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Resource Incentives

Valuing Resources in PJM's Wholesale Markets

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This final version benefits from comments from that workshop. We also incorporate some additional information from late 2011. Current events may quickly outpace the suggestions in this paper, or lead to their modification. There are still many unanswered questions and evolving concepts related to performance incentives for resources in wholesale competitive markets.

-The Authors

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Executive Summary

A. Introduction

This paper evaluates how specific resources could receive enhanced compensation in RTO wholesale markets. We focus on the PJM Interconnection as an example of RTO wholesale markets that could provide incentives to resources with desirable attributes. We discuss market incentives for three general categories of resource characteristics:

- Resources with operational flexibility to respond to system needs in two hours or less;
- Resources that satisfy specific state or federal policies such as renewable portfolio standards or specific resource-type goals; and
- Resources that provide reductions in the carbon footprint of existing system resources.

PJM has no obligation or authority today to select any of these resources for special treatment. However, evolving trends in system planning and public policies at the state and federal level may provide support for one or more of these classes of resources to be provided preferences.

B. Background Issues

There are several new trends that are likely to require changes in system planning and resource selection in the 21st century. The most fundamental change is the decoupling of electric demand from economic growth. Since the mid-20th century, the linkage between economic growth and increased energy consumption has steadily eroded. Electricity consumption relative to overall economic growth has been cut in half from 1949 through 2009; recent trends indicate that it will be cut in half again in the next decade. Energy intensity, the amount of electricity per unit of GDP, has steadily decreased in the last decade. This trend reflects fundamental changes to the US and the world economy since the initial oil shortages of the 1970s.

Other trends are also increasing this shift away from traditional generation and transmission infrastructure growth. States and the federal government are enacting public policies that promote energy efficiency, renewable generation, distributed generation, and restrictions on air emissions that damage the public health. We document the elements of many of these changes and the response from the Federal Energy Regulatory Commission (Order 1000) that requires regional planning authorities to consider these changes in their system planning processes.

PJM has already begun proposing fundamental changes to its planning process, a process that covers the largest wholesale market in the country and impacts 13 states and the District of Columbia. PJM also administers numerous wholesale competitive markets and administrative compensation mechanisms that produced almost $35 billion of billings in 2010.

C. Resources for Enhanced Revenues

We discuss three categories of resources that could be eligible for enhanced revenues. These are not the only resources that could be designated as eligible, but they are the ones that we judge to be at the top of most lists.

Fast start resources, which we define as resources available in two hours or less, will provide more flexibility to grid operators who will need to schedule resources in an increasingly complex and variable bulk power system. The growing penetration of wind and solar resources, the likely retirement of significant quantities of fossil fuel resources, and the greater participation of demand response and price responsive demand will increase the value of flexible, fast starting resources. In well designed markets, the increased value of these resources should be reflected in increased market revenues.

Resources that are developed to meet state or federal policy goals should also have opportunities to earn extra market revenues. These enhanced revenue opportunities could come from premium payments from particular markets, or through preferences in scheduling or dispatch. In the same manner that RTOs currently dispatch resources to maintain reliability, with more expensive (out-of-market) resources getting a preference to ensure an adequate supply of reserves, RTOs could dispatch renewable resources (for example) out-of-merit in order to meet air quality standards or goals.

RTOs may also be asked to coordinate dispatch and market compensation to achieve state or federal carbon reduction targets or mandates. Such actions would need to be specifically authorized for a wholesale market administrator such as PJM, either through specific legislation or delegated authority from the Federal Energy Regulatory Commission. The detailed market mechanisms that an entity such as PJM would develop and implement would also need to be specified. Wholesale market administrators are uniquely situated to coordinate such legislative and regulatory mandates, should they be enacted.

D. Market Enhancements

We discuss two primary market mechanisms for providing enhanced revenues: 1) PJM's three-year forward capacity market, the reliability pricing model (RPM); and 2) ISO New England's forward reserve market (FRM).

RPM, similar to ISO New England's forward capacity market (FCM), conducts an annual capacity auction for a resource delivery period three years into the future. All resources that clear in the auction are paid the same clearing price, with adjustments for locational delivery constraints (congestion). In addition, RPM pays demand response resources a slightly different price based on their availability. New England also pays a single clearing price for its capacity resources, with adjustments for locational constraints and a reduction in payment for emergency demand response resources that have a very limited availability. We suggest that PJM could develop additional categories of resources, based on the three general characteristics discussed above, and pay them a direct capacity premium through the RPM auction or allow them to clear at a higher price.

The New England FRM is a separate market for resources that can provide reserves within ten minutes or thirty minutes. The FRM also has a locational component that allows for higher payments to reserve resources in constrained zones with limited import capability. PJM could implement a market similar to the FRM and include a separate category for resources that could respond in two hours, in addition to resources with ten-minute and thirty-minute response times. Alternatively, PJM could develop a separate market for renewable resources or carbon reducing resources modeled after the FRM.

E. PJM Process

We include a brief discussion of the options that stakeholders could use to advance market changes in PJM. There is the traditional stakeholder committee process that can often require many months, if not years, of discussion and review. Proposals that are endorsed through the stakeholder process are filed at the FERC under section 205 of the Federal Power Act, and action by the Commission (usually approval) is required in sixty days. PJM also has an option for a group of five stakeholders to create a self-defined User Group. Proposals developed through the User Group process have a shorter route to a final decision by PJM stakeholders (less than a year) but the shortened process may also decrease the likelihood of endorsement and filing under section 205. A third option is a section 206 filing under the Federal Power Act. A 206 filing goes directly to the FERC, but the burden of proof is substantially higher than a 205 filing and the Commission is not obligated to act within any specific timeframe.

We conclude that there are options for providing enhanced revenues to specific resources through wholesale market mechanisms in PJM, or any other RTO. The need for these revenue enhancements is likely to grow in the 21st century based on the trends we have identified. The key uncertainty is the enactment of public policies, legislation, or regulations that will define the resources eligible for enhanced payments and authorize RTOs to implement specific changes to their wholesale market structures to provide the incentives.

1. Introduction

This paper examines how wholesale electricity markets can be modified or expanded to align financial incentives from the marketplace with resources that have certain desired policy attributes.

In this paper, we examine two approaches for providing enhanced revenues through wholesale markets to selected categories of resources. We focus on PJM's Reliability Pricing Model (RPM) and New England's Forward Reserve Market (FRM) as examples of structures that can provide additional revenues to resources with specific characteristics. Other structures could also be developed either as part of regional wholesale markets or as stand-alone mechanisms. We focus on two options that could be models for providing enhanced revenues. It is uncertain if any mechanism, market or otherwise, will be developed to provide incentives for resources with specific attributes. And, there is no current mandate for regional transmission entities (RTOs and ISOs) to be the primary implementers of such mechanisms. The decisions as to whether these models or other mechanisms are developed and who will develop them are the subject for a future paper.

We discuss market incentives for three general categories of resource characteristics:

- Resources with operational flexibility to respond to system needs in two hours or less;
- Resources that satisfy specific state or federal policies such as renewable portfolio standards or specific resource-type goals; and
- Resources that provide reductions in the carbon footprint of existing system resources.

The mechanisms we discuss could also be applied to resources with other desired characteristics that satisfy operational needs or state and federal policy goals. We are not advocating for any specific resources in this paper. Instead, we are reviewing current industry trends and identifying ways that existing markets structure could be used to provide incentives to different categories of resources. There needs to be a broad discussion about which specific resources should receive incentives, and the magnitude of those incentives. Once that debate has taken place and decisions are made, the options identified in this paper may assist in the development of specific mechanisms to implement those decisions.[1]

To provide context to our discussion and analysis, we focus on the PJM Interconnection. We could have chosen another regional transmission organization, but PJM is the largest and most complex of the existing RTOs and ISOs. In addition, PJM is one of the oldest RTOs and has a history of innovation and responsiveness. We believe that our analysis applies to other regional organizations. With certain modifications, other regions could also implement mechanisms to provide enhanced revenues to resources with specific attributes.

[1] In prior reports, we have recommended changes to RTO planning processes to address overall electric system efficiency and associated environmental impacts. This paper focuses on changes to competitive markets that could also improve efficiency and reduce environmental damage. Ideally, RTOs should focus on changes to both planning procedures and market structures.

2. Background

In this section, we provide the historical and current context for proposing enhanced revenues for specific resources.

A. The Evolving Power Sector

Many of the historical certainties related to bulk power electric systems are much less certain today. Fundamental economic shifts on a global basis have led to a steady erosion of manufacturing and industrial production in the United States; a more service- and technology-based economy has developed. Technological changes continue to create downward sloping cost curves for many renewable resources, including wind and solar. More efficient appliances, lighting, motors, and buildings have the potential to stabilize energy consumption for many years while providing enhanced services and comfort. State and federal policy makers are developing and implementing new rules and procedures that will encourage more sustainable energy resources and reduce harmful environmental impacts. Regional grid operators are reforming system planning and market structures to better forecast and align bulk power electric systems with the numerous technological and policy changes that are occurring. In this section of the report, we briefly identify and discuss some of these important changes.

Decoupling Electricity Demand and Economic Growth

A core historical trend that is driving the need to reform bulk power system markets and planning is the decoupling of electricity use from economic growth. This trend is illustrated in the two figures below.

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

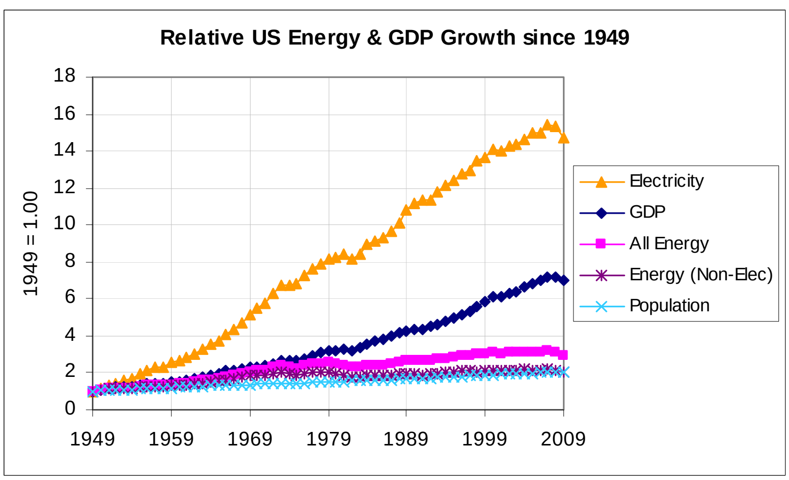


Figure 1 shows that historical constant load growth in electricity consumption has been slowing since the mid-1970s. Taking the two 30-year periods shown on the graph, during the first 30 years (1949 – 1979), electricity consumption increased by a factor of four. Over the next 30 years (1979 – 2009) electricity consumption increased by a factor of two. This implicit change in annual growth rates roughly coincides with the increase in commodity fuel costs since the first oil embargo in

1973. This long-term trend of lessening electricity consumption relative to economic growth reflects structural changes in the economy, consumer responses to prices, and the impact of specific programs and policies. As a result of these two factors, energy use and electricity consumption growth rates have begun to flatten over the last decade. 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

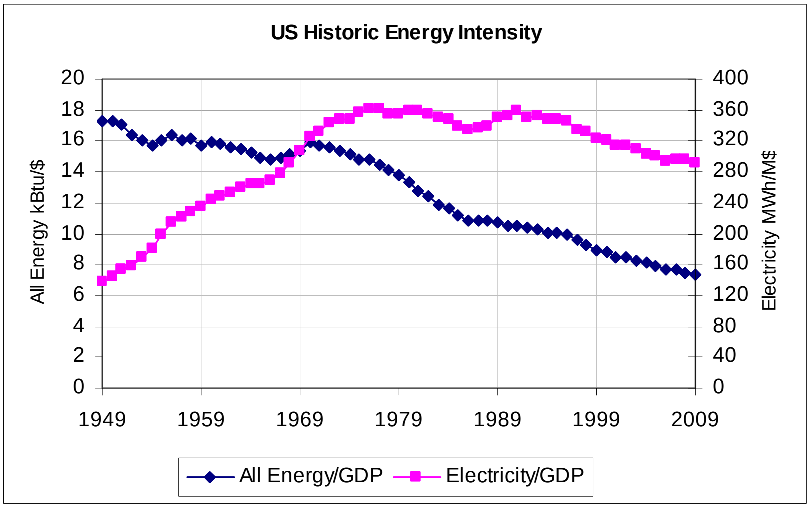


Figure 2 illustrates this improving trend by comparing the amount of energy we consume with the quantity of goods we produce. Energy intensity (the measure of how much energy is needed to produce a widget, heat a building, and so on) has been improving under both the "all energy" metric and the "electricity 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.[2]

These improvements in energy consumption and energy intensity also reflect changes to the kinds of goods and services that our economy provides. The industrial and manufacturing processes that once dominated our economy have been replaced with information, technology, health, and services industries. In general, these new industries do not use as much energy to produce valuable products and services as the old industries, many of which are now dominated by overseas companies.

[2] 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.

The electric industry that evolved during the last half of the 20th century was 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 generation and transmission upgrades 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" facilities would be just what were needed.

That time has passed. It is critically important that grid operators recognize the new trends in technology and resources that will be developed in the 21st century for bulk power system planning. If they do not, they will over-estimate electrical demand, resulting in an over-built and overly expensive bulk power system due to stranded assets. 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 bulk power paradigm may be eroded even faster as more direct public policies kick in. These trends of increased efficiency and renewable resources are occurring without an explicit carbon price adder that would only act to accelerate these trends. Nor do these trends fully reflect recent efforts to accelerate efficiency and renewable resources 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 years (if ever).

Specific Technology and Policy Changes

Other shifts further challenge traditional notions of system 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 grid 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 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, a challenge that 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.

In the next sub-sections, we examine a few of these new trends and how they can have significant impacts on PJM's bulk power system.

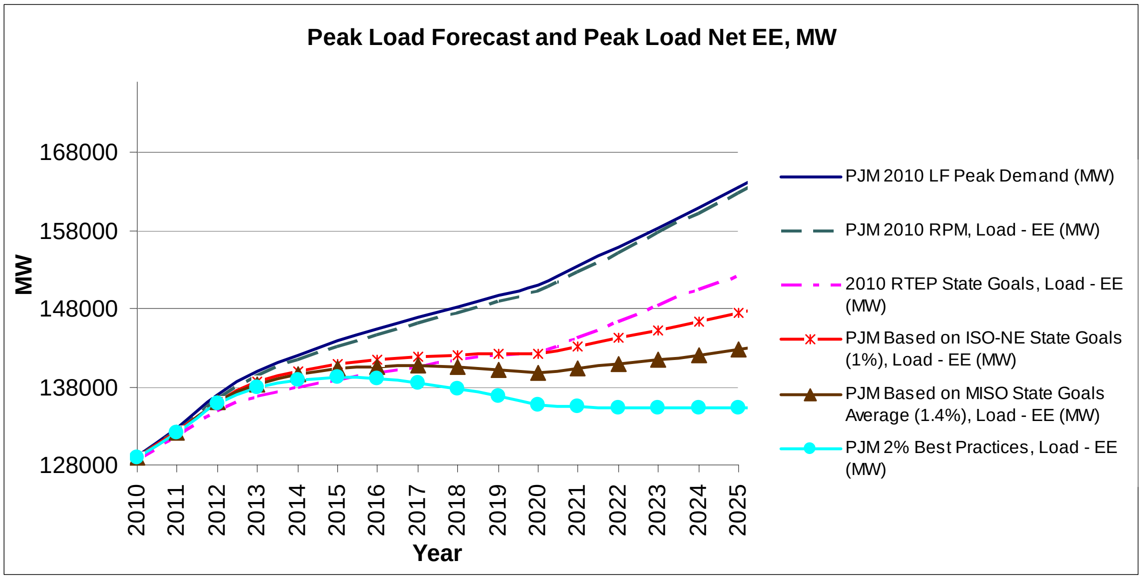
Impacts in PJM from State EE programs

Figure 3 below illustrates PJM's load forecast throughout 2025 under five different assumptions about energy efficiency (EE) penetration in PJM. In our analysis we used the current 2010 PJM load forecast, as reported in the 2010 RTEP,[3] and adjusted the peak loads based on different assumptions about EE program implementation.[4]

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

[4] 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).

Figure 3. PJM Base Load Forecast and Net Peak Load Under 5 EE Assumptions



The five scenarios represent different assumptions about the rate of implementation of EE programs.[5]

The quantity and types of resources that PJM will need in the future will vary a great deal depending on which EE forecast proves to be the most accurate. If the states in PJM implement energy efficiency measures at a rate similar to either the New England or MISO states, the PJM system peak will be approximately 20,000 MW lower in 2025. If the PJM states are able to implement energy efficiency measures at a best practices level, the reduction will be almost 30,000 MW.

Impacts in PJM from State RPS Goals

Most of the fourteen states that make up the PJM footprint have enacted regulations that require increasing amounts of annual energy consumption to be met by certain defined renewable resources.[6] Table 1 below summarizes the renewable portfolio standards that have been adopted.

[5] See appendix A for a discussion of each of the assumptions.
[6] All PJM states and the District of Columbia have enacted some form of renewable portfolio standard except Indiana, Kentucky, and Tennessee.

Table 1. RPS Goals in PJM States

State	RPS Percentage
DC	Total – 20% by 2020
DE	Total – 26% by 2026
IL	25% by 2026
MD	Total – 20% by 2022
MI	10% by 2015
NC	12.5% by 2021

State	RPS Percentage
NJ	Class I – 17.8% Total – 22.5% by 2021 Solar – 5,316 GWh (2026)
OH	12.5% by 2024
PA	Tier I – 8.0% Total – 18.0% by 2021
VA	12% by 2022
WV	25% by 2025

Source: PJM 2010 Regional Transmission Expansion Plan

The RPS goals are expressed as percentages of annual energy use, but they can also be translated into peak load MW values by applying assumptions about resource types (each with a specific capacity factor) and operational characteristics. For example, the MWh of energy from solar PV systems could be converted to peak load MW values based on locational solar radiation tables and adjustments to account for cloudy, partially cloudy, or clear days. Similarly, MWh from wind systems could be adjusted to peak load values based on seasonal and, eventually, daily capacity factors.

On a system-wide basis, implementation of RPS goals would provide significant MW of new resources that would alter the need for traditional generation resources, or transmission enhancements to deliver those traditional resources. However, depending on the location of the RPS resources, additional transmission infrastructure could be necessary in order to deliver the output of remote RPS resources to load centers.

State or federal policies to encourage specific resources through feed-in tariffs would have similar impacts to RPS goals on the bulk power system. Distributed generation goals and demand response goals would also need to be accounted for in system planning studies that evaluate future resource and transmission needs.

Impacts in PJM from EPA Regulations

Table 2. Composition of Coal-fired Capacity in PJM by Age, Size, and Location[7]

	PJM RTO	MAAC	Rest of PJM
Total Coal	78,613	18,761	59,852
Coal > 40 years	41,815	12,334	29,481
Coal < 400 MW	26,645	7,162	19,483
Coal > 40 years, < 400 MW	22,907	5,759	17,138

[7] Source: Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants, PJM Interconnection. Page 15, Table 5. August 26, 2011.

The potential retirement of over 22,000 MW of coal-fired generation is likely to present significant challenges to the PJM grid operators. Many of the older, less efficient plants that are most likely to retire are located close to loads and have been essential elements of the bulk power system for decades. The retirement of these units will require close scrutiny of resource adequacy, operational, and stability issues.

Resource adequacy involves an annual assessment of the total quantity of resources available to meet peak loads. These peak loads most often occur during the summer period of June through September for PJM. Because many of the coal-fired units that are anticipated to retire are small, the issue of resource adequacy may be limited to areas that are currently experiencing congestion due to inadequate or near-inadequate quantities of resources.[8] However, multiple small unit retirements or a single large unit retirement could trigger resource adequacy concerns.

Operational concerns refer to the day-to-day commitment of resources to meet anticipated loads and maintain adequate reserves. Even if total resource adequacy issues are met, the specific combination of resources that the PJM grid operators schedule to meet each day's loads must be flexible and robust enough to meet both known and unknown contingencies.[9] To meet NERC established reserve requirements, there must be a minimum level of resources that can ramp up their output or start-up and synchronize to the grid within predetermined time parameters.[10] Most coal-fired units are not able to ramp or start-up on short-notice; if some retire, and grid operators replace them with other resources that previously had been held in reserve to provide energy on short-notice, the operators may not be able to maintain their reserve requirements unless additional, new fast-start resources are built.

Stability issues refer to voltage fluctuations, short-circuits, and other technical issues related to the overall balance of the bulk power grid. Grid operators must constantly monitor the stability of the bulk power system to ensure that power flows smoothly and seamlessly throughout the interconnected system. The removal of existing resources and the addition of new resources have the potential to cause disruptions to power flows. All new resources and all retiring resources need to be modeled to ensure that their operation, or removal, will not disrupt the overall stability of the system. The precise physical location of the resource can have a major impact on the system, too. In many circumstances, enhancements to the overall grid must be made before a specific resource can either be added or removed.[11]

The cost of system enhancements can be large or small, and the timeframe for implementing them can also vary a great deal depending on whether or not the enhancements require shutting down small or large parts of the existing grid for either short or long periods of time. In summary, while it may be easy to estimate the costs of compliance for individual coal-fired resources, the overall compliance costs for the bulk power system are extremely dependent on the location and

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[8] In PJM, these areas of congestion appear to be limited to portions of the mid-Atlantic region.

[9] A known contingency is a resource or transmission line that will not be available due to a scheduled or unscheduled outage. An unknown contingency is the sudden loss (trip) of a resource or a transmission element during the day. These unknown contingencies may be random, but they are still "planned" for in the day-ahead commitment schedule by committing some units as reserve units.

[10] The time requirements are often as short as ten to thirty minutes, although a resource that can start with two hours notice can be very useful to grid operators. Two-hour flexible resources are helpful when the grid operators have committed the ten-minute and thirty-minute resources and then need to have additional resources available if more contingencies (resource or transmission failures) occur.

[11] These enhancements may include the addition of transformers, shunt reactors, new ring busses, new wires, etc.

size of the specific units that plan to retire. Until those at-risk units are identified, the PJM grid operators will have difficulty analyzing and proposing accommodations for those retirements.

FERC Recognizes the Need for Change

In July 2011, the FERC issued Order No.1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*. In Order 1000, the Commission expands upon prior Order No. 890 and 888.[12] The Commission states that planning authorities, such as RTOs, must consider public policies that can drive transmission needs, provide comparable treatment of traditional and non-traditional solutions to reliability needs, and develop mechanisms for funding solutions to reliability needs that are not unduly discriminatory. The goal is to provide stakeholders in a regional transmission planning process with the information necessary to allow them to propose and evaluate the most cost-effective and efficient solutions to regional and inter-regional needs.[13]

The Order provides a lot of flexibility in regard to how a regional planning process will meet the requirements of the Order. For many particular compliance goals, the Order establishes minimum standards that must be met and invites each planning authority, along with its stakeholders, to develop specific procedures tailored to that region that meet or exceed the minimum requirements. For example, public policies that must be considered include state or federal statutes, rules, or regulations, but each region is allowed to develop its own lists of these public policies and expand them as they see fit.[14]

A public policy that drives transmission needs could be a policy that requires new transmission to be built (such as the development of remote renewable resources), a policy that modifies an existing transmission need (such as distributed generation or feed-in tariffs in a load pocket that reduce the need for a transmission line to import resources), or a public policy that eliminates the need for a transmission line (such as energy efficiency programs that reduce peak loads to the point that a proposed transmission line becomes unnecessary).

The consideration of public policies in transmission planning assessments is an overdue and essential change. It will provide stakeholders and grid operators with important new information beyond the traditional inputs of economic growth and new generation projects.

PJM Recognizes the Need for Change

In the spring of 2010, PJM's Board instructed PJM staff to re-evaluate its transmission planning processes. The Regional Planning Process Task Force (RPPTF) was chartered to address numerous issues related to transmission planning analyses, criteria, and decision-making in June 2010. At the same time, FERC issued its Notice of Proposed Rulemaking (NOPR) regarding transmission planning and cost allocation.[15] Although the RPPTF was originally charged with

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[12] Order No. 888 (1996) established the need to remedy discrimination in the provision of transmission services by transmission operators, including RTOs. This requirement for "open access" to transmission facilities was a major step in the development of competitive markets. Order No. 890 (2007) required all planning authorities to amend their tariffs and planning documents to comply with eight comprehensive planning principles.
[13] Order No. 1000, July 21, 2011, 136 FERC ¶61,051, *see* ¶¶ 148, 150, 155, 203, 204, and 558-560.
[14] Id at ¶ 215. PJM has proposed language to expand upon the minimum requirements established by Order 1000. *See* Appendix C.
[15] The NOPR, Docket No.RM10-23-000, was the basis for FERC's Order No.1000, discussed above.

developing recommendations for PJM to file in December 2010, the need to address many of the same planning issues for the FERC NOPR led to an extension of the proposed PJM filing to December 2011. At an RPPTF meeting on September 28, PJM proposed a limited filing in January 2012 and a comprehensive Order 1000 compliance filing for October 2012.

Among the topics that the RPPTF has been addressing are a comprehensive analysis of state and federal public policies, including the EPA regulations that may lead to significant retirements of coal-fired generation; modifications to load forecasts; adoption of non-bright-line decision criteria for system upgrades; opportunities for non-incumbent transmission owners to develop projects; incorporation of state-determined (and funded) system upgrades; and methodologies for assigning costs for non-reliability upgrades.

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, expensive 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. PJM will be examining many of the policy and technology issues identified and discussed in earlier sections of this paper.

B. PJM Markets

Resources in PJM can receive revenues for capacity, energy, and a variety of ancillary services revenues. To be eligible for compensation, the resource must qualify for each market or revenue category; that is, it must be able to provide the particular service required by each market.

Table 3, below, summarizes those revenues for the last five years. Appendix B contains an expanded version of this table as well as a bar graph illustration.

Table 3. Revenue categories for resources in PJM. Total Price per MWh ($/MWh)

Category	2006	2007	2008	2009	2010	Avg (2006-10)
Energy	$53.35	$61.66	$71.13	$39.05	$48.35	$54.71
Capacity	$0.03	$3.97	$8.33	$11.02	$12.06	$7.08
Transmission Service Charges	$3.15	$3.41	$3.65	$4.00	$4.00	$3.64
Operating Reserves (Uplift)	$0.45	$0.63	$0.61	$0.48	$0.79	$0.59
Reactive	$0.29	$0.31	$0.32	$0.36	$0.44	$0.34
PJM Administrative Fees	$0.40	$0.38	$0.24	$0.31	$0.36	$0.34
Regulation	$0.53	$0.63	$0.70	$0.34	$0.35	$0.51
Transmission Enhancement Cost Recovery				$0.09	$0.20	$0.15
Transmission Owner (Schedule 1A)	$0.09	$0.09	$0.09	$0.08	$0.09	$0.09
Synchronized Reserves	$0.10	$0.11	$0.09	$0.05	$0.06	$0.08
NERC/RFC		$0.01	$0.01	$0.01	$0.02	$0.01
Black Start	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.15	$0.01	$0.01	$0.01	$0.01	$0.04
Day Ahead Scheduling Reserve			$0.00	$0.00	$0.01	$0.00
Load Response	$0.03	$0.07	$0.03	$0.00	$0.00	$0.03
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$58.58**	**$71.30**	**$85.24**	**$55.85**	**$66.72**	**$67.54**

The largest revenue source for most resources is the energy market; in recent years the capacity market has provided the second largest source of revenue. However, an individual resource may be completely dependent on a single market (such as EE dependence on the capacity market, or flywheel dependence on the regulation market), or more dependent on a smaller revenue source (such as DR that cannot easily participate in the energy market, or peaking units that run only a few hours each year being dependent on capacity revenue). Even resources that receive the bulk of their revenues from the energy market (such as base load units) may still depend on smaller revenue streams to achieve profitability.

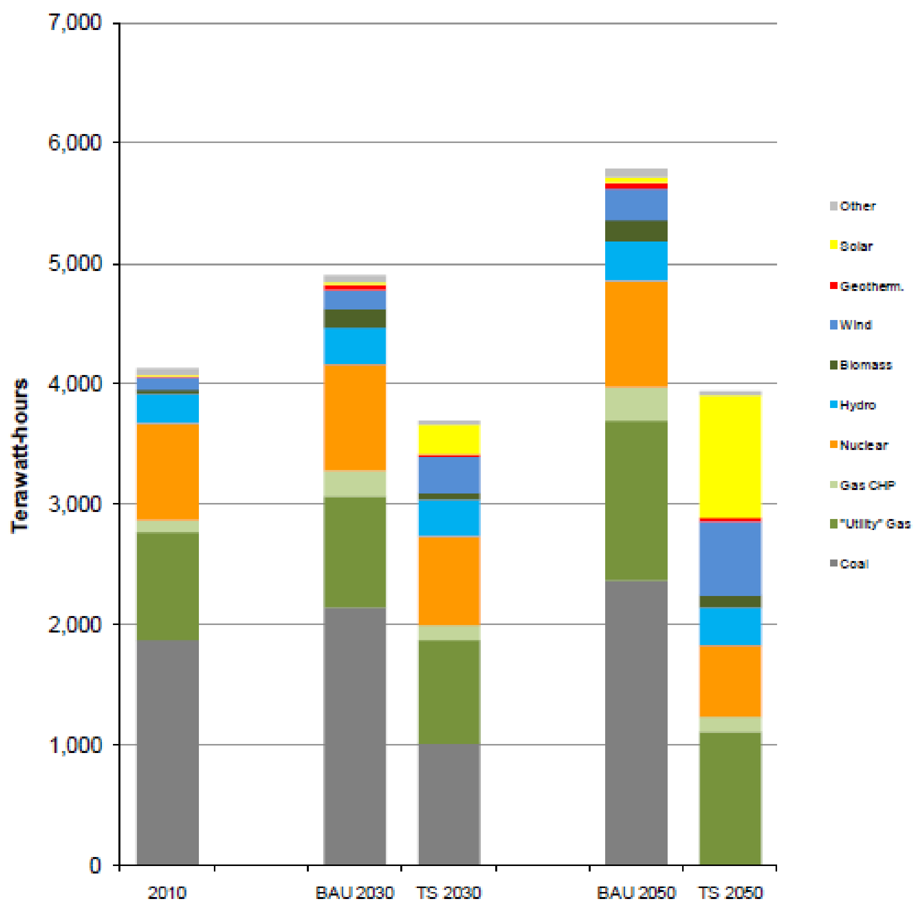
As PJM adopts new planning processes and addresses new resources and technologies, there may be opportunities to align wholesale markets with these new developments. Either enhancements to existing market structures or new market structures may be useful to address particular resource needs and resource attributes. In 2010, PJM billed $34.8 billion dollars to its wholesale market customers.[16] Adjustments to PJM's markets could provide significant revenue streams to desired resources. In the next two sections of this paper we examine the resources and resource characteristics that may have increased value to PJM, and the market enhancements that could provide incentives to these desired and needed resources.

[16] PJM 2010 Annual Report at p.7.

C. Future Resource Mix

The potential for dramatic changes to the resource mix that is used to meet electricity needs is real. As a nation, we have the technical ability to reduce our reliance on environmentally damaging resources by focusing on the development of efficiency, renewable, and cleaner resources. Synapse recently published a report commissioned by the Civil Society Institute (CSI) that documents a transition to a 2050 resource mix with no coal or oil fired resources and a reduced reliance on nuclear generation.[17] Figure 4, below, shows the transition scenario (TS) to that potential resource mix in 2050 in comparison to a current business-as-usual (BAU) mix.[18]

Figure 4. Resource Mix for BAU and Transition Scenarios: 2030 and 2050



Source: Synapse report for CSI: Toward a Sustainable Future for the U.S. Power Sector.

[17] *Re-Inventing Fire*, by Amory Lovins (2011) depicts a resource mix similar to our CSI 2050 mix in his Scenario #3 Renew. The Lovins Scenario #4, Transform, expands upon Scenario #3 by removing all nuclear generation (in addition to coal and oil) and substituting more distributed solar generation.

[18] The BAU case was developed using the 2011 Annual Energy Outlook from DOE. In addition to using less energy, the Transition Scenario provides billions of dollars of savings in comparison to the BAU case.

3. Enhanced Revenues for Resources

In this section, we discuss the resources that could qualify for enhanced revenue streams based on three general criteria:

- Resources with operational flexibility to respond to system needs in two hours or less;
- Resources that satisfy specific state or federal policies such as renewable portfolio standards or specific resource-type goals; and
- Resources that provide reductions in the carbon footprint of existing system resources.

A. Operational Flexibility

As discussed above, RTO wholesale markets rely on the entire mix of resources that offer into those markets and select resources largely based on the lowest price offers. However, RTOs utilize a security-based dispatch model to ensure that the resources selected can meet essential operational requirements. The location of resources is the most obvious operational need; that is, there must be sufficient resources available throughout the bulk power system for both energy and reserves that are not constrained by the physical transfer limits of the wires. There must also be resources that can be available for dispatch (by starting or ramping up) within guidelines established by the North American Electric Reliability Council (NERC). This is due to several factors:

- The unexpected loss of scheduled resources due to equipment failure
- The variability in output of certain scheduled resources such as wind and hydro
- The variability of loads due to changes in weather
- The increasing participation of demand response resources in energy markets
- The unexpected loss of transmission or distribution lines

Grid operators need resources that can be available on short notice (30 minutes to 2 hours). In the case of traditional peaking units, they may be in limited supply and have high variable costs. In the case of demand response resources, they may have limitations on either how frequently or for how long they can be dispatched. To avoid running out of fast-start resources, grid operators may schedule units with long lead times out-of-merit (more expensive than other resources) in order to maintain fast-start resources in reserve. These long lead time resources (often steam generators) may need twelve hours or more of advanced notice and may have minimum operational times of up to two days.

Resources that can ramp up their output on short notice or start up and connect to the grid on short notice are more valuable to grid operators than resources that cannot. A mechanism that can provide enhanced revenues will encourage the development and availability of these fast-start resources. With more fast-start resources, grid operators can avoid the costs of more expensive resources that may operate out-of-merit for many hours. In addition, the overall reliability of the system will improve if more fast-start resources are available.

B. Public Policy Goals

The wholesale market rules that RTOs use to determine the daily scheduling of resources primarily focus on offer prices and associated bidding parameters from a diverse population of resources. In general, the resources with the lowest offer prices are selected to meet anticipated day-ahead loads, subject to adjustments for bidding parameters (including start-up costs, minimum run times, minimum down times, etc.) and subject to a security constrained dispatch (can the resources actually be delivered over the transmission system in a reliable manner). After the RTO clears the day-ahead market, further adjustments to the dispatch schedule may occur due to re-offers, updates on unit availability and changes to the forecasted load (usually weather related). In real-time, further small adjustments are made to the dispatch schedule as needed due to changes between day-ahead and real-time offers, changes to unit availability (forced outages), loss or de-ratings of transmission lines, and changes to system loads (again, usually weather related). RTOs update their anticipated dispatch schedule right before and during each hour. All changes are subject to a security constrained (reliability) dispatch model that identifies constraints related to any changes in resources, system topology, or loads.

All of the RTOs decisions are made, under normal circumstances, without regard to the fuel source of the resources that are being dispatched. Under certain stress conditions, RTOs may adjust the dispatch schedule to address limitations on fuel supply, such as pipeline limitations for gas-fired generation in New England on extremely cold winter days, hydro units that have limited water supplies, or significant disruptions to coal, oil, or gas supplies. In addition, in anticipation of severe weather (thunderstorms, hurricanes, tornadoes, etc.), RTOs may create temporary adjustments to the dispatch schedule.[19]

RTOs could incorporate public policies in their dispatch schedules in the same way that they incorporate reliability policies. They could adopt rules that require the dispatch of certain resources, renewables for example, ahead of other resources, in order to achieve state or federal renewable portfolio standards. Similar preferences could be given to specific resources such as solar, wind, demand response, or CHP that are developed in response to specific state, regional, or federal goals. Rules could also be developed to restrict or limit the dispatch of certain resources, coal or diesel-fueled resources for example in order to improve air quality and protect the public health. These limitations could be applied throughout the RTO footprint or targeted to specific locations that are not achieving clean air and water standards.

C. Carbon Reductions

RTOs may also consider mechanisms to help achieve state, regional or federal carbon reduction goals. Some states and RTOs are adopting carbon adders for use in planning studies in anticipation of federal or international programs to initially cap and then reduce overall carbon output. Many people concerned about climate change argue that significant carbon adders of $40 or more per ton are necessary to stem, and then reverse, the environmental impacts of two hundred years of rapidly accelerating fossil fuel consumption. Alternatively, some form of cap-and-trade program for carbon could be used instead of a straight carbon adder. Carbon abatement

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[19] NY-ISO makes changes to the dispatch schedule whenever severe thunderstorms are anticipated for the New York City zone. ISO-NE adjusted its dispatch schedule in anticipation of impacts from Tropical Storm Irene in August 2011.

policies on a regional or national scale may consider existing wholesale electricity market structures as useful mechanisms to achieve their goals.[20]

Ambitious goals such as stabilizing carbon emissions to achieve a 350 parts-per-million concentration by 2050 or limiting global temperature increases to 2 degrees Celsius will affect the electric power sector significantly. In addition to creating pressure for a low-carbon energy mix, it is likely to increase demand for electricity. Fossil-fueled vehicles will need to be gradually replaced with electric vehicles. During this process, there will be an initial increase of electricity consumption and, given our current reliance on fossil-fuel generation resources, an increase in the carbon output from the electric sector (even though overall carbon use across all sectors would decline from the savings in vehicle fuel emissions). Wholesale electricity markets, through either enhanced market incentives or a dispatch priority system, could be used to achieve carbon reduction goals through the daily scheduling of resources to meet loads.

A market incentives approach could include either a straight carbon adder or a cap and trade approach. With a carbon adder, fossil-fuel resources would have to offer at higher prices and be displaced by lower-cost non-carbon or reduced-carbon generation options. Similarly, a cap and trade approach would provide an ever smaller pool of allowances that would become increasingly more expensive.[21]

A dispatch priority approach would establish a hierarchy of resources from least to most carbon intensive. The emissions characteristics of each generation (or demand) resource could be used to rank the resources. RTOs could then administratively establish a dispatch priority that incorporated increasing amounts of the cleanest resources over time to meet specific emissions reductions goals. The rate at which the emission goals were reached could be balanced with the increased costs associated with the cleaner resources.

RTOs have the technical expertise and are well-positioned to implement carbon reduction programs on a regional or national scope. However they are not structured or authorized by the FERC to do so today. RTOs would need a clear mandate and guidance from relevant legislative, regulatory, and policy-based decision makers to develop the mechanism to achieve carbon reduction goals.

RGGI

One market-based mechanism to reduce electric-sector carbon emissions is already in place. The Regional Greenhouse Gas Initiative (RGGI) is the first market-based CO_2 emissions reduction program in the United States, and includes ten Northeast and Mid-Atlantic states.[22] Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of

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[20] Today, there is no obligation for RTOs to consider climate goals in their market designs or dispatch algorithms. A carbon tax or a cap and trade approach could operate completely outside of the wholesale electric markets. This section discusses the possibility for policy makers to incorporate RTO wholesale market mechanisms in the design and implementation of their policies and goals.

[21] There are many variations on carbon adder and cap and trade approaches and the details are important. Under either approach, the collection and distribution of revenues need to be carefully considered in order to make sure the program is effective and provides some cushioning to increased consumer costs.

[22] Three of the RGGI states are part of PJM: Delaware, Maryland, and New Jersey. Governor Christie recently announced the withdrawal of NJ from the RGGI program by the end of 2011. http://www.northjersey.com/news/environment/052611_Christie_to_pull_NJ_out_of_cap-and-trade_energy_program.html

achieving a ten percent reduction in these emissions by 2018 from levels at the start of the program. Each state has a CO_2 Budget Trading Program, and the ten programs function together to create a regional market for carbon emissions.

RGGI is not directly incorporated into any of the wholesale market structures in New England, New York, or PJM. It operates as a stand-alone system outside of the FERC-approved wholesale markets. However, the costs associated with meeting the RGGI emissions goals are reflected in the offers of resources that participate in the New England, New York, and PJM markets.

4. Market Enhancements

In this section we focus on market enhancements that RTOs could implement to provide incentives for the three general categories discussed above: flexible resources, public policies, or carbon reductions. Some market enhancements are better suited for one particular category, while others could apply to more than one.

A. Changes to Current Market Structures

Several RTO market structures exist today that could be adapted to provide incentives for a particular category or categories of resources. They include capacity markets, reserve markets, and special markets, or sub-markets.

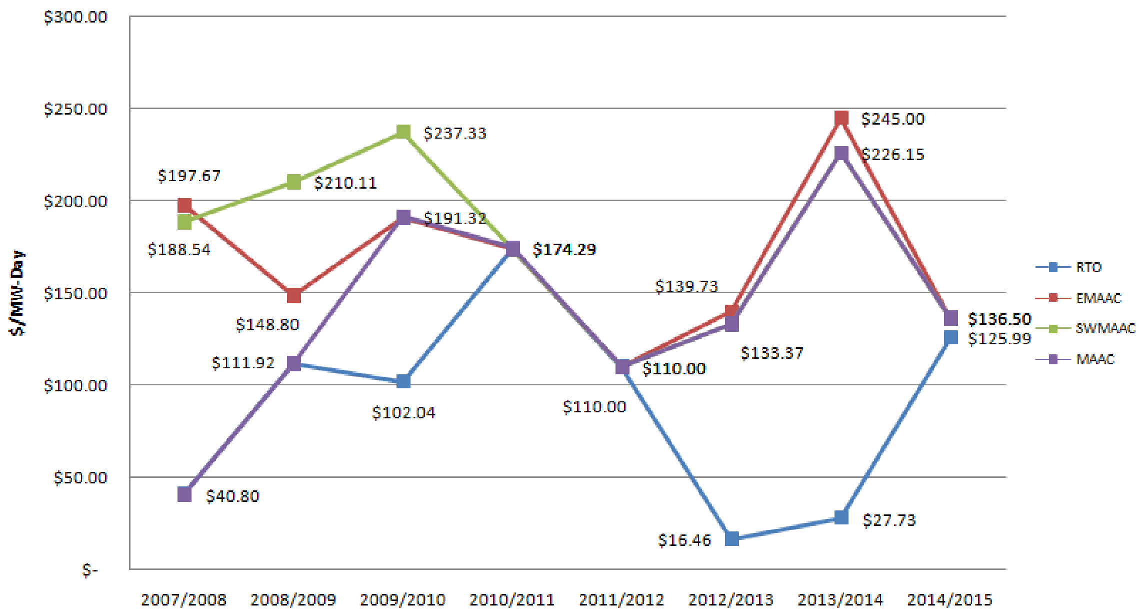
Capacity Markets

Both PJM and New England have three-year forward capacity markets that provide a price signal, three years in advance of the delivery year, for resources that can meet defined resource adequacy goals. Although they are structured very differently, both RTO capacity markets were established on the principle of a single clearing price. In a single clearing price market, all resources provide offers on a dollar per megawatt basis. The RTO selects offers from lowest to highest to meet a specific reliability-established level of resources for a specific delivery year.[23] The last resource selected establishes the base clearing price that all resources that clear the auction will receive, assuming that they deliver their resources three years into the future.

Physical delivery constraints can create sub-zones within either the PJM or New England footprints. When this occurs, the zones "separate" and the clearing price for each zone will be different. The zone affected by the constraint will usually have a higher base clearing price than the zone that has no constraint (the uncongested zone). Since its inception, PJM has experienced considerable congestion between zones. That congestion has resulted in a variety of RPM clearing prices since 2007 as depicted in the Figure 5 below. The variation in clearing prices has been large in most years with an extreme variation of $27/MW-day versus $245/MW-day in the 2013-14 delivery year.

[23] The delivery year, or power year, runs from June 1 to May 31. Each RTO establishes a specific target amount of resources and then runs an auction process to select a sufficient quantity of resources to meet that target. Both PJM and New England have rules that allow some variation in the exact quantity of resources selected through the auction, but it is a relatively narrow band-width within which they can vary the quantity.

Figure 5. RPM Base Residual Auction Resource Clearing Prices, 2009-10 delivery year through 2014-15 delivery year.[24]



* RTO and MAAC Resource Clearing Prices for the 2007/2008, 2008/2009, 2010/2011, and 2011/2012 BRA are equal.

The annual volatility in prices makes it difficult for a new resource to know what its likely revenue stream will be over a multiple year period. A high price in one year that triggers new resources to enter may lead to low prices in subsequent years due to the entry of those new resources. The new resources can create a large supply of resources that push the clearing price lower in subsequent annual auctions.

New England has not experienced constraints between zones for its Forward Capacity Auctions (FCA) [25] except for an export constraint between the Maine zone and the rest of New England. An export constraint means that there is more capacity within the Maine zone than is needed to meet the Maine load and the "excess" capacity cannot be exported to the rest of New England. The result of an export constraint is that the base clearing price in Maine is lower than the price in the rest of New England. That price variance began in FCA-3 and is shown in Table 4 below. The difference in clearing prices in New England for the five auctions to date is relatively small when compared to the PJM variations.[26]

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[24] PJM DOCS #645284, 2014/2015 RPM Base Residual Auction Results, Page 13. Figure 2 – Base Residual Auction Resource Clearing Prices.

[25] Each FCM auction is for a power year. FCA-1 is for the power year June 2010-May 2011; FCA-2 is for the power year ending in May 2012; FCA-3 is for the power year ending 2013; FCA-4 is for the power year ending 2014; etc.

[26] In order to compare PJM clearing prices ($/MW-day) with New England clearing prices ($kW-month) it is helpful to know that $100/MW-day approximately equals $3/kW-month.

Table 4. FCA Clearing Prices in New England

	FCA 1	FCA 2	FCA 3	FCA 4	FCA 5
Installed Cap. Req. (MW)	33,705.000	33,439.000	32,879.000	33,043.000	34,154.000
Net Installed Cap. Req. (MW)	33,305.000	32,528.000	31,965.000	32,127.000	33,200.000
FCA Clearing Prices ($/kW-month)					
Rest of pool	$4.500	$3.600	$2.951	$2.951	$3.209
Maine	$4.500	$3.600	$2.951	$2.951	$3.209
Pro-rated Prices ($/kW-month)					
Rest of pool	$4.254	$3.119	$2.535	$2.516	$2.855
Maine	$4.254	$3.119	$2.465	$2.336	$2.855

Only two FCM auctions have had price separation and in both cases they were due to an export constraint from Maine to the rest of New England. The potential exists for other areas to have separate prices if there are significant constraints between regions in New England. Under current market rules, ISO New England reviews constraints prior to each auction and only models the constrained zones in the auction if it anticipates price separation. Based on a recent FERC Order, ISO New England will modify the auctions so that all zones are modeled separately for each auction in case constraints should develop. If constraints between zones develop in the future, New England FCM auctions will have separate prices for zones, similar to most of the PJM auctions to date.

Significantly, all New England capacity auctions have cleared at the floor price. When that occurs, there are excess resources above the Net Installed Capacity Requirement (ICR) value, the quantity that must be purchased in that auction.[27] The market rules state that the total payment from load will not exceed the Net ICR times the clearing price, so resource owners may elect to pro-rate their MW or pro-rate the price they are paid per MW to reflect the excess quantity that is purchased.[28] For a hypothetical 100 MW resource in FCA-1, the choice would be to be paid $4.25/kW-month for 100 MW or be compensated $4.50/kW-month for approximately 94.4 MW. Most resource owners chose to pro-rate their MW (reduce their capacity supply obligation) and be paid the full clearing price for each MW.

New England does allow new resources to lock in the clearing price for up to five years. This is a one-time option available to new resources the first year that they clear the auction. The five-year lock-in is an effort to address the need for new resources to have some stability (over five years) in their capacity revenues. Although a five-year option is better than the one-year limitation in PJM, many investment consultants have advised that a ten-year lock-in, at a minimum, is what is needed to obtain private capital support for new generation projects.

[27] The Net ICR value is the Installed Capacity Requirement (ICR) value minus the value of interconnection credits between New England and its neighbors. We include both values to avoid confusion regarding the widely-published ICR values. Due to the structure of the descending-clock auction used for FCM, the auction stops at the floor price.

[28] Real-Time Emergency Generation resources must pro-rate the price, see discussion below on FCM Emergency Generation resources.

PJM DR Modifications

PJM created three categories of demand response resources for its 2014-15 RPM auction that took place in May 2011 based upon modifications approved by the FERC on January 31, 2011.[29] The categories distinguish resources based on the frequency that a demand response resource can be called (asked to respond). Annual Product Resources are demand response resources that agree to be available 365 days annually, from 10:00 am to 10:00 pm for May through October, and 6:00 am to 9:00 pm for November through April). Extended Summer Resources are demand response resources that agree to be available from May through October from 10:00 am to 10:00 pm. Finally, Limited Product Resources are the current demand response resources that agree to be available a maximum of 10 times during the summer period, June through September, from 12:00 pm to 8:00 pm.

PJM establishes, prior to the auction, a minimum amount of annual resources (generation and Annual DR resources) and a slightly higher quantity that includes Extended Summer DR resources (in addition to the annual generation and DR resources). If the minimum targets are met in the auction for each LDA, then all cleared resources, including all three categories of DR resources, would receive the same clearing price. However, if the minimum targets are not reached based on the initial auction results, PJM would add more expensive annual resources (generation or DR) until the annual minimum was reached. Remaining quantities of DR resources (Extended and Limited) would receive lower clearing prices. If the Extended Summer minimum was not reached, PJM would add additional (more expensive) resources until that minimum was reached. In this circumstance, Limited DR resources would receive an even lower clearing price than the Annual or Extended Summer DR resources.

The total quantities of each resource type cleared in the 2014-15 action are shown in Table 5.

Table 5. Breakdown of Demand Resources Offered versus Cleared by Product Type in the 2014/15 BRA Represented in UCAP30

Coupling Scenario	Resource Offer MW (UCAP)			Cleared MW (UCAP)		
	Limited Product Type	Extended Summer Product Type	Annual Product Type	Limited Product Type	Extended Summer Product Type	Annual Product Type
Annual, Extended Summer, and Limited	8,622.1	8,766.6	8,701.0	6,712.5	1,139.0	20.2
Annual and Extended Summer	-	-	-	-	-	-
Annual and Limited	36.6	-	36.6	-	-	8.7
Extended Summer and Limited	455.3	454.4	-	413.5	41.8	-
Annual Only	-	-	515.4	-	-	482.6
Extended Summer Only	-	376.9	-	-	260.2	-
Limited Only	5,312.0	-	-	5,039.9	-	-
Grand Total	**14,426.0**	**9,597.9**	**9,253.0**	**12,165.9**	**1,441.0**	**511.5**

[29] FERC Docket No. ER11-2288, Order of January 31, 2011. All descriptions of the demand response changes to RPM are based on that Order.

[30] PJM DOCS #645284, 2014/2015 RPM Base Residual Auction Results. Page 7. Table 2B- Breakdown of Demand Resources Offered versus Cleared by Product Type in the 2014/15 BRA Represented in UCAP.

For the 2014-15 capacity auction, the minimum requirement for annual resources was met, but the minimum requirement for annual and Extended Summer resources was not. The adjustment to the clearing price was $0.52/MW-day for the RTO and $11.03 for the MAAC (and related sub-regions).[31] Those additional payments were made to all resources except Limited DR resources.

FCM Emergency Generation Market

New England includes a special category of FCM resources in its auctions that have consistently received a lower clearing price than other capacity resources. Real Time Emergency Generation (RTEG) resources are a category of demand response resources that have operational limits. Emergency generators are mostly back-up diesel generators that customers install to ensure that they have power during a black out or loss of load event. RTEG resources have air permits that only allow them to operate under emergency conditions (in anticipation of system collapse).

During the stakeholder process that developed the rules for the Forward Capacity Market, the quantity of Emergency Generation that could qualify as a capacity resource was limited to 600 MW. This 600 MW cap was an explicit limit due to the air permit restrictions on operation of Emergency Generation applied by state air regulators. If more than 600 MW cleared in an annual auction, the amount paid to each resource would be pro-rated, based on a total payment of 600 MW times the clearing price in the annual auction.

Table 6 below shows the quantities cleared in the first five auctions and the pro-rated price for RTEG resources. Because all resources in Maine received a lower price in FCA-3 and FCA-4 (due to the export constraint discussed above), the payment to Maine Emergency Generation was lower than the payment to “Rest-of-Pool” Emergency Generation. Some Emergency Generation resources de-listed (dropped out) as the clearing price and the pro-rated clearing price have decreased in the first four auctions.

Table 6. Quantities Cleared in First Five Forward Capacity Auctions and the Prorated Price

	FCA 1	FCA 2	FCA 3	FCA 4	FCA 5
Installed Cap. Req. (MW)	33,705.000	33,439.000	32,879.000	33,043.000	34,154.000
Net Installed Cap. Req. (MW)	33,305.000	32,528.000	31,965.000	32,127.000	33,200.000
FCA Clearing Prices ($/kW-month)					
Rest of pool	$4.500	$3.600	$2.951	$2.951	$3.209
Maine	$4.500	$3.600	$2.951	$2.951	$3.209
Pro-rated Prices ($/kW-month)					
Rest of pool	$4.254	$3.119	$2.535	$2.516	$2.855
Maine	$4.254	$3.119	$2.465	$2.336	$2.855
RTEG Payment Rate ($/kW-month)					
Rest of pool	$2.918	$2.467	$2.413	$2.194	$2.374
Maine	$2.918	$2.467	$2.347	$2.036	$2.374

The treatment of RTEG resources is another example of how capacity resources in a single-clearing price auction can receive different payments.

[31] Id. at p.12.

Capacity Markets Summary

Both the PJM and New England capacity constructs demonstrate that even with a “single clearing price” auction design there are many variations to the actual payments that resources receive. Similar variations in payment could be designed for resources that can meet operational flexibility criteria, resources that meet public policy goals, or resources that reduce carbon emissions.

Based on the current variations in PJM and New England, an auction subcategory for flexible resources could be established that clears all resources that can respond to dispatch instructions in two hours or less. PJM could specify on an annual basis the quantity of flexible resources needed in each reliability zone and provide a premium payment above the zonal clearing price for that quantity of resources based on the lowest offers from qualified flexible resources. If PJM determined it needed resources that could respond to dispatch instructions in a shorter time-frame, say 30 minutes, PJM could include such a subcategory within the two-hour product or establish a separate category for just the 30-minute product.[32]

A similar approach could be used to provide a premium payment for resources that meet a particular public policy requirement such as a state renewable portfolio or feed-in tariff standard. As with the flexible resource option discussed above, PJM could establish an annual requirement that would specify a maximum quantity to purchase. In a situation where a state or federal requirement also provided an incentive payment to the resource (outside of the annual RPM Base Residual Auction) there could be an adjustment to the RPM premium payment as needed. For example, a state policy to acquire 2000 MW of solar PV resource over a ten-year period could be expressed as an annual 200 MW goal for each annual RPM auction. If less than 200 MW was procured in the first year, the unpurchased quantity could be added to the next year’s annual auction goal. If the state was offering a specific MW incentive for solar PV, that incentive could be either an adder to the incentive that PJM was providing or a deduction (full or partial) to the PJM incentive.[33]

For low-carbon resources, PJM would first need to define what qualifies for incentive payments. This could be pre-determined based on a federal or state statue or it could be determined through a stakeholder decision-making process. There could be a single category based on a specific reduction of 90% or more of the carbon emissions from a proxy coal unit. It could also be a sliding scale of incentives to cover 50% reductions (such as a gas-fired resource) up to 100% reductions for resources with zero carbon emissions.

[32] There are many design details that would need to be developed by PJM through its stakeholder process and reflected in tariff and operating agreement language that would need to be filed with the FERC. Ultimately, the Commission would need to approve the changes. See also the discussion below about the New England Forward Reserve Market which could be adapted by PJM as an alternative option to an enhanced RPM clearing price approach.

[33] For the purposes of this paper, we take no position on the appropriate size for either a PJM or state incentive for a specific resource. Nor do we take a position on whether any incentives should be fully additive, partially additive, or not additive at all. Those design details are appropriately determined by the entity that establishes the public policy requirement, PJM Stakeholders, or both. The FERC may also establish guidelines for how such determinations should be made. Our goal is to demonstrate how various premiums or incentives could be incorporated into PJM’s current market mechanisms such as RPM.

Forward Reserve Market

New England has a Forward Reserve Market (FRM) that has operated since 2003. The FRM purchases specific quantities of ten-minute non-spinning reserves (TMNSR) and thirty minute operating reserves (TMOR) on a system wide basis. The ISO conducts two auctions each year, one for a four-month summer period (June 1 thru September 30) and one for the other eight months of the year (October 1 thru May 30). Resources that clear in the FRM are required to offer their units day-ahead above a strike-price established by the ISO. The strike price is established for each month in advance and it is set at a level such that resources would only be dispatched in 2-3% of the hours in the year (to simulate the historic revenues that a gas-fired peaking unit would need to earn based on an assumed heat-rate and the price of natural gas). If the Real-Time price exceeds the strike price, then the FRM resources are dispatched. There are penalties for failing to offer a unit and for any failures to perform when called.

In 2006, the FRM became a locational market and the first locational FRM auction was held in August 2006 for the delivery period of October 1, 2006 through May 30, 2007.[34] The locational aspect introduced four separate zones. From smallest to largest, the zones are Southwest Connecticut (SWCT), Connecticut (CT), Northeast Massachusetts/Boston (NEMA/Boston), and Systemwide.[35] Over time, the NEMA Boston zone (due to system enhancements) has not experienced separate prices for 2009 or 2010. Table 7 and Table 8 show the FRM clearing prices since it became a locational market.

Table 7. Forward Reserve Market Auction Results ($/kW-Month) - Winter[36]

Reserve Zone	Reserve Category	2006/ 2007	2007/ 2008	2008/ 2009	2009/ 2010	2010/ 2011
Systemwide	TMNSR	4.20	9.05	6.74	6.08	5.50
Systemwide	TMOR	4.20	0.00	4.99	0.00	5.50
SWCT	TMOR	14.00	14.00	14.00	14.00	6.02
CT	TMOR	14.00	14.00	14.00	14.00	6.02
NEMA/Boston	TMOR	14.00	8.50	5.55	0.00	0.00

Table 8. Forward Reserve Market Auction Results ($/kW-Month) - Summer[37]

Reserve Zone	Reserve Category	2007	2008	2009	2010
Systemwide	TMNSR	10.80	8.88	6.30	5.95
Systemwide	TMOR	3.55	6.50	0.00	5.95
SWCT	TMOR	14.00	14.00	14.00	13.90
CT	TMOR	14.00	14.00	14.00	13.90
NEMA/Boston	TMOR	14.00	14.00	0.00	0.00

[34] 2007 Annual Markets Report, p.78; 2006 Annual Markets Report p.71.
[35] SWCT is a sub-zone of CT that has an import constraint. NEMA/Boston comprises the city of Boston and an area northeast of Boston. Systemwide is the entire New England footprint.
[36] Data from ISO-NE 2008 Annual Markets Report (June 16, 2009) and 2010 Annual Markets Report (June 3, 2011).
[37] Ibid.

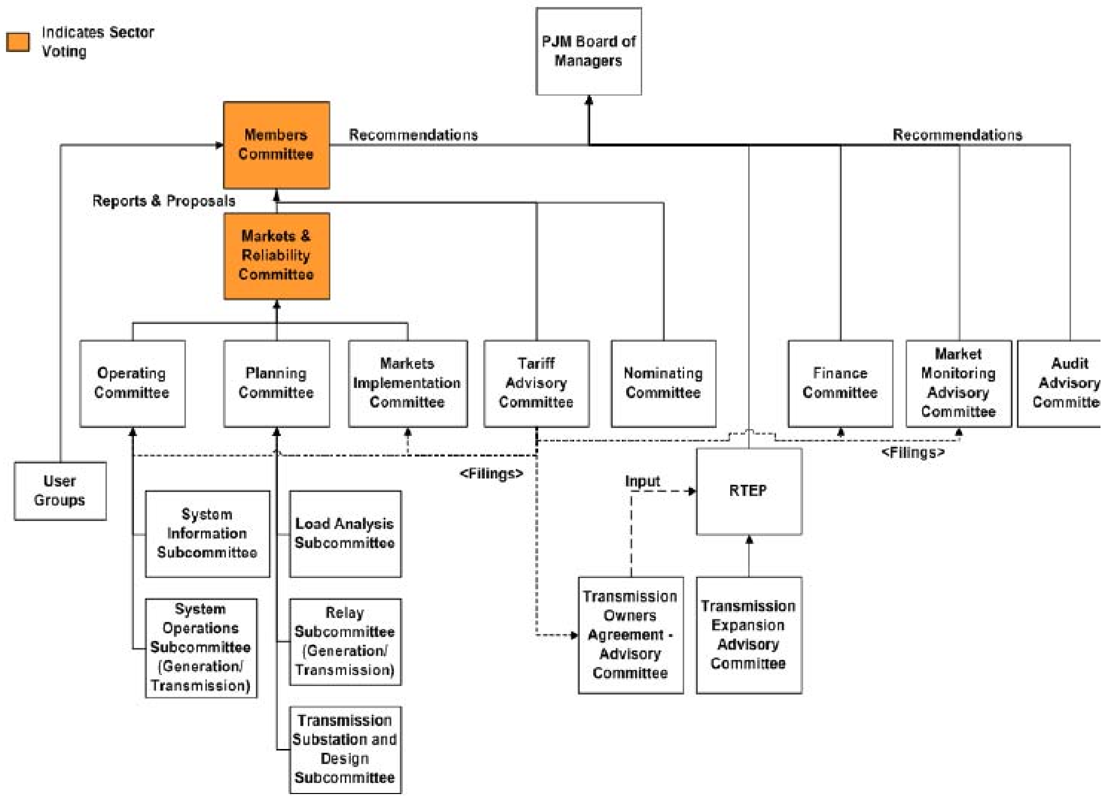
The New England FRM is a separate market mechanism that could be a model for providing incentives for resources with specific characteristics. To incent fast-start resources, PJM could design a market similar to the New England FRM or PJM could expand the categories of resources beyond just TMNSR or TMOR to include resources that could be available within two hours. Alternatively, PJM could design two separate markets: one for TMNSR and TMOR and one for a two-hour operating reserve (THOR) market.

The development of a separate market could also be used to address incentives for resources that meet public policy goals or qualify as low-carbon resources. PJM currently provides revenues for resources that can provide “black start” services (recovery from a system-wide collapse) as well as for resources that can supply regulation and reactive power services. Creating a separate market or revenues for other useful services is an alternative to relying on the capacity market to provide enhanced revenues.

5. Process for Implementing Change

PJM has an extensive stakeholder committee system that includes voting committees, task forces, and working groups. Figure 6 provides an overview of the PJM stakeholder participation and decision-making process.[38]

Figure 6. PJM Committee Structure Diagram



PJM has a variety of stakeholder forums available to discuss a targeted program or market to provide enhanced revenues to resources with specific characteristics. Recent practice at PJM has been to create a Task Force with a charter to look at certain issues and then report back to a more senior committee(s) for actions related to Tariff, Operating Agreement or Manual changes.

For example, in April 2010, PJM created a charter for the Regional Planning Process Task Force to consider substantive changes to PJM's planning processes that would impact the Planning Committee and its Transmission Expansion Advisory Committee.

[38] The diagram of PJM committee structure is from the PJM Stakeholder Manual 34; a more detailed diagram is in Appendix D.

There are three processes that could be used to implement changes to the PJM markets to accommodate specific types of resources. We discuss each of them in this section.

A. PJM Stakeholder Committee Process

This is the most common process for implementing changes to the PJM Tariff, operating Agreement and Manuals. For the types of market design changes discussed above, a proposal would be brought to the Markets and Reliability Committee (MRC) for assignment to a lower committee or a special Task Force. The MRC would discuss the issue and decide where to assign it in the PJM stakeholder process. The MRC could specify a charter for a new Task Force or simply create a new Task Force and ask it to develop a charter based on some initial guidance from the MRC. The Charter would describe the specific tasks assigned to the new Task Force, the next upper level committee to which the Task Force would provide its recommendations, and a general timeframe for completing the Task Force's assignment.

The Task Force can return to the MRC to ask for clarification or additional guidance, as well as ask for additional time to compete its assignment. If the Task Force develops recommendations, they can be referred to the appropriate Standing Committee for further discussion and action. The Standing Committee then makes a recommendation to the Markets and Reliability Committee. The MRC, based on sector voting defined in the Operating Agreement, can then make a recommendation to the Members Committee.[39] The Members Committee, again pursuant to sector voting, can then make a recommendation to the PJM Board and seek their concurrence for a FERC filing to make changes to the PJM Tariff, operating Agreement, Manuals, or other documents.

B. User Group

A seldom used option for raising issues in the PJM stakeholder process is the creation of a stakeholder User Group.[40] Any group of five or more PJM members can create a User Group to address common issues. The PJM members who create the User Group can invite other PJM stakeholders to join the User Group as they deem appropriate. All meetings of the User Group must be open to all PJM stakeholders and PJM staff. In addition, any PJM stakeholder may request a copy of the meeting notice and agenda for any meeting of the User Group.

The User Group, with an affirmative vote by three-fourths or more of the voting members of the User Group, can refer a proposal to the Chair of the Members Committee. The Chair will refer the proposal to the appropriate PJM stakeholder committee for consideration at its next meeting (with at least thirty days advance notice). The committee receiving the referral must provide a recommendation to the Members Committee on the proposal from the User Group for the next regular scheduled meeting of the Members Committee. This process assures that the Members Committee will consider any proposal from the User Group within a relatively short period of time (usually within three months).

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[39] PJM, as most other RTOs, has a stakeholder voting system based on sectors of interest. The five voting sectors in PJM are: Generation Owners, Other Suppliers, Transmission Owners, Electric Distributors, and End Users. PJM Operating Agreement, Section 8.1.1.

[40] PJM Operating Agreement, Section 8.7.

If the Members Committee does not adopt the proposal of the User Group, the User Group may submit the proposal to the PJM Board for its consideration if nine-tenths of the voting members of the User Group support the proposal. The PJM Board, at its discretion, may submit any amendment it deems appropriate to the Operating Agreement or any schedule of the Operating Agreement (including a new schedule) to the Members Committee for its consideration.[41]

The provisions for the creation of a User Group and the opportunity to request prompt and decisive action by both the Members Committee and the PJM Board provide an important avenue around entrenched majority opposition in the normal PJM stakeholder process.

C. FERC Section 206 Filing

A third option for implementing changes to the PJM Tariff or Operating Agreement is a filing with the FERC pursuant to Section 206 of the Federal Power Act. The entity making the filing must initially demonstrate that an existing Tariff or Operating Agreement provision is not just and reasonable or is unduly discriminatory. If the Commission agrees, then the proposal to replace the non just and reasonable or unduly discriminatory provision can be considered. This is a very high standard or burden of proof. Moreover, there is no specific timeframe within which the FERC must respond to a Section 206 filing; some Section 206 filings have never been acted upon by the Commission.

This is in sharp contrast to a Section 205 filing to the Operating Agreement or PJM tariff that has been approved through the PJM stakeholder process. Under Section 205 of the Federal Power Act, a filing does not have to demonstrate that the current provision is not just and reasonable or is unduly discriminatory. The filing entity only needs to demonstrate that its proposal is likely to achieve just and reasonable rates and is not unduly discriminatory. This is a much lower burden of proof than a Section 206 filing. A proposal that goes through the standard stakeholder process, discussed in Section A, above, is filed with the FERC under Section 205.

[41] PJM Operating Agreement, Section 7.7.v.

6. Recommendations and Conclusions

Our recommendations are organized into the same general categories discussed in Section 4, above.

A. Modifications to PJM RPM Auctions

PJM could create categories of resources with specific characteristics and clear them in the annual RPM Base Residual Auction. PJM has already done this for three categories of demand response resources based on their availability. Such an approach is also consistent with the existing auction methodology that analyzes local constraints and provides higher payments to resources in constrained local delivery areas. PJM would need to define the specific characteristics it wanted (such as fast-start capability or emissions profile) and then allow resources to compete in the annual RPM auction to provide those characteristics at the lowest price.

Alternatively, PJM could administratively determine a specific premium payment for resources with the desired characteristics (such as a low or zero carbon output) and simply add it to the clearing price for all resources that possess those characteristics and clear in the RPM auction. Annual maximum quantities could be established for each auction.

There are significant challenges to using the RPM auctions to provide enhanced payments. How would PJM be authorized to provide special incentive payments? How would the incentive levels be established and administered year to year? Could states impose such requirements or would Federal action be necessary? Could stakeholders propose modifications and establish them through either a FERC Section 205 or 206 filing? Could PJM propose changes on its own initiative as the regional reliability coordinator?

B. Implementation of New Markets

PJM could also develop and implement new markets to enhance revenues to specific resources using the New England Locational Forward Reserve Market as a template. The FRM provides higher payments, as necessary, to fast-start resources using a competitive auction approach. PJM could use a FRM approach just for fast-start resources, including a broadening of the definition of a fast-start resource to include resources that can synchronize to the grid in two hours or less. Or, PJM could develop a market for renewable resources, zero-carbon resources, or low-carbon resources.

As with modifications to the RPM auctions, there are many threshold questions that would need to be resolved. What is the basis for PJM's authority to create these new markets? Is new federal legislation or rule-making a necessary first step? Can PJM stakeholders or PJM's Board initiate the process through the Federal Power Act? How will PJM make adjustments to either the quantities or the prices paid for specific categories of resources?

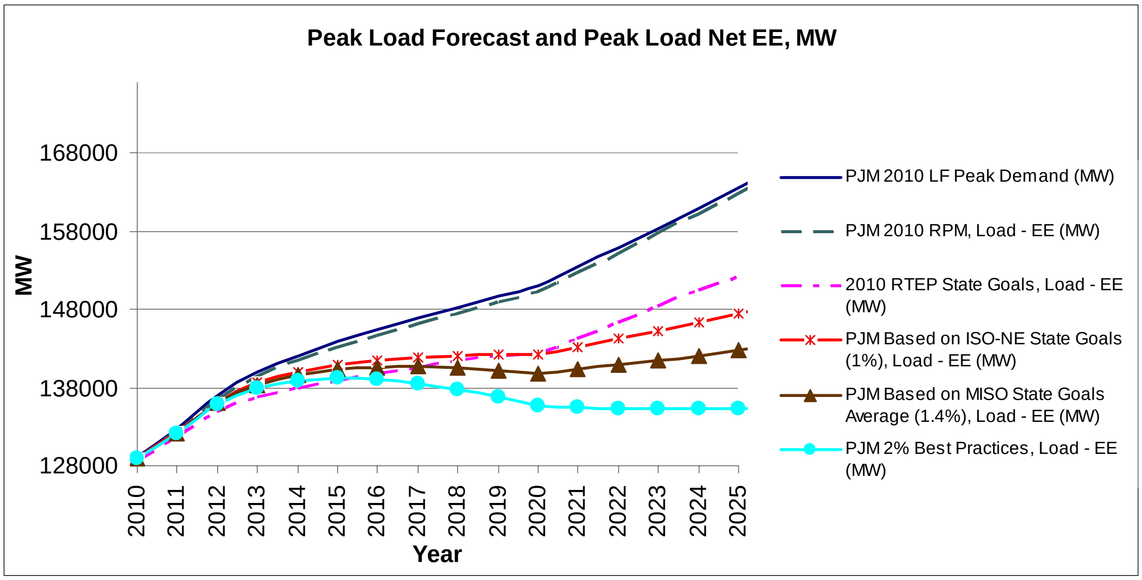
C. Conclusion

Profound changes to the way we produce and deliver electricity to homes, businesses, and factories are underway in the 21st century. Some of these trends will undermine traditional views of how to plan and operate the regional bulk power systems across the country. Recognizing these evolving trends and incorporating them in a timely manner into system planning and operating procedures are the responsibility of the planning authorities that currently manage and control the integrated bulk power systems that blanket North America. As these FERC and NERC designated planning authorities modify and enhance their procedures to address these new trends and as technology continues to provide new and more cost-effective tools to assist in these changes, market mechanisms will come under increased pressure to align compensation with the most valuable, however defined, resources. If agreement can be reached on the specific resources that deserve higher compensation levels, RTO markets can be effective mechanisms for providing those enhanced revenues.

Appendix A.

Section 2.A.of this report discusses the impacts of energy efficiency (EE) on load forecasts in PJM. Figure A-1 below, the same as Figure 3 in Section 2.A, 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,[42] and adjusted the peak loads based on different assumptions about EE program implementation.[43]

Figure A-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.

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

[43] 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.[44] 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%.[45] 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.[46] 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.[47] 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.[48] Figure A-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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[44] PJM 2010 Regional Transmission Expansion Plan, Section 4, p. 77.

[45] 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.

[46] 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.

[47] 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.

[48] 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 A-1. Comparison of PJM Net Load under Five 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 B.

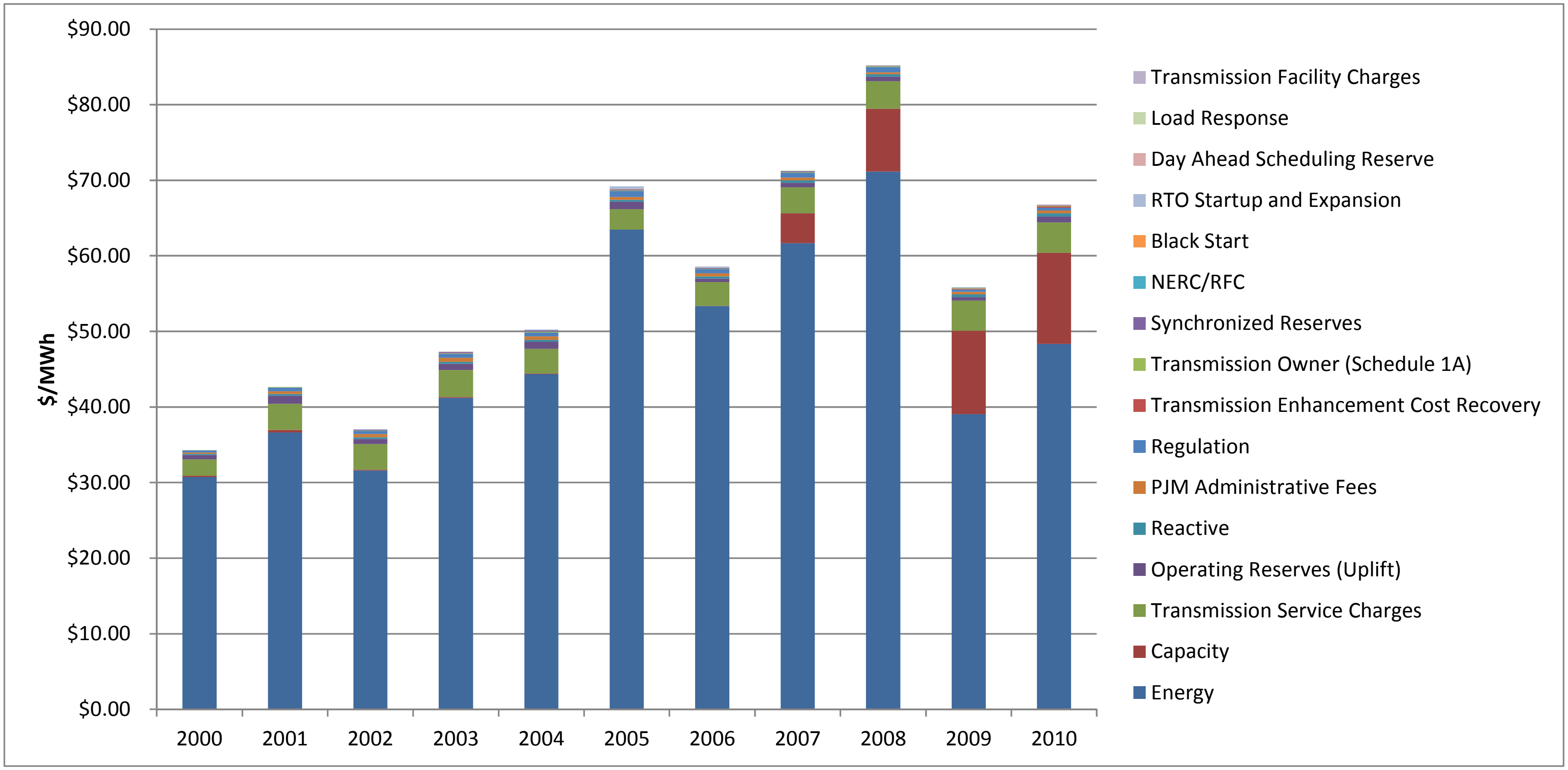
Section 2.B. of this report provides a table of PJM revenues paid to resources from 2006 through 2010. Table B-1 provides the same data for years 2000-2010. Figure B-1 shows the same data in a graph.

Table B-1. All-In Cost for Electricity – PJM. Total Price per MWh ($/MWh).

Category	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average	Avg (2006-10)
Energy	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$47.41	$54.71
Capacity	$0.20	$0.32	$0.12	$0.08	$0.09	$0.03	$0.03	$3.97	$8.33	$11.02	$12.06	$3.30	$7.08
Transmission Service Charges	$2.17	$3.46	$3.37	$3.56	$3.26	$2.68	$3.15	$3.41	$3.65	$4.00	$4.00	$3.34	$3.64
Operating Reserves (Uplift)	$0.57	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79	$0.73	$0.59
Reactive	$0.15	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44	$0.28	$0.34
PJM Administrative Fees	$0.15	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36	$0.37	$0.34
Regulation	$0.30	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35	$0.51	$0.51
Transmission Enhancement Cost Recovery										$0.09	$0.20	$0.15	$0.15
Transmission Owner (Schedule 1A)	$0.05	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09	$0.08	$0.09
Synchronized Reserves			$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06	$0.11	$0.08
NERC/RFC								$0.01	$0.01	$0.01	$0.02	$0.01	$0.01
Black Start			$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion			$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01	$0.08	$0.04
Day Ahead Scheduling Reserve									$0.00	$0.00	$0.01	$0.00	$0.00
Load Response		$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00	$0.01	$0.03
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$34.32**	**$42.66**	**$37.05**	**$47.36**	**$50.25**	**$69.20**	**$58.58**	**$71.30**	**$85.24**	**$55.85**	**$66.72**	**$56.23**	**$67.54**

Source: 2010 State of the Market Report for PJM, Table 1-8

Figure B-1. Data from Table B-1 shown in graphical form.



Appendix C.

A Regional Planning Process Task Force (RPPTF) presentation on October 13, 2011 proposed the following Schedule 6 changes to the PJM Operating Agreement (OA) in the definitions section:

> **"Public Policy Requirements"** shall refer to planning considerations arising from (i) policies pursued by state or federal entities, where such policies are reflected in enacted statutes or regulation, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations, and (ii) public policy initiatives that have not yet been codified into law or regulation, but which nonetheless may have important impacts on long-term planning considerations.

The above definition was slightly modified in the final version approved by the Markets and Reliability Committee on December 21, 2011. PJM plans to submit the definition along with other changes to Schedule 6 in a filing to the FERC in January 2012 as a first step in its Order No. 1000 compliance obligation. Overall, the changes to Schedule 6 describe enhancements to the PJM planning process to address both reliability and economic system upgrades. They include evaluating the impacts of public policies, demand response, energy efficiency, and price responsive demand on the reliability and competitiveness of the PJM administered bulk power system. PJM will expand its sensitivity studies, modeling assumptions, and scenario analysis to provide more robust and diverse future options. There will be a new Independent State Agencies Committee (ISAC) that will provide PJM with guidance and suggestions on modeling the impacts of state agency regulations and policies.

The changes to Schedule 6 are significant and positive steps towards addressing changing system needs and achieving compliance with Order 1000. After the January filing, PJM will continue to work with its stakeholders to implement additional elements of Order 1000 in a compliance filing due in October, 2012. The stakeholder discussions that develop the October compliance filing may provide opportunities to discuss proposals for providing enhanced revenues to specific categories of resources.

Appendix D.

PJM stakeholder process.

Figure D-1. PJM Stakeholder Process Diagram

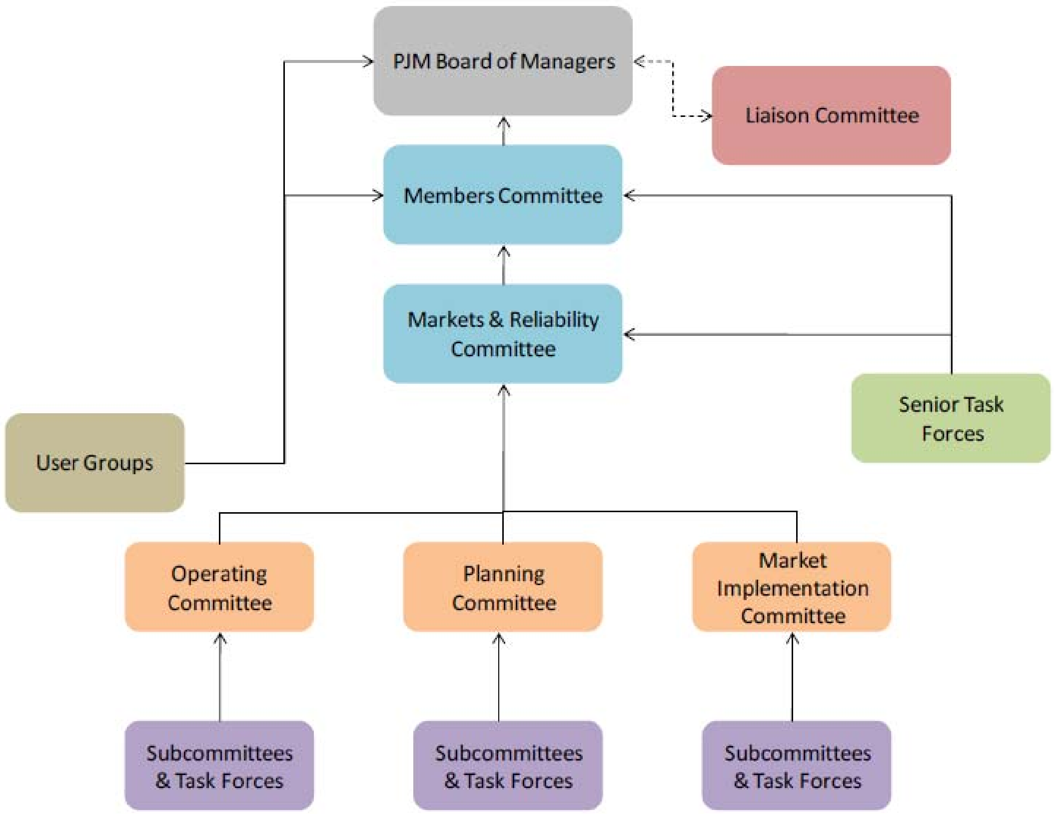


Figure D-2. PJM Stakeholder Process Groups Diagram