



A Review of Generation Compensation and Cost Elements in the PJM Markets



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Table of Contents

Executive Summary.....	6
Introduction and Purpose	8
PJM Market Design Philosophy.....	9
Energy Market Compensation.....	10
Generator Offer Requirements and Practices.....	11
Cost-Based and Market-Based Supply Offers.....	11
Mitigation and Offer Selection.....	12
Directly Incurred Cost Components of the Cost-Based Offer	12
Fuel-Related Costs.....	13
SO ₂ , NO _x , and CO ₂ Emission Allowances	13
Variable Operating and Maintenance Adder	13
Contribution of Directly Incurred Cost Components to the Cost-Based Offer.....	14
Other Components of the Cost-Based Offer	14
Ten-Percent Adder	14
Frequently Mitigated Unit (FMU) Adder.....	15
Opportunity Costs for Generators with Environmental and Energy Limits.....	15
Price Formation and Compensation in the PJM Energy Markets	16
Incentives to Reveal True Costs of Operation.....	17
Incentives to Follow Dispatch Instructions and Meet Operational Needs.....	19
Energy Market Revenues to Cover Variable and Fixed, Going Forward Costs.....	20
Scarcity Pricing.....	22
Ancillary Service Market Compensation.....	23
Regulation Market.....	23

Offers into the Regulation Market.....	24
Price Formation in the Regulation Market and Revenues to Cover Going Forward Costs.....	25
Out of Market LOC Payments	25
Tier 2 Synchronized Reserve Market.....	25
Offers in the Tier 2 Synchronized Reserve Market.....	26
Price Formation in the Tier 2 Synchronized Reserve Market and Revenues to Cover Going Forward Costs	27
Out of Market LOC Payments	27
Day-Ahead Scheduling Reserve Market.....	27
Offers in the DASR Market.....	27
Price Formation in the DASR Market and Revenues to Cover Going Forward Costs.....	28
Black Start Costs	28
Reactive Power and Voltage Control	29
Balancing Operating Reserve Payments.....	29
RPM Capacity Market Compensation	30
Rationale for the RPM Capacity Market.....	30
Energy and Ancillary Service Markets Alone Do Not Provide Enough Revenue to Encourage New Investment	31
Historic Capacity Payments.....	31
Prior to RPM: Insufficient Revenue to Support New Investment	33
Capacity Offer Requirements.....	33
Market Power Mitigation in the RPM Capacity Market.....	34
Offers into the RPM Capacity Market	34
Demand in the RPM Capacity Market.....	35
Price Formation in the RPM Capacity Market.....	35
Revenues in the RPM Capacity Market	35
Conclusion and Potential Overlaps in Compensation.....	38
RPM Capacity Market Revenues.....	38



Frequently Mitigated Unit Adders.....	39
Other Areas of Overlap.....	41
Appendix A.....	42

Executive Summary

PJM has prepared this document at the request of a group of PJM stakeholders who requested an explanatory document detailing the various revenue streams and associated underlying costs for generation resources in the PJM Markets, along with background and underlying purpose and an examination of any potential areas of overlap in areas of compensation (Stakeholder Request).¹

The PJM Markets are designed to serve customers with reliable electric service at the lowest cost. The market design encourages suppliers to offer their supply at their true costs and optimizes the dispatch of these resources to provide services at the lowest overall cost to consumers. Prices suppliers receive for provision of services in the PJM Energy Markets, the Ancillary Service Markets, and the RPM Capacity Market provide incentives for suppliers to follow PJM dispatch instructions. Moreover, the resulting revenue streams provide incentives regarding new investment and retention or retirement of existing capacity.

In general, the PJM Energy and Ancillary Service Markets compensate suppliers for the incremental cost of operation of their supply resources, and can also cover some part of the fixed or going-forward costs of operation. Prices and revenue streams in Ancillary Service Markets insure that participants in those markets suffer no lost revenues compared to simply participating in the Energy Markets. Ancillary Services are vital to maintaining reliability and as such must not financially harm participants in comparison to other markets. There is no overlap in areas of compensation as a result of these markets.

The RPM Capacity Market is designed to compensate suppliers for their going-forward costs that are not covered by operating in the PJM Energy and Ancillary Service Markets.² Revenue suppliers receive from all PJM Markets provides incentives for new investment or retention of existing supply capacity in order to maintain required reserve margins and reliability on the system. As a general matter, units that receive compensation for going-forward costs in both the Energy and RPM Capacity Markets have higher going-forward costs, which would not be fully covered by either the RPM Capacity Market or Energy Market alone. As such, there is no overlap in compensation.

One potential area of overlap in compensation that merits further discussion is the Frequently Mitigated Unit (FMU) adders in the cost-based offers of the Energy Market. These adders were ordered by the Federal Energy Regulatory Commission (FERC) in order to ensure that the going-forward costs for generators that were frequently found to have structural market power (and subsequently mitigated to their cost-based offers) were appropriately covered. These FMU adders, instituted prior to the creation of the RPM Capacity Market, had a total impact on the load-weighted average price of energy of \$0.30/MWh or 0.4% of the LMP in 2008 and \$0.19/MWh or 0.5% of LMP in 2009 through the end of September.³

¹ See "Stakeholder Request for Information" ("Stakeholder Request") presented at the July 30, 2009 meeting of the PJM Markets and Reliability Committee at 5, available at <http://www.pjm.com/committees-and-groups/committees/-/media/committees-groups/committees/mrc/20090730/20090730-item-09-request-for-holistic-review-of-generation-compensation.ashx>.

² For the purposes of this document, the terms "going-forward costs" or "fixed, going-forward costs" include costs that do not change with supplier output such as fixed operation and maintenance costs, administrative costs, insurance, and the cost of investment plus a rate of return on the investment. On a yearly basis the "going-forward cost" is analogous to annual levelized fixed cost.

³ 2008 State of the Market Report for PJM, Volume 2: Detailed Analysis, March 11, 2009, Monitoring Analytics, LLC, Independent Market Monitor for PJM available at

Given the market design of the RPM Capacity Market and that FMU adders were intended by the FERC to aid in cost recovery, a further discussion of the interaction of these two design features is beneficial to aid in understanding their complex interactions. The cost-based offers into the RPM Capacity Market are net of energy revenues which may already include revenues that result application of the FMU adder. But a generator that is frequently mitigated after clearing the RPM Capacity Market may not recover the energy revenue that is assumed when it cleared in the RPM Market. Therefore it can be argued the FMU adder is likely to be still needed in many circumstances. There is also an argument that can be made for FMU adders as a form of localized scarcity pricing. Both RPM and the scarcity pricing mechanisms currently in discussion at the stakeholder process have locational features to incent investment in appropriate areas. However these signals are at a somewhat broad level and not designed to provide investment signals in localized areas. The FMU adders are designed to provide cost recovery, and therefore provide signals to maintain investment in existing resources that are required for reliability on a more granular level than RPM. While PJM has concluded in the review that FMU adders are not redundant with capacity market compensation, a review of the magnitude of the FMU adders and their interaction with any proposed changes to scarcity pricing design should be undertaken in the PJM stakeholder process.

http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008/2008-som-pjm-volume2.pdf ("2008 SoM Report"), Table 2-57 at 61. 2009 Quarterly State of the Market Report for PJM: January through September, November 13, 2009, Monitoring Analytics, LLC, Independent Market Monitor for PJM available at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009q3-som-pjm.pdf ("2009 Q3 SoM Report") at 27.

Introduction and Purpose

On July 30, 2009, a number of PJM stakeholders made a request at the Markets and Reliability Committee (MRC) meeting for a review of generator costs and all payments made to generators.⁴ This request was made to both PJM and the Independent Market Monitor (IMM) by the stakeholders listed in the Appendix A.⁵ At the September 23, 2009 MRC meeting, PJM agreed to develop an explanatory document to outline the intended purpose of, and interaction between, each cost item or payment, including background educational material for each item and the IMM agreed to perform a quantitative analysis of generation revenue components.⁶ PJM committed to coordinate with the IMM and present its analysis at the January 20, 2010 MRC meeting. This document is intended to provide a narrative explanation of the design of the PJM's Energy, Ancillary Services, and Reliability Pricing Model (RPM) Capacity Markets (PJM Markets) with respect to compensation paid to generators and Demand Resources for the provision of services to ensure reliable and least-cost electricity service in PJM. The report also provides an assessment of any potential overlap in the design of these items. This document is not intended to serve as a detailed, technical resource on the manner in which PJM compensates generators to ensure reliable grid operation through its markets, but rather provide a high level discussion on how resources make supply offers and how prices are formed in each of PJM's Markets which ultimately determines the compensation paid to generators and Demand Resources. For readers interested in the more technical details, citations will be provided to the appropriate sections of the PJM Tariff, Operating Agreement, and Manuals as warranted.

In order to provide the broader context in which compensation is paid within the PJM Markets, the next section outlines the specific PJM Markets and market design philosophy that is common to all PJM Markets. Subsequently, details of each of the PJM Markets are discussed starting with the Day-ahead and Real-time Energy Markets, moving to Ancillary Services, and concluding with the RPM Capacity Market. The discussion of each market begins with the formulation and components of supply offers, next outlines the role of market power mitigation, and ultimately explains price formation which determines compensation to suppliers of services in the PJM Markets.

In order to provide context to the reader in understanding the proportions of the various markets, the following chart shows the contribution to the overall wholesale cost in dollars per MWh for 2008.⁷ The Energy Markets account for a large portion of the overall cost at 84 percent, followed by capacity at 10 percent, while services such as Regulation, Black Start, and other Ancillary Services are only 2 percent of the overall cost.

⁴ See Stakeholder Request at 5.

⁵ Id. at 6.

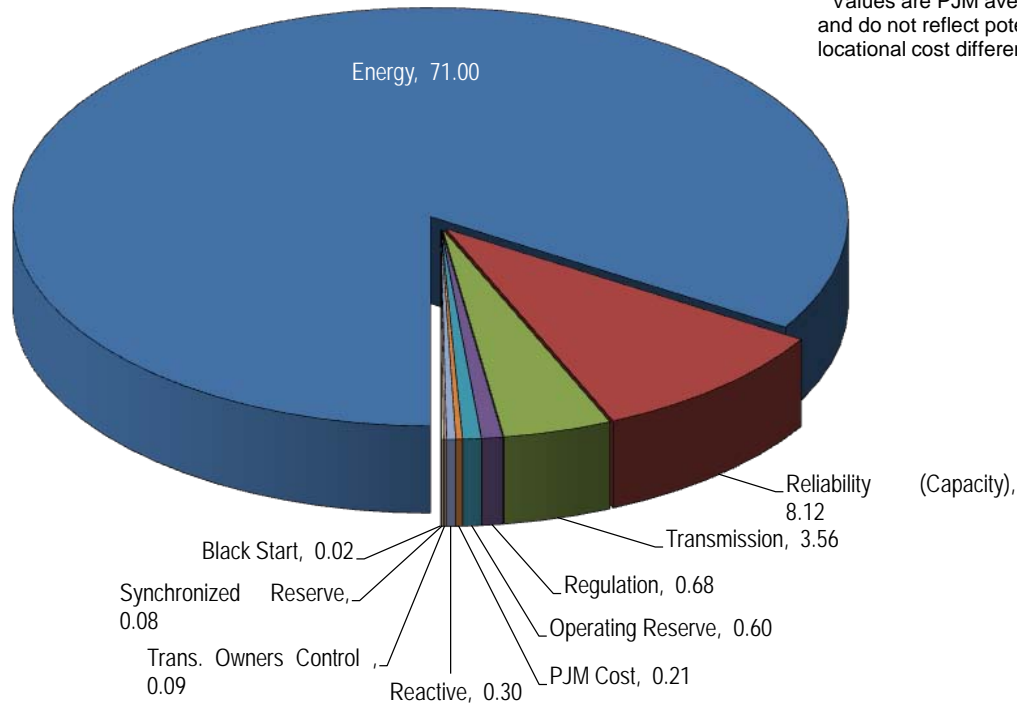
⁶ "Markets and Reliability Committee Response to Stakeholder Information Request", presented at the September 23 meeting of the PJM Markets and Reliability Committee, Andrew L. Ott, Senior Vice President, Markets, PJM Interconnection, L.L.C., available at <http://www.pjm.com/committees-and-groups/committees/-/media/committees-groups/committees/mrc/20090923/20090923-item-09-response-to-information-request-related-to-generator-compensation.ashx> (MRC Response) at 5.

⁷ See "Executive Report" presented at the November 19, 2009 meeting of the PJM Members Committee available at <http://www.pjm.com/committees-and-groups/committees/-/media/committees-groups/committees/mc/20091119/20091119-item-07a-markets-executive-report.ashx> at 3.

PJM Wholesale Cost Full-Year 2008 (\$/MWh)

TOTAL: \$84.66/MWh

* Values are PJM averages and do not reflect potential locational cost differences.



PJM Market Design Philosophy

PJM's first objective is to maintain reliability in both short-term grid operations⁸ and long-term capacity adequacy to meet the one-day-in-ten-year reliability criterion⁹. The means by which PJM meets these reliability objectives are through its Energy, Ancillary Services, and RPM Capacity Markets. PJM markets are operated under the foundational principle of maintaining reliable short-term grid operations (e.g., energy balance, reserves, frequency response) and long-term capacity adequacy reliability at the lowest possible cost (maximum possible benefit). In order to best achieve and maintain this goal, it is imperative that PJM's markets provide incentives to generation resources to reveal through their offers their true cost of short-term and long-term operation. Moreover, the resulting prices from PJM's markets should also provide incentives to generation resources to follow PJM dispatch instructions in the Real-Time Energy and Ancillary Service

⁸ For an overview of the operations to maintain short-term reliability during non-emergency conditions, see "PJM Manual 12: Balancing Operations, Revision: 20, Effective Date: October 5, 2009 available at <http://www.pjm.com/documents/~media/documents/manuals/m12.ashx> (PJM Manual 12).

⁹ See "PJM Manual 20: PJM Resource Adequacy Analysis, Revision: 03, Effective Date 06/01/2007 available at <http://www.pjm.com/documents/~media/documents/manuals/m20.ashx> (PJM Manual 20) at 8. The "one-day-in-ten-year" standard implies PJM holds enough capacity so that there is a loss of load expectation (LOLE) or statistical probability of a loss of load due to lack of capacity one day in ten years. See also "Standard BAL-502-RFC-01 — Resource Planning Reserve Requirements", ReliabilityFirst Corporation, available at <http://www.rfirst.org/Documents/Standards/Approved/BAL-502-RFC-01.pdf> at 1.

Markets, maintain forward commitments from the Day-Ahead Energy Market and RPM Capacity Market, and take actions such as making available and maintaining existing generation or demand resources or bringing new generation or demand resources to the PJM Markets to ensure long-term capacity adequacy needs are met through the RPM Capacity Market.

The PJM markets are all linked in terms of providing and maintaining reliability as well as linked by the revenues generation and demand resources derive from participating in the PJM markets that retain existing resources and/or attract new resources allow PJM to maintain reliable operations at all times. For existing resources, if the total revenues derived from operating in all the PJM markets are greater than or equal to all variable and fixed (going-forward) costs for the resource, that resource will have the incentive to remain available to PJM markets and help maintain reliability.¹⁰ In contrast, if the revenues for the existing resource are unable to cover all variable and fixed, going-forward costs, then the resource has the incentive to exit the PJM markets. If existing resources have an incentive to exit the PJM markets, it should be the case that capacity adequacy reliability can be maintained without this resource by deploying the remaining resources in the PJM markets. Similarly for potential new resources (new entrants) into the PJM markets, if the potential, new entrant believes the revenue that can be derived from the PJM markets exceeds its anticipated variable and fixed, going-forward costs, new entry of resources will occur. This new entry should occur if new resources are needed to maintain reliability, or new resources can displace existing resources to achieve reliability aims at a lower cost. However, if the potential, new entrant anticipates that any anticipated revenues will be less than variable and going forward costs, new entry will not occur. There should be no new entry if there are already sufficient resources to meet reliability requirements and new entry would not lead to a lower cost of maintaining reliability.

In short, when resources are needed in PJM to maintain reliability, it should be financially attractive for them to do so. Conversely, when units are not needed to maintain reliability, the financial signals should reflect that.

Energy Market Compensation

The objective of the PJM Day-Ahead and Real-Time Energy Markets (Energy Markets) is to minimize the bid production cost of maintaining system energy balance while observing transmission limitations, maintaining reserves and regulation (frequency response), and ensuring individual generator constraints such as ramp rates or minimum run-times are not violated.¹¹ The rules governing the bidding (offering supply) into these markets are the same, and therefore the Day-Ahead and Real-Time Energy Markets will be discussed together. It is the bids from suppliers (offers) that define the bid production cost that is to be minimized to meet energy balance while not violating other constraints in system operation, and consequently it is those supply offers that will determine the price in the Day-Ahead and Real-Time Energy Markets that is paid to generation or demand resources. The structure and characteristics of supply offers will be discussed first, followed by price formation and the implications for covering variable and going-forward costs.

¹⁰ For the purposes of this document, the terms “going-forward costs” or “fixed, going-forward costs” include costs that do not change with supplier output such as fixed operation and maintenance costs, administrative costs, insurance, and the cost of investment plus a rate of return on the investment. On a yearly basis the “going-forward cost” is analogous to annual levelized fixed cost.

¹¹ See “PJM Manual 11: Scheduling Operations, Revision: 43, Effective Date: September 24, 2009 available at <http://www.pjm.com/documents/-/media/documents/manuals/m11.ashx> (“PJM Manual 11”) at 13, 62.

Generator Offer Requirements and Practices

Any generator that is a capacity resource (i.e. clears in any RPM auction or is a Fixed Resource Requirement (FRR) resource) is required to offer its energy into the PJM Energy Markets.¹² Such generators must offer into the Day-Ahead Energy Market by noon each day for the following day, and the market solution is generated by 4 p.m. each day.¹³ Any generator that is selected to run (based on the Day-Ahead Energy Market solution) is locked into the offer they had submitted and may not alter it, and generators who are not selected in the Day-Ahead Energy Market may revise their offer if they wish by 6 p.m. in preparation for participation in the reliability scheduling and Real-Time Energy Market.¹⁴

Cost-Based and Market-Based Supply Offers

All generators are required to make a **cost-based offer**.¹⁵ This offer must be computed according to the methods defined in *Manual 15: Cost Development Guidelines* (PJM Manual 15).¹⁶ PJM Manual 15 defines the manner in which generator costs are calculated and define the maximum cost-based offer that may be submitted. Generators that can operate on more than one type of fuel can submit more than one cost-based offer, based on the different fuels on which the generator can operate. The cost-based offer is used when a transmission constraint arises on the system, and the generator owner is determined to have local market power according to the Three Pivotal Supplier (TPS) test. A generation owner may choose to submit an offer lower than the PJM Manual 15 cost-based offer, and if it does so this offer is used when the TPS test determines the generation owner to have local market power as discussed below.

Generators may also make a **market-based offer** or **price-based offer**.¹⁷ This offer is not limited by cost development guidelines in PJM Manual 15, but is limited by the overall \$1,000/MWh cap. Such market-based offers are submitted by the generation owner based on their view of costs, operating risks, market forces, or any other factors which may contribute to their expectation of market conditions. Generation owners may choose not to make a market-based offer, and instead only submit a cost-based offer.

Cost-based offers are subject to review by the IMM.¹⁸ The Cost Development Task Force (CDTF) oversees the content of Manual 15. Any potential revision of PJM Manual 15 requires the approval of the PJM Markets and Reliability Committee, the PJM Members Committee (MC), and the PJM Board of Managers.¹⁹

¹² Id. at 11.

¹³ Id. at 12.

¹⁴ Id. at 18.

¹⁵ Id. at 20. In the past, some generators were exempt from this requirement, however this exemption has been terminated by the Federal Energy Regulatory Commission (FERC) and at this time, all capacity resources must submit a cost-based offer. See *PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,169 at P 34-39, 46-47 for a brief discussion.

¹⁶ "PJM Manual 15: Cost Development Guidelines, Revision: 10, Effective Date: June 1, 2009 available at <http://www.pjm.com/documents/-/media/documents/manuals/m15.ashx> ("PJM Manual 15").

¹⁷ PJM Manual 11 at 20-21.

¹⁸ For example, see PJM Manual 15 at 11, 20. The language in the current PJM Manual 15 refers to the IMM as the PJM MMU.

Mitigation and Offer Selection

In general, market-based offers are used to determine the bid production cost in the operation of the PJM Energy Markets. Cost-based offers of a generating unit are used only in circumstances where the transmission constraints limit available supply in a sub-region of the market and the owner of the generation unit is deemed to possess structural market power as indicated by the TPS test.²⁰

The TPS test is a structural market power test, executed by the PJM dispatch software every time a transmission constraint is binding on the system, which examines the pool of generators that are available to provide relief on the binding constraint. The test determines whether the tested generation owner's output, plus the output of two largest suppliers, is required to control the constraint. If so, then they are jointly pivotal, and considered to possess local, structural market power. The TPS test makes no determination on whether there has been any actual attempt to exercise market power.²¹

In the cases where a generation owner is found to possess local market power according to the TPS test, if that owner's generator must be committed to resolve the constraint, then the generator is dispatched on the lower of its cost-based or market-based offer.²² If the TPS test does not indicate the existence of structural market power to resolve the constraint, the implication is that there is sufficient competition to resolve that constraint, and the market-based offers are used.

In summary, cost-based offers are used in the energy market:

- a) When a generator must be committed to relieve a transmission constraint and there is a finding of local market power and the market-based offer is higher than the cost-based offer, or
- b) When a generation owner makes only a cost-based offer and has submitted no market-based offer.

Directly Incurred Cost Components of the Cost-Based Offer

There are two main components of a cost-based energy market offer submitted by a generation owner:

- Start-up costs – These are the costs to bring the boiler, turbine, and generator from shut-down conditions to a state ready to connect and be synchronized to the system. Start-up costs vary depending on the type of generator and the amount of time the generator has been off-line.²³

¹⁹ PJM Manual 15 at 2 and Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (Operating Agreement) available at <http://www.pjm.com/documents/agreements/~media/documents/agreements/oa.ashx>, Schedule 2, paragraph (d).

²⁰ For a quick overview see PJM Manual 11 at 30-31. For more detail, see Operating Agreement, Section 6.4.1 (e)-(f)

²¹ For a detailed discussion of the mechanics of the TPS test and examples, see "Three Pivotal Supplier Test in the PJM Real-time Energy Market" prepared for the Three Pivotal Supplier Task Force (TPSTF) available at <http://www.pjm.com/committees-and-groups/closed-groups/~media/committees-groups/task-forces/tpstf/postings/20080926-real-time-energy-market-tps-test-documentation.ashx>.

²² PJM Manual 11 at 30.

²³ See PJM Manual 15 at 30-34.

- Hourly production costs – The cost per hour to operate a generator assuming start-up has already occurred. The hourly production cost has two elements:
 - No-load costs – the cost per hour to maintain the boiler operating and the turbine and generator spinning at synchronous speed, but not generating any output.²⁴
 - Segmented energy costs – the cost per hour to produce the energy segments above the 0 MW generation level.²⁵

Both the start-up costs and the hourly production costs are composed of several elements.

Fuel-Related Costs²⁶

These costs relate largely to materials consumed in order for a generator to produce electricity. The most obvious is the fuel burned – coal, oil, natural gas, etc. The cost of fuel may be the actual price at which the fuel was purchased, or the replacement cost of the fuel (generally the spot market price of fuel). The use of actual or replacement fuel cost is defined by the generator’s fuel policy, which is submitted to and reviewed by the IMM. Other elements of the fuel-related costs are materials such as the reagents needed to operate pollution control systems. For example the lime necessary to operate a flue gas desulfurization unit is included in the fuel costs, as it is used to control the SO₂ emissions of the plant.

SO₂, NO_x, and CO₂ Emission Allowances²⁷

In cases where the generator is required to retire sulfur dioxide (SO₂), nitrogen oxide (NO_x), and/or carbon dioxide (CO₂) emission allowances for each ton of SO₂, NO_x, and/or CO₂ emitted, they may include the cost of those allowances that are used in startup or hourly production. Each company must submit their policy for computing the cost of these allowances to the IMM for review and approval.

Variable Operating and Maintenance Adder²⁸

This adder covers the cost of activities related to the variable operation and maintenance of the generator. These costs can occur over a significant number of years, and are generally divided by the hours of operation to derive a cost per hour of operation. Expenses in this category include items like:

- Air filter replacements
- Inspections and overhauls, including labor, parts, and rentals
- Water treatment expenses
- Catalyst replacements
- Major overhaul expenses

²⁴ Id. at 7.

²⁵ Id at 5-29.

²⁶ Id at 11-13, 15-19.

²⁷ Id at 14-15.

²⁸ Id at 20-29.

Such expenses are examined over a ten- or twenty-year cycle of operation, and then divided out among the hours of operation. While such expenses can be significant, the fact that they are spread out over such a long period means that they end up contributing a relatively small amount to the hourly cost.

Contribution of Directly Incurred Cost Components to the Cost-Based Offer

The majority of the directly incurred costs manifested in the cost-based offer in the PJM Energy Market are a result of fuel-related costs. The individual elements of the cost offer are not submitted to PJM, however it is possible to estimate the components based on known information about the generators. A review submitted cost offer data in 2008 shows that on average, fuel is 85% to 95% of the hourly production cost. This data includes all cost-based offers submitted in 2008.

Type of Cost Element	Fuel Costs	SO ₂ Allowances	NO _x Allowances	Operations and Maintenance Adders
Steam and CC	87%	4%	1%	7%
CT	96%	<1%	<1%	3%

Other Components of the Cost-Based Offer

There are three additional components that may be a part of the cost-based offer: A ten-percent adder to account for uncertainty in calculating costs, a Frequently Mitigated Unit (FMU) adder to account for units that are subject to market power mitigation for the majority of their run hours, and an opportunity cost for environmental and energy limitations.

Ten-Percent Adder

Per the Operating Agreement (OA), a generator may include a ten-percent (10%) adder to their computed cost offer as defined in PJM Manual 15.²⁹ A generator may elect to include this adder in full, in part, or not at all.

This adder is to account for uncertainty in the process of defining costs.³⁰ The adder was developed during the time PJM operated as a power pool rather than a full market, utilizing a “split savings” approach. This model was developed in the 1960’s and utilized for decades prior to the establishment of electricity markets.³¹ At that time, it was recognized that it can

²⁹ Operating Agreement, Section 6.4.2 (a) (ii).

³⁰ See “Reply Comments of the Independent Market Monitor for PJM” in Docket No. EL08-47, November 5, 2008, at 4. “The definition of costs includes a 10 percent adder to calculated short-run marginal costs (“SRMC”) in order to account for potential uncertainties in measurement.”

³¹ The use of the 10 percent adder goes back decades. For example, see *Terra Comfort Corporation, et al.*, 52 FERC ¶ 61,241 at 61,840 (1990), “With respect to the Applicants’ argument that the ten percent adder is a contribution to fixed costs, we have always viewed percentage adders as mechanisms to recover only incremental energy costs. 28/ Such adders are traditionally supported by utilities - and approved by the Commission - on the grounds that the ten percent adders recover incidental, miscellaneous expenses that are expensive or difficult to quantify. 29/ It continues to be the industry’s consistent practice to justify ten percent adders to incremental costs as allowing recovery of incremental energy costs, not as providing a contribution to fixed costs. 30/”

be difficult to determine with complete accuracy all elements of the cost of operating a generator, and no exceptions or special cases were recognized. The PJM members of the time agreed on an adder of ten percent as an appropriate means to compensate for the uncertainty in accurately determining costs. It is likely that the level of this adder reflected the "customary and ordinary" adders used in other regulatory areas at the time.

The adder also provides protection against unintended understatement of variable operating costs which could be harmful to reliable grid operation because it could create an incentive for generators to restrict their generation offer parameters. In certain circumstances, it may be possible that the cost development guidelines are in error and are too low for a particular generator or for a particular time period. In this case, the generator would not recover its operating costs and may be reluctant to offer fully flexible parameters due to concerns with under recovery of valid costs. The adder mitigates this situation by allowing some flexibility in variable cost submission while still ensuring that cost offers remain in a reasonable range.

Frequently Mitigated Unit (FMU) Adder

If a generator meets criteria defined in the Operating Agreement³² (OA) as being "Frequently Mitigated", it may include an adder into the cost offer. While the terms in the OA are more detailed, a brief overview is given here. Generators that are offer-capped for constraints more than 60% of their run hours in the prior 12 calendar months may include a \$20 adder to their cost-based offer. At an offer cap frequency of 70% this adder can rise to \$30 and at an offer cap frequency of 80% it is \$40. Generators may elect not to include the adder, or may only include part of it. Generators with identical electrical characteristics, also known as Associated Units (AU), are also allowed to include this adder (i.e. a generator at the same plant that by happenstance may not have been run as often). This is to prevent generators from being eligible for the adder in cycles based on alternating economic selection of units in dispatch.

In the order approving the FMU adder, FERC has stated that the purpose of the adder is to cover the going forward costs of the generator that may not be adequately covered if a generator is frequently mitigated. This topic will be discussed in more detail in the *Potential Areas of Overlap in Compensation* section below.

A cost-based offer may include either the ten-percent adder **or** the FMU adder (if the unit qualifies) **but not both**.³³

Opportunity Costs for Generators with Environmental and Energy Limits

Generators that are subject to run-time restrictions by external regulatory agencies (for instance, a state environmental regulator limiting the run hours due to emissions concerns) may include opportunity costs in their cost-based offer.³⁴

If generators with only a limited number of hours are forced to run on their cost-based offer due to a transmission constraint, the generator is giving up revenue that it could earn if it was running at a more profitable time of the year. Furthermore, since price is tied to need on the system, it is also reasonable to say this generator would be needed more

³² Operating Agreement, Section 6.4.2 (a) (iii).

³³ Id. at Section 6.4.2 (a) (iii) (a)-(c).

³⁴ See *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,145 (2009) ("February 19th Order") at P 47-48. FERC ordered PJM to submit a compliance filing addressing opportunity costs, and PJM has done so on July 31, 2009 in docket EL08-47-001 available at <http://www.pjm.com/documents/ferc-manuals/ferc-filings/-/media/documents/ferc/2009-filings/20090731-el08-47-001.ashx> ("July 31st Filing"). At the time this document was written, FERC has yet to rule on the PJM filing.

by the system at these times of higher prices. The opportunity cost adder is a means of providing an economic signal to the market that a generator is only available for a limited number of run hours by pricing the generator appropriately so that it is operated at times when it is most needed for reliability.³⁵

Opportunity costs are also a component of cost that was ordered by the FERC as a result of the paper hearing on the TPS test.³⁶

PJM's filing regarding opportunity cost provides only generators subject to an operating constraint by an external regulatory agency are eligible for inclusion of opportunity costs in their offer.³⁷ However the FERC has instructed PJM and its stakeholders to consider all legitimate and verifiable opportunity costs and discussions are underway at the CDTF on such costs.³⁸

It is important to note that opportunity costs are a market signal that helps drive reliability. Generators with a limited number of run hours could be in the position of being offer-capped to run for a transmission constraint more frequently early in the year (or other compliance period) and be forced to shut down for the remainder of the year (or compliance period). At which point they would be completely unavailable to the system to help provide reliable electric service. This is an undesirable outcome for the generator, for the load and for PJM.³⁹

The ten-percent adder and the FMU adder do not overlap with the opportunity cost adder due to the way opportunity costs are calculated. If a generator includes the ten percent adder or the FMU adder, it will result in a lower calculated opportunity cost and total to the same final offer.⁴⁰

Price Formation and Compensation in the PJM Energy Markets

The objective of the PJM Energy markets is to minimize the bid production cost, as defined by the relevant market-based and cost-based supply offers, to maintain energy balance while ensuring transmission limits are not violated, reserves and regulation (frequency response) are maintained, and individual generator constraints such as ramp rates or minimum run times are also not violated.⁴¹ At each location (node or bus) on the PJM System, the market price that results from

³⁵ See "Unit-Specific Opportunity Cost Calculation Proposal" by Paul M. Sotkiewicz, Ph.D, Laura R. Walter, and Thomas F. Zadlo, PJM Interconnection, LLC (PJM Opportunity Cost Proposal) presented to the July 13, 2009 meeting of the Cost Development Task Force available at <http://www.pjm.com/committees-and-groups/task-forces/-/media/committees-groups/task-forces/cdtf/20090713/20090713-item-02b-opportunity-cost-proposal.ashx>. A simple example is presented at 3-4.

³⁶ See February 19th Order at P 47-48.

³⁷ See July 31st Filing at 4-5.

³⁸ See *PJM Interconnection, L.L.C.*, 127 FERC ¶ 61,188 (2009) (May 28th Order) at P 7.

³⁹ PJM Opportunity Cost Proposal at 4.

⁴⁰ To verify this, see "Example Opportunity Cost Calculator.xls" posted for the May 29, 2009 meeting of the CDTF available at <http://www.pjm.com/committees-and-groups/task-forces/-/media/committees-groups/task-forces/cdtf/20090529/20090529-item-03b-example-opportunity-cost-calculator.ashx>. Follow the directions in the file using 50 hours as the run-time restriction and then \$0 and \$10 as the FMU adder.

⁴¹ PJM Manual 11 at 13, 62.

minimizing bid production cost is the marginal cost of providing one more megawatt (MW) of energy to that location. Energy prices in the PJM Energy markets are called Locational Marginal Prices (LMP).⁴² All supply resources and demand at the same location pay the same LMP. LMP includes: (1) the marginal cost of providing energy as if there were no transmission constraints or losses from moving power from one location to another, (2) the marginal cost of congestion which is the additional cost required to deliver power to a location in order to avoid overloading transmission lines; and (3) the marginal losses attributable to delivering power to the specified location. Because LMPs directly factor in transmission system constraints, the price signals sent are consistent with real-time dispatch requirements and short-term operation reliability needs.

Given the large contribution of fuel costs to cost-based offers shown above, it is not surprising that the contributions to LMP by cost-offer component for price setting units follow a similar pattern as shown in the table below detailing the contributions to LMP in 2008.⁴³ Consequently, as fuel prices rise and fall, the marginal cost of providing energy rises and falls, and therefore LMP will rise and fall along with fuel prices, all else equal.

Source	Contribution to LMP	Percent
Fuel	\$65.03	91.4%
Emissions	\$2.52	3.5%
VOM	\$3.00	4.2%
FMU	\$0.30	0.4%
Markup	\$2.04	2.9%
Other	(\$1.76)	-2.5%

Incentives to Reveal True Costs of Operation

The price formation mechanism is what is known as a uniform price auction in that all parties, in this case at the same location, are paid or pay the same price. The uniform price auction mechanism provides supply resources with the incentive to reveal their true costs of operation in their market-based offers even in the absence of cost-based offer requirements consistent with the PJM market design philosophy discussed above. The reason supply resources would want to reveal their true costs of operation in a uniform price auction is that they know they will be paid the marginal cost of delivering one more MW to the market regardless of their cost. For example, a supply resource with a marginal cost of \$30/MWh would want to submit this cost as their market-based offer because any time the marginal cost of delivering power exceeds \$30/MWh, the supply resource will make money equal to the difference between the market price and their marginal cost for every MWh sold. Consequently, because supply resources have the incentive to reveal their true costs, the PJM Energy Markets do minimize the production cost of providing energy to consumers subject to operational and reliability constraints.

The incentives in a uniform price auction stand in sharp contrast to the incentives to reveal true costs in a “pay-as-bid” auction design. Under “pay-as-bid” supply resources will be paid exactly what they bid into the market and consumers would pay some weighted average of the supply costs. However, because supply resources know that PJM would have to

⁴² See “PJM Manual 28: Operating Agreement Accounting, Revision: 42, Effective Date: July 31, 2009” available at <http://www.pjm.com/documents/~media/documents/manuals/m28.ashx> (PJM Manual 28) at 7-8.

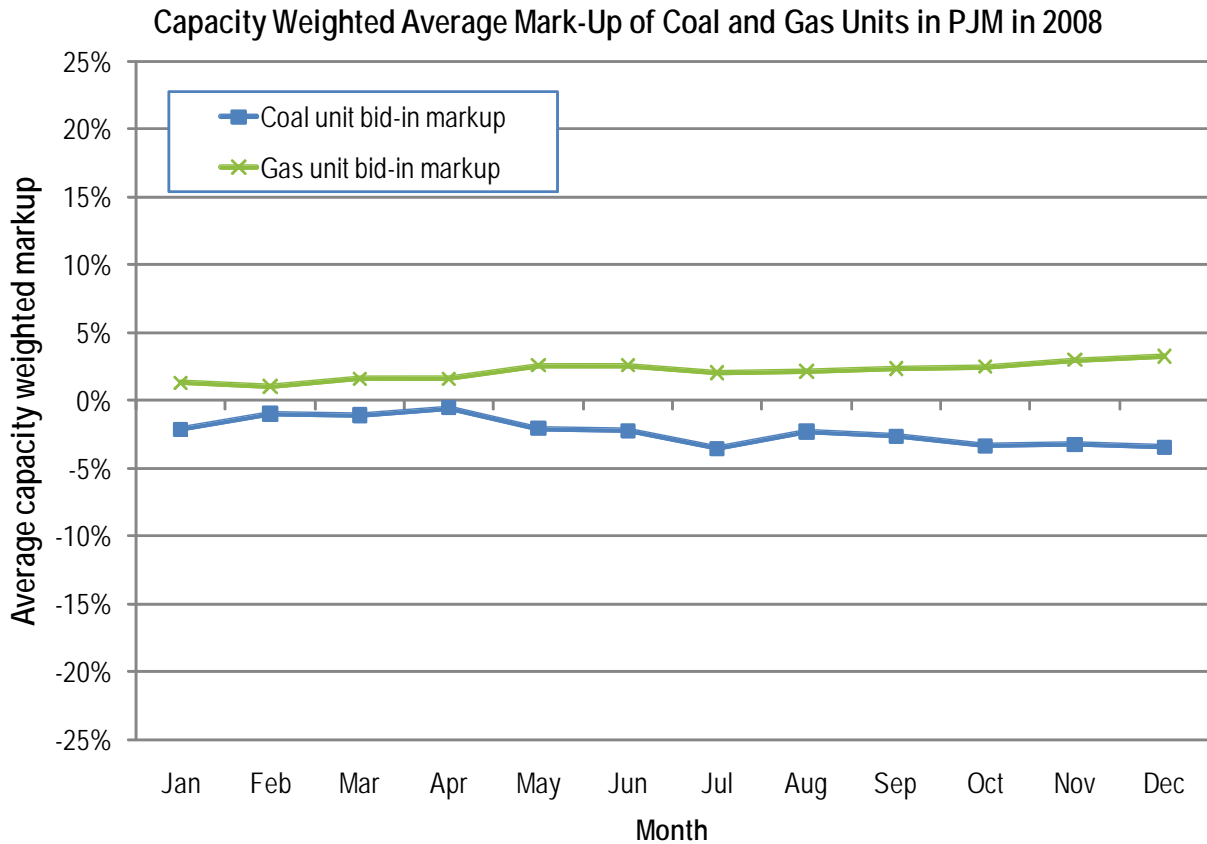
⁴³ Data summarized from the 2008 SoM Report, Table 2-57 at 61.

call resources up to a certain cost to ensure that energy balance was maintained, resources would have the incentive to “guess” what the highest cost resource required to maintain energy balance since they are paid as bid. In this case, supply resources have the incentive to overstate and misrepresent their true costs of operation due to the incentives provided by the “pay-as-bid” auction design. For example, a supply resource with a marginal cost of \$30/MWh believes PJM would have to call upon a \$50/MWh resource to maintain energy balance. The \$30/MWh resource would then submit an offer of \$50/MWh in order to receive the same price as the \$50/MWh resource it believes PJM needs to maintain energy balance. Moreover, because individual supply resources do not have perfect foresight or knowledge of system conditions, they are likely to “guess” incorrectly leading to a situation where minimizing bid production cost does not match up with minimizing the actual production costs because some low cost suppliers may submit very high prices and not be dispatched for energy while high cost suppliers may submit lower offers and be dispatched ahead of low cost resources.

In summary, the uniform price auction mechanism provides incentives for generators to reveal their true costs of operation in their market-based offers and helps ensure that the production cost of providing energy is minimized for consumers of electricity. As consistently stated in the annual State of the Market Reports issued by PJM's Independent Market Monitor (IMM), LMP in PJM is consistently close to costs and is “strong evidence of competitive behavior and competitive market performance.”⁴⁴ The offer behavior of coal and gas units in PJM for 2008 is shown below. The figure clearly shows market-based offer behavior within a very tight interval of +/- 4 percent around the cost-based offer on average.⁴⁵

⁴⁴ For example, see 2008 SoM at 8.

⁴⁵ Figure reproduced from “PJM’s Comments Regarding the 2008 State of the Market Report Issued by the Independent Market Monitor”, April 7, 2009 available at <http://www.pjm.com/documents/-/media/documents/reports/responses-to-som.ashx> at 6-7.



Under the PJM market rules, a generator is guaranteed to recover at least its variable operating cost via energy market revenue⁴⁶ and may recover a portion of their fixed costs if they have operating costs that are below the marginal price. In practice, generators do not receive sufficient revenue to recover fixed costs through the energy market alone, which is one reason that the PJM market design includes a capacity market.

Incentives to Follow Dispatch Instructions and Meet Operational Needs

LMP reflects the actual impact of binding transmission constraints and the contribution to losses from moving power from supply resources to consumers of energy. Consider a simplified transmission system with two locations and one transmission line between them. At one location there is a surplus of low cost generation relative to the load to be served. For the ease of exposition suppose the price at the low cost location is \$20/MWh. At the other location, there is only high cost generation and there is not enough transmission capacity to serve the load at the high cost location with low cost energy. The price at the high cost location is \$50/MWh. For generators at the low cost location, if the price of energy were set at \$50/MWh ignoring the transmission constraint, generators at the low cost location would have the incentive to run to their maximum and risk tripping the transmission line out of service, so the \$20/MWh price at the low cost location provides the right dispatch incentive to provide energy while not tripping out the line. In this way the LMP is consistent with the needs of the system and consistent with dispatch instructions to only operate at a certain level of output to maintain

⁴⁶ PJM Manual 28 at 33-34.

transmission reliability. Similarly, for generators at the high cost location, a price of only \$20/MWh would result in the high cost generators not wanting to run which would require demand at the high cost location to be curtailed in order to maintain energy balance and maintain transmission security because power would want to flow across the line in excess of its limit. Consequently, paying the higher price at the high cost location (\$50/MWh) provides generators to incentive to run so that energy balance is maintained and that flows on the transmission line remain below its limit.

Also, the interaction of LMPs between the Day-Ahead and Real-Time Energy Markets provide incentives for supply resources to maintain their commitments, and to follow dispatch instructions to maintain energy balance and system reliability. For supply resources that are committed and clear in the Day-Ahead Energy Market, those commitments are financially binding. For example, consider a supply resource that clears 100 MWh between 2 p.m. and 3 p.m. (hour ending 15) the next day at an LMP of \$70/MWh. In the Real-time Energy Market the LMP between 2 p.m. and 3 p.m. is \$100/MWh. The committed resource has the incentive to honor its day-ahead commitment because failing to do so would result in the supply resource buying back its supply position with a loss of \$30/MWh on each MWh committed day-ahead. The supply resource even has an incentive to supply additional energy to the Real-Time Energy Market in excess of its day-ahead commitment, if available at an offer below \$100/MWh. In this sense, if the load forecast was below the actual load, it should be the case that LMP in real-time is greater than LMP day-ahead and that resources committed day-ahead are needed, and have the incentive to honor their commitments in real-time. Conversely, suppose the load forecast day-ahead is above the actual real-time load leading the real-time LMP to be \$50/MWh. In this case operation needs require some generators to back down from their day-ahead commitments to maintain energy balance. The supply resource being paid \$70/MWh day-ahead can buy back its position in real-time at a price below what it was paid day-ahead, thereby making \$20/MWh on every MWh it does not produce in real-time and matching the incentives with operational needs.

Energy Market Revenues to Cover Variable and Fixed, Going-forward Costs

In general, supply resources are not dispatched in the PJM Energy markets unless the relevant market-based or cost-based offer of the supply resource is less than or equal to the LMP that would be paid to the supply resource. In general, supply resources dispatched to provide energy will cover their variable costs, as represented by their offer, any time they run, albeit with some exceptions as discussed below.⁴⁷ Consequently, supply resources operating in PJM Energy markets will also be able to recover part of their fixed, going-forward costs with the difference between the LMP and their applicable offer under which they operating for every MWh sold.⁴⁸ For example, a supply resource with a \$30/MWh offer supplies 100 MWh of energy at an LMP of \$50/MWh. Its variable costs as represented by the offer are \$30/MWh multiplied by 100 MWh for a variable cost of \$3,000. The supply resource earns \$50/MWh multiplied by 100 MWh for revenues of \$5,000. The revenues cover the \$3,000 variable cost plus \$2,000 of fixed, going-forward costs.

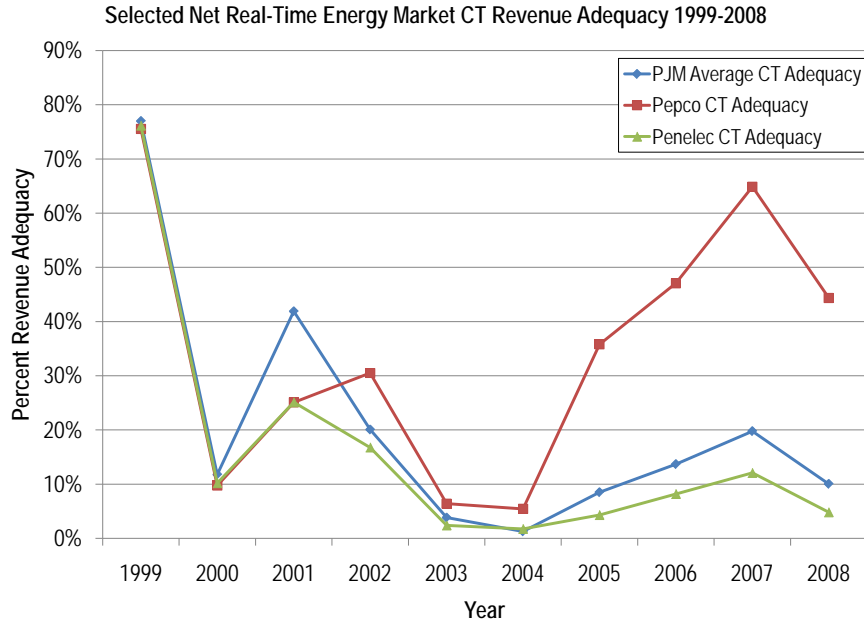
However, potential new generation resources historically would have been unable to cover their fixed, going forward costs through the energy market alone as shown by the net revenue analysis conducted by the IMM in various State of the Market Reports over time.⁴⁹ The two figures below show the percentage of fixed, going-forward costs recovered by new

⁴⁷ Id. at 33-34. The issue of supply resources being dispatched at LMP below their offers can occur due to minimum run time constraints, or generators may not be able to recover all start-up costs. Compensation will be discussed in the section on Operating Reserve Payments below.

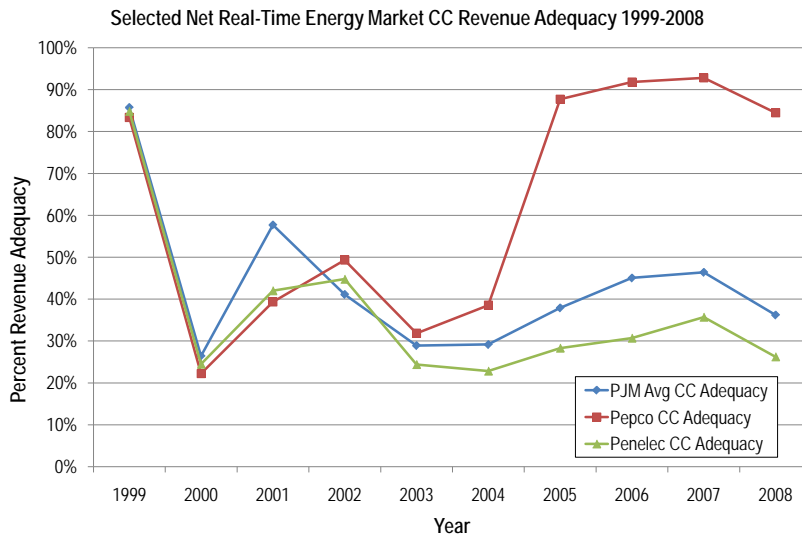
⁴⁸ The applicable offer could be the cost-based offer if the resources was mitigated, otherwise this would be the market-based offer.

⁴⁹ For example, see the summary over time in the 2008 SoM at 143-155.

entry combustion turbines (CTs) and combined cycle gas plants (CCs) through the PJM Real-Time Energy Market. Even in zones such as Pepco where LMPs are higher than they are on average in the rest of PJM, there is not enough net Energy Market revenue to justify the entry of new resources.⁵⁰



⁵⁰ Data source for CTs is 2008 SoM Tables 3-7 at 132, 3-11 at 135, and 3-23 at 143. Data source for CCs is 2008 SoM Tables 3-8 at 132, 3-13 at 137, and 3-25 at 147.



Consequently, to provide incentives to attract new supply resources to the PJM markets it has been necessary to implement the RPM Capacity Market as a source of revenues to maintain or attract resources to maintain capacity adequacy requirements into the future. (These revenues are discussed in more detail later in this document.)

Scarcity Pricing

The PJM Real-Time Energy Market has provisions for a scarcity pricing mechanism. In brief, scarcity pricing works as follows:⁵¹

- The implementation of certain emergency procedures that signal the system is running short of supply resources to maintain energy balance and reserves can trigger a scarcity pricing event in areas previously established in the PJM Tariff.
- The areas subject to scarcity pricing correspond with busses impacted by a high-voltage constraint on the transmission system
- During a scarcity event, all market power mitigation and cost-based offer caps are lifted in the scarcity pricing zone
- The LMP in the scarcity pricing zone is set to the price of the most expensive generator operating in the scarcity pricing zone

⁵¹ See Operating Agreement, Section 6A.

Since the LMP is set by the most expensive generator in the scarcity pricing zone operating at PJM's direction, all generators will receive that price. A robust scarcity pricing mechanism is valuable both in helping generators recover their fixed, going-forward costs in addition to their variable costs, as well as providing a pricing signal to other market participants, such as demand response participants, of the value of energy in times of reserve shortages. To date, there have only been two scarcity pricing events in PJM, both on August 8, 2007.

As a result of FERC Order 719, the PJM stakeholder process is discussing replacing the current scarcity pricing mechanism with one based on the principles established by the FERC in Order 719.⁵²

Ancillary Service Market Compensation

Ancillary services are necessary for the reliable operation of the transmission system as it moves electricity from generating sources to customers. In 2008 Ancillary Services contributed to only 1.3 percent of the total cost of wholesale power.⁵³ PJM currently operates three markets for ancillary services:

- Regulation is a service that corrects for short-term changes in energy balance to maintain system frequency at 60 Hertz (cycles per second) and maintain stability of the power system.
- Synchronized Reserves are comprised of generating or demand-side capacity that has the ability to produce energy within 10 minutes of the occurrence of a system contingency such as the loss of a generator or loss of a large transmission facility.
- The Day-Ahead Scheduling Reserve (DASR) Market satisfies a supplemental thirty minute reserve requirement to account for errors in load forecasting day-ahead and to account for the probability of generator outages that may occur between day-ahead commitments and real-time operation.

In addition, Black Start Service supplies electricity for system restoration in the unlikely event that the entire grid would lose power, and Reactive Power and Voltage Control service ensures that transmission voltages are maintained at the appropriate levels. Each of these cost-based services represents a potential revenue stream for those generators which are both qualified to provide the services in question and choose to offer to provide those services.

Regulation Market

Regulation, also known as frequency response, corrects for short-term changes in energy balance to maintain system frequency at 60 Hertz (cycles per second) and maintain stability of the power system. As more or less electricity is consumed, this must be balanced moment-to-moment with corresponding changes in generation. If it is not, the frequency of the system will rise (too much generation) or fall (too little generation) accordingly. Should the frequency deviate too far from 60 Hertz, it will cause the equipment to trip out of service to prevent and/or cause damage to the equipment. This

⁵² The discussion has been taking place at the SPWG (<http://www.pjm.com/committees-and-groups/working-groups/spwg.aspx>).

⁵³ Calculated from "Executive Report" presented at the November 19, 2009 meeting of the PJM Members Committee available at <http://www.pjm.com/committees-and-groups/committees/-/media/committees-groups/committees/mc/20091119/20091119-item-07a-markets-executive-report.ashx> at 3.

could lead to widespread outages or system collapse if uncontrolled. In order for the grid to remain reliable and stable, frequency must be maintained, and consequently regulation service is a vital component of this stability.

Offers into the Regulation Market

Unlike the PJM Energy markets where there is a must-offer requirement for capacity resources, there is no must-offer requirement into the regulation market, and market-based offers are limited by a cap of \$100/MWh.⁵⁴ Not all generators are eligible to participate in the regulation market, as special equipment is required for a generator to provide this service. For those resources eligible to provide regulation and willing to participate in the regulation market, regulation resources must submit cost-based offers and may also submit market-based offers just as is the case for the PJM Energy markets.⁵⁵

The TPS test is used in the regulation market, just as it is in the PJM Energy markets, to determine whether owners of regulation resources possess structural market power.⁵⁶ The test determines whether the tested regulation resource owner's regulation supply, plus the output of two largest regulation suppliers, is needed to satisfy the regulation requirement. If so, then they are jointly pivotal, and considered to possess structural market power in the regulation market. Regulation suppliers deemed to possess structural market power are mitigated to the lower of the cost-based or market-based offer.

The methodology for computing cost-based offers for the regulation market is defined in PJM Manual 15. In order to supply regulation, a generator is required to operate at a point less than the full economic output of the generator. This point is a less efficient operating point than the full output point. As such, some of the elements of the cost offer are intended to capture the cost increases due to this loss in efficiency, as well as the cost of increased wear and tear on the generator. Moreover, a generator providing regulation may also be asked to produce less energy than would otherwise be optimal given the prices in the energy market, and this "lost opportunity cost" must also be factored into the cost of providing regulation. Components of the cost-based regulation offer include:⁵⁷

- The increased fuel costs resulting from operating the generator at a lower, less efficient output point;
- The costs resulting from operating the generator in a non-steady-state condition;
- The increased maintenance cost of operating a generator at the lower output point;
- A margin/risk adder not to exceed \$12 per MW of regulation service to account for uncertainty in the costs of providing regulation service and the potential increased risk of a unit tripping because it is operating in a non-steady-state condition; and
- Lost Opportunity Costs (LOC) that account for forgone profits from the PJM Energy Market when a generator provides regulation. (LOC is computed by PJM and not a part of the offer submitted by the supplier.)

The LOC is consistent with the PJM market design philosophy in that it is necessary to ensure the incentives to provide energy and regulation are identical. Without LOC, generators would have little incentive to supply regulation if they are able to more profitably provide energy instead. Additionally, because LOC is explicitly accounted for in the regulation

⁵⁴ PJM Manual 11 at 39.

⁵⁵ Id. at 39.

⁵⁶ Id. at 42-43.

⁵⁷ PJM Manual 15 at 40-42.

offers, suppliers of regulation have the incentive to reveal their true costs of providing regulation satisfying the PJM design principle regarding the revelation of true operating costs.

Price Formation in the Regulation Market and Revenues to Cover Going Forward Costs

The provision of regulation is simultaneously co-optimized with the provision of synchronized reserves (discussed below) and expected energy dispatch an hour before the actual dispatch hour through the Synchronized Reserve and Regulation Optimizer (SPREGO) software tool.⁵⁸ SPREGO recognizes the substitutability between energy, synchronized reserves, and regulation in finding the cost minimizing solution to provide regulation in jointly minimizing the bid production cost of providing regulation, synchronized reserve, and expected energy, where the regulation offers define the production costs for regulation.

The Regulation Market Clearing Price (RMCP) is the marginal cost of providing one more MWh of regulation service determined in a uniform price auction framework with all the incentives for truthful cost revelation as discussed above, and all suppliers receives the RMCP. Historically according the State of the Market Reports issued by the IMM, for regulation suppliers at the margin, the LOC component of the offer is approximately 65 to 75 percent of the RMCP.⁵⁹ A closer examination of the remaining part of regulation offers also reveals that regardless of whether market power mitigation was in place, the cleared offers for regulation have been between \$10 and \$12/MWh since 2006, further reinforcing the idea that the uniform auction design incents truthful cost revelation.⁶⁰

Much like in the PJM Energy Market, if a supplier of regulation is paid the RMCP, but has an offer (inclusive of LOC) below the RMCP, the supplier is generating revenues that can help cover the going forward costs.

Out of Market LOC Payments

Because the RMCP is determined based on LOC from expected energy dispatch and prices, it is usually the case that the actual Energy Market prices differ from the expected Energy Market prices that are used to calculate the LOC in offers used to determine the RMCP. Consequently, suppliers of regulation are also paid out of market LOC payments, specific to each supplier of regulation, based on the actual Real-Time Energy Market LMPs. These payments only cover the actual LOC and therefore do not contribute to covering the fixed, going forward costs of supply resources.⁶¹

Tier 2 Synchronized Reserve Market

Synchronized reserves are comprised of generating or demand-side capacity that has the ability to produce energy within 10 minutes of the occurrence of a system contingency such as the loss of a large generator or loss of a large transmission facility. The loss of a generator or transmission facility causes an imbalance in supply and demand that is too large to be

⁵⁸ PJM Manual 11 at 38.

⁵⁹ For 2006 figures, see 2006 State of the Market Report, Volume II: Detailed Analysis, Market Monitoring Unit, March 8, 2007, available at <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/2006-somvolume-ii.pdf> ("2006 SoM Report") at 250; For 2007 figures, see 2007 State of the Market Report, Volume 2: Detailed Analysis, Market Monitoring Unit, March 11, 2008, available at <http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-sumvolume2.pdf> ("2007 SoM Report") at 288; For 2008 figures see 2008 SoM Report at 313; for 2009 figures see 2009 Q3 SoM Report at 112, 117.

⁶⁰ See *supra* note 55.

⁶¹ PJM Manual 11 at 46-47.

managed by regulation alone and can lead to a collapse of the grid if not managed. Synchronized reserves allow PJM to maintain reliability and keep the lights on when such events occur.

PJM classifies synchronized reserves in two categories: (1) Tier 1 Synchronized Reserve which is comprised of unloaded capacity of generators already running to provide energy based on PJM dispatch that can respond within 10 minutes; and (2) Tier 2 Synchronized Reserve which is comprised of generators that are started in condensing mode and synchronized to the grid, but not providing output, Demand resources that can drop load within 10 minutes, and on-line generation that must be dispatched down from what would otherwise be their optimal dispatch point.⁶² For instance if an 800 MW unit is optimally dispatched for 700 MW of energy, there are 100 MW Tier 1 Synchronized Reserves available if those 100 MW can be delivered within 10 minutes. Separately, if the optimal dispatch for a 400 MW unit is to run at its maximum for energy, but is backed down to 350 MW of energy output, then the 50 MW of available capacity is considered Tier 2 Synchronized Reserve since it would optimally be dispatched at its 400 MW maximum for energy, but for the need for Synchronized Reserves.

To the extent there is not enough Tier 1 Synchronized Reserve to satisfy the Synchronized Reserve requirement, PJM operates a market for Tier 2 Synchronized Reserve to ensure the Synchronized Reserve requirement is met.

Offers in the Tier 2 Synchronized Reserve Market

Participants in the Tier 2 Synchronized Reserve Market are only allowed to submit cost-based offers due to ongoing concerns regarding structural market power in the Tier 2 Synchronized Reserve Market.⁶³ There is no must-offer requirement into the Tier 2 Synchronized Reserve Market. The methodology for determining cost-based offers for Tier 2 Synchronized Reserve is defined in PJM Manual 15. Components of the cost-based offer include:⁶⁴

- Start-up costs (similar to the start-up costs in the Energy markets);
- Variable Operations and Maintenance costs;
- The cost of power consumed during condensing operations;
- Lost Opportunity Costs (LOC) (as computed by PJM Market Settlements) for generation that is backed down from what is otherwise profitable output for the Energy Market; and
- A risk/margin adder of up to \$7.50 per MWh of spinning reserve service provided.

In the same fashion as in the Regulation Market, the LOC component of offers is consistent with the PJM market design philosophy in that it is necessary to ensure the incentives to provide energy and synchronized reserves are identical. Without LOC, generators would have little incentive to be backed down from profitable energy output to supply Tier 2 Synchronized Reserve. Additionally, because LOC is explicitly accounted for in the Tier 2 Synchronized Reserve offers, suppliers of Tier 2 Synchronized Reserve have the incentive to reveal their true costs of providing Tier 2 Synchronized Reserve satisfying the PJM design principle regarding the revelation of true operating costs.

⁶² PJM Manual 11 at 49.

⁶³ Id. at 50.

⁶⁴ PJM Manual 15 at 35-38.

Price Formation in the Tier 2 Synchronized Reserve Market and Revenues to Cover Going Forward Costs

As discussed above in the context of regulation, the provision of synchronized reserve is simultaneously co-optimized with the provision of regulation and expected energy dispatch an hour before the actual dispatch.⁶⁵ The amount of Tier 2 Synchronized Reserve procured is dependent upon the expected Tier 1 Synchronized Reserve available as a by-product of the expected dispatch in the Energy Market.⁶⁶ The objective is to jointly minimize the bid production cost of providing Regulation, Synchronized Reserve, and expected energy, where the Tier 2 Synchronized Reserve offers define the production costs for Tier 2 Synchronized Reserve.

The Tier 2 Synchronized Reserve Market Clearing Price (MCP) is the marginal cost of providing one more MWh of Tier 2 Synchronized Reserve service determined in a uniform price auction framework with all the incentives for truthful cost revelation as discussed above, and all suppliers receive the MCP. Tier 1 Synchronized Reserve is not paid for Tier 2 Synchronized Reserve.

Much like in the PJM Energy Market, if a supplier of Tier 2 Synchronized Reserve is paid the MCP, but has an offer (inclusive of LOC) below the MCP, the supplier is receiving revenues that can help cover the going forward costs.

Out of Market LOC Payments

Because, much like the Regulation Market, the Tier 2 Synchronized Reserve MCP is determined based on LOC from expected energy dispatch and prices, it is usually the case that the actual Energy Market prices differ from the expected Energy Market prices that are used to calculate the LOC in offers used to determine the MCP. Consequently, suppliers of Tier 2 Synchronized Reserve are also paid out of market LOC payments where applicable, specific to each supplier of Tier 2 Synchronized Reserve, based on the actual Real-Time Energy Market LMPs. These payments only cover the actual LOC and therefore do not contribute to covering the fixed, going forward costs of supply resources.⁶⁷

Day-Ahead Scheduling Reserve Market

The Day-Ahead Scheduling Reserve (DASR) Market satisfies a supplemental thirty-minute reserve requirement to maintain capacity to manage errors in load forecasting day-ahead and potential generator outages as expressed in equivalent forced outage rates that may occur between day-ahead commitments and real-time operation. Resources committed to DASR on a day-ahead basis are not required to respond in real-time to contingencies or to maintain frequency, but are expected to respond to PJM dispatch instructions within the thirty-minute time required.

Offers in the DASR Market⁶⁸

There is no must-offer requirement, but supply resources that have provided offers into the Day-Ahead Energy Market and have capacity that can be dispatched for energy within thirty minutes, are by default considered available to provide DASR unless those supply resources specifically indicate they are unavailable. Demand resources may also make themselves

⁶⁵ PJM Manual 11 at 48.

⁶⁶ Id. at 53-54.

⁶⁷ Id. at 59.

⁶⁸ PJM Manual 11 at 127-128.

available to the DASR Market. There are only market-based offers and no requirement to submit cost-based offers in this market as there is no market power mitigation in this market. In evaluating DASR offers, if a supply resource must be de-committed from providing energy in the Day-Ahead Energy Market, the lost opportunity cost (LOC) of forgone energy profits are also included in the offer in the same manner as Regulation or Tier 2 Synchronized Reserves.

Price Formation in the DASR Market and Revenues to Cover Going Forward Costs

The DASR Market is co-optimized with the Day-Ahead Energy Market to minimize the bid production cost as defined by DASR offers and LOC, of providing DASR.⁶⁹ However, given there are only market-based offers the clearing price for this market is typically low and often zero. The average clearing price in 2008 was \$0.26/MWh and through the end of September 2009 it was \$0.05/MWh.⁷⁰ The IMM has concluded that the results of the market were competitive in 2008 and 2009.⁷¹ Because of the limited revenues available through the DASR Market, the contribution of proceeds from the DASR Market toward covering fixed, going forward costs is minimal.

Black Start Costs

Black Start Service supplies electricity for system restoration in the unlikely event that the grid would lose power entirely. It typically requires electricity from the grid in order to start a generator. Black Start generators are able to start without external electricity – for instance by having a backup generator on site. In the absence of Black Start generation, it would be impossible to restore the power grid after a collapse.

There are a limited number of generators that can provide this service in PJM – approximately 200. Of those, just over 100 are compensated for Black Start costs. The Black Start Service is a cost-based service that is not procured through a market mechanism and consequently there are no market-based offers, market power mitigation, or cost-based offers for Black Start.

There are two ways in which the costs for Black Start Services can be determined. The first is where the provider and the transmission owner reach an agreement on the costs, and file those costs with the FERC.⁷² If approved, this defines the cost of the service for that generator. Only a small number of Black Start generators in PJM use this method.

The second method is the formulaic method. The components of cost in this method are:⁷³

- The cost of the operation and maintenance of any additional equipment needed to provide the service (for instance, the maintenance of the backup generator on site);
- The cost of the fuel reserve maintained to provide the service if needed; and
- The cost of training the plant personnel to operate the additional equipment.

These costs are submitted to PJM and the IMM.

⁶⁹ Id. at 129.

⁷⁰ 2008 SoM Report at 302 and 2009 Q3 SoM Report at 114.

⁷¹ 2008 SoM Report at 305 and 2009 Q3 SoM Report at 115.

⁷² PJM Open Access Transmission Tariff (“PJM OATT”), Schedule 6A, Section 17.

⁷³ PJM OATT, Schedule 6A, Section 18.

Reactive Power and Voltage Control

Reactive power is necessary to support and maintain prescribed voltages on the transmission system in order to allow power transfers from one part of the system to another. Reactive power supply and voltage control is a transmission service that is a non-market, cost-of-service product.⁷⁴ All generators and non-generation sources capable of providing reactive power are obligated to do so in accordance with the Interconnection Agreement.⁷⁵

Supply resources receive a cost of service payment equal to their monthly revenue requirement for providing reactive power, where the monthly revenue requirement is approved by the FERC. For new entry generation, the IMM analysis shows indicates that reactive power net revenues account for one to five percent of PJM Market net revenues depending on technology.⁷⁶

Balancing Operating Reserve Payments

A supply resource operating at PJM's direction for energy and ancillary services will never be asked to operate over the course of a day where revenues will be less than the variable cost, as represented by the value of the offer on which it is operating (market-based or cost-based), consistent with PJM's market design philosophy that supply resources have the incentive to follow PJM dispatch instructions.⁷⁷ If resources were dispatched by PJM without sufficient revenues to cover variable costs (value of the offer), then they would have little incentive to follow PJM dispatch instruction if they believe such instruction would lead them to operate at a loss, and PJM's ability to control the system would be diminished.

Consequently, supply resources receive Balancing Operating Reserve (BOR) payments when Energy and Ancillary Service Market revenues over one day resulting from a supply resource's PJM directed operation are not sufficient to cover the production cost of the generator as defined by the resource's Energy and Ancillary Service Market offers.⁷⁸ BOR payments only contribute to covering a supply resource's variable cost of operation as defined by their energy and ancillary service offers, and do not contribute to covering the fixed, going forward costs of the supply resource. These payments are also called "make-whole payments" or "uplift payments", as they will make a generator whole to their offer, providing the compensation equal to the difference between the LMP and the generator's offer. PJM attempts to manage the system so as to minimize the amount of these payments and operate the system economically. However in real environments, BOR payments can be minimized but never completely eliminated.

For example, generators with minimum run-time restrictions may require BOR payments to ensure that revenues cover their offer-defined costs. A generator operating at PJM's direction, and committed for its minimum run-time in the Energy Market, is paid the locational marginal price (LMP) for energy produced. However, during the minimum run-time period, it is possible that the LMP can drop below the offer made by that generator due to changing load levels or transmission constraint patterns. If generators were able to start and stop at will, the generator would stop operating, since the

⁷⁴ PJM OATT, Schedule 2.

⁷⁵ See PJM OATT, Appendix 2 Standard Terms and Conditions for Interconnections Section 4.7.2.

⁷⁶ 2008 SoM Report, Tables 3-10, 3-12, and 3-14 at 134, 136, and 138.

⁷⁷ PJM Manual 28 at 31-40.

⁷⁸ This is true but for revenues received in the Regulation Market which are not offset against BOR credits. See *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231 (2008) at P 5, 16.

compensation received is no longer at or above the level that the generator is willing to operate as revealed by its offer. However the minimum run-time restriction precludes the generator from shutting on and off at will, and consequently over the minimum run-time period, the generators' revenues may be less than its variable cost as represented by the offer.

RPM Capacity Market Compensation

PJM's Reliability Pricing Model (RPM) Capacity Market is a long-term resource adequacy mechanism designed to ensure PJM can meet its resource adequacy requirement of having enough supply capacity to meet forecast peak load plus the installed reserve margin and ensure the appropriate location of resources.⁷⁹ The resource adequacy requirement is necessary to maintain safe, reliable grid operation through system peaks. The objective of the RPM Capacity Market auctions is to maximize the benefit to both suppliers of capacity and buyers of capacity (social benefit) as defined by the demand for capacity derived from the resource adequacy requirement and the Variable Resource Requirement (VRR) Curve, less the cost of capacity as defined by the supplier offers of capacity into the market.

The RPM Capacity Market is conducted through a Base Residual Auction (BRA) three years prior to the delivery year for capacity.⁸⁰ To account for potential changes between the BRA and leading up to the delivery year such as changes in the load forecast or changes in the ability to meet capacity obligations, PJM conducts three Incremental Auctions (IAs).⁸¹ In the discussion that follows, the basics and rules of the BRA and IAs are essentially identical, but any differences that may arise with the IAs will be noted.

Rationale for the RPM Capacity Market

PJM is required to ensure there are sufficient supply resources to meet expected peak demand plus an installed reserve margin, and to also ensure that supply resources are appropriately located in the PJM system.⁸² However, neither PJM nor the FERC can require market participants to invest in new supply resources, nor can PJM or FERC dictate the location of any new investments. Therefore addressing the challenge of setting the correct investment incentives is the principal motive for the RPM Capacity Market and drove its design and implementation. If the wholesale power markets provide the proper incentives through robust design, prices, and resulting revenue streams, the retention of existing resources and the development of new generation and demand-side resources will occur and in the locations where these resources are needed. The resulting mix of resources, at the appropriate location and with the types of operating characteristics that allow the electricity system to be operated reliably and efficiently, will be in place. If the incentives are incorrect (in that prices and revenue streams are not sufficient to retain the right mix of existing resources or attract desired new resources), then operational reliability and capacity adequacy reliability will be put at risk. In short, getting the wholesale price incentives right is fundamental to maintaining reliability at the lowest cost.

⁷⁹ PJM Manual 18: PJM Capacity Market, Revision: 8, Effective Date: January 1, 2010 available at <http://www.pjm.com/documents/-/media/documents/manuals/m18.ashx> ("PJM Manual 18") at 3.

⁸⁰ Id. at 56.

⁸¹ Id. at 56.

⁸² Id. at 7-13.

Energy and Ancillary Service Markets Alone Do Not Provide Enough Revenue to Encourage New Investment

PJM reliability requirements and market rules act together to limit PJM Energy Market prices, and by extension, revenues to cover supply resources' fixed, going-forward costs. First, the resource adequacy requirement that PJM hold enough resources to meet the forecast peak load plus an installed reserve margin creates a situation where there is generally an excess of supply. This large supply of generation resources will vigorously compete and drive Energy Market prices down to their competitive levels, where price is equal to marginal cost.⁸³ The volume of generation supply also reduces the number of shortage events where prices would be set by demand's marginal willingness to pay, which would allow peaking resources to earn enough money in the Energy Market over their marginal cost to cover going-forward costs and continue operating. If the Energy Market were left to operate on its own in the absence of any resource adequacy requirement or capacity market, eventually some generation resources would leave the market. The exit of resources would result in energy prices rising over all hours as well as increasing the frequency of shortage events. The consequence of the exit of resources from the market, however, would also result in a violation of the resource adequacy requirement. Second, during hours of shortage, the prices in the PJM Energy Market are limited by the \$1,000/MWh offer cap. It is difficult to have the price set by demand's marginal willingness to pay if it is in excess of the \$1,000/MWh offer cap. The inability of generators to earn enough revenue to cover their fixed, going-forward costs due to these reliability and market rules has been referred to as the "missing money problem". Without sufficient price signals and market revenues to support the level, types, and location of investments in resources needed to support reliability objectives, reliability will be degraded and the competitiveness of the Energy Market will be eroded.

PJM's RPM Capacity Market seeks to address the "missing money problem" by providing payments to demand-side resources and generators to "make them whole" for providing resource adequacy if they operate as expected in the PJM Energy and Ancillary Service Markets and as required by the RPM Capacity Market. This idea is consistent with the PJM market design philosophy of providing the correct incentives for following PJM direction. In addition to paying for resource adequacy, payments from the RPM market reflect revenues resources would have earned if wholesale energy market prices reflected the true value of energy and reserves during shortage conditions in the absence of any offer caps. In other words, RPM's capacity payments are not designed to give generators "windfalls" nor do they subsidize investments at capacity levels that would not be approved under cost-of-service regulation. Rather, RPM takes as a given whatever reliability targets the region adopts (such as a 15 percent planning reserve margin), and then seeks to provide the missing revenues that would be needed to support the corresponding level of investment need to maintain the reliability objective.

Historic Capacity Payments

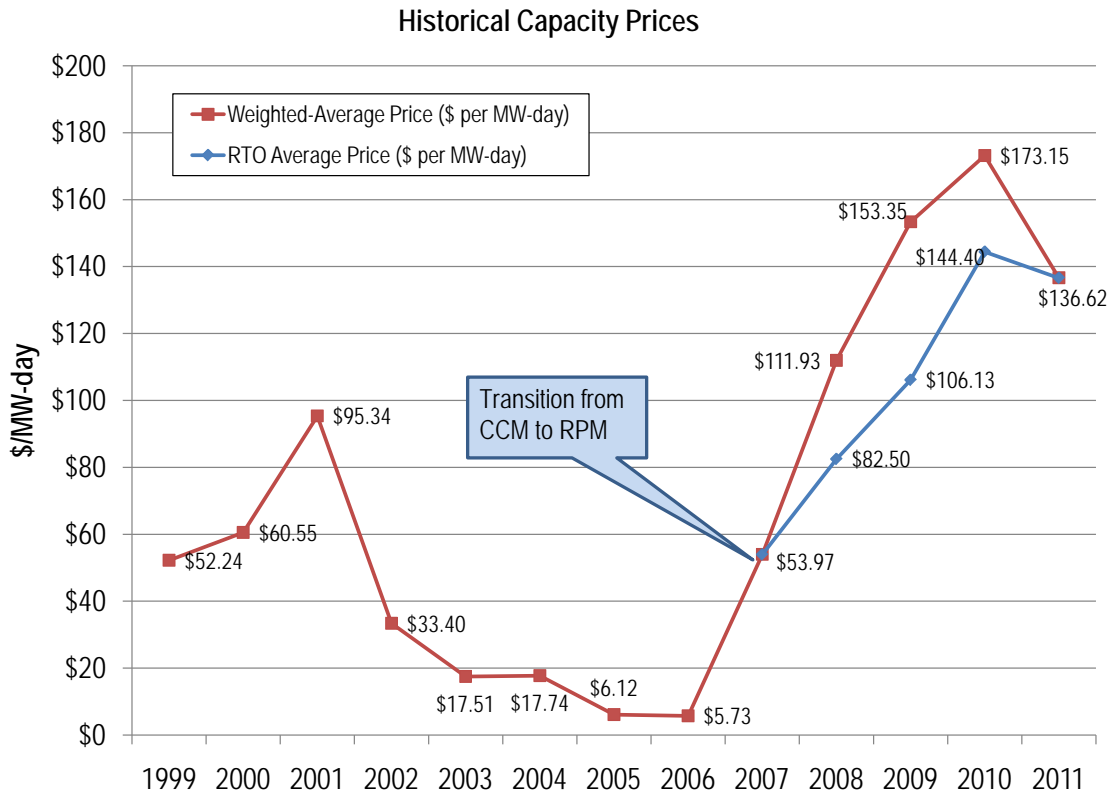
Prior to the formation of formal capacity markets, the cost of reliability pricing was met via the PJM Installed Capacity Accounting (PICA). Under PICA, PJM determined the capacity obligation of each member and the member was responsible for meeting that obligation either via their own generation or through bilateral contracts. Since these arrangements were between members and did not involve PJM, no data is readily available on the historic cost of reliability at this time. However, the historic reference price for installed capacity was the levelized, fixed cost of a new peaking plant which was \$167 per MW per day when the PJM markets formed in 1998.

As part of the transition to a regional wholesale electricity market, in 1999 PJM began operation of the Capacity Credit Market (CCM). The timeframe for this market was primarily daily and monthly and the market price was the same across

⁸³ This can be seen in the evidence presented above showing market-based offer behavior practically mirrors cost-based offer behavior.

the entire PJM region, regardless of any specific locational needs. This market design was susceptible to price volatility and did not include specific and transparent market power mitigation procedures. As a result, in 2001 when the market became short and prices rose, concern over market manipulation rose.

The historical capacity prices in the PJM region are shown below.⁸⁴



In the early years of the CCM, capacity shortages were significantly higher than in the later years of the CCM. Capacity shortages caused higher prices and along with deregulation, low natural gas prices, and new electricity markets, spurred the investment in new generation. As this new generation came on-line after 2001, capacity prices fell as would be expected. However, due to the capacity market design issues, price were suppressed to unsustainable levels, especially in transmission-constrained regions of the market, because the reliability value of additional capacity beyond the requirement was implicitly zero under this market design.

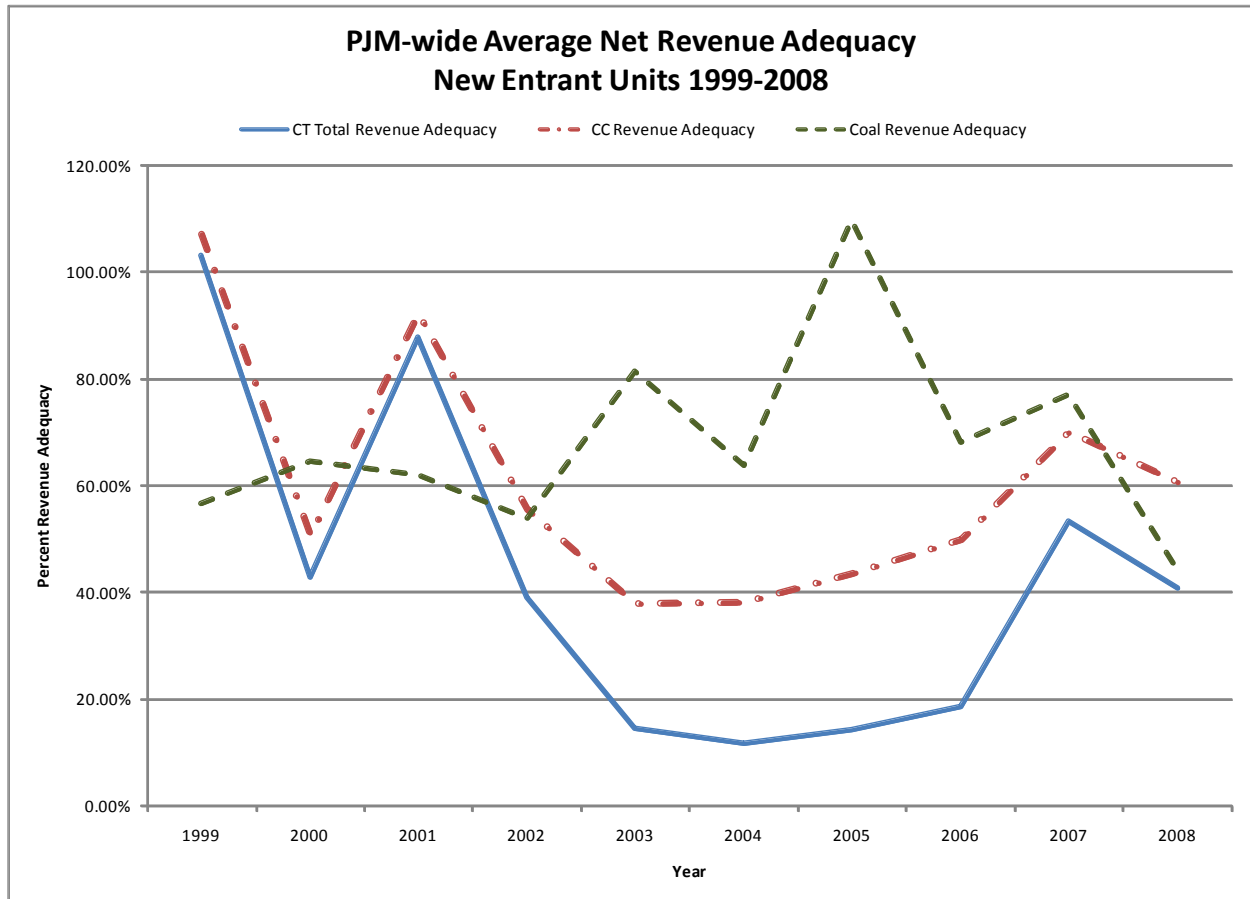
When these prices fell, the Independent Market Monitor consistently concluded that the payments were not adequate to cover the going-forward costs for potential new generation entrants into the PJM Markets in the Net Revenue Analysis included in the State of the Market Reports.⁸⁵

⁸⁴ 2008 SoM Report, Figure 5-1 at 272.

⁸⁵ For example, see 2008 SoM Report, Tables 3-23, 3-25, and 3-27 at 143, 147, and 151.

Prior to RPM: Insufficient Revenue to Support New Investment

For several years prior to the implementation of the RPM Capacity Market, the PJM Markets were not providing sufficient revenues for new entry in spite of the Capacity Credit Market construct that was in place. Using data from the 2008 State of the Market Report issued by the IMM, the graph below shows that, on average across PJM for different technologies, there was insufficient revenue to attract new investment into the PJM market. From 2000 through 2006, net revenue adequacy declined for new entry combustion turbines (CTs) and combined cycle plants (CCs). For all technology types, there was only one year in which they achieved enough revenues from the PJM Energy, Ancillary Service, and Capacity markets to their 20-year levelized fixed cost (going-forward cost).⁸⁶



Capacity Offer Requirements

There is no requirement that a supply resource must offer its capacity into the Capacity Market. However, if a supply resource does not offer any part of its capacity into the BRA, it is generally not allowed to later offer its unoffered capacity into any later IA.⁸⁷ If a supply resource elects not to participate in RPM, it will not receive any payment from the RPM Capacity Market.

⁸⁶ *Supra* note 81.

⁸⁷ PJM OATT, Attachment DD, Section 6.6 (a)-(d).

If a supply resource has capacity that is offered into the BRA or an IA, but does not clear, it is not required to participate in any subsequent IAs. However if it does not participate in a subsequent IA, it generally may not participate in further IAs for that delivery year.⁸⁸

Market Power Mitigation in the RPM Capacity Market

Prior to conducting the BRA three years in advance of the delivery, a Preliminary Market Structure Screen (PMSS) is applied to determine the presence of structural market power and identify owners of capacity resources that are deemed to possess structural market power to determine which existing generation capacity resources must submit **cost-based offers** into the BRA and IAs. The PMSS consists of three separate tests to determine structural market power:

- (1) The market share of any Capacity Market Seller exceeds twenty percent;
- (2) The HHI for all such sellers is 1800 or higher; or
- (3) There are not more than three jointly pivotal suppliers.⁸⁹

If any capacity supplier fails these tests, then they are subject to market power mitigation and cost-based offers. Existing demand resources in BRAs prior to the 2013/2014 BRA were also subject to market power mitigation and cost-based offer capping. **To date in each BRA, no existing capacity resources have passed the PMSS and consequently have been subject to market power mitigation and cost-based offers in the RPM Capacity Market.**

Offers into the RPM Capacity Market

Supply resources are free to offer capacity into the RPM Capacity Market at **market-based offers** less than their cost-based offers even if the supply resource owner does not pass any of the PMSS. However, supply resources may only submit a market-based offer in to the BRA or IAs that is in excess of their cost-based offer under the following circumstances:

- The offer is from a planned resource that has not previously offered into a BRA;⁹⁰ or
- The offer is from a Demand Resource or Energy Efficiency Resource;⁹¹ or
- The offer is from an existing Capacity Resource that has passed the Preliminary Market Structure Screen.

Cost-based offers into the RPM Capacity Market are constructed around generation resource's **avoidable costs** – the costs that would not be incurred if the generating station was shut down, less the resource specific projected net market revenues (revenues less cost-based offers) from other PJM markets.⁹² The projected net market revenues, also known as

⁸⁸ Id.

⁸⁹ PJM OATT Attachment DD, Section 6.3 (a) ii.

⁹⁰ The planned resource needs to also pass certain market power screens that differ from those applied to existing resources. To date planned resources have not been subject to market power mitigation. See PJM OATT, Attachment DD, Section 6.4 (a) (ii)

⁹¹ Prior to the 2013/20134 BRA, existing Demand Resources not passing the PMSS were mitigated, and in practice the mitigated offers were zero price offers as alluded to in the previous subsection. Beginning in the 2013/2014 BRA, these resources are no longer subject to market power mitigation.

⁹² PJM OATT Attachment DD, Section 6.4 (a)-(b) and Section 6.7.

the Energy and Ancillary Service Offset, are the net market revenues from the previous three calendar years of operation that are used as the expectation going forward of the resource's ability to recover fixed, going forward costs in the Energy and Ancillary Service markets.⁹³ The greater the net market revenues are from other PJM markets, the lower the cost-based offer of a mitigated supply resource. It is conceivable that the net market revenues from the PJM Energy and Ancillary Service markets are high enough that the cost-based offer may be zero.

Demand in the RPM Capacity Market⁹⁴

The foundation of demand for Capacity Resources in the RPM Capacity Market is the resource adequacy requirement that mandates PJM have enough Capacity Resources to satisfy the forecasted peak load for the delivery year plus an installed reserve margin, and to ensure there is enough capacity in the appropriate locations. However, demand in the BRA also recognizes price responsiveness in the demand for Capacity Resources and that Capacity Resources in excess of the resource adequacy requirement do provide reliability value as a hedge against uncertain load growth, weather conditions, or resource availability in the future. Moreover, the price sensitivity of demand in RPM helps reduce capacity price volatility from one year to the next. The demand in RPM is called the Variable Resource Requirement (VRR) Curve, and there can be multiple VRR Curves that represent the demand for capacity in locationally constrained parts of PJM.

The VRR is constructed from three price-quantity pairs based on how much capacity will be procured at given price. The prices used to construct the VRR Curve are derived from the Cost of New Entry (CONE) for reference resource less the expected Energy and Ancillary Market revenues the reference resource also called Net CONE.⁹⁵

The quantity of capacity corresponding to an RPM price equal to Net CONE is one percent over the forecast peak load plus installed reserve margin in the RTO and for each locationally constrained area. . At capacity procurement levels beyond this point, the value of capacity on the VRR Curve declines, showing that the capacity is less valuable beyond the required reserve margin, but having a non-zero value nonetheless.

Price Formation in the RPM Capacity Market

The price of RPM Capacity is determined by the intersection of the demand defined above with the largely cost-based offers submitted by suppliers. If there are locationally constrained areas within the RTO, there will be a separate market clearing prices that are at least as great as the price in the RTO. In this sense, the separate clearing prices in the locationally constrained areas are analogous to constrained-in areas of the energy market where LMPs in the constrained-in areas are greater than in unconstrained areas. Market-clearing prices are expressed in dollars per MW of capacity per day (\$/MW-day).

Revenues in the RPM Capacity Market

For capacity resources that clear the BRA, they will receive a revenue stream for that capacity that is intended to cover any remaining fixed, going-forward costs that are not otherwise covered through operations in the PJM Energy and Ancillary Service Markets.

⁹³ PJM OATT Attachment DD, Section 6.8 (d) (ii).

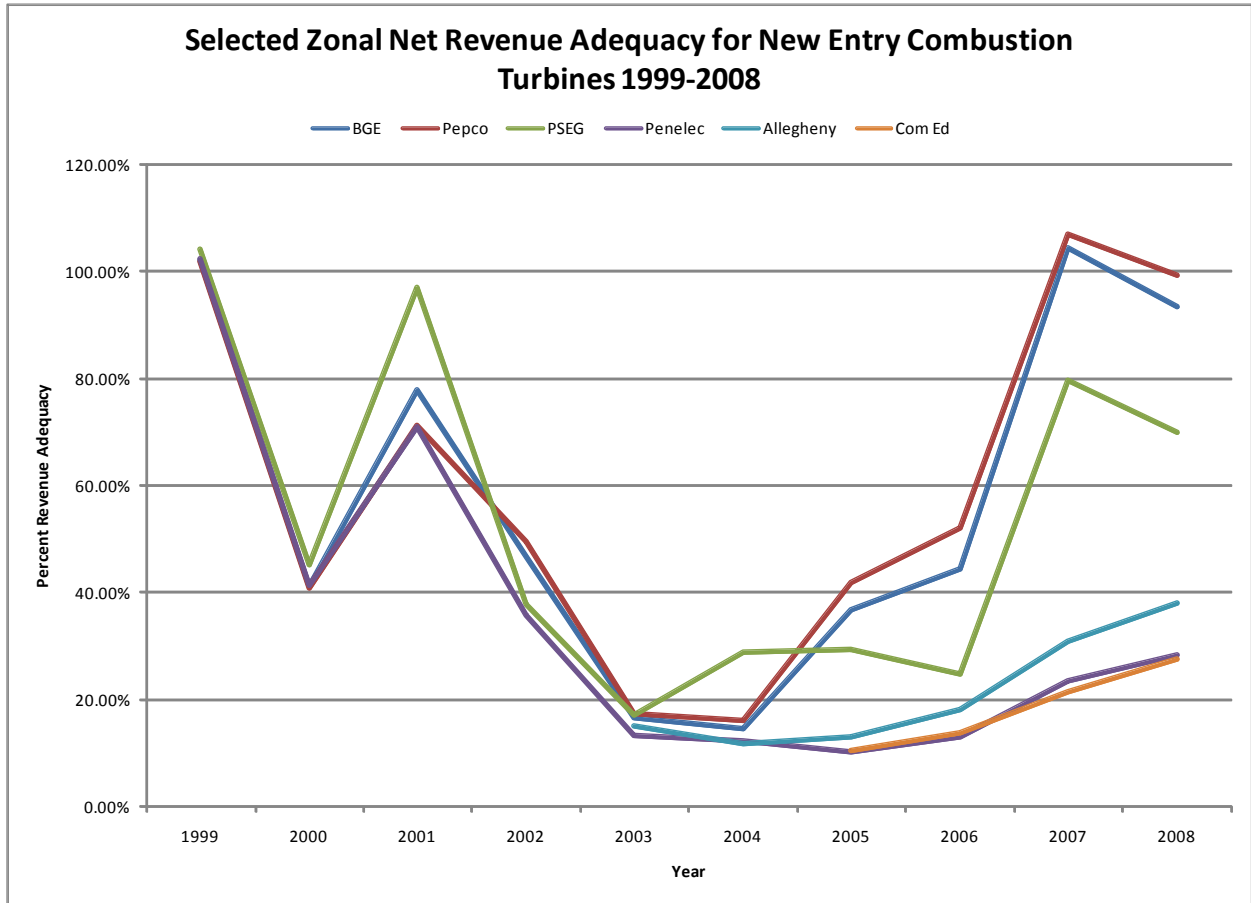
⁹⁴ PJM Manual 18 at 14-20.

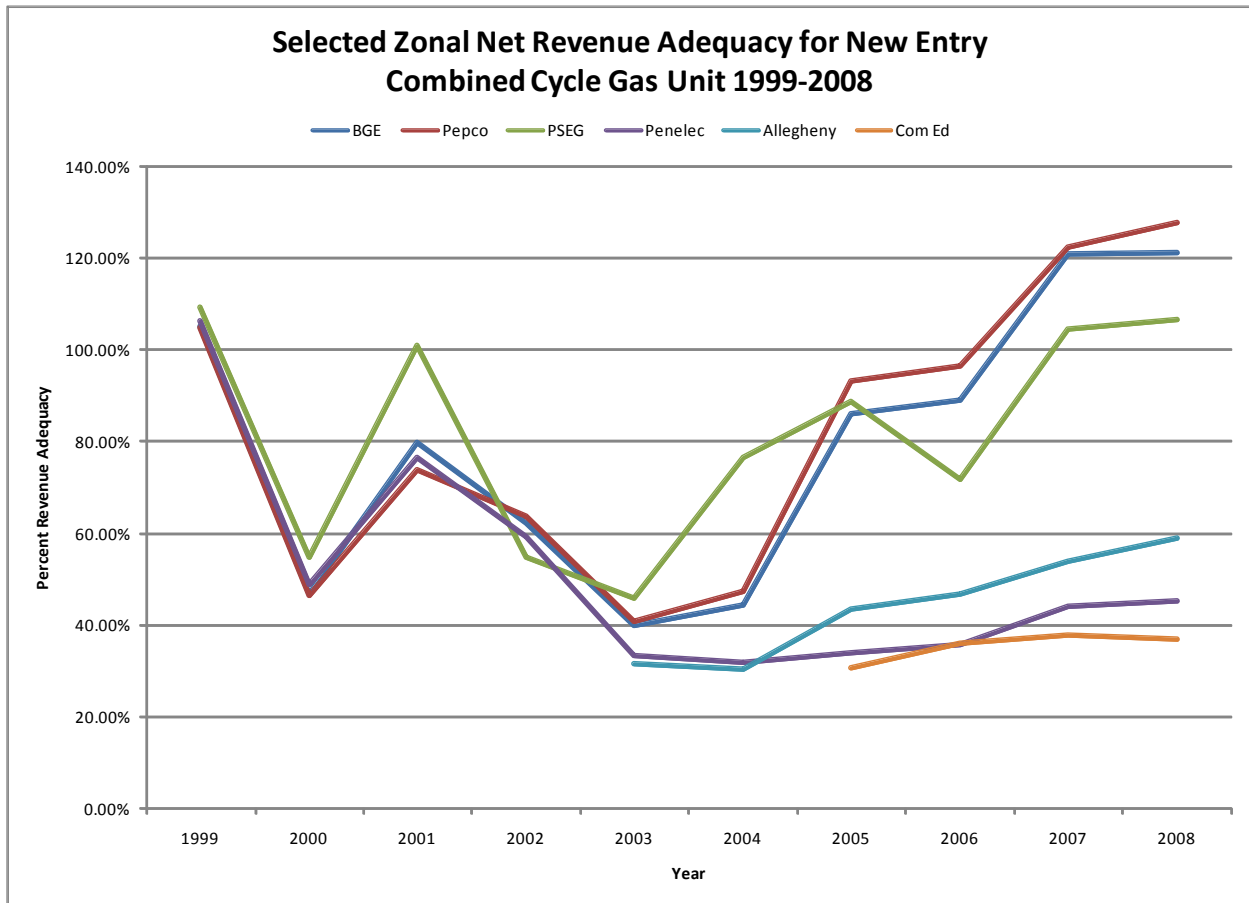
⁹⁵ The reference resource is a natural gas combustion turbine (CT).

RPM's more advanced features recognize that payments must also be structured to provide the right incentives at the right geographic locations, depending on whether a sub-region of the transmission grid has limited ability to import electricity. Transmission limits into an area may restrict access to lower cost supply, forcing wholesale prices there to be higher, while prices in unconstrained areas are lower. Hence, a uniform payment to all generators across PJM, regardless of location, would provide the wrong incentives – either too high or too low --to resources at each location. This problem was becoming particularly severe in transmission-limited areas, where new investments were needed but were not being pursued. The RPM solution allows capacity payments to differ in different sub-regions of PJM, with higher payments made in locations with limited transmission and resource availability.

The effectiveness of the locational incentives generated by the RPM Capacity Market is evident in net revenue adequacy for CTs and CCs since RPM was implemented in 2007. As seen in the two figures below, zones such as BGE, Pepco, and PSEG which are on the constrained side of transmission interfaces have seen their revenue adequacy improve in 2007 and 2008. At the same time, while revenue adequacy has improved upstream of the constrained transmission interfaces (Com Ed, Penelec, and Allegheny), the need for capacity is not as acute and the price signals being sent in those zones indicate the entry of new capacity is not necessary.⁹⁶

⁹⁶ Derived from 2008 SoM Report, Tables 3-7 at 132, 3-11 at 135, and 3-23 at 143 for CTs, and Tables 3-8 at 132, 3-13 at 137, and 3-25 at 147 for CCs.





The RPM Capacity Market also conditions payments on performance, helping to ensure that suppliers make their resources available when they are most needed rather than simply making payments for having “iron in the ground”.

Conclusion and Potential Overlaps in Compensation

RPM Capacity Market Revenues

There is a mistaken presumption among some entities that in years prior to RPM implementation, there was no cost associated with capacity requirements to maintain reliability. There was a cost prior to the establishment of capacity markets, but that cost was included in regulated rates and not visible as a separate cost. The reference price for this cost was approximately \$167 per MW per day for the least expensive type of installed capacity. The reliability revenues from the RPM Capacity Market are not “new” revenue streams, but a better market mechanism to signal the price of reliability and the need for additional capacity on the system and to ensure that investment incentive will sustain ongoing reliable operations.

A fundamental design goal of the PJM Energy Market, RPM Capacity Market, and Ancillary Service Markets is that the revenues of the combined markets will allow a generator to receive adequate cost recovery for both its going-forward costs, and its marginal production costs.

To clarify, the marginal costs are the costs directly associated with the production of energy. Costs such as the fuel cost and cost of emissions allowances are examples of marginal production costs. A useful analogy exists in the automobile. The marginal cost of operating the car is the cost of gasoline, tires, and oil changes, i.e. the costs that are directly linked to driving the car over distances. These production costs are described in the Energy Market Compensation section. The going-forward costs (or fixed costs) are the costs incurred to keep a generating plant operational and available to produce energy. (For a car, this is the cost of insurance and state inspections. These costs occur regardless of how far the car is driven, but must be paid so the car is ready to be used.) Costs such as the financing of capital investment necessary to keep existing generators operational, build new generators, staffing, fees, and administrative overhead fall into this category – any cost which would be avoided if an existing generating plant was closed down and retired, or if a new plant was not constructed and placed into commercial operation.

The market design is that the **combined** markets cover the **combined** marginal and going-forward costs. This should not be misinterpreted to say that the Energy Market revenues are designed to cover only the marginal production costs and the RPM Capacity Market revenues are designed to cover only the going-forward costs in all cases.

RPM utilizes demand and supply curves. The demand curve, and hence compensation, in the RPM Market is based around the cost of building a new combustion turbine (CT) generator. Such generators are typically peaking units, used to cover high demand periods, and are typically more expensive to operate than base-load nuclear or coal steam generators. These CTs run less frequently than base-load generators and usually when energy market prices are higher. They are also less expensive to build and maintain, and so have lower going-forward costs.

For new CTs, it is true that the marginal production costs will generally be covered by the energy and ancillary service markets and the majority of the going-forward costs will be covered by the RPM Market. (Indeed they should as the RPM Market demand curve is calibrated to such a point.)

However for a base-load nuclear or steam generator, this is not the case. These types of generators will see much greater revenues in the energy markets that will go toward covering some part of going forward cost as their marginal production cost is much lower and they will see additional revenues as the LMP rises above their production costs. Such generators also typically have much greater going-forward costs. These costs are not fully recovered in the revenues received from the RPM market (which is calibrated to cover the much lower going-forward costs of a new CT). However this is offset by the greater revenues from the energy markets.

The combined markets are necessary, working together, to ensure not only adequate cost recovery for existing generators, but also to provide appropriate signals for investment such that reliability can be maintained in the future. PJM does not believe there is any overlap in cost recovery related to the RPM Capacity Markets.

Frequently Mitigated Unit Adders

In their order issued on May 6, 2004, the FERC established the need for adders for generators subject to frequent mitigation.⁹⁷ In this order the FERC states:

“Accordingly, a frequently mitigated unit may set the market price in many periods when it is dispatched, and during these periods it will only receive its incremental costs + 10%, which might not be sufficient to enable recovery of its fixed costs

⁹⁷ *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 (2004) (“May 6, 2004 Order”) at P37-40.

over the long term. In addition, under PJM's current tariff, these frequently mitigated units do not have a right to alternative compensation that would allow them to recovery their going forward costs, at the minimum.⁹⁸

And also

"Since these units are providing reliability services and may not currently receive adequate compensation for this service, these must-run units need to be compensated at a level that adequately covers their fixed and variable costs. We direct PJM to develop a policy which would provide a reasonable opportunity for recovery of going forward costs, at the minimum, when the above conditions hold."⁹⁹

FERC clearly states that the intention of the adder is to allow the adequate recovery of fixed costs for generators that are frequently mitigated.

FMU adders were created prior to the RPM Capacity Market at a time when capacity prices were low. At the time of this order, CCM prices averaged \$17.74/MW-day and new entry generation would not have been able to recover their fixed, going-forward costs as has been shown above.

The question has been raised as to whether such adders are still necessary, given the new RPM Capacity Market. This question can be examined a number of ways.

As discussed above, for a new, peaking combustion turbine generator (CT), the majority of going-forward costs of the generator should be generally recovered from the RPM Market, and the marginal production costs and small portion of going-forward costs from the Energy Markets. If this holds true, then it suggests that the CT should be seeing adequate cost recovery for fixed costs in the RPM Market if it is needed to satisfy capacity adequacy requirements, and should not require the adder to increase the revenues from the Energy Markets. However this may not be the case, as an existing CT generator would not be expected to operate as efficiently as a new generator. Further, the mitigated generator may not be a peaking unit, and therefore may need to recover some of its going-forward costs in the Energy Markets.

The situation is slightly different for a steam generator. Such generators are much more dependent on revenues from the Energy Markets to cover their fixed costs. As such it is more likely that mitigation could cause under-recovery of fixed costs. However this likelihood is lessened by several factors. First, a mitigated generator receives the higher of their cost-based offer, or LMP. As steam generators tend to be lower cost generation, the LMP will more often be above their cost-based offer as a general matter, lessening the financial impact of mitigation. Second, almost all frequently mitigated units are CTs, not steam generators.

Given the market design of the RPM Capacity Market and that FMU adders were intended by the FERC to aid in cost recovery, it could be argued that FMU adders may no longer be necessary in the current PJM market construct. However this conclusion is not absolutely clear. The capacity market compensation is targeted to be net of energy revenues for the reference unit which is modeled as having some revenues from the Energy Market that can cover going-forward costs. Generally speaking, an FMU may not be expected to recover the energy revenue that is assumed for the reference unit in the RPM VRR curve precisely because the unit is frequently mitigated and does not generally get marginal energy rents above their operating cost. Therefore the FMU adder is likely to be still needed in many circumstances.

⁹⁸ Id. at P 37.

⁹⁹ Id. at P 40.

There is also an argument that can be made for FMU adders as a form of localized scarcity pricing. Both RPM and the scarcity pricing mechanisms currently in discussion at the stakeholder process have locational features to incent investment in appropriate areas. However these signals are at a somewhat broad level and not designed to provide investment signals in localized areas. Generators that are frequently mitigated are needed for reliability in a specific area of the transmission system. Mitigation due to a temporary situation, such as a maintenance outage, does not require an investment signal, and indeed a generator mitigated for such reason will likely not be mitigated often enough to be considered for the adder. However mitigation on an on-going basis suggests a lack of adequate generation in that localized area. FMU adders can be seen as an investment signal for a particular area in response to localized scarcity which broader regional mechanisms do not address.

The FMU adders are designed to provide cost recovery, and therefore provide signals to maintain investment in existing resources that are required for reliability on a more granular level than RPM. While PJM has concluded in the review that FMU adders are not redundant with capacity market compensation, a review of the magnitude of the FMU adders and their interaction with any proposed changes to scarcity pricing design should be undertaken in the PJM stakeholder process.

Other Areas of Overlap

Based on the analysis PJM has performed at the request of stakeholders, PJM concludes that there are no additional areas of potentially redundant compensation in the current market design. Revenues from the Energy and Ancillary Service Markets are designed to cover the costs associated with the provision of those specific services.

Appendix A

On July 30, 2009, a number of PJM stakeholders made a request at the Markets and Reliability Committee (MRC) meeting for a review of generator costs and all payments made to generators.¹⁰⁰ This request was made to both PJM and the Independent Market Monitor (IMM) by the following stakeholders:

- Maryland Public Service Commission
- ODEC
- PJMICC
- SMECO
- Blue Ridge Power Agency
- Allegheny Electric Cooperative
- NJ Division of Rate Counsel
- Maryland OPC
- Ohio Consumers' Counsel
- DC Office of the People's Counsel
- PA Public Utilities Commission
- Duquesne Light
- Public Power Coalition
- PPANJ
- American Municipal Power
- NCEMC
- PA Office of Consumer Advocate
- Delaware Public Service Commission
- District of Columbia Public Service Commission
- Indiana Utility Regulatory Commission

¹⁰⁰ See Stakeholder Request at 6.