SECTION 6 – ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to the FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

PJM does not provide a market for black start services, which are procured and paid zonally, but does ensure that there are adequate black start resources.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two Synchronized Reserve Markets, and the PJM DASR Market from January through June 2009.

Overview

Regulation Market

The PJM Regulation Market in 2009 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented several changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost and a change to the treatment of regulation revenues with respect to operating reserve credits. The MMU analyzes the impact of these changes using data from December 1, 2008 through June 2009.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report for PJM,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.
3 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

Market Structure

- **Supply.** During the first six months of 2009, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2009. The ratio of eligible regulation offered to regulation required averaged 2.74 throughout the first six months of 2009, an increase from the 2008 ratio.

- **Demand.** Beginning August 7, 2008, PJM began to calculate on-peak and off-peak regulation requirements. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in the first six months of 2009 was 843 MW, compared to 922 MW for the first six months of 2008.

- **Market Concentration.** During the first six months of 2009, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1239 which is classified as "moderately concentrated."[4] The minimum hourly HHI was 702 and the maximum hourly HHI was 3519. The largest hourly market share in any single hour was 55 percent, and 64 percent of all hours had a maximum market share greater than 20 percent. In the first six months of 2009, 49 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in the first six months of 2009 was characterized by structural market power in 49 percent of the hours.

4 See the *2008 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Regulation offer prices are provided by the unit owner, applicable for the entire operating day and, with lost opportunity cost (LOC), comprise the total offer to the Regulation Market. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12/MWh margin adder, and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units of owners who fail the three pivotal supplier test for an hour are dispatched at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue against operating reserve revenue and PJM now calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the cost based offer. The impact on market performance for these December 1, 2008 PJM changes has been significant.

Market Performance

- **Price.** For the PJM Regulation Market during the first six months of 2009 the load weighted, average price per MWh (i.e., the regulation market clearing price, including lost opportunity cost) associated with meeting PJM's demand for regulation was $24.48. This is significantly lower than the load weighted average price in 2008, but this price does not include all the summer months. On December 1, 2008, PJM implemented new Regulation Market rules that cap the offers at cost of units offered by suppliers which are pivotal and do not cap the offers of units whose suppliers are not.

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made two significant changes to the Synchronized Reserve Market during the first six months of 2009. These changes were intended to ensure that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic subzone within the RFC Synchronized Reserve Market from Bedington-Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available south of the AP South interface that it will consider as available to the Mid-Atlantic subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes have reduced the amount of additional, out of market, synchronized reserve required by PJM Dispatch. This reduced LOC payments and aligned the total cost of synchronized reserves with Synchronized Reserve Market prices. Synchronized reserves added out of market were only two percent of all synchronized reserve during April, May, and June of 2009 while they were 58 percent for the same time period in 2008. Similarly, LOC accounted for 11 percent of total costs during April, May, and June of 2009 compared to 59 percent during the same time period in 2008.

Market Structure

- **Supply.** For the period January through June 2009, the offered and eligible excess supply ratio was 1.4[5] for the PJM Mid-Atlantic Synchronized Reserve Region.5 The excess supply ratio is determined using the administratively required synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available. Throughout the first six months of 2009, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,365 MW for the RFC Synchronized Reserve Zone and 1,162 MW for the Mid-Atlantic Subzone. These requirements are a function of administratively determined, regional requirements established by each market zone's reliability council. Since there was usually enough Tier 1 in the RFC Synchronized Reserve Zone to cover the requirement, only five percent of hours cleared a Tier 2 Synchronized Reserve market in the RFC. For the Southern Synchronized Reserve Zone only 1 hour had a non-zero Tier 2 requirement in 2009. For the PJM Mid-Atlantic Synchronized Reserve Region, 62 percent of hours cleared a Tier 2 Synchronized Reserve Market. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. Demand for Tier 2 declined after adjustments were made in December, 2008 to the Tier 1 estimate. Further adjustments were made to the process for estimating Tier 1 in January and February of 2009. Since then demand for Tier 2 has risen. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 271 MW. All demand for Tier 2 in the Southern Synchronized Reserve Zone was satisfied by 15-minute quick start units. A Southern Synchronized Reserve Zone market cleared only one hour in the first six months of 2009.

The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement has been greatly reduced. For January through June 2009, 19 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through June 2009 only three percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

5 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for January through June 2009 was 2898. For purchased synchronized reserve (cleared plus added) the figure was 4039. Less than one percent of all hours had a market share of 100 percent. In 42 percent of hours the maximum market share was greater than 40 percent (compared to 56 percent of hours in 2008). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the period January through June 2009, 93 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2009 are characterized by structural market power.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the merit order price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** During January and to a lesser extent February, only a very small amount of Tier 2 was needed. This resulted in lower clearing prices. The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $5.89 per MW for January through June 2009, a $4.76 per MW decrease from calendar year 2008.

- **Demand.** Demand for Tier 2 synchronized reserve was unstable during the first quarter of 2009. On December 1, 2008 PJM significantly increased the amount of Tier 1 forecast during the market solution. This reduced the demand for Tier 2 in January and February 2009. On March 13, 2009 PJM reduced the amount of Tier 1 from outside the Mid-Atlantic subzone that SPREGO will consider as available for the operational hour. This increased demand for Tier 2. Demand stabilized in the second quarter. Demand side resources remained significant participants in the Synchronized Reserve Market from January through June 2009. In 27 percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

- **Availability.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during January through June 2009.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[6] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[7] The RFC and Dominion DASR requirements are added together to form a single RTO DASR Requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

The DASR Market from January through June 2009 had three pivotal suppliers in a monthly average of 44 percent of all hours. The MMU concludes from these results that the PJM DASR Market in the first six months of 2009 was characterized by structural market power.

6 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
7 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.

Market Conduct

Economic withholding remains a problem for the DASR market. Continuing a pattern seen since the inception of the DASR market, a significant number of units offered at levels effectively guaranteed not to clear. In June, six percent of units offered at $50 or more and four percent of units offered at $990 or more, which is equivalent to withholding in a market with an average clearing price of $0.05 and a maximum clearing price of $1.00.

Market Performance

For January through June, 2009, the load weighted price of DASR was $0.05, including the 37 percent of hours when the market cleared at a price of $0.00. Demand side resources do participate in the DASR market but remain insignificant.

Black Start Services

Black Start Service is necessary to help ensure the reliable restoration of the grid following a black out. Black Start Service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[8]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start reserve, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million. For the first six months of 2009, charges were about $6 million.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised rates also provide a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[9] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[10] A number of parties filed comments, including the MMU on October 20, 2008.[11] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the Market Monitoring Unit to prepare a report due on November 26, 2009.[12]

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. As a result, the Regulation Market results in the first half of 2009 were competitive.

8 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.

9 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: <http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf>.

10 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

11 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics' Website at <http://www.monitoringanalytics.com>.

12 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

The MMU also concludes that the other changes to the Regulation Market implemented on December 1, 2008 have significantly increased the price of regulation. The MMU will provide an updated analysis of results and associated recommendations to FERC, due November 26, 2009.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for synchronized reserve in the RFC Synchronized Reserve Zone and in the Southern Synchronized Reserve Zone are market-clearing prices determined by the supply curve and the administratively defined demand. The cost based synchronized reserve offers are defined to be the unit specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

The issue of Tier 2 synchronized reserve purchases after market clearing began in the last quarter of 2007. Beginning in October and increasing substantially in November and December 2007, there was an increase in the amount of combustion turbine, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. On December 1, 2008, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing.

The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement was greatly reduced by June 2009. For January through June 2009, 19 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through June 2009 only three percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

The MMU concludes that the DASR Market is not structurally competitive. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in the first half of 2009.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that the Regulation Market results were competitive in the first half of 2009, as a result of the implementation of the three pivotal supplier test in the Regulation Market on December 1. The MMU concludes that the Synchronized Reserve Market results were competitive in the first half of 2009. The MMU concludes that the DASR Market results were competitive in the first half of 2009.

Regulation Market

Market Structure

Supply and Demand

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement: January through June 2009 (See 2008 SOM Table 6-1)

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2009 (Jan - Jun)	843	2.73
Spring	771	2.81
Summer	882	2.69
Winter	938	2.63
Off-Peak	773	2.67
On-Peak	921	2.80

Market Concentration

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through June 2009 (See 2008 SOM Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,620	6,231	82%	2,279	30%
Off Peak	7,620			2,023	27%
On Peak	7,620			2,563	34%

Table 6-3 PJM cleared regulation HHI: January through June 2009 Calendar year 2008 (See 2008 SOM Table 6-3)

Market Type	Minimum HHI	Load-Weighted Average HHI	Maximum HHI
Cleared Regulation, 2009	702	1239	3519

Figure 6-1 PJM Regulation Market HHI distribution: January through June 2009 (See 2008 SOM Figure 6-1)

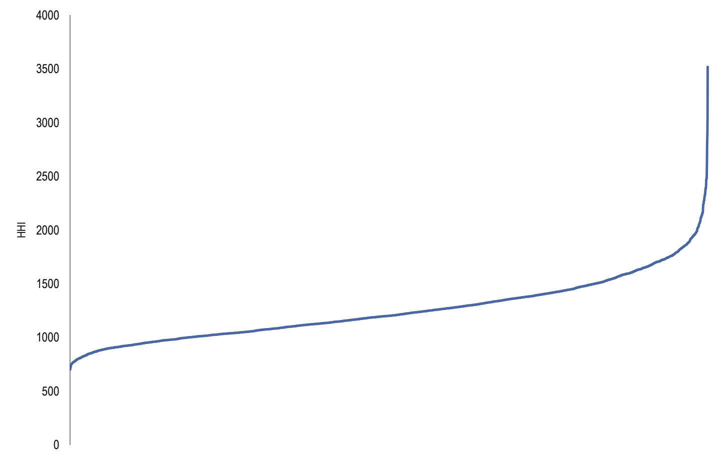


Table 6-4 Highest annual average hourly Regulation Market shares: January through June 2009 (See 2008 SOM Table 6-4)

Company Market Share Rank	Cleared Regulation Top Market Shares
1	18%
2	10%
3	8%
4	8%
5	7%

Table 6-5 Regulation market monthly three pivotal supplier results: January through June 2009 (See 2008 SOM Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	84%
Feb	61%
Mar	42%
Apr	40%
May	31%
Jun	37%

Market Performance

Price

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): January through June 2009 (See 2008 SOM Figure 6-2)

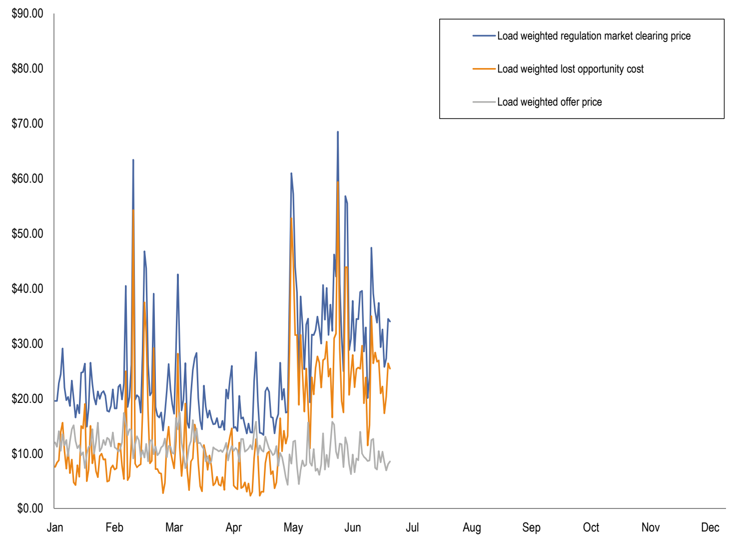


Figure 6-3 Monthly average regulation demand (required) vs. price: January through June 2009 (See 2008 SOM Figure 6-3)

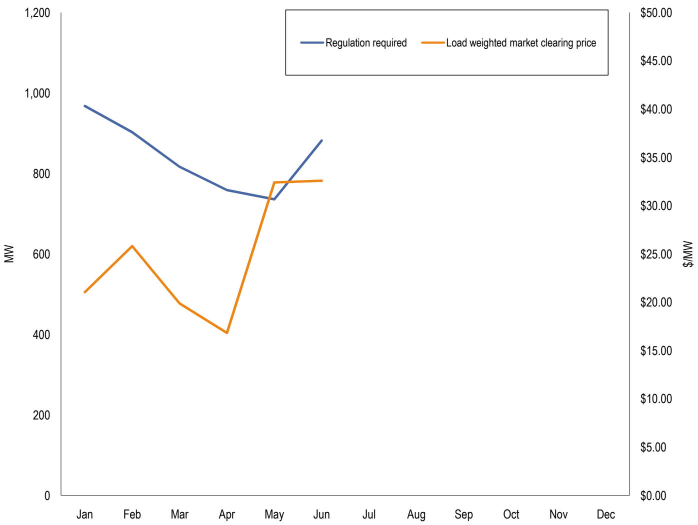


Figure 6-4 Monthly load weighted, average regulation cost and price: January through June 2009 (See 2008 SOM Figure 6-4)

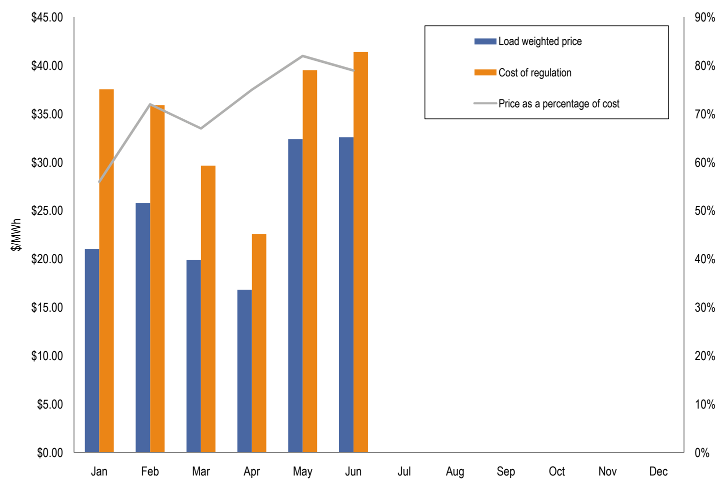


Table 6-6 Total regulation charges: January through June 2009 (See 2008 SOM Table 6-6)

Month	Total Purchased Regulation (MW)	Total Regulation Charges	Weighted Average Regulation Market Price	Regulation Cost (per MW Regulation)	Regulation Cost (per MW of Load)
Jan	708,801	$26,614,050	$21.04	$37.55	$0.40
Feb	597,418	$21,455,212	$25.83	$35.91	$0.39
Mar	601,980	$17,853,025	$19.90	$29.66	$0.33
Apr	538,993	$12,172,449	$16.84	$22.58	$0.25
May	535,862	$21,180,526	$32.41	$39.53	$0.42
Jun	595,554	$24,665,164	$32.59	$41.42	$0.45

Analysis of Changes to PJM Regulation Market

On December 1, 2008 PJM implemented four changes to the Regulation Market. The first change was the implementation of the three pivotal supplier test for market power, in a manner comparable to the energy market and the capacity market. The offers of suppliers that fail the three pivotal supplier test are capped at the lesser of their price offer or their cost offer. The percentage of hours with pivotal suppliers has decreased since the introduction of the new market rules.

Prior to December 1, 2008, regulation revenue above offer price plus LOC was used to offset unit specific operating reserve credits. The second change to the Regulation Market was to eliminate this offset against operating reserve credits, resulting in higher revenue to units for given regulation price levels. Although the amount of regulation revenue eligible for operating reserve offset was significant (15 percent to 50 percent of the total credits earned for regulation), the impact of this rule change was small because the actual operating reserves credits earned by the units that cleared in the regulation market were low (Table 6-7).

The third change to the Regulation Market was an increase in the profit margin that could be included in cost based regulation offers, from $7.50 to $12.00 per MW. The increased margin had an impact on clearing prices in the regulation market, based on an analysis of the amount of the margin above $7.50 that was included in the marginal unit's offer for every period and whether that additional adder impacted the regulation market clearing price. In approximately 85 percent of hours the marginal unit had a cost based offer greater than cost plus $7.50. In approximately 33 percent of hours, offers above cost plus $7.50 impacted the regulation market clearing price. A marginal unit's cost based offer greater than cost plus $7.50 would not affect the clearing price if the unit's owner passed the TPS test or its price offer was lower than its cost plus $7.50. The increase in the margin resulted in an increase in the final regulation market clearing prices (Table 6-8). This impact has decreased since December 2008.

Table 6-7 Regulation credits offset against operating reserves: September 2008 through June 2009 (New Table)

Year	Month	Load Weighted Regulation Market Clearing Price	Regulation Credits Before Offset	Regulation Credits Eligible for Operating Reserve Offset	Actual Credits Offset Against Operating Reserves	Final Regulation Credits	Percentage of Total Regulation Credits Offset Against Operating Reserves
2008	Sep	$39.99	$36,137,080	$10,715,728	$297,125	$35,839,955	1%
2008	Oct	$29.58	$23,801,953	$6,117,145	$210,407	$23,591,545	1%
2008	Nov	$29.48	$25,335,645	$7,049,813	$172,452	$25,163,193	1%
2008	Dec	$24.71	$25,608,469	$5,740,097	$0	$25,608,469	0%
2009	Jan	$21.04	$26,614,105	$4,055,087	$0	$26,614,105	0%
2009	Feb	$25.83	$21,455,214	$6,433,040	$0	$21,455,214	0%
2009	Mar	$19.90	$17,853,247	$3,916,361	$0	$17,853,247	0%
2009	Apr	$16.84	$12,172,532	$2,888,677	$0	$12,172,532	0%
2009	May	$32.41	$21,180,576	$11,355,085	$0	$21,180,576	0%
2009	Jun	$32.59	$24,665,686	$15,220,119	$0	$24,665,686	0%

Table 6-8 Payments to generation from offers greater than costs plus $7.50: December 2008 through June 2009. (New Table)

Year	Month	Periods When Marginal Unit Offer Greater than Cost Plus $7.50	Periods When Marginal Unit Offer Greater Than Cost Plus $7.50 Impacts Regulation Price	RMCP Credits Attributable To Marginal Unit's Cost Offer > Cost Plus $7.50	Percent Increase in Total RMCP Credits Due To Marginal Unit With Offer > Cost Plus $7.50
2008	Dec	627	454	$1,829,441	11%
2009	Jan	610	380	$1,281,527	9%
2009	Feb	590	274	$845,440	6%
2009	Mar	667	154	$389,591	3%
2009	Apr	659	155	$369,023	4%
2009	May	638	125	$290,392	2%
2009	Jun	596	130	$380,387	2%

The fourth change to the Regulation Market was to change the definition of lost opportunity cost (LOC). Prior to December 1, 2008, SPREGO solved the regulation market using a forecast LOC based on the (energy) offer curve in use by the unit. If the unit was operating on its price based offer curve, the price based curve was used. The change was to use the lower of the highest cost based offer curve or the price based offer curve. The result was to significantly increase the measured LOC and to increase regulation market clearing prices (Table 6-9). If the original method of calculation LOC had remained in place, clearing prices in the regulation market would have been approximately 23 percent lower.

Table 6-9 Impact on RMCP of revised LOC calculation: December 2008 through June 2009, (New Table)

Year	Month	Actual RMCP	Percent Reduction RMCP by Using Higher of Price/ Cost Curve	Reduced RMCP
2008	Dec	$24.79	19%	$20.23
2009	Jan	$21.04	23%	$16.20
2009	Feb	$25.83	26%	$19.11
2009	Mar	$19.90	23%	$15.32
2009	Apr	$16.84	19%	$13.64
2009	May	$32.41	25%	$24.31
2009	Jun	$32.59	28%	$23.46

Synchronized Reserve Market

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through June 2009 (See 2008 SOM Figure 6-5)

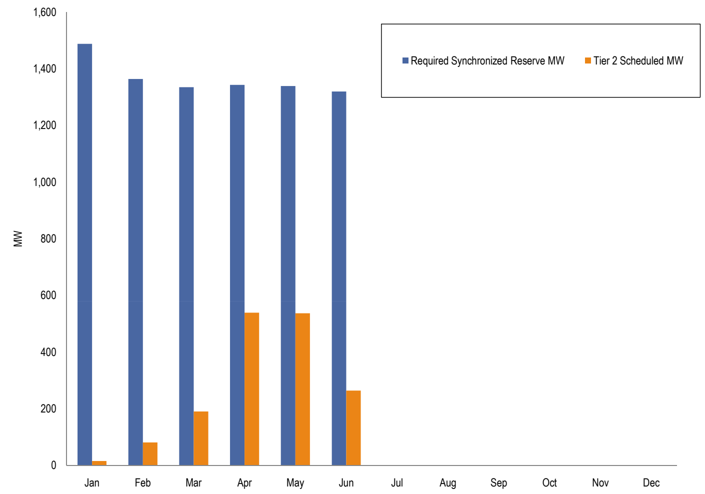
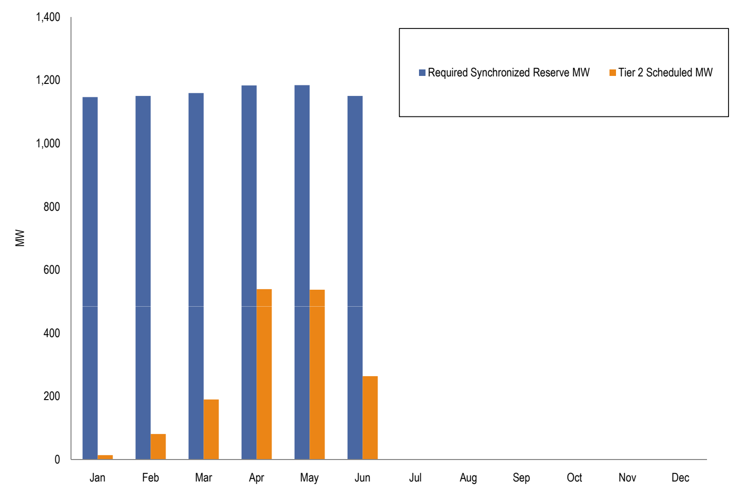


Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through June 2009 (See 2008 SOM Figure 6-6)



Market Concentration

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through June 2009 (See 2008 SOM Figure 6-7)

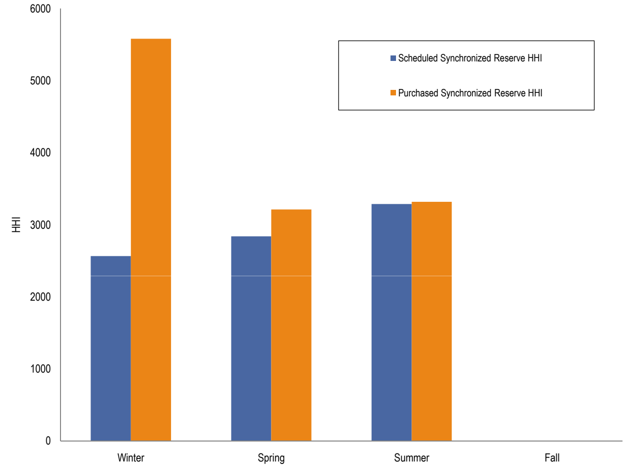
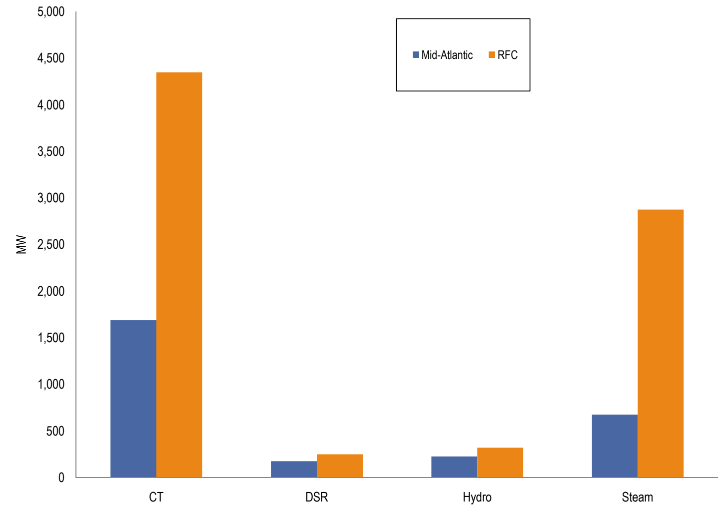


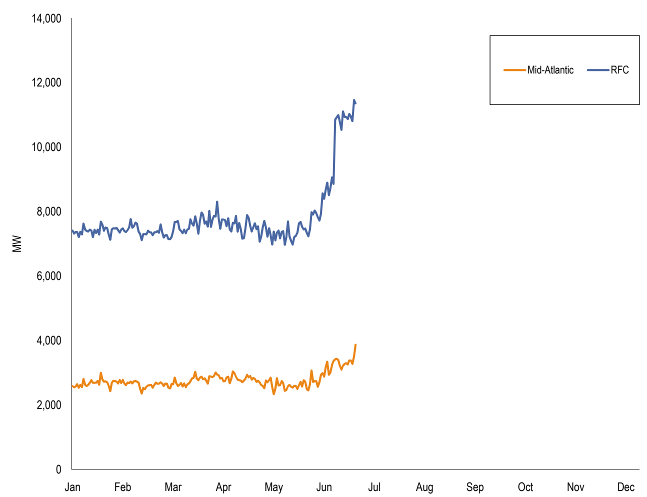
Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through June 2009 (See 2008 SOM Figure 6-9)



Market Conduct

Offers

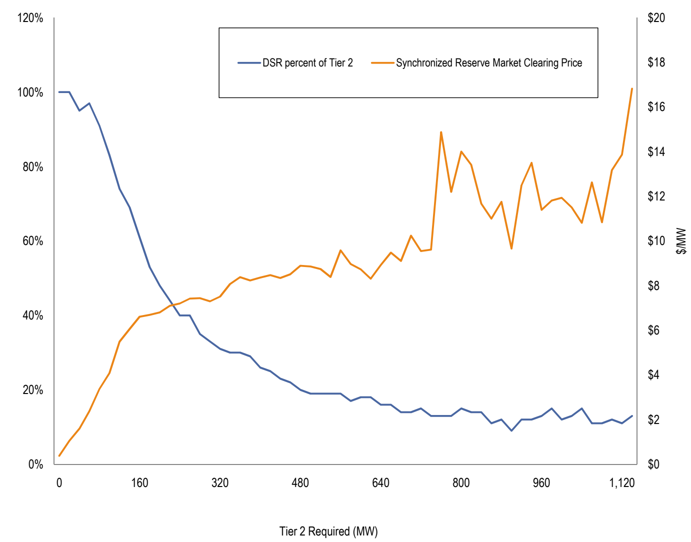
Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through June 2009 (See 2008 SOM Figure 6-8)



Market Performance

Price

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2: January through June 2009 (See 2008 SOM Figure 6-10)



Price and Cost

Figure 6-11 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through June 2009 (See 2008 SOM Figure 6-11)

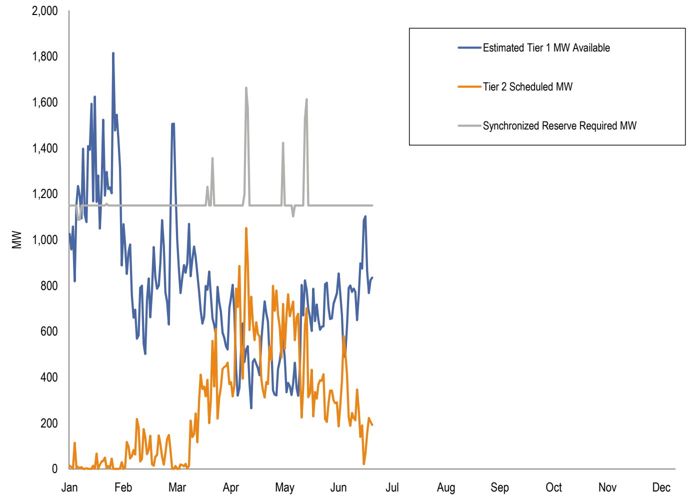


Figure 6-12 Synchronized reserve purchases by month; PJM scheduled, self-scheduled, and added: January through June 2009 (See 2008 SOM Figure 6-12)

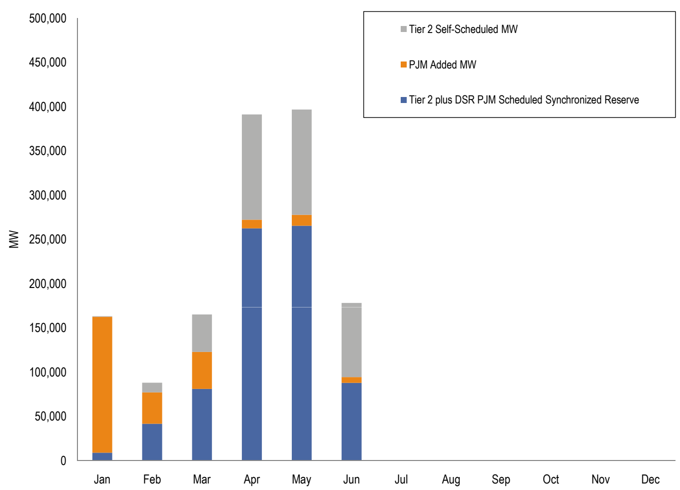


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: January through June 2009 (See 2008 SOM Figure 6-13)

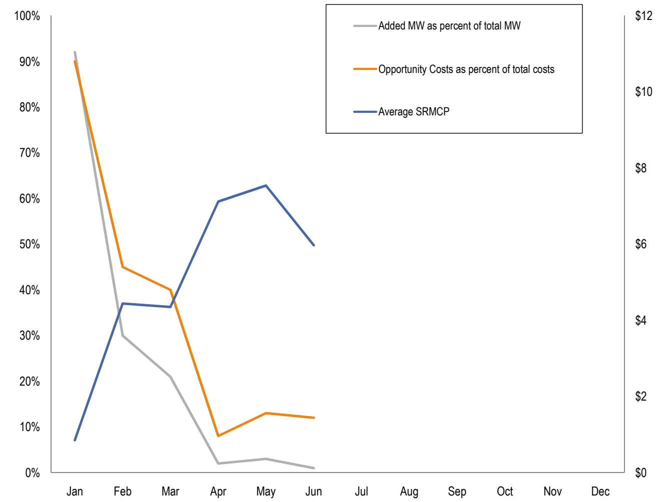
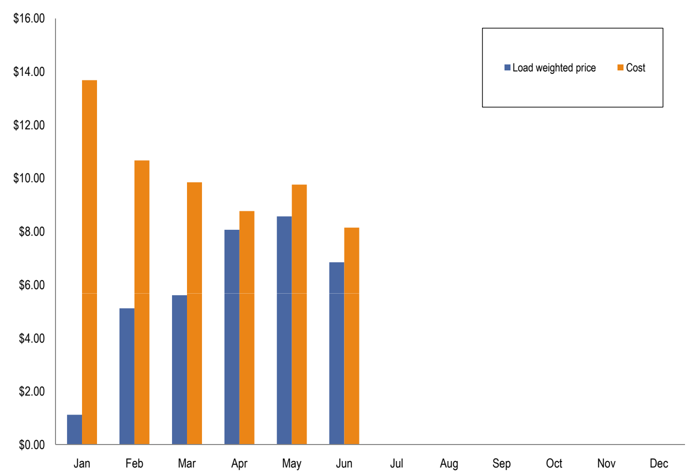


Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): January through June 2009 (See 2008 SOM Figure 6-14)



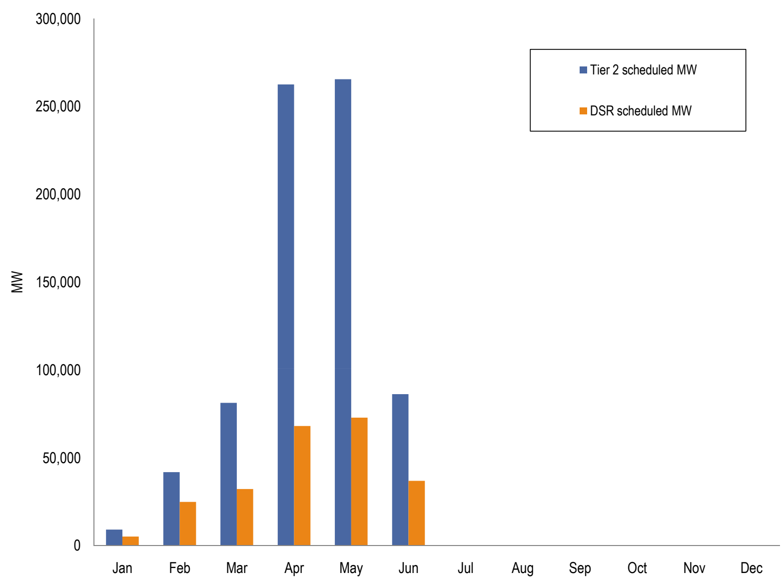
Market Solution and Actual Dispatch of Ancillary Services Availability

DSR

Table 6-10 Average SRMCP when all cleared synchronized reserve is DSR: January through June 2009 (See 2008 SOM Table 6-8)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$1.24	$5.90	43%
Feb	$2.01	$5.09	47%
Mar	$1.98	$5.50	26%
Apr	$2.49	$7.12	9%
May	$1.91	$7.56	12%
Jun	$1.76	$5.97	27%

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through June 2009 (See 2008 SOM Figure 6-15)



Day Ahead Scheduling Reserve (DASR)

Table 6-11 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through June 2009 (See 2008 SOM Table 6-9)

Month	Average Required Hourly DASR MW	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578

Table 6-12 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results: January through June 2009 (See 2008 SOM Table 6-10)

Month	Percentage of Hours With Three Pivotal Suppliers
Jan	16%
Feb	61%
Mar	75%
Apr	55%
May	48%
Jun	6%

Black Start Service

Table 6-13 Black Start yearly zonal charges for network transmission use: January through June 2009 (See 2008 SOM Table 6-11)

Zone	Network Charges
AECO	$206,192
AEP	$360,676
AP	$66,715
BGE	$236,356
ComEd	$3,340,231
DAY	$71,702
DLCO	$13,083
DPL	$176,763
JCPL	$214,109
Met-Ed	$199,072
PECO	$354,606
PENELEC	$165,245
Pepco	$109,389
PPL	$62,238
PSEG	$464,511

