information about which units are planning to comply with the new EPA rules and which units are not. For units making capital investments, their overall financial situation could improve or worsen. For units not making capital investments, their continued operation would be doubtful. And a screen based on clearing annual capacity auctions, as suggested by PJM in its straw proposal, would help identify units that are becoming uneconomic resources.

iii. Thresholds for Retirement Analysis

PJM could use the results of these screens to establish thresholds. A resource that passes a threshold could be removed from future Baseline Reliability Analyses, be analyzed for reliability violations, or be monitored for further analysis. We recommend a three-tier approach.

- Tier 1 would include units likely to retire and removed from future power flow models. PJM would evaluate the reliability impacts of each unit's retirement. Those that create reliability violations would be retained until system enhancements could be implemented to allow the unit to retire. PJM would have the authority to request proposals for system enhancements, evaluate them, and select solutions to implement. Specific criteria would need to be established to designate a unit as a Tier 1 resource; some combination of inadequate market revenues, failure to budget for compliance costs, or failure to clear RPM auctions would define a Tier 1 resource.

[75] The exceptions to this are peaking units that are designed to run only a few hours a year. Very few coal-fired resources, if any, are designed to be peaking units.

- Tier 2 would include units with significant indicators of likely retirement. PJM would evaluate these units for reliability impacts from their retirement, but would not have the authority to request, evaluate, and implement solutions. Units that showed no reliability impacts from retirement might be re-classified as Tier 3 resources. As with Tier 1 resources, Tier 2 resources would have specific criteria used to establish their designation. Some combination of age, market revenues, minimal compliance cost investments, or RPM auction clearing would define a Tier 2 resource.
- Tier 3 would include units with some indicators of retirement such as age, size, marginal market revenues, or significant compliance control investments. Tier 3 resources would be defined by specific criteria to warrant their inclusion as a Tier 3 resource, but PJM would not conduct any reliability analyses. Tier 3 resources would be on a watch list.

The application of criteria (age, fuel, market revenues, capital investment, RPM status, etc.) to establish thresholds will require judgment and recalibration based on experience. PJM's Straw proposal suggests a threshold for Tier 1 of 40 year or older coal plants, less than 400 MW, that fail to clear two consecutive RPM annual auctions. Another threshold for Tier 1 could be old, small coal units that must make upgrades to comply with EPA regulations and have not made any such investments in time to comply with the new rules. A threshold for Tier 2 could be old, small coal units that have made investments to comply with EPA rules but have failed to clear one or more RPM annual auctions. Over the next few years, PJM will learn a lot more about the importance of these specific criteria in retirement decisions and can adjust the thresholds as necessary.

C. Adjustments to Stress Testing and Reliability Analyses

With the benefits of enhanced notice and modeling, PJM will be able to assess the impacts of generator retirements on its reliability standards. To do so, it will have to build these results into its reliability modeling by removing those highly likely retiring plants. Highly likely retirements include those units that have given notice that they will retire and those units that have failed a battery of retirement screens (such as repeated failure to clear the capacity auction). PJM should remove these resources from its baseline modeling and use sensitivities to consider the retirement of plants in lower tiers, where retirement is less certain.

C. Integrated Solutions for Reliability Needs

Once PJM has identified reliability violations resulting from at-risk generation retirements, or other public policy-triggered changes, it needs to address those violations as quickly, and as cost-effectively, as possible. Often, several possible solutions for a given violation may be available. In order to avoid excessive costs or lengthy delays, carefully and publicly vetting these solutions is critical. Indeed, as the PATH and Cromby/Eddystone experiences suggest, transparent and early analysis of possible solutions can help avoid costly premature projects and unnecessary must run agreements. Developing a more robust approach to generating and testing solutions will help avoid such problems, especially as the challenges we describe above become more acute. Already, New York ISO has established a useful solution identification process that is designed to develop multiple solutions to reduce costs for ratepayers while protecting reliability. We encourage PJM to develop similar public processes that allow it to gather and assess creative solutions from its stakeholders and entrepreneurs, and describe some options for those processes here.

1. PJM's Planning Process

In Schedule 6 of its Operating Agreement, PJM indicates that it will identify "existing and projected limitations on the transmission system's physical, economic and/or operation capability or performance" [76] It goes on to say that PJM will identify, evaluate, and analyze various ways to resolve these limitations, including demand response solutions "appropriate to maintain system reliability."[77] PJM's manual 14B, which describes the Region Transmission Planning Process (RTEP), notes that demand response solutions are included in transmission planning by clearing in the relevant Reliability Pricing Model (RPM) auction.[78] There does not seem to be any other process by which demand side solutions may be evaluated as an alternative to transmission expansion.[79] Indeed, the most recent RTEP explicitly states that load management solutions are only considered once they have cleared the RPM three-year forward capacity market, in order to "ensure reliability".[80]

Because solutions are limited to just traditional transmission upgrades, PJM does not engage in a process to evaluate a "non-transmission alternative" (NTA), sometimes called a "non-wires solution" (NWS), even if such an alternative is less costly and requires less lead time to install. PJM relies almost exclusively upon its transmission owning members to suggest solutions to address potential reliability violations and does not require alternatives that may be lower cost or impact to be evaluated.

2. New York ISO Process for Alternatives

The New York ISO (NYISO) has codified a process to evaluate combinations of wires and non-wires solutions to determine the relative costs and impacts on the reliability need. After completing its Reliability Needs Assessment, NYISO requests that the affected transmission owners present "a proposal for a regulated solution or combination of solutions"[81] which "may include generation, transmission, or demand response."[82] Simultaneously, NYISO requests proposals for market based solutions, which, as with the regulated solutions, may include generation, transmission, and demand response.[83] If there are no proposed market solutions or the proposed market solutions are deemed inadequate, NYISO may also request an alternative regulated proposal which again may include demand response solutions.[84]

[76] PJM Operating Agreement, Schedule 6, Section 1.5.3(a)
[77] *Ibid.*, Section 1.5.3(c)
[78] Manual 14B, Section 2.4
[79] PJM uses the term "demand response" in a variety of ways. On some occasions, "demand response" is a general term that refers to all the options for the demand or load to impact the bulk power system. On other occasions, "demand response is referring to demand resources that can actively "respond" (turn on or turn off) based on price or dispatch signals. Because of the multiple meanings of "demand response" the references to it in PJM rules and procedures can be ambiguous. We use the term demand resources to refer to all the various options for load to "respond". We use explicit terms for active demand resources that respond to price/dispatch signals (demand response) and for passive demand resources that are generally non-dispatchable (energy efficiency measures and small-scale distributed generation such as PV, wind, or CHP). Some distributed generation resources are active demand resources (dispatchable).
[80] PJM 2010 Regional Expansion Plan, Section 2.2.3
[81] NYISO Tariff, Attachment Y, Section 31.2.4.1.1
[82] *Ibid.*
[83] *Ibid.* Section 31.2.4.3
[84] *Ibid.* Section 31.2.4.5

The entire NY ISO process is designed to identify the most cost-effective solutions for solving reliability violations and specifically includes generation and demand resources as options, The last element of this process, a NY ISO request for alternative *regulated* solutions, represents a significant departure from the traditional approach of limiting regulated cost-recovery (through the OATT) to just poles, wires, and substations. PJM could adopt a similar approach.

The NYISO and the New York State Department of Public Service ("NYDPS") review all proposals for system upgrades through their existing procedures. As part of its review in a docketed proceeding, the NYDPS may request additional proposals for regulated responses that will meet the reliability need including "reasonable alternatives that would effectively address the identified Reliability Need."[85] Such a feature may not be applicable to PJM's planning process due to the multiple states in the PJM footprint. However, there may be situations where a proposed transmission line across neighboring states may evolve into a regional review with one or more of the states required to solicit and examine alternatives.

Transmission owners and developers may submit proposals to the NYDPS for review at any point in their planning process.[86] On occasion, the NYISO will identify a system reliability need that is urgent enough to warrant bypassing the normal planning timeline. In these cases the NYISO and the NYDPS will together work with the relevant transmission owners to develop a gap solution. Developers may also submit their own proposals for review by the NYISO and the NYDPS.[87]

If the NYDPS selects a regulated non-transmission solution from a transmission owner or an independent developer, that solution is eligible for cost recovery under the same tariff that provides for recovery of traditional transmission upgrades. To date, the NYDPS has not received any proposals for system upgrades that included non-transmission elements. The actual implementation of the provisions in NYISO's Attachment Y will have to await future developments.

3. Northwest Initiatives

The Bonneville Power Administration (BPA) has developed some innovative approaches to addressing system reliability issues that include an analysis and implementation of "non-wires alternatives" (NWA). The application of BPA approaches may not be entirely transferable to PJM planning due to the structural and legal differences between a Federally designated power administration (by statute) and a FERC-designated RTO such as PJM. Nonetheless, an understanding of the processes in the Pacific Northwest may be useful to PJM's development of its own processes.

In January of this year, BPA announced that it would reconvene an expert panel (from 2003) to evaluate a proposal to resolve issues related to its I-5 Corridor Reinforcement Project with aggressive energy efficiency measures. BPA had proposed a 500kV transmission line in 2009 to address the I-5 Corridor issues. As part of its evaluation process, BPA commissioned an independent analysis of alternatives in 2010. The expert panel will review the recommendations of the independent analysis that included the aggressive energy efficiency investment option.[88]

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85 *Ibid.*
86 *Ibid.* Section 31.2.4.5.2
87 *Ibid. Section 31.2.5.9.3 and 31.2.5.9.4*
88 BPA News, January 21, 2011, available at:
http://www.bpa.gov/corporate/BPANews/ArticleTemplate.cfm?ArticleId=article-20110121-01.

In Appendix D, we provide some initial language changes to the Operating Agreement and Manual 14B that would expand PJM's planning process to include evaluations of any combination of system resources (load, supply, or transmission) to address system reliability concerns. The actual transmission tariff changes that would allow for a regulated recovery of the most cost-effective solution are beyond the scope of this report. This would be an appropriate topic for further RPPTF work.

5. Process for Implementing Change

PJM has an extensive stakeholder committee system that includes task forces, working groups, sub-committees, and voting committees. As mentioned earlier in this report, the Regional Planning Process Task Force (RPPTF) is the stakeholder group that has been tasked to review and recommend enhancements to the overall planning process. Recommendations developed through the RPPTF can follow several paths. Some may be referred to a separate sub-committee or other working group for further discussion; some may go directly to the voting committees from the RPPTF; and some may ultimately be part of tariff changes filed with the FERC. Implementation of RPPTF proposals may be done though changes to the PJM Manuals, the Operating Agreement, or the Open Access Transmission Tariff (OATT) depending on the type of change and its impacts on existing procedures and rules.

A. RPPTF PJM Straw Proposal

In March 2011, PJM provided the RPPTF with a straw proposal for enhancements to PJM's planning process. PJM staff has vetted the proposal with the PJM Board and has invited stakeholder to add their comments on the 60 issues identified and indicate their agreement with or suggested alternatives to PJM's proposed changes. Some of the key elements of that Straw proposal are listed below. We do not necessarily endorse all of these proposals, but note that many of them track our independent recommendations above:

- One-year planning cycle for lower voltages and two-year planning cycle for higher voltages
- Develop single three-year load forecast for use in RPM analyses; develop a range of load forecasts for years 4-15 for use in RTEP
- Address at-risk generation by removing generation from baseline reliability analysis that does not clear two consecutive RPM auctions
- Track at-risk resources in light of new environmental regulations
- Model renewable resources based on the achievement of 100% of state RPS goals
- Model demand response resources at 100% of state goals, or a lesser percent
- Model energy efficiency resources at 100% of state goals, or a lesser percent
- Develop price responsive demand models as participation by demand-side resources increases
- Model wind based on current interconnection queue, with variations for off-shore and mid-west scenarios

- Trigger upgrades at 100% of line loadings, but do not abandon upgrades unless loadings fall below 95%[89]
- Consider options for decision making after RTEP analyses: market alone; state compact; critical mass of projects; or PJM orders it all.

In subsequent RPPTF meetings, the concepts above have been discussed and further refined. At the April 29 meeting, the environmental coalition that is sponsoring this report provided their issues and concerns with the PJM straw proposal and the overall effort of the RPPTF.[90] The environmental coalition comments closely parallel many of the recommendations in this report. PJM plans to continue RPPTF discussions over the next several months with the goal of moving proposed enhancements through the higher stakeholder committees staring in September. PJM staff and the Board of Managers remain committed to a FERC filing by the end of December that will detail the enhancements and the needed changes to PJM's governing documents (manuals, Operating Agreement, and OATT).

6. Recommendations and Conclusions

Our recommendations are organized into the same general categories discussed in Section 4: forecasting, at-risk resources, and solutions. The recommendations also reference the PJM Straw proposal for transmission planning reform being discussed at the RPPTF stakeholder meetings. These are a set of recommendations with interaction between some of the specific elements.

A. Forecasting Issues

We recommended PJM implement several enhancements to the system forecasts that are used when modeling the system for reliability analyses. These include estimates of peak loads, energy consumption, and resources available for use in modeling the bulk power system for power flow studies and other planning activities. We also discuss potential enhancements to the criteria PJM uses to stress the system during its power flow modeling. Our specific recommendations include are described below.

1. **Make appropriate adjustments to the use of econometric load forecast models as outlined in the ITRON report.** These changes should include a comparison of the different econometric forecasts available and the tracking of the accuracy of the different econometric models. Specific decisions regarding the econometric forecast to use can be made with input from the stakeholder process. It is important to determine how each forecast model treats revised building and efficiency standards (state and national), current state program initiatives (particularly EE resources), and changes in energy intensity. In particular, additional scrutiny should be given to structural shifts in the different sectors of the region's economy that may result in significant changes to consumption patterns, relative to historical trends. PJM's Straw proposal identifies the ITRON study as a specific element of potential transmission planning reform.

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[89] This "deadband" is problematic, as it may bias the process towards unnecessary transmission upgrades. We urge PJM to carefully consider the ratepayer implications of locking in upgrades, even if they no longer appear to be necessary.

[90] That presentation is included in Appendix G.

2. **Incorporate state policy goals into forecasts of future load and power flow models.** As discussed in Section 4.A.2, including just the impact of state energy efficiency programs can have a dramatic impact on future load forecasts. PJM needs to include the quantities of energy efficiency resources that state programs are likely to achieve and not limit the quantity to just the resources offered into the RPM capacity auctions. In order to develop a more refined estimate of future load, PJM also needs to include the impact of demand response resources, state RPS programs, specific resource feed-in-tariffs, and other customer based resources including combined heat and power (CHP).

   Demand response resources should be modeled for their full potential reductions to peak load and daily energy consumption due to participation in both capacity and energy markets. State RPS programs that focus on specific quantities of new resources need to be appropriately modeled regarding quantity and operational characteristics. Wind generation is best modeled at interconnection voltage levels to better understand local distribution impacts and avoid exaggerating the impacts on higher voltage elements of the bulk power system. Customer-based resources such a PV or CHP are best modeled as load reductions to the system at the distribution level, rather than as injections of energy at some distant high voltage node. Greater focus on lower-level transmission and distribution system impacts will allow for more targeted, less costly solutions in many cases.

   The total quantity of customer resources (that look like demand reductions to PJM) need to be specifically addressed. This analysis will also need to include storage and load-shifting technologies for larger customers as well as installations of new solar and wind technologies. PJM's Straw proposal suggests incorporating 100% of state RPS goals. We recommend including 100% of all state goals that are being modeled as a base case, and then adjusting that percentage downward and upward as part of sensitivity analyses.

3. **Include the likely impacts of specific federal policies.** Currently, this means evaluating the impact of proposed EPA rules related to emissions output, water consumption, combustion waste, and the movement (transport) of pollution related to fossil fuel generation facilities. PJM has already devoted significant effort to defining the potential scope of the impact of the EPA rules.[91] As PJM develops screens for categorizing at-risk resources, the results of those screenings need to be included in Base Line reliability analyses and Longer-Term reliability analyses as appropriate. PJM's Straw proposal includes several references to the importance of managing these evaluations in a proactive manner.

   However, there may be additional Federal regulations and rules related to a nation-wide renewable portfolio standard or some form of carbon tax or cap-and-trade system. If such rules are enacted, PJM will need to assess the likely impacts of these Federal policies and apply the results to the elements of its future forecasts that address peak load, energy consumption, and available resources.

4. **Apply forecasting adjustments to reliability analyses.** The adjustments to PJM's forecasts need to be applied to both the Baseline and Longer-Term reliability analyses. PJM's Straw includes an option to reduce the Baseline analysis to three years, rather than the current five years. This will provide PJM with more flexibility for analyzing the system after year three,

[91] See appendix C for the PJM charts of at-risk resources and EPA rules

while still providing fixed short-term values that can be used for setting capacity market parameters for RPM auctions.[92] Under this option, the Longer-Term analysis (that includes sensitivity analyses) would cover the years four through fifteen, rather than the years six through fifteen. Whatever time period is chosen, PJM should include the most up to date estimates for future loads and resources as applicable.

The specific location of these resources on the bulk power system will become more important over time as the entire grid becomes more decentralized and interactive. If retirements of old, inefficient resources start to occur in greater numbers, the reliability analyses of these retirements can be more accurately modeled when resources (both supply and demand) can be attributed to a specific location on the system. The mapping of resources to specific locations will allow the development of more targeted, less-costly upgrades.

5. **Evaluate and revise criteria for conducting power flow assessments of reliability.** There are numerous criteria that PJM uses for setting up its models to test the reliability of the system (stressing the system). Some of those criteria are prescribed by other entities, such as the NERC Category A, B, and C tests. Some are based on long-standing PJM practice or local utility practice. As discussed in Section 4.A., PJM should evaluate all the criteria and assumptions that it is using and determine whether or not modifications to those criteria are appropriate given recent trends affecting bulk power system operations and the potential for future developments.

B. Evaluation of At-Risk Resources

PJM needs to build upon its efforts to date to be better prepared to address an influx of retirements from an aging, financially stressed generation fleet, in particular from the older coal and oil or gas-fired steam units. This could be the most significant planning challenge for RTOs since their inception. Some, or many, of these stressed units may also need to make substantial capital investments to continue operation under proposed EPA rules that start taking effect in 2015. In one context, 2015 is now, due to the recent capacity auction for the 2014-2015 delivery year. This highlights the urgent need for PJM to develop additional tools for the identification, analysis, and actions steps necessary to avoid uneconomic RMR contracts for units that need to retire. Enhancements to PJM's current process of assessing at-risk resources include the following:

1. **Expand retirement notice to three years. T**he current 90-day notice requirement for a unit retirement is inadequate for providing PJM with an opportunity to identify the reliability impacts of a retirement and evaluate solutions. Current EPA rule changes strongly indicate that significant quantities of generation in the PJM footprint are at-risk to retire. In order to conduct the analyses necessary to maintain a reliable system while avoiding uneconomic RMR agreements, PJM needs more advance notice. A three-year notice requirement is consistent with interconnection request time frames and the three-year forward commitment for RPM capacity resources.

[92] PJM must provide a fixed value for its estimate of peak demand three-years forward in order to establish the parameters for the RPM capacity auction.

2. **Maintain a current list of all resources affected by EPA Regulations.** PJM has provided useful information to date on its estimates of resources directly impacted by proposed EPA regulations.[93] Numerous other entities are also providing public estimates. For its own use, PJM needs to maintain a list of resources impacted by the EPA proposals and include details on each resource's current compliance or non-compliance with each EPA proposed regulation. PJM's Straw proposal encourages these changes to the planning process and they are being actively discussed in the RPPTF process.

3. **Develop screens to evaluate resources.** PJM has screened resources based on age and size for several years. The recent development of sub-categories based on non-compliance with EPA regulations is a very useful addition. Other useful additions would be unit-specific estimates of compliance costs, unit-specific information on capital investments, and estimates of annual revenues. The PJM MMU already provides summary information on estimates of annual revenues for PJM resources. The MMU also receives information regarding capital investments through the RPM offer submittal process. While some of this information may need confidentiality protection, it should be available to the PJM personnel responsible for developing power flow models to test reliability. PJM's Straw proposal endorses most of these recommendations.

4. **Develop thresholds based on screens.** PJM should develop thresholds based on objective screening criteria to categorize at risk resources. PJM's Straw proposal suggests a threshold for removing resources from reliability analyses based on a resource not clearing two consecutive annual capacity auctions. We encourage PJM to expand upon this approach to include other criteria that may also indicate retirement within the planning period studied.

   We recommend developing three thresholds based on a combination of screening criteria. Resources at the highest level of risk (Tier 1) would be removed from power flow analyses used to test system reliability. If removal of the at-risk unit caused a reliability violation, PJM would conduct a more detailed analysis and request solutions to resolve the reliability need. Resources at the second highest level of risk (Tier 2) would be tested for reliability violations, but a violation would not immediately lead to a request for solutions. Testing Tier 2 resources would provide PJM advance notice that a solution would or would not be needed if the resource moved to the Tier 1 category. It might also suggest that a more detailed analysis is needed for Tier 2 units that have reliability violations. The third highest category (Tier 3) would be for resources that met only a few of the risk criteria, similar to a watch list.

Objective screening criteria would include the age, size, annual revenues evaluation, RPM commitment, capital investment in EPA compliance equipment, cost of compliance, and any other relevant licensing or compliance requirements. The RPPTF stakeholder process is already considering some, if not all, of these criteria as elements of the PJM Straw proposal. The PJM Straw proposal suggests using a continuum of "high pace of retirements" to "slow pace of retirements". We think the three tier approach provides stronger support for PJM action. The value of developing screening and threshold analysis is to provide PJM with tools to address reliability violations in a timely manner and avoid uneconomic RMR agreements. There are many more

[93] PJM TEAC presentation, slides 22-30, May 12, 2011, available at http://pjm.com/~/media/committees-groups/committees/teac/20110512/20110512-reliability-analysis-update.ashx.

details that would need to be worked out, including provisions for Tier 1 resources to be re-instated in planning studies based on changed circumstances or updated information.

C. System Solutions

PJM Straw proposal includes options for a decision framework for system upgrades that include “let the market do it”; or “establish a state compact”; or “leave it all to PJM”; or “a hybrid approach”. We lean towards a hybrid approach that assigns most of the analysis to PJM but includes state regulators and other stakeholders in some fashion when determining the “lowest cost reliable solution.” With that purpose in mind, we recommend the following changes to PJM’s current process for ordering, implementing, and paying for solutions to reliability violations include the following:

1. **Adopt a comprehensive RFP process for system solutions**. Borrowing from the NY ISO, PJM should develop an RFP solutions process for reliability violations. The RFP would be open to incumbent transmission providers and third parties who want to propose solutions to specific PJM-identified system needs. Solutions may be transmission upgrades, generation additions, demand resource applications or a combination of transmission, generation, or demand solutions. Proposals must demonstrate that they resolve the relevant reliability violations and provide an estimate of the cost of the proposed solution.
2. **Evaluate the proposals and select the lowest cost, reliable solution.** PJM’s evaluation of the proposals should be designed to identify the lowest-cost reliable solution. Implementing such a process may be very difficult if it relies on the PJ stakeholder process. The NY ISO process utilizes the NY Public Service Commission to evaluate the proposals and select the lowest cost reliable option. For PJM, a third-party entity might be appropriate to conduct the evaluation. A third-party evaluation approach could be developed with the assistance of the Organization of PJM States (OPSI). OPSI includes state regulatory representatives from each PJM-state.
3. **Include the costs of the solutions in a transmission tariff.** Comparable reliability solutions should have comparable access to a transmission tariff mechanism for recovering costs. This is easy to say and hard to do. Transmission assets have traditionally received cost-of-service treatment. PJM states have varying degrees of cost-of-service and market-based generation resources, which complicates the use of a single PJM transmission tariff. Complicating matters, demand resources have rarely had their costs recovered through either mechanism. EE resources are implemented based on cost-effectiveness tests established by state regulatory bodies. The costs of demand response resources are sometimes recovered through special local utility tariffs or through RTO market mechanisms. It is not a simple task to develop a single transmission tariff for such a wide variety of resources; yet comparability demands just that.
4. **Allocate costs the same way as for current reliability upgrades.** If cost recovery for the entire solution to a reliability violation is successfully integrated into transmission tariffs, PJM should allocate those costs similar to the allocation of the costs of current transmission upgrades. That would mean assigning costs across a broad spectrum of parties for reliability upgrades that provide system benefits and assigning costs across a narrower spectrum of parties for upgrades that provide only local benefit

All of the recommendations in this section are part of a comprehensive package of enhancements to PJM's planning process. While all the individual enhancements are not dependent upon the implementation of the entire set, omitting some of the enhancements could lead to the need for additional or alternative recommendations. For instance, if new resources are included in models earlier based on completion of a Facility Study Agreement (FSA), the Load and Generation deliverability tests will be more robust. If resources with an FSA are excluded from the models, this would lead to a recommendation to PJM to run sensitivities to evaluate these resources. Similarly, if non-transmission components of solutions are barred from cost recovery through a transmission tariff, an alternative recommendation may be to develop a special mechanism for the recovery of the costs of non-transmission components.

D. Conclusions

In summary, PJM needs new tools to manage and prepare the bulk power system for future conditions while maintaining a reliable structure for the delivery of electricity services. In order to comply with Federal Power Act requirements to do all this without undue discrimination and at just and reasonable rates, PJM needs to minimize uneconomic resources retained through RMR contracts and implement system upgrades that resolve reliability concerns with the lowest cost solutions. Base on all of our research and analysis, PJM appears to be well aware of its responsibilities and is proactively seeking stakeholder input on enhancements to its current planning processes. The stakeholder process over the coming months will be a critical venue for implementing the many enhancements necessary.

Enhancements to PJM's solutions process will enable more robust system upgrades that do not treat every reliability violation as a nail that must be hammered with a high voltage transmission solution. Providing comparable treatment of non-transmission alternatives in analyses, implementation plans, and cost allocation under the PJM tariff will help ensure reliable operation of the bulk power system while implementing the most cost-effective solutions. Ultimately, improvements to the planning process are necessary to target investments appropriately in anticipation of future system conditions.

Appendix A.

Figures A-1 and A-2 are from a PJM RPPTF presentation on April 11, 2011.

The two figures below illustrate the challenge for transmission planners. Ideally, they want to identify future reliability violations far enough in advance to develop and implement solutions. The first figure illustrates a situation in which the uncertainty about the length of time to construct an upgrade and the onset of a violation is manageable. The second figure illustrates a less desirable situation in which the violation has already occurred before the upgrade can be completed; this situation leads to an RMR contract.

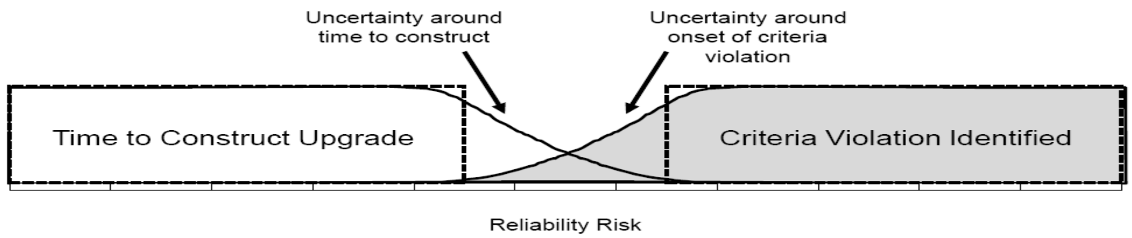

Figure A-4. Violation resolved with an upgrade.

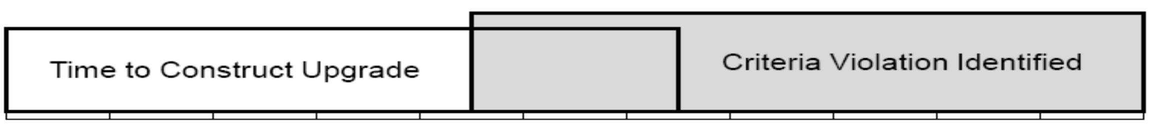

Figure A-5. Violation resolved with an RMR contract.

Figure A-3 (on the following page) is from a PJM presentation to the RPPTF on May 24, 2011. It shows a continuum of ways to authorize upgrades from a “let the market do it all” approach on the far left to a “let PJM order upgrades only after a violation” approach.

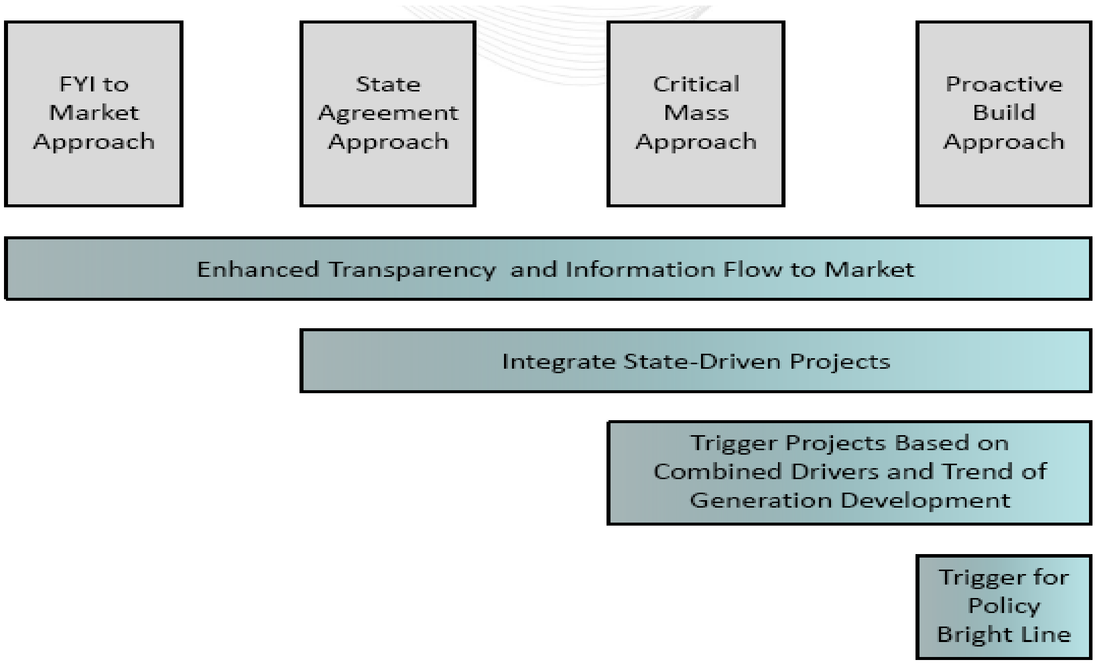

Figure A-6. Decision process options for upgrades.

Appendix B.

Section 4.2 of this report discusses the effects of energy efficiency (EE) on load forecasts in PJM. Figure B-1 below illustrates PJM's load forecast throughout 2025 under five different assumptions about EE penetration in PJM. In our analysis we used the current 2010 PJM load forecast, as reported in the 2010 RTEP,[94] and adjusted the peak loads based on different assumptions about EE program implementation.[95]

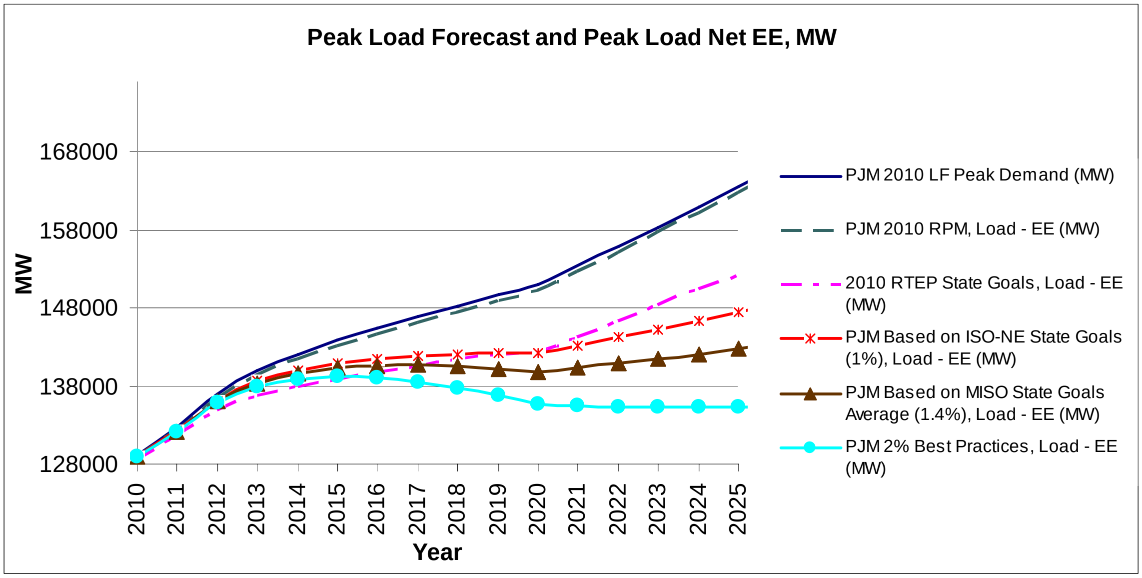

Figure B-1. PJM Base Load Forecast and Net Peak Load Under 5 EE Assumptions

We developed five net peak load projections through 2025 and compared them to a baseline estimate of future peak demand. The first projection represents PJM's current process of estimating load, which uses the amounts of EE resources that clear in the annual capacity auctions (for delivery three years forward) to adjust the PJM load forecast for future auctions. PJM assumes that the total amount of EE available in the following years stays constant at the level of EE resources cleared in the last base residual auction (BRA). However, given the results of EE participation in the recent BRAs and state EE goals and achieved EE savings, we believe that PJM's current process—labeled "PJM 2010 RPM"—significantly underestimates the impact of EE on the load forecast. To correct for this, we propose four additional scenarios with more realistic levels of EE implementation.

[94] PJM 2010 Regional Transmission Expansion Plan. Available at: http://pjm.com/documents/reports/~/media/documents/reports/2010-rtep/2010-rtep-report.ashx

[95] We based this analysis on a similar analysis we did in two recent Synapse reports: a report on demand side resource potential in MISO, *Demand Side Resource Potential: A Review of Global Energy Partners' Report for Midwest ISO ("GEP Report")*, September 3, 2010, and a report on transmission planning, *Public Policy Impacts on Transmission Planning Report for Earthjustice ("Earthjustice Report")*, December 21, 2010 (revised).

The second projection used EE numbers through 2025 based on PJM's estimate of state EE programs, as reflected in the 2010 RTEP.[96] We label this the "2010 RTEP State Goals" scenario for this report. The 2010 RTEP State Goals scenario results in significantly higher 2025 cumulative peak load savings from EE, compared to the current PJM process. These cumulative savings from EE result in a substantial reduction of the 2025 net peak load (~10,000 MW lower).

The third projection of net peak load, labeled "PJM Based on ISO-NE State Goals (1%)" scenario, is based on the performance of state-sponsored EE programs in New England, as developed by ISO-NE for the New England States Committee on Electricity (NESCOE) 2010 Economic Study. This assumption results in annual energy savings of approximately 1%.[97] Although a 1% energy savings assumption produces lower savings from EE in the first decade as compared to the RTEP 2010 State Goals scenario, it results in a continuously lower net peak load starting in 2020.

Next, we modeled a scenario based on the average of state goals for EE in the MISO states, labeled "PJM Based on MISO State Goals Average (1.4%)" scenario.[98] Based on the estimates of EE potential in numerous studies analyzed in our earlier reports, Synapse determined an average annual achievable energy savings of about 1.4% per year.[99] Compared to the 2010 RTEP State Goals scenario, this MISO States 1.4% scenario produces greater energy savings from EE starting in 2017. Through 2025, the total reduction is 20,000 MW lower than the PJM RPM case.

Finally, we developed an additional scenario that reflects a "best practices" goal for EE investment, labeled "PJM 2% Best Practices." Recent estimates of achieved EE savings and the establishment of aggressive efficiency goals in leading states support a 2% annual energy savings level.[100] Figure B-1 above illustrates the impact on the net peak load from a PJM Best Practices scenario. Peak load grows throughout 2015, then decreases slightly for the next 4 to 5 years, and then stays relatively flat throughout 2030 at a level slightly higher than the 2010 net peak load, but substantially lower than that in the other four scenarios, and especially in the PJM RPM case (more than 25,000 MW lower).

Overall, this analysis shows that all the scenarios that modify PJM's current process of peak load forecasting result in significant energy savings and reduced net load by 2025, with the Best Practices scenario resulting in a decreasing and almost flat peak load after 2015. Maintaining a constant peak load over twenty years (or decreasing it) would have profound impacts on system planning needs. Therefore, a better analysis of state EE programs will result in more accurate estimates of future peak loads in order to target investments most cost-effectively to maintain a reliable electric system.

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[96] PJM 2010 Regional Transmission Expansion Plan, Section 4, p. 77.

[97] The NESCOE 2010 Economic Study done by ISO-NE used the average increase of EE resources in the first three Forward Capacity Auctions and held that annual increase constant through 2030. The cumulative annual impact is slightly less than 1% per year.

[98] The full list of studies analyzing MISO state EE goals is provided and discussed in more details in the GEP Report and the Earthjustice Report.

[99] As reported in Synapse Energy Economics report "*Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the U.S.*", May 2010, pp. 60-61.

[100] 2% EE goal is based on the achieved efficiency savings for the selected entities' efficiency programs. The full list of these programs and a more detailed discussion of the best practices approach is provided in the GEP Report and the Earthjustice Report.

Table B-3. Comparison of PJM Net Load under 5 Scenarios

Year	PJM 2010 RPM, Load - EE (MW)	2010 RTEP State Goals, Load - EE (MW)	PJM Based on ISO-NE State Goals (1%), Load - EE (MW)	PJM Based on MISO State Goals Average (1.4%), Load - EE (MW)	PJM 2% Best Practices, Load - EE (MW)
2015	143,913	138,782	140,977	140,304	139,168
2020	150,983	142,494	142,166	139,697	135,594
2025	163,454	152,213	147,427	142,800	135,272

Appendix C.

EPA Compliance Costs

The figure below is from a report prepared by Synapse for Earthjustice, December 21, 2010. It shows several estimates of the costs of various control technologies necessary to meet new EPA regulations to improve public health by limiting air and water pollution.

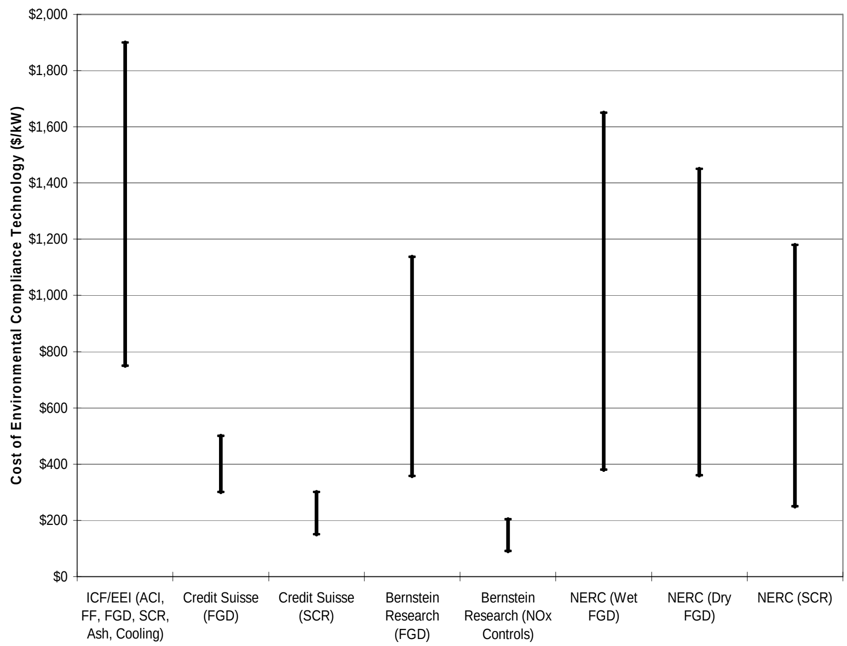

Figure 1. Estimates of Environmental Compliance Costs by Entity and Technology

TEAC Slides

The following tables come from a PJM presentation to the Transmission Expansion Advisory Committee (TEAC) on May 12, 2011. They show several different ways that PJM is analyzing (screening) at-risk coal plants that will need to retire or make significant investments in new equipment to comply with new EPA regulations.

MW of summer coal capacity without necessary SO2 controls

	PJM RTO	MAAC	Rest of PJM
Total Coal	30,156	8,873	21,283
Coal > 40 years	23,601	8,199	15,402
Coal < 400 MW	17,387	6,651	10,736
Coal > 40 years, < 400 MW	16,830	6,407	10,423

Source: PJM EIA-411 Submittal as of January 1, 2009 and
United States Environmental Protection Agency Database of Unit Characteristics
MW of Net Dependable Summer Capacity

MW of summer coal capacity without necessary SO2 and NOx controls

	PJM RTO	MAAC	Rest of PJM
Total Coal	22,849	6,326	16,523
Coal > 40 years	17,724	5,652	12,072
Coal < 400 MW	15,237	5,338	9,899
Coal > 40 years, < 400 MW	14,680	5,094	9,586

Source: PJM EIA-411 Submittal as of January 1, 2009 and
United States Environmental Protection Agency Database of Unit Characteristics
MW of Summer Net Dependable Capacity

MW of summer coal capacity without necessary mercury controls

	PJM RTO	MAAC	Rest of PJM
Total Coal	28,227	7,084	21,143
Coal > 40 years	21,577	6,400	15,177
Coal < 400 MW	15,458	4,862	10,596
Coal > 40 years, < 400 MW	14,806	4,608	10,198

Source: PJM EIA-411 Submittal as of January 1, 2009 and
United States Environmental Protection Agency Database of Unit Characteristics
MW of Summer Net Dependable Capacity

MW of summer capacity (all fuels) using once through cooling

	PJM RTO	MAAC	Rest of PJM
Oil and Gas	4,271	3,070	1,201
Nuclear	11,930	4,658	7,271
Coal	28,167	9,498	18,669
Coal > 40 years	25,554	8,878	16,676
Coal < 400 MW	17,470	6,947	10,523
Coal > 40 years, < 400 MW	17,157	6,947	10,210

Source: PJM EIA-411 Submittal as of January 1, 2009 and
EIA-767, 2000 and 2005, EIA-860, 2008
MW of Summer Net Dependable Capacity

Suggestions for Operating Agreement Changes

The following changes to PJM's Operating Agreement would provide a more comprehensive analysis of at-risk resources, improve PJM's estimates of likely retirements, and allow time to develop solutions for actual retirements. The proposed changes (in **bold**) are to the Operating Agreement, Schedule 6.

- Change section 1.4(b) of Schedule 6 to read:

  "The Regional Transmission Expansion Plan shall reflect, consistent with the requirements of this Schedule 6, transmission enhancements and expansions; load forecasts; expected demand response; and capacity forecasts, including generation additions and retirements, for at least the ensuing ten years. **With regard to retirements, PJM should identify at-risk generation, assess the specific nature of the risk and any costs associated with remediating the risk (e.g. compliance with specific regulations), and assess which specific plants may retire at some point over the ten-year period."**

- Change section 1.5.4(d) of Schedule 6 to read:

  "The Transmission Expansion Advisory Committee and the Subregional RTEP Committee shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the RTEP process. The purpose of the assumptions meeting shall be the following: (i) establish the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities, (ii) incorporate regulatory initiatives as appropriate, including **federal and** state regulatory agency initiated programs **that may impact generation retirements**, (iii) provide an open forum to review the impacts of regulatory actions, projected changes in load growth, demand response resources, generating capacity **including additions and retirements**, market efficiency and other trends in the industry, and (iv) provide an open forum for the review of alternative scenarios proposed by the Committee participants. The final assumptions shall be determined by the Transmission Expansion Advisory Committee for both the Regional RTEP Project and Subregional RTEP Project."

- Change section 1.5.7(k)(viii) of Schedule 6 to read:

  "Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues and Capacity Resource Clearing Prices under Attachment DD of the PJM Tariff. **PJM should also evaluate generation units that are impacted by existing, proposed, or anticipated federal or state actions, and consider whether or not these generation units may elect to retire as a result.** If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues."

These changes to the Operating Agreement should be sufficient to develop the specific screens and thresholds by which PJM could make reasonable decisions about the resources that will be available to meet reliability needs.[101] For resources deemed not available but necessary for reliable system operations, PJM could request proposals for solutions and initiate studies to accommodate the retirement of these resources while reliability standards are maintained.

[101] The screens and threshold may be specified in a Manual, the Operating Agreement, or Tariff as appropriate.

Appendix D.

With NYISO's example in mind, we recommend that PJM change the RTEP process to include consideration of demand response and other alternative solutions that have not cleared the RPM. To this end, we recommend the following changes to Schedule 6 of the Operating Agreement and to Manual 14B (new text in **bold**):

- Change section 1.4(d) of Schedule 6 of the Operating Agreement to read:

  The Regional Transmission Expansion Plan shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities; (iii) take in account the legal and contractual rights and obligations of the Transmission Owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM Region**, including non-transmission alternatives**;

- Change section 1.5.6(c) of Schedule 6 of the Operating Agreement to read:

  The recommended plan shall include proposed Merchant Transmission Facilities within the PJM region and any other enhancement or expansion of the Transmission System**, or non-transmission alternatives,** requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System…

- Change the Section 2.6 of Manual 14B to read:

  Market efficiency analysis is performed as part of the overall PJM Regional Transmission Expansion Planning (RTEP) process to accomplish the following two objectives:

  1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.
  2. Identify new transmission upgrades **or alternative solutions, including generation and demand response resources,** that may result in economic benefits.

Appendix E.

General Jurisdiction

FERC's jurisdictional authority over transmission derives primarily from Section 205 of the Federal Power Act, which gives FERC authority to regulate:

> "…rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electricity subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or changes."[102]

From the perspective of transmission planning, the key phrases are "in connection with" and "affecting or pertaining to," which grant FERC the authority to look at issues that extend beyond simple ratemaking. For example, FERC has used Section 205 to assert that it has the "authority to set the compensation level for demand response in organized wholesale energy markets" [103] and that it further "has jurisdiction to regulate the market rules under which an ISO or RTO accepts a demand response bid into a wholesale market." [104]

That FERC has exclusive jurisdiction over transmission regulation was established in Order 888, in which the Commission declared that it had "exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, up to the point of local distribution."[105] To differentiate transmission from local distribution, FERC established a seven-factor test,[106] though it has generally deferred to state regulators to determine the jurisdictional boundary.

FERC reaffirmed this stance in Order 890, noting further that it recognized "the need for heightened cooperation between federal and state regulators in areas where there are overlapping federal and state policy concerns."[107]

In a recent Synapse report for Earthjustice[108], we addressed the issue of FERC jurisdiction with regard to ordering changes to the RTO's transmission planning process. As discussed in the report, the Commission has the statutory obligation pursuant to the Federal Power Act to ensure that rates are just and reasonable and not unduly discriminatory. The Commission has exercised

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[102] 16 U.S.C. 8 824d(a)
[103] FERC Order No. 745, paragraph 112
[104] *Ibid,* paragraph 113
[105] FERC Order No. 888 at 31,781
[106] (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems, and rarely, if ever flows out; (4) when power enters a local distribution system, it is not re-consigned or transported on to some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographic area; (6) meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and (7) local distribution systems will be of reduced voltage. Order No. 888 at 31,771 and 31,981.
[107] FERC Order 890, paragraph 94.
[108] Synapse Energy Economics. September 2010. "Public Policy Impacts on transmission Planning", prepared for Earthjustice. We refer to this report throughout as the *Earthjustice* report.

that authority in Order 890 to impose obligations on planning authorities. The current transmission NOPR recommends further enhancements to existing planning processes.[109]

FERC Order 890 Compliance

Order 890

On February 16, 2007, FERC issued Order 890 to prevent undue discrimination in transmission services.[110] The Order identified key principles that all Planning Authorities must address in their transmission planning processes. Complying with these principles is necessary to provide for non-discriminatory, reliable service to transmission customers. The Order 890 principles include the following:

- coordination
- openness
- transparency
- information exchange
- comparability
- dispute resolution
- regional participation
- economic planning studies
- cost allocation for new projects

To demonstrate compliance with these principles, each Planning Authority was required to make a filing that specifically incorporated these principles in its transmission planning process or identify where in its current rules that these principles were being implemented. PJM, similar to other RTOs and ISOs, had already developed transmission planning processes that incorporated many of the principles and had them approved by the Commission prior to the issuance of Order No. 890. Nonetheless, PJM submitted a compliance filing that enumerated its current compliance and enhancements to its planning process to meet all of the principles and related criteria specified in the Order No. 890 process.

In the next appendix, we include excerpts form a FERC Staff White Paper that details the many issues that all transmission planning entities must address to be complaint with Order No. 890.

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[109] *Transmission Planning and Cost allocation by Transmission Owning and Operating Public Utilities,* RM10-23, 75 Federal Register 37,884 (June 30, 2010).
[110] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs.

Appendix F.

The language below is excerpted from a White Paper prepared by FERC Staff to assist entities required to comply with Order No. 890 (*Preventing Undue Discrimination and Preference in Transmission Service, RM05-17 and RM05-25)*. The White Paper, inserted into the official record on August 2, 2007, lists many issues that transmission providers must address in their compliance filings to show that their planning process meets Order No. 890 standards.

Order 890 Principles

1. Coordination

Purpose: Eliminate the potential for undue discrimination in planning by opening communication between transmission providers, their transmission-providing neighbors, affected state authorities, customers, and other stakeholders

Recommended issues:

a) Describe whether any committees or meeting structures will be used to conduct planning activities

b) If groups or committees are used, describe how they will be formed, the responsibilities of each, and how decisions will be made within the group and/or committee

    a. Identify the rules governing committee and group activity and whether those rules are established by the transmission provider or committee/group itself

    b. Clearly identify the matters for which a particular group or committee is responsible so that stakeholders can easily access to particular planning activities in which they are interested. Keep number of groups to a manageable size.

c) Describe role transmission provider will play in coordinating activities of the planning committees

d) Describe existing processes, and changes thereto, that will be used to satisfy requirements

e) Describe frequency of meetings. Recommend schedule provide opportunity for input regarding

    a. Data gathering and customer input

    b. Review of study results

    c. Review of draft transmission plans

    d. Coordination of draft plans with those of neighboring transmission providers

f) Describe procedures use to notice meetings. Recommends use of OASIS page containing information such as

    a. Notice procedures and contact info

b. Calendar of meetings

c. Subscription page

d. Form in which meetings will take place

2. Openness

Purpose: Requires that transmission planning meetings be open to all affected parties.

Recommended issues:

a) Describe who participants will be

b) Describe what data is confidential, the criteria used to identify such data, and the eligibility criteria and process for obtaining access

   a. Provide clear rules governing:

      i. Party access

      ii. Disclosure to FERC, state commissions, and other authorized parties, including timeline for disclosure

      iii. Use and applicability of non-disclosure agreements or other arrangements

      iv. Procedures regarding breach and liability

3. Transparency

Purpose: Requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans, including how they treat native loads, in order to ensure that standards are consistently applied. To that end, transmission providers must describe in relevant attachment the method(s) they will use to disclose the criteria, assumptions and data that underlie its transmission system plans. Sufficient information should be made available such that interested parties are able to replicate the results of planning studies.

Recommended issues:

a) Describe planning cycle and important milestones in the cycle

   a. Identify frequency of transmission plans and planning study horizon

   b. Provide flow chart diagramming the steps of the planning process. Should include where in process various resources (generation, DR, transmission) are considered

b) Describe planning methodology and protocols use to develop plans

   a. Describe clearly methodology (load flow, stability, short circuit, voltage collapse, and production cost), criteria used, and process for establishing assumptions, as well as the methodology for determining import/export capability.

b. Provide description of the criteria for the design of new facilities or qualification of DR

c. Any software or analytical tools used should be identified and described

c) Describe procedure for communicating with customers and other stakeholders regarding basic criteria, assumptions, and data

a. Describe how assumptions are developed

b. Details regarding the type, rating or size, responsiveness and other operating info should be readily available to stakeholders at all stages of the planning process

c. Clearly identify the process that an interested party should follow to obtain access to the underlying data used for transmission planning, such as load flow base cases and associated files needed for transmission planning, e.g. contingency files, and whether such data will be subject to confidentiality protections.

d. Participants should be given the opportunity to question and discuss the initial assumptions. Identify the process for this dialogue (in-person meetings, written submissions, etc.)

e. Develop process to notify interested parties of changes or updates in the data bases, and whether change was made independently or in response to stakeholder concern.

d) Describe how and when transmission plans and other info will be presented to customers and other stakeholders

a. Develop transmission plan briefing paper

b. Identify a knowledgeable technical point of contact to respond to questions

c. Involve customers early in process

e) Describe procedure for sharing information regarding the status of upgrades

a. Identify frequency of updates and how such upgrades or alternatives are reflected in future plan development (i.e. in-service, under construction, planned, proposed, or concept)

b. Establish a process by which stakeholders can discuss, question, or propose alternatives for any upgrades identified by the transmission provider

4. Information Exchange

Purpose: Requires network customers to submit information on their projected loads and resources on a comparable basis as used by transmission providers in planning for their native load. Point-to-point customers are required to submit any projects they have of a need for service over the planning horizon. Transmission providers are to develop guidelines and a schedule for the submittal of such customer information. To the extent applicable, transmission customers should provide information on existing and planned DR and their impact on demand, and stakeholders should provide proposed DR resources.

Recommended issues:

a) Describe obligations and methods for customers to submit data to transmission provider

    a. Identify how information will be used

    b. Describe schedule and procedures for submission of information

        i. Data exchange could be accomplished through automated means

5. Comparability

Purpose: Requires transmission providers to develop a transmission system plan that meets the specific service requests of their transmission customers and otherwise treats similarly-situated customers comparably in planning. DR should be considered on a comparable basis. This is a **core legal obligation** and should be addressed throughout process.

6. Dispute Resolution

Purpose: Requires transmission provides to identify a process to manage disputes that arise from the planning process. If existing system is to be utilized, must specify how it will address matters related to transmission planning. Transmission providers are encouraged to use FERC's Dispute Resolution Service (DRS) to develop a three step dispute resolution process: (1) negotiation; (2) mediation; (3) arbitration

Recommended issues:

a) Describe process

b) Describe issues, procedural and substantive, that will be addressed

7. Regional Participation

Purpose: Each transmission provider is required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources.

Recommended issues:

a) Identify entities with which the transmission provider engages in regional planning and responsibilities of each.

    a. Identify interconnected systems; if duties are shared, detail how

    b. If planning is performed by regional entity, participants and their obligations should be identified

    c. Consider the use of sub regional groups to aid in regional planning

b) Describe interaction between local planning and regional planning activities

a. Explain whether local process differs from regional process

b. Address whether assumptions used in local planning will differ from those used in regional planning

c) Describe inter-regional planning activities in which the transmission provider participates

d) Describe process for reviewing and coordinating the results of sub regional, regional, and inter-regional planning activities.

a. Process for certifying or approving the results of studies should be clearly described.

b. Develop process for determining whether local, sub regional, regional, and inter-regional plans are simultaneously feasible.

e) Describe

a. The forms of sub regional or regional planning that occur today

b. Modifications or improvements that are being proposed

c. Reasons why a particular region or sub region was chose

d. Process by which proposed sub regional or regional planning processes can evolve over time

8. Economic Planning

Purpose: Requires transmission providers to account for economic, as well as reliability, considerations in the planning process. This principle is designed to ensure that economic considerations are adequately addressed when planning for OATT customers. The scope of economic studies should not be limited to just individual requests. Customers must be given the opportunity to obtain studies that evaluate potential upgrades ore other investments that could reduce congestion or integrate new resources and loads.

Recommended issues:

a) Describe scope of economic planning

a. Type of planning studies performed and the classes of transmission users on whose behalf they are performed

b. Explain whether reliability and economic projects are considered separately and, if so, how do the results of one feed into the other

b) Describe how economic planning studies may be requested

a. Identify the number of high priority studies they will perform on behalf of stakeholders in a given timeframe. Procedures for adding additional studies should also be identified

b. Recommended to provide an open forum for all stakeholders to identify and prioritize which studies will be requested

c. Data exchange requirements should be clearly identified

d. Transmission providers should state the procedures for posting requests for studies and responses to requests

c) Describe mechanism to recovering costs incurred to perform economic planning studies

a. How are these costs reflected in OATT rates

b. Identify mechanism for recovering cost of additional studies from those stakeholders that requested the study

9. Cost Allocation

Purpose: Requires that transmission providers address in their filing the allocation of costs of new facilities that do not fit under existing rate structures. Transmission providers were directed to identify the types of new projects that are not covered under existing cost allocation rules.

Recommended issues:

a) Factors to consider

a. Proposal should fairly assign costs among participants, including those who cause them to be incurred and those who benefit from them

b. Cost allocation proposal should provide adequate incentives to construct new transmission

c. Cost allocation proposal should be generally supported by state authorities and participants

b) Describe the methodology for allocating costs associated with economic and reliability upgrades

a. Consider need for ex ante certainty through definite cost allocation rules and clear rules for identifying who benefits from specific projects

b. For transmission owners or regions that propose to roll-in the cost of certain facilities across more than one transmission owner, parties should consider the factors addressed in recent precedent to determine which projects should qualify for rolled in treatment (e.g. reliability or economic), what criteria is used for project approval (e.g. net benefits using production cost simulations) and at what voltage level rules will apply

c. For transmission owners or regions that seek to rely on a “beneficiaries pay” approach, as much detail as possible should be provided regarding how the approach will be applied.

i. How beneficiaries will be identified and whether classes of customers will be identified for purposes of allocating project costs

ii. How project costs will be allocated to an entity whose needs may not have given rise to the upgrade, but that nevertheless has a need during the planning horizon that is met in whole or in part by that upgrade

iii. How identified beneficiaries may address alternatives or deferrals of transmission line costs, such as through the installation of distributed resources

d. Transmission owners and regions seeking to rely on a “requester pays” approach should also include as much detail on how that approach will be applied

i. How project costs will be allocated when more than one entity requests them

ii. How project costs will be allocated when the requested project accelerates or expands an upgrade that was already planned for native load customers

iii. How project costs will be allocated for “lumpy additions” in which the upgrade is far larger than needed by the requester

c) Describe the roles and responsibilities of the transmission provider and stakeholders during the cost allocation process

a. Clearly identify the obligations they and their stakeholders have with regard to cost allocation at each stage of the project development cycle.

b. Describe the processes for stakeholder involvement in the cost allocation process

10. Recovery of Planning Costs

Purpose: Transmission providers should work with other participants in the planning process to develop cost recover proposals in order to determine whether all relevant parties, including state agencies, have the ability to recover the costs of participating in the planning process. Transmission providers should also consider if regional cost sharing mechanisms are appropriate

Recommended issues:

a) Describe methodology

a. Describe any existing mechanisms under OATT or other funding sources

b. If additional cost recover mechanisms are contemplated, describe them clearly along with specific types of costs to which they will apply and how they interact with mechanisms to recover the costs of economic planning

c. Work with stakeholders and state agencies to determine if any other entities are in need of cost recover for planning related activities and, if so, how these costs will be recovered

d. Describe whether costs associated with planning activities will be allocated to any particular customers, including whether regional cost allocation agreements are considere