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Affidavit of Joseph E. Bowring

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.	)	**Docket No. ER05-____-000**
	)	**and EL05-____-000**

AFFIDAVIT OF
JOSEPH E. BOWRING
ON BEHALF OF
PJM INTERCONNECTION, L.L.C.

My name is Joseph E. Bowring and I am the PJM Market Monitor. My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403. I am responsible for the market monitoring activities of PJM. These activities are defined by the PJM Market Monitoring Plan, Attachment M to the PJM Open Access Transmission Tariff. I am a Ph.D. economist and have substantial experience in applied energy and regulatory economics. I have taught economics as a member of the faculty at Bucknell University and at Villanova University. I have served as a senior staff economist for the New Jersey Board of Public Utilities and as Chief Economist for the New Jersey Department of the Public Advocate's Division of Rate Counsel. I have worked as an independent consulting economist. I have been the PJM Market Monitor since March 1999.

I am submitting this affidavit to explain and support several aspects of the Reliability Pricing Model ("RPM") filed by PJM in this proceeding. In particular, in this affidavit, I will:

- explain and support the methodology used in RPM to calculate the net energy and ancillary services revenue offset to the cost of new entry;

- explain and support the use of a nominal levelized financial model to calculate the cost of new entry;

- review the level of net revenues received by generation owners since the PJM energy market started operations in 1999; and

- explain and support the market power mitigation rules filed as part of RPM.

I. Net Energy and Ancillary Service Revenue Offset Against the Cost of New Entry

As explained by Mr. Andrew Ott in his affidavit for PJM, RPM uses a variable resource requirement curve ("VRR Curve") to represent the demand side in each RPM auction market. The cost of new entry ("CONE") for a new generation unit, net of the revenues such a unit would receive in the energy and ancillary services markets ("net CONE"), is a key parameter of the VRR Curve and therefore of the maximum price that will be paid for capacity under various supply conditions. In his affidavit for PJM, Mr.

Ray Pasteris calculates the cost of new entry for a combustion turbine ("CT") generator. He bases his estimate of the capital and fixed operating costs of a new entrant on a power plant configuration utilizing two 170 megawatt GE Frame 7FA turbines (the "Reference Resource"). Recent CT plants installed in PJM and other regions have incorporated these turbines. The 170 megawatt GE Frame 7FA turbine was chosen by Mr. Pasteris because it has lower capacity costs than the alternative CT technology evaluated.

Mr. Pasteris' calculations incorporate all fixed costs of a new generator including equipment and construction costs, interest payments, depreciation, taxes, fixed operation and maintenance expenses and return on investment. These are the costs that must be recovered from all PJM markets including energy, capacity and ancillary services markets. In PJM, capacity, energy and ancillary service markets are all significant sources of revenue to cover the fixed costs of generators.

If a new unit is to recover all of its costs from the PJM markets in equilibrium, the unit needs to recover from the capacity market only those costs not recovered in the other PJM markets. A competitive offer price in the RPM market for a new CT for its first year of operation equals the total annual fixed costs of the CT, less expected net revenues from all other sources. This is the incremental cost of new capacity. Accordingly, the CONE value provided by Mr. Pasteris must be reduced by an amount equal to the revenue a new CT can expect to receive from the PJM energy and ancillary services markets, less the variable expenses incurred to obtain those revenues ("revenue offset").

Net revenue is the contribution to fixed costs received by generators from PJM energy and ancillary services markets.[1] Although generators receive operating reserve payments as a revenue stream, these payments are not included here as a component of net revenues because the analysis is based on economic dispatch in the PJM model. Gross energy market revenue is the product of the energy market price and generation output. Gross revenues are also received from ancillary services markets. Net revenue equals total gross revenue less variable operating costs.

The RPM proposal relies on a formula to determine this revenue offset amount for the Reference Resource. As set forth in section 5.10 of new Attachment Y to the PJM Tariff, PJM will determine the energy market portion of the revenue offset as the annual average of the revenues that would have been received by the "Reference Resource" in the preceding six years based on "(1) the heat rate, variable cost, and other characteristics of the Reference Resource; and (2) the actual fuel prices and Locational Marginal Prices experienced in the PJM Region during such six-year period." Under this approach, the revenue offset is equal to the net revenues calculated based on how a unit with the characteristics of the CT for which the CONE is calculated would have operated under actual PJM prices.

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[1] The net revenues calculated in the Market Monitoring Unit's PJM State of the Market Report include capacity market revenues. Such revenues are not included here as the goal is to determine a competitive offer price in the capacity market for new entry after accounting for net revenues from all the markets except the capacity market.

While the CONE will be a stated amount in the PJM Tariff, a formula will be used to determine the revenue offset from the energy and ancillary services markets net revenues to subtract from the CONE. The CONE is generally not expected to change significantly from year to year. As explained by Mr. Pasteris, the primary determinants of the cost of a new CT include the cost of the generating equipment, the cost of construction, the cost of capital, the cost of land, the cost of labor, and taxes. Although these costs are subject to market pressures and may move up or down in response to those pressures, they generally are not expected to change significantly from year to year.[2]

In contrast, net revenues from the PJM energy market can be expected to change significantly from year to year, based on changes in the level of energy prices. As shown below, actual net revenues in PJM have shown such significant year to year changes since the PJM energy market was established (e.g. Table 1 and Figure 1). Net revenues are high in years with a high spread between energy prices and fuel prices and net revenues are low in years with a low spread between energy prices and fuel prices. A formula therefore will be more accurate than a stated rate in capturing net energy market revenues that vary significantly over time.

The revenue offset is based on the operating parameters of the same resource on which the CONE is based. The CONE is based on the GE Frame 7FA combustion turbine and the net capacity and net heat rate of this Reference Resource are used to calculate revenue offset values based on historical data from defined time periods.

The revenue offset calculation is used in RPM auctions that will determine capacity prices for Delivery Years four years in the future. The objective in the revenue offset calculation is to get the incentives right both for investors in generation and for load that will purchase capacity. In determining how best to calculate an appropriate revenue offset in the present period for a future period, the choice is between historical data and forward prices. (This assumes that there will not be an offset based on actual market conditions during the delivery year.) Historical data appear to be the only choice as there is no reliable source of market-based data on LMP and fuel costs for four years in the future. Given reliance on historical data, the choice is among possible numbers of years and annual weights. Investors are making decisions about constructing capacity based on expectations of energy revenues for the economic life of the facility. Thus investors are unlikely to build a unit based on the expectation that the last one or two years of net revenues represents future net revenues, especially in light of actual historical net revenue fluctuations. Historical net revenues over a representative measure of a full market cycle are a proxy for the expectations of investors about net revenues in the PJM energy market. Ultimately, investors focus on the actual net revenues received. The actual net revenues in the PJM energy market are a function of the actual market conditions during the delivery year.

I recommend the use of a rolling six-year simple average of net revenues for the Reference Resource for the revenue offset calculation. A six-year simple average provides equal weight to each year and covers a sufficiently long period that it is likely to

[2] The RPM Tariff requires PJM to review the parameters of the VRR Curve, including the CONE, within three years.

capture the effects of both relatively high net revenue years and relatively low net revenue years.

In order to get the incentives right, reliance on six years of history is clearly preferable to relying on one or two recent years. If the most recent year were a low net revenue year, use of a single year would understate likely future net revenues and therefore overstate the cost of capacity and overstate the required investment incentives. If the most recent year were a high net revenue year, use of a single year would overstate likely future net revenues and therefore understate the cost of capacity and understate the required investment incentives.

Nonetheless, neither PJM nor investors can perfectly predict net revenues for the operating year. One goal in calculating both the CONE and the revenue offset is to define a reasonable measure of the competitive cost of new entry while leaving room for competitive forces to actually determine the clearing price in the capacity auctions, subject to the constraint of the VRR Curve. If actual competitive participant offers are less than the estimated net CONE, the clearing price will be lower than the net CONE and if actual competitive participant offers are greater than the estimated net CONE, the clearing price will be higher than the net CONE. (The net CONE is Mr. Pasteris' CONE calculation less the revenue offset for the Reference Resource.)

Another goal of calculating the revenue offset is to provide a mechanism for equilibrating the results of the energy markets and the capacity market. If the revenue offset is high, the competitive offer price for new entry will decline correspondingly as will the net CONE. The reverse is also true. In the absence of such an equilibrating mechanism, there is a risk that total payments from all markets could exceed or fall short of the incentives consistent with resource adequacy. In addition, such an equilibrating mechanism provides a disincentive to the exercise of market power in the energy market. If market power is exercised in the energy market so as to increase prices and net revenues, this mechanism would reduce the capacity market price correspondingly but the impact would be attenuated by the inevitable differences between the historical average revenue offset and actual delivery year results.

The revenue offset formula includes an estimate of variable operations and maintenance costs. These are the variable costs that, along with fuel costs, are incurred when the unit operates and are therefore required to realize the energy market revenues. For this purpose, the formula uses an amount of $5.00 per MW-hour, which Mr. Pasteris explains in his affidavit is an appropriate variable cost for the GE Frame 7FA plant configuration.

The revenue offset formula calculates energy market revenues using a "perfect dispatch" approach. The perfect dispatch approach assumes that a unit will operate whenever the LMP is greater than the marginal costs of the unit (fuel plus variable operation and maintenance expense). This is the simplest approach and thus works well in a tariff formula but it does not take account of operating constraints like minimum run times and other similar constraints.

A revenue offset can also be calculated for the Reference Resource from historical data using a "peak-hour" approach which explicitly accounts for such operating constraints for the Reference Resource. This approach produces a more refined estimate but also requires a number of detailed assumptions about how the unit would run. I present the results in the following section for the revenue offset calculated using both methods. The peak-hour revenue offset results assume that the CT plant will be dispatched by PJM in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average PJM real-time LMP is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block.[3] The blocks are dispatched independently. If there are not at least two economic hours in any given block, then the CT is not dispatched for the block.

While the submitted tariff sheets reflect the perfect economic dispatch approach, I believe either of these approaches could be acceptable. If the peak-hour approach is adopted, the detailed assumptions could be specified in the PJM Manuals.

The revenue offset formula adds $2,254 per MW-year for the ancillary service revenues likely to be realized by the Reference Resource. For CT units based on the GE Frame 7FA turbine, the type of generator on which the CONE value is based, the source of ancillary service revenues is Schedule 2 of the PJM Tariff, "Reactive Supply and Voltage Control from Generation Sources Service." To maintain acceptable transmission voltage levels, PJM has the authority to direct generator operations in a way that produces, or absorbs, reactive power. Generators capable of providing this service receive payments based on their reactive service revenue requirements approved by FERC, as stated in Schedule 2. Such revenue requirements vary from one generator class to another. For example, the cost of supplying reactive service from a combined cycle unit will not be fairly representative of the cost of supplying reactive service from a CT. The reactive service revenue amount of $2,254 per MW-year in the revenue offset formula is a weighted-average figure calculated from the reactive service revenue requirements filed for the 20 CT units that have been approved for recovery by FERC under PJM's Schedule 2. The details of this calculation are shown on Attachment I to my affidavit. The formula uses a fixed number for ancillary services revenues because the reactive services revenue requirement is not likely to change significantly from year to year. However this element of the offset also could be reviewed at the same time that the CONE is reviewed.

The revenue offset formula does not include revenues from other types of ancillary services because CT units based on the GE Frame 7FA are less likely to provide these services. Such units typically are not configured to provide either spinning reserve or regulation service, so no net revenues are included for either of those services. Similarly, these units are not routinely configured to provide black-start service, which requires a significant added investment in equipment needed to start the unit without an outside electrical supply. The filed CONE values do not reflect the cost of such equipment and as a result, no offset is included here for revenues from black-start service.

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[3] The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at 2000 EPT until hour ending 2300 EPT.

The revenue offset formula does not include operating reserve payments. Under the PJM tariff, operating reserve payments are a form of make-whole payment for generation units that operate at PJM's request when the LMP applicable to the unit is less than the unit's offer over the day of operation. Such payments are made when daily net revenue would otherwise be negative. The formula does not include negative net revenue days.

II. Calculation of Net Revenue Offset per Formula for Recent Years

To demonstrate the application of the formula, I present a calculation of the energy and ancillary services revenue offset, using data from the six years 1999 through 2004. As explained above, the revenue offset formula includes a calculation of the net energy market revenues that would have been received by the Reference Resource had it operated in the PJM market for the prior six years, based on actual fuel prices and LMPs in the PJM region during that time period.

As stated above, the Reference Resource is the same plant configuration on which Mr. Pasteris based the CONE value, i.e., a natural gas-fired combustion turbine consisting of two GE Frame 7FA units, equipped with full inlet air mechanical refrigeration and selective catalytic reduction ("SCR") for NO_x reduction.

For this calculation, the period from 1999 through 2004 constitutes the most recent six years of energy market experience. Burner-tip gas prices in the PJM Region are based on the published daily prices at the "Transco Zone 6 Non-New York" delivery point, adjusted for local transportation costs. The net revenue calculation uses daily fuel costs.

The calculation uses the actual LMPs in effect for each hour of the period 1999-2004, inclusive. This data, which is voluminous, is available for download from the PJM web site.

Per the filed formula, the variable O&M expenses for the Reference Resource are \$5 per MWh. This cost is incurred as a result of unit starts and each hour the unit operates. Similarly, in accordance with the formula, ancillary service revenues are \$2,254 per installed MW-year.

I present the results of two approaches to calculating the revenue offset. The first is the perfect dispatch approach and the second is the peak dispatch approach.

Had the Reference Resource been in service in the PJM region from the period 1999 through 2004, and had it been dispatched by PJM under the perfect dispatch assumptions (i.e. whenever the PJM LMP exceeded the plant's costs to generate including start-up and no-load costs) then, based on unit characteristics, the fuel prices, LMPs, reactive revenues, and variable O&M expenses described above, the plant's estimated net energy and ancillary service revenues would have been as shown in Table 1

Table 1 Energy market and ancillary service net revenues for a combustion turbine plant (dollars per installed MW-year) – perfect dispatch case.

	Energy	Reactive	Total
1999	$62,065	$2,254	$64,319
2000	$16,476	$2,254	$18,730
2001	$39,269	$2,254	$41,523
2002	$23,232	$2,254	$25,486
2003	$12,154	$2,254	$14,408
2004	$8,063	$2,254	$10,317
AVG	$26,876	$2,254	$29,130

Had the Reference Resource been in service in the PJM region from the period 1999 through 2004, and had it been dispatched by PJM during peak daily hours (see above for detailed description of parameters) when LMPs exceeded the plant's costs to generate (including start-up and no-load costs) then, based on unit characteristics, the fuel prices, LMPs, reactive revenues, and variable O&M expenses described above, the plant's estimated net energy and ancillary service revenues would have been as shown in Table 2.

Table 2 Energy market and ancillary service net revenues for a combustion turbine plant (dollars per installed MW-year) – peak dispatch case

	Energy	Reactive	Total
1999	$55,612	$2,254	$57,866
2000	$8,498	$2,254	$10,752
2001	$30,254	$2,254	$32,508
2002	$14,496	$2,254	$16,750
2003	$2,763	$2,254	$5,017
2004	$919	$2,254	$3,173
AVG	$18,757	$2,254	$21,011

The results in Table 1 and Table 2 are for the PJM region as a whole. However RPM relies on CONE values for three subregions of PJM, eastern, central, and western. (See Attachment II - CONE Map.) Thus, net revenue calculations are needed for each subregion. The formula specifies that subregional offsets will be calculated only when there are at least two full calendar years of LMP data available. The PJM region average net revenue will be used where there is not such data.

In Table 3 and Table 4, I present data on the net energy and ancillary services revenues for the eastern and central subregions. As there are not two full calendar years of data available for the Commonwealth Edison Company ("ComEd") zone in Illinois, a subregional revenue offset is not calculated for that zone. When such data becomes available, the revenue offset for that subregion will be calculated in the same manner as described below, except that the relationship between the subregion and PJM region-wide numbers in the years for which data is available will be used to estimate the subregion revenue offset in the years for which PJM market data is not available in that subregion.

When he prepared the CONE estimates, Mr. Pasteris assumed the new entry plant for the eastern region would be located in the Atlantic City Electric Company ("AECO") service area and that the central region plant would be located in the Baltimore Gas & Electric Company ("BG&E") service area. Accordingly, the eastern and central subregion revenue estimates use 1999-2004 LMP data for the AECO and BG&E transmission zones, respectively.[4]

Table 3 presents the results of the applying the revenue offset formula to a CT with AECO zonal prices using the perfect dispatch method. The AECO zone average net revenue results are $6,892 per MW-year higher than the corresponding PJM-wide perfect dispatch results because the AECO zonal LMPs have been higher than the PJM region average LMPs.

Table 3 Energy Market and Ancillary Service Net revenues for a combustion turbine plant at AECO zonal average prices (Dollars per installed MW-year) – perfect dispatch case

	Energy	Reactive	Total
1999	$62,798	$2,254	$65,052
2000	$21,187	$2,254	$23,441
2001	$51,880	$2,254	$54,134
2002	$29,715	$2,254	$31,969
2003	$16,643	$2,254	$18,897
2004	$20,385	$2,254	$22,639
Avg	$33,768	$2,254	$36,022

Table 4 presents the results of applying the revenue offset formula to a CT with BG&E zonal prices using the perfect dispatch method. The BG&E zonal net revenue results are only $593 per MW-year higher than the corresponding PJM-wide perfect dispatch results because the BG&E zonal prices are almost identical to the PJM region average LMPs.

Table 4 Energy market and ancillary service net revenues for a combustion turbine plant at BG&E zonal average prices (Dollars per installed MW-year) – perfect dispatch case

	Energy	Reactive	Total
1999	$61,148	$2,254	$63,402
2000	$14,395	$2,254	$16,649
2001	$31,026	$2,254	$33,280
2002	$30,455	$2,254	$32,709
2003	$15,207	$2,254	$17,461
2004	$12,581	$2,254	$14,835
Avg	$27,469	$2,254	$29,723

[4] The analysis for each of the two transmission zones uses the zonal-average LMPs for all nodes for such zone.

III. Use of Nominal Levelized Financial Model to Determine CONE

Mr. Pasteris uses an iterative process to calculate the revenue requirements needed over the twenty-year financing life of a new CT plant to recover the plant's costs. As he explains in his affidavit, he starts with an initial estimate of an annual revenue requirement. The financial model deducts from that revenue the amounts needed to recover the operating costs and capital costs, other than the return to equity, escalated at a predetermined 2.5% per year, including interest, taxes, debt principal and other cash flow items, and calculates the resulting internal rate of return ("IRR"). Mr. Pasteris' calculations result in the annual revenue requirement necessary to achieve the target IRR.

Mr. Pasteris presents the revenue requirements in two ways. The first method, "real levelized," is a stream of increasing payments over 20 years which vary only by the assumed inflation rate of 2.5%. This method is termed real levelized because it is constant in real, or inflation adjusted, terms. The second method, "nominal levelized," is a stream of 20 constant annual payments. This method is termed nominal levelized because it is constant in nominal, non-inflation adjusted, terms. Both payment streams provide the same net present value ("NPV") to the project developer. The nominal levelized revenue stream provides higher payments earlier in the project life and lower payments later in the project life than does the real levelized revenue stream. Thus, if the project developer owned the unit for 20 years and received the specified annual revenues in each year, the developer would be indifferent between the revenue streams resulting from the two methods.

Both methods result in levelized annual revenue requirements and both provide for full recovery of project costs including inflation and realization of the target rate of return over the project's twenty-year life, rather than focusing only on the accounting costs accrued in a single test year. As Mr. Pasteris states, levelized approaches to evaluating power generation investments are commonly used by owners and developers. The only difference between the two levelization methodologies is that the real revenue requirement increases each year by the assumed inflation rate whereas the nominal revenue requirement remains constant each year.

In the RPM model this matters because new entry can set the price of capacity in the market based on its full cost of entry only when it is offered as a new unit and cannot set the price of capacity based on its full cost of entry after operation has begun.[5] An actual competitive offer by a potential entrant could reasonably be based on either method of levelizing the revenue requirements. The net CONE calculation functions as an upper bound on the price that will be paid to new entrants in the capacity market, recognizing that when the reserve margin is less than IRM plus 1 percent, the price will exceed the net CONE but will be a function of the CONE.

I recommend the use of a nominal levelized revenue requirement for the CONE. As a general matter, the RPM construct relies upon market forces to ensure that the offer prices of new capacity are competitive. It is appropriate to base the CONE calculation

[5] A unit is defined to be new for purposes of offering into the RPM until its commercial date.

and therefore the demand curve on the nominal levelized payment stream in order to ensure that the market rules do not exclude reasonable competitive offers. If potential entrants make offers at the real levelized net cost of new entry, they will appropriately win the auction, the clearing price would equal the real levelized net cost of new entry and there will not be an issue. However if potential entrants determine that a competitive offer is equal to the nominal levelized payment stream then a demand curve based on the nominal levelized payment stream would result in the same price as the demand curve based on the real levelized payment stream, assuming all new entry offers at the same price. However, more capacity would be purchased at the clearing price if the VRR is based on the nominal levelized CONE rather than the real levelized CONE under certain conditions. In addition, if total supply offers are less than the demand curve, the clearing price would be higher under the nominal levelized payment CONE than under the real levelized payment CONE.

The nominal levelized method results in an annual revenue requirement that incorporates expected cost increases over the life of the project in the first year revenue requirement. The real levelized method results in a first year annual revenue requirement that does not reflect expected inflation-based cost increases over the life of the project. The nominal levelized approach is appropriate for a fixed CONE value that will be used to clear auctions for multiple delivery years several years in the future. The CONE estimate prepared by Mr. Pasteris is based on a project with its first year of operations in 2006. Under the filed RPM market rules, that CONE value will be used to clear markets in auctions for delivery years at least through 2010,[6] and probably several years thereafter.[7] The CONE value stated in the tariff can only be changed following a stakeholder process and with FERC approval. It would be inappropriate to ignore cost escalation beyond 2006 as this would result in an underestimate of the cost of new entry and thus reduce incentives for new entry in auctions for subsequent years.

As an example, the 2006 revenue requirement under the real levelized approach is $61,726 per MW-year while the 2006 revenue requirement under the nominal levelized approach is $72,207. The 2010 revenue requirement under the real levelized approach is $68,134 per MW-year while the 2010 revenue requirement under the nominal levelized approach is $72,207. The real levelized method would result in an understatement of the cost of new entry for each year after 2006. The cross over point where the two revenue requirements are equal occurs between 2012 and 2013. Beginning in 2013, the annual revenue requirement under the real levelized approach exceeds the annual revenue requirement under the nominal levelized approach.

IV. Generator Net Revenues in PJM

In this section of my affidavit, I present data on generator net revenues in the PJM markets. Generator net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to

[6] Under the RPM transition provisions, auctions for the first four delivery years, through 2010, will be conducted in 2006.

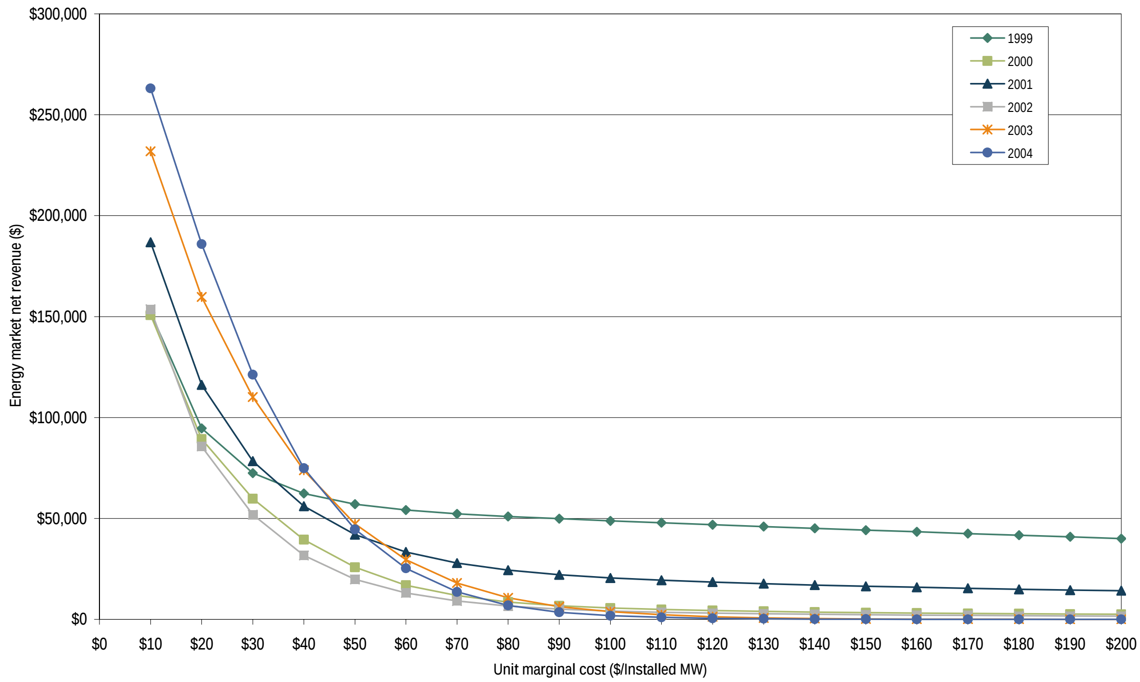
[7] The CONE value is to be reviewed no later than three years after RPM is implemented, i.e., by 2009, by which time PJM will be clearing auctions for the 2013 delivery year.

invest in new generation to serve PJM markets. Net revenue quantifies the contribution received by generators from all PJM markets to cover fixed costs including a return on investment, depreciation, taxes, and fixed operations and maintenance expenses. As discussed below, the levels of generator net revenue may result from cyclical supply and demand fluctuations, but also can highlight market design shortcomings.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. In PJM, the capacity, energy and ancillary service markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to provide an incentive to the entry of new capacity. Net revenue fluctuates annually based on actual conditions in all relevant markets.

Figure 1 displays net revenue curves for the PJM energy market, showing net revenues that would be earned by units with a range of marginal costs, for each year from 1999 through 2004. Differences in the shape and position of net revenue curves for the six years result from different distributions of energy market prices. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units. Periods of high prices were responsible for the shape of the 1999 net revenue curve. The limited number of high-priced hours in 2000, 2002 and subsequent years resulted in lower energy market net revenue for units operating at higher marginal costs.

Figure 1. PJM energy market net revenue by unit marginal cost: Calendar years 1999 to 2004



The PJM Market Monitoring Unit analyzes generator net revenues as part of its ongoing assessments of the state of the PJM markets. These analyses consider the net revenues available for new entrants assuming three different power plant configurations: a natural gas-fired combustion turbine ("CT"), a two-on-one natural gas-fired combined-cycle plant ("CC") and a conventional pulverized coal-fired, single reheat steam generation plant ("CP").

In 2004, total PJM net revenues for a CT, a CC and a CP were significantly below the level required to cover the fixed costs of each unit type. Using essentially the same methodology Mr. Pasteris describes in his affidavit to estimate the CONE, the PJM MMU has estimated the 20-year nominal levelized annual cost of a new CT plant as $72,207 per MW, a new CC plant as $93,549 per MW, and a new CP plant as $208,247 per MW.

The PJM MMU estimates that, under perfect dispatch assumptions (as described above), a new entrant CT plant's net revenue from 1999 through 2004 would have averaged $44,177 per installed MW-year, a new entrant CC plant would have averaged $77,107 per installed MW-year, and a new entrant CP plant would have averaged $141,747 per installed MW-year. Thus, over the six-year period, average net revenue was not adequate to cover the fixed costs of a CT, CC, or CP plant under the perfect dispatch calculations. These reported net revenues include payments from the current capacity markets.

Figure 2, Figure 3 and Figure 4 compare total net revenues calculated using the perfect dispatch assumptions to the nominal levelized fixed costs for combustion turbine, combined cycle and pulverized coal plants. The flat line in each graph represents the 20 year nominal levelized fixed costs for each unit type. The bars show the annual capacity market revenues separately for reference purposes although these capacity market revenues are included in the net revenue line. The net revenue line in each graph includes net revenues from the energy and ancillary services markets plus the revenues from the capacity markets. This net revenue line represents the total contribution to unit fixed costs from these PJM markets.

Figure 2. PJM total net revenue for a combustion turbine plant and nominal levelized fixed costs: Calendar years 1999 to 2004. Perfect dispatch case.

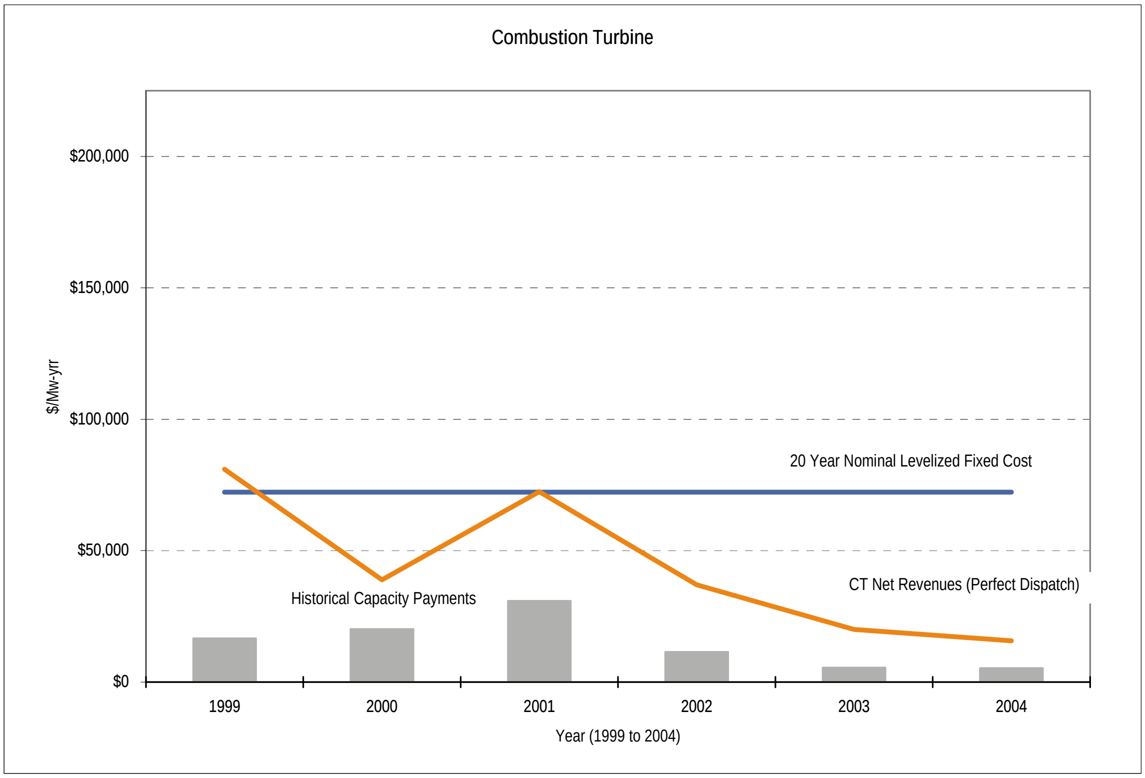


Figure 3. PJM total net revenue for a combined cycle plant and nominal levelized fixed costs: Calendar years 1999 to 2004. Perfect dispatch case.

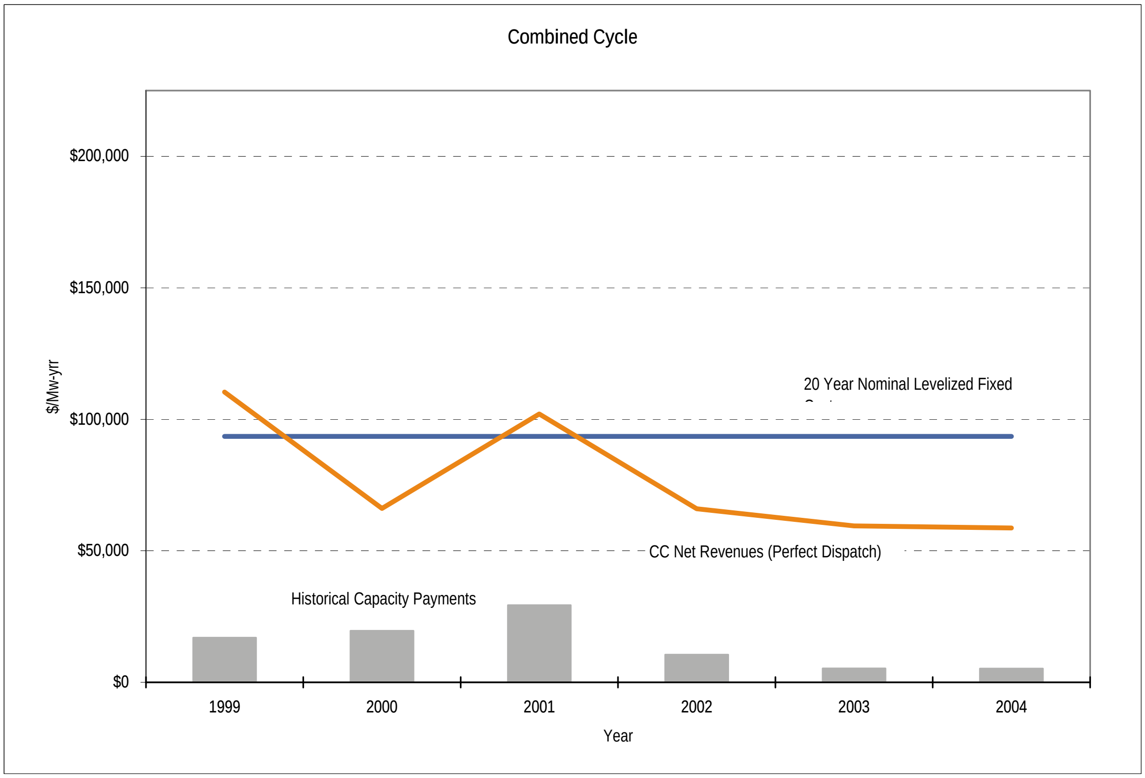
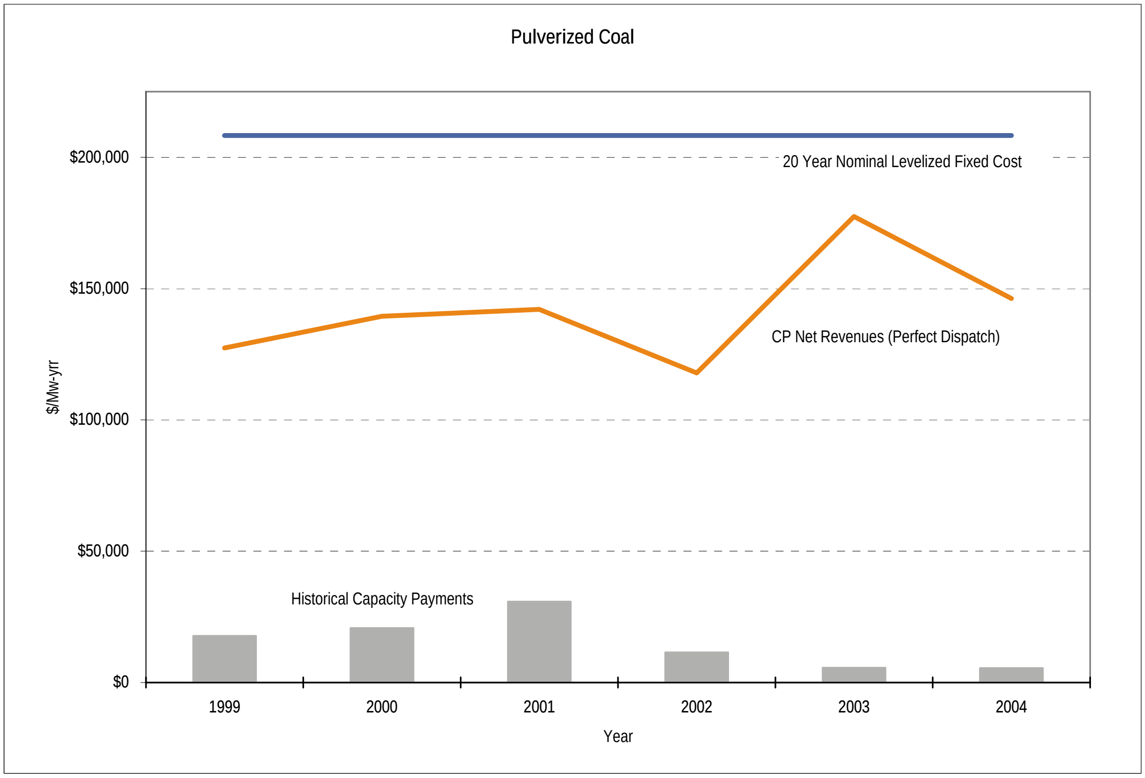


Figure 4. PJM total net revenue for a pulverized coal plant and nominal levelized fixed costs: Calendar years 1999 to 2004. Perfect dispatch case.



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. When the weather is extreme, prices will be higher, as they were in 1999 and 2001, and when the weather is mild, prices will be lower as they were in 2004. Combinations of market conditions and weather will produce a wide range of results. Analysis of 2004 net revenue shows that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower energy and capacity market prices which were, in turn, a result of market fundamentals.

While net revenue in PJM has been sufficient to cover the costs of new peaking units in some years, net revenue has been below the level required to cover the full costs of new generation investment for several years, and below that level on average for new peaking units for the entire period PJM has operated an energy market. (See Figure 2.) While to some degree this reflects cyclical fluctuations in supply and demand, this generally low level of revenues, coupled with the fact that some units needed for reliability in PJM are retiring because they are not receiving enough revenue to cover annual going forward costs, suggests that market price signals and reliability, or resource adequacy, needs are not fully synchronized. While retirements are a normal part of the operation of markets, the desire of generators to retire due to inadequate revenues raises a concern when such generators are critical to maintaining regional grid reliability. This suggests that market price signals and reliability needs are not fully synchronized and that the revenue inadequacy observed in PJM is not merely the result of expected cyclical fluctuations. The fact that the retirement of units with low net revenues would lead to unreliable operations in the absence of out of market actions suggests that market conditions in the region where these units are located are not reflected in the capacity market prices.

Moreover, when PJM determines that a retirement will result in reliability issues, the PJM market rules permit out of market payments to the units to keep them in service. While making such payments is an appropriate short run response to maintain reliability, this response is a symptom of the underlying investment incentive issue and cannot resolve the issue in the long term, consistent with markets. The logical end result of this approach would be out of market contracts with a significant number of peaking units in affected regions. This creates an incentive to declare unit retirements which in turn has a detrimental effect on the dynamics of the capacity market.[8] Units which are compensated via an RMR contract are indifferent as to the clearing price in the capacity market and have no incentive to make competitive offers or optimal offers in the capacity markets. If a regional shortage of capacity is reflected only in RMR payments and not in capacity market prices, there is no market signal for entry. The fact that RMR contracts continue to be needed to protect local reliability indicates that the market is not solving the regional reliability problem. The continued use of RMR contracts will simultaneously undermine the ability of the market to solve the reliability problem.

[8] It is not generally economically rational to retire a unit if is earning more than its annual avoidable costs but less than its full annual revenue requirements.

A rational approach to the resource adequacy issue in wholesale electricity markets with administratively enforced reliability requirements is a capacity market. The capacity market can be designed to achieve a competitive outcome that can be evaluated against objective benchmarks and that is consistent with reliability objectives. Another benefit of capacity markets is that they are consistent with competitive wholesale electricity markets. Capacity markets address the incentives for resource adequacy issue directly and explicitly and therefore do not require ad hoc modifications to the definition of competition in the energy markets that, for example, would permit the exercise of market power in order to derive adequate market revenues. In large energy markets like PJM, a locational feature of the capacity markets will also address geographical differences in resource adequacy.

Since the need for a capacity market is fundamentally driven by reliability requirements, it is vital that the capacity market design provides consistency between capacity prices and reliability requirements. The current PJM capacity construct falls short of this fundamental requirement and this result has driven the need for development of the Reliability Pricing Model. RPM addresses the resource adequacy issue, providing signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the energy markets. RPM also provides longer-term capacity price signals which are consistent with the lead-time requirements of generation installations and which therefore encourages competition from new entrants.

V. Market Power Mitigation Rules

RPM includes explicit rules governing market power mitigation in the capacity market. This is an important benefit of the RPM proposal, as PJM's existing capacity market does not include explicit market power mitigation rules. As I have concluded in the 2004 and prior State of the Market Reports, market power is endemic to the current capacity market design, yet there are no explicit rules limiting the exercise of market power in the capacity market. Given that, all else equal, RPM will increase market power, e.g through the creation of smaller, regional or LDA-based (Locational Deliverability Area) capacity markets, this explicit set of market power mitigation rules is central to the RPM construct. The RPM mitigation rules are required to make the RPM construct produce competitive outcomes. At the same time, the RPM market power mitigation rules are designed to minimize intervention in the capacity markets and to explicitly permit scarcity pricing as described below.

Section 6 of the RPM rules in proposed Attachment Y to the PJM Tariff contains the proposed market power mitigation rules for RPM. In general, the market power mitigation rules are narrowly targeted to specific market conditions that create the conditions for the potential exercise of market power. The unit-specific offer caps in the market power mitigation rules apply to LDAs only where an LDA is constrained and only where offers from new entrants are not required in order to clear the market. The market power mitigation rules also apply to the entire PJM region market but unit-specific mitigation would occur only if the market failed the market power tests and only where offers from new entrants are not required in order to clear the market. Mitigation is not applied to new entrants, rather competitive forces are relied upon to provide competitive prices when new entry is required. The RPM market power mitigation rules are based on the following principles:

- New entry is assumed to be competitive and mitigation based on unit-specific offer caps is therefore not necessary when new entry is required to clear any aggregate or local capacity market;

- Rational and accurate mitigation requires detailed unit-specific data. The preliminary market structure screen is intended only to determine whether more data should be provided by capacity owners;

- Proposed mitigation based on unit-specific offer caps is applied only in the situation where the relevant market structure fails the market structure tests and there is enough existing capacity to meet the demand for capacity in a constrained LDA or the PJM region. In addition, mitigation is applied only if the actual offers exceed the offer cap and if the offer would increase the market clearing price in the absence of mitigation;

- Proposed mitigation can never reduce a legitimate scarcity price. When existing capacity is not adequate to serve the load in a market, unit-specific mitigation is not applied. In this case the market clearing price is determined either by new entry and/or by the VRR Curve. As a result, the market clearing price will be greater than or equal to the CONE as determined by new entrant offers and the VRR Curve;

- Mitigation of offers from existing units is based on the incremental cost of such capacity, which is the competitive price of existing capacity. The incremental cost of existing capacity equals total annual avoidable costs less net revenue from other PJM markets. For existing capacity, a competitive offer covers the annual avoidable costs not recovered from other PJM markets. The incremental cost of existing capacity also includes the annual costs associated with any new investment in the unit required to maintain its viability as a generating unit. A rational seller will offer capacity into the capacity market at a price that covers its avoidable costs, net of energy and ancillary services revenues. It is profitable to sell at any price in excess of that price and it is not profitable to sell at any price less than that price;

- Physical withholding is a potentially profitable strategy for exercising market power in the aggregate market or in local markets. Market sellers must offer all of their PJM capacity resources (after adjustment for EFORd) to the market in all four seasons or they will not be permitted to sell any withheld capacity in any RPM auction. If this rule does not provide an adequate incentive to offer capacity resources to the market, withholding is addressed explicitly by including a 5 percent price trigger in all seasons. If withholding results in a market price increase of 5 percent or greater compared to the price absent withholding, a filing with FERC and a postponement of the final clearing of the auction are triggered.

A. <u>Market Structure Screens</u>

The market power mitigation rules include a preliminary market structure screen to determine whether additional generator data is required and a market structure test to determine whether non-competitive offers require mitigation, under defined circumstances.

1. Preliminary Screen to Determine Need for Data

The preliminary market structure screen is designed only to determine whether market structure conditions exist that could permit the exercise of market power. The screen is based on: the unforced capacity that is both located in a locational deliverability area ("LDA") and available for the relevant delivery year; the demand for capacity in the LDA (the reliability requirement); and firm obligations to sell unforced capacity from resources in the LDA. The screen is applied to the PJM region as a whole and also to each LDA. The logic of the screen as applied to LDAs is that, when transmission limits into the LDA are binding and no further imports are possible, the remaining capacity in the LDA forms the incremental supply curve that is capable of meeting the remaining demand for capacity. The market structure characteristics of this incremental supply curve therefore must be evaluated to determine whether there is a risk of market power in the LDA.

The preliminary market structure screen includes three measures: market shares of individual sellers; market concentration; and the extent to which suppliers are pivotal. Market shares are the proportion of generation owned by an individual entity. Consistent with Commission precedent, the market share screen is failed by an individual firm market share in excess of 20 percent. Market concentration is measured by the Herfindahl-Hirschman Index ("HHI"), calculated by summing the squares of the market shares of all sellers in the relevant market. This component of the screen is failed if the HHI exceeds 1800, consistent with the Commission's Merger Policy Statement that defines a highly concentrated market as one with an HHI greater than 1800.[9] Under the last component of the screen, suppliers are pivotal if the market cannot clear without the capacity of the identified suppliers. The residual supplier index ("RSI") is the measure of whether an identified group of suppliers are pivotal. Consistent with the market mitigation rules pending in Docket No. EL03-236, this aspect of the screen considers whether three suppliers are jointly pivotal. The screen is failed if the RSI is less than 1.0 for the three largest suppliers together.

The preliminary market structure screen is failed if any one of the three component screens is failed. In that event, capacity owners in the defined LDA or the entire market are required to submit data that will permit the PJM MMU to calculate the market structure test that will determine whether mitigation is required.[10]

2. Test to Determine Need for Mitigation

Consistent with the test proposed for the energy market in other proceedings now pending before the Commission, the market structure test includes only one measure, the

[9] 77 FERC 61,623, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act:: Policy Statement," Order No. 592, pp 64-70.

[10] The referenced data is primarily the avoidable cost data described in the market power screen.

three pivotal supplier test. Only this test is needed because, if it is passed, no mitigation is needed regardless of the outcome of market share and HHI tests, whereas, if it is failed, mitigation is needed regardless of the outcome of other tests. If a market fails the market share test or the market concentration test, but passes the three pivotal supplier test, that indicates excess supply is available that would be considered adequate to offset the results of the market share and market concentration tests.[11] Conversely, if the market share and market concentration tests are passed, but the three pivotal supplier test is failed, the market would not be competitive, because the three dominant suppliers are required to clear the market, regardless of market shares or HHIs.

The market structure test will be applied to LDAs as the auction is cleared by PJM, in a manner similar to the operation of PJM's local market power mitigation rule. If a local constraint becomes binding in the optimization algorithm used to clear an RPM auction, then the market structure test is applied to that LDA. If the LDA fails the test, then the offers in that LDA that are required to solve the constraint and meet the remaining LDA load obligations are capped if necessary, as discussed below. In the PJM region market, the test will also be applied as the auction is cleared by PJM. If the PJM region market fails the market power test, offers will be capped if necessary as discussed below.

B. Market Seller Offer Caps

1. Basic Structure of the Cap

Market seller offer caps are intended to reflect competitive offers for capacity resources, recognizing that capacity in the RPM construct is fundamentally an annual product. At the most basic level, a competitive offer for an annual offer of capacity is the annual avoidable cost of the unit, less net revenues from other PJM markets, including the bilateral sale of any product from the unit. This is a competitive offer because it reflects the incremental cost of capacity for a year. If a unit has avoidable costs of $100 per MW-day and net revenues from other PJM markets of $30 per MW-day, the incremental cost of maintaining the unit for a year in order to sell capacity is the difference, $70 per MW-day. In a competitive market, this incremental cost is the competitive offer. (This assumes no opportunity cost as discussed below.)

A unit-specific revenue offset is used to determine the unit-specific offer caps. The unit-specific revenue offset is calculated on a unit-specific basis in contrast to the revenue offset in the net CONE calculation which is based on the Reference Resource.. Net revenues will vary by type of unit, e.g. steam, combined cycle and combustion turbine, and by the actual market conditions faced by the individual unit.

There are three additional complexities that are addressed in the definition of market seller offer caps: EFORd risk; opportunity cost; and firm obligations to sell.

[11] This result differs from the preliminary screen because failure of any of the three components of the preliminary screen determines only the need for further data; whereas failure of this test determines the need for offer capping.

2. EFORd Risk

EFORd is the measure of the rate of forced outages and unit deratings used in PJM. The EFORd is an estimate of the probability of a unit failing to perform when called upon by PJM, based on historical data for each unit. A unit's EFORd can change over time, because PJM calculates EFORd using the unit's actual operating experience. Both the existing PJM capacity construct and RPM are based on "unforced capacity," where unforced capacity equals the installed capacity in MW adjusted for the EFORd of the unit. This is stated formulaically as [Unforced capacity = Installed capacity * (1 – EFORd)]. Thus, the higher the EFORd, the less unforced capacity available to sell in the market from a given unit. EFORd can act as an incentive to perform since decreases in EFORd translate into increases in unforced capacity to sell and corresponding increases in available revenue. For example, a 100 MW unit with an EFORd of 5 percent has 95 MW of unforced capacity available to be sold. If the capacity price is $80 per MW-day, the 95 MW of unforced capacity would be sold for $7,600 per day or $2,774,000 for the year. If the EFORd increases to 10 percent, then only 90 MW of unforced capacity can be sold. If the capacity price again is $80 per MW-day, the 90 MW of unforced capacity would be sold for $7,200 per day or $2,628,000 for the year, a reduction of $400 per day or $146,000 per year, i.e., about 5.3 percent. Based on the fact that EFORd is an historical measure, it is a relatively weak incentive for capacity resources to perform in the delivery year.

EFORd risk in RPM derives from the fact that an EFORd rate must be specified at the time an existing unit is offered into the RPM auction, while the amount of unforced capacity actually sold in the delivery year depends on the 12 month EFORd for a period ending three months prior to the delivery year. Specifically, the risk is that the EFORd used to calculate unforced capacity for the delivery year will increase compared to the EFORd used to determine the level of MW offered into the base residual auction. If the unit's offer in the base residual auction is based on an EFORd of 5 percent, but the EFORd increases to 10 percent prior to the actual delivery year, then the unit owner has to make up the additional MW of unforced capacity by purchasing it in the incremental auction or in a bilateral transaction. The risk faced by the seller at the time of the initial offer into the base residual auction is that the EFORd will increase and that the unit owner will have less unforced capacity than offered. If the EFORd decreases, the generation owner is better off and there is a benefit rather than a risk as the unit owner has more unforced capacity than offered.

The market seller offer caps address this risk by permitting an identified level of MW to be offered into the auction at a price that reflects the EFORd risk. The price is higher than the avoidable cost of the unit and equals the net CONE for the delivery year. The MW offered at the avoidable cost are termed the Base Offer Segment of the supply curve for a unit. The MW offered at the CONE are termed the EFORd Offer Segment. The EFORd Offer Segment is defined in Attachment Y, 6.7(c) (iii) as the unit's installed capacity level multiplied by the potential difference between the EFORd required to be used in the auction and the EFORd required to be used to define actual MW in the delivery year. In particular, to account for the possibility that EFORds are cyclical and that the 12-month EFORd may be low compared to the five-year average, the MW of unforced capacity in the EFORd Offer Segment may equal the positive difference between the five-year average EFORd and the 12-month average EFORd. In addition, if the unit is expected to undergo an anticipated degradation in EFORd performance, the

MW of unforced capacity in the EFORd Offer Segment may equal the positive difference between the documented expectation of EFORd performance as defined for the delivery year and the 12-month average EFORd.

The CONE is selected as the offer price for the EFORd Offer Segment to reflect the price risk to a generation owner that the EFORd applicable to the Delivery Year may exceed the EFORd used to determine the level of MW offered into the Base Residual Auction. In that case, the generation owner would have sold more unforced MW in the Base Residual Auction than it actually had available for the Delivery Year. In this case the generation owner would have to purchase the difference in the third or final incremental auction. The CONE is used to reflect the risk that the owner could face a high price for the EFORd related MW difference in the final incremental auction.

3. Opportunity Cost

Opportunity cost, in the context of market seller offer caps, refers to the documented price at which a PJM capacity resource could be sold in a market external to PJM. Any generation owner can submit an offer based on the opportunity cost available to a unit, provided that the opportunity cost is documented. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of PJM’s ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. For all units that do not have an accepted opportunity cost offer to export, their offers will be evaluated without the opportunity cost component.

This approach to opportunity costs provides a market-based mechanism for equilibrating RPM with external capacity and firm energy markets while limiting the ability to use potential exports as a method of physical withholding.

4. Firm Obligations to Sell

Generation owners may have firm obligations to sell their capacity. These obligations could take the form of a bilateral contract, the obligation of an integrated utility to meet load, or a provider of last resort obligation. Regardless of the exact nature of the obligation, if the market seller wishes its net capacity position to be used in the market power screens (rather than gross capacity position), the seller must self schedule or offer the capacity designated to serve the firm obligation at a zero price. Such sellers would receive the market clearing price for capacity.

5. Application of the Offer Cap

Sell offers by market sellers are subject to mitigation in specific LDAs only if there is a positive locational price adder in the auction and if the sell offers that are available to the PJM auction clearing algorithm to resolve the local constraint fail the market structure test. Sell offers would be subject to mitigation in the PJM regional market only if the market consisting of all sell offers to the RPM auction fails the market structure test. Mitigation will be applied only if the relevant sell offers are greater than the offer cap and only if, absent mitigation, the offer would increase the market clearing price. If the conditions for mitigation are met, the relevant sell offers are set equal to the market seller offer cap.

Sell offers of new entrants are not subject to mitigation, because new entry is assumed to be competitive. New generation resources may offer into a base residual auction, or an incremental auction, only if the owner has executed before such auctions, respectively, a facilities study agreement, or an interconnection service agreement. Accordingly, potential entrants must anticipate making an offer by the corresponding number of months in order to be entered into a queue and to have met the required milestones.

Offers of demand resources are not subject to mitigation because demand resources cannot set the clearing price in markets where mitigation is applied. While demand resources may offer at any price, the market clearing algorithm in markets where mitigation is applied will not let a demand resource set the clearing price. If demand resources were potential price setters, they would be subject to mitigation comparable to that applied to generation capacity sellers and demand resource avoidable costs would have to be identified. This raises a practical problem. The avoided cost formula in the tariff is designed for generation resources. Given the wide variety of demand resources, there is no defined standard approach for determining avoided costs for such resources. As a result, avoided cost would have to be determined on a case by case basis.

C. **Withholding**

Market power is generally exercised via either physical or economic withholding. The RPM auction rules need to address the potential for withholding to ensure that market power is not exercised and that the auction has an efficient solution. Economic withholding occurs when capacity is offered into the market at a price greater than its competitive price. The offer capping rules address the potential for economic withholding. Physical withholding occurs when capacity is not offered into the market. In order to address the potential for physical withholding, the RPM rules provide that if an existing generation resource in PJM does not offer its capacity into all the seasons of the base residual auction then it will be precluded from earning capacity revenues in PJM directly or indirectly for the that delivery year. This offer of capacity is at an unforced MW level using an EFORd less than or equal to the EFORd for the prior twelve months ended three months prior to the offer submission date. The associated EFORd risk is addressed via the inclusion of an EFORd offer segment in the capacity offer price as explained above. If the capacity resource does not clear in the base residual auction the same rules govern offers into each subsequent auction for all the seasons of the specified delivery year.

The only exceptions to the requirement that capacity resources must offer into the auction are capacity resources that are reasonably expected to be physically unable to participate in the market in the delivery year, capacity resources that have a physically firm commitment to an external sale of capacity and units that were originally interconnected to the transmission system as energy resources and remain energy resources.

If a capacity resource is not offered into the Base Residual Auction and subsequent capacity auctions for any of the seasons of a delivery year and does not qualify for any of the exceptions noted above, it may not be used to satisfy any entity's capacity obligation for any season of the specified delivery year in any manner, cannot receive payment for any season of the specified delivery year, and cannot be offered into any subsequent auctions for any season of the specified delivery year. Such capacity resource cannot be used as the basis for a bilateral capacity contract and it cannot be swapped with a capacity resource being exported so that it is effectively used to satisfy a capacity obligation for any season of the delivery year. The point of this rule is to make it clear that it is not possible to withhold in the base residual auction with the intent of increasing the clearing price and to then take advantage of that higher price via bilateral transactions or via sales into subsequent auctions for the same delivery year.

Notwithstanding these restrictions, there are still plausible incentives for market participants to withhold capacity resources. Therefore, the RPM rules provide that if withholding occurs, and would increase the clearing price in any auction for any season by more than five percent compared to the clearing price absent withholding, PJM will postpone clearing the auction and posting the results. In such cases, PJM will apply to FERC for an order compelling participation in the auction or for other appropriate relief. The ultimate enforcement authority on the issue of withholding lies with FERC.

D. Avoidable Cost Definition

As explained above, avoidable cost, net of other market revenues, is the incremental cost of capacity in an annual capacity market. Avoidable costs are the costs that the seller would avoid if the unit shut down. These are the costs that the seller incurs simply as a result of maintaining the unit's capability to participate in the energy market. A rational seller will offer capacity into the capacity market at a price that covers its avoidable costs, net of energy and ancillary services revenues. It is profitable to sell at any price in excess of that price and it is not profitable to sell at any price less than that price.

The proposed rules (Attachment Y Section 6.8) include a detailed formulaic definition of avoidable costs. In most respects, this definition is the same as the deactivation avoidable cost rate definition accepted by the Commission in connection with retiring units needed for reliability. The version of the formula used for RPM differs from the previously approved version only in its use of a ten percent adder; and its detailed provisions on incremental investments needed to maintain the resources as a capacity resource.

The ten percent adder is not intended to include a profit in the definition of avoidable costs, but to recognize the uncertainty associated with the exact measurement of avoidable costs for a period four years in the future. The 10 percent adder appropriately addresses such uncertainty.

The definition of avoidable costs also provides for the potential that an owner may need to make an incremental investment in a unit in order to maintain it as a capacity resource for the delivery year and for future years. The definition of avoidable costs provides for inclusion of the annual carrying costs of making such an investment (the capital recovery factors). These carrying costs include the return on and of capital including a rate of return and depreciation. The underlying financial model assumptions are identical to those used in PJM's definition of the CONE, with one important exception. The definition of avoidable costs explicitly recognizes that the useful life of a capacity investment in an existing unit is directly related to the age of the existing unit. It can reasonably be expected that an investment in a unit that is 20 years old will have a shorter useful life than an investment in a unit that is 5 years old. The capital recovery factors included in the definition of avoidable costs are therefore calculated on the basis of the age of the unit and therefore the expected remaining useful life. This provides an appropriate incentive to maintain and invest in existing capacity resources.

This completes my affidavit.

	)	Commonwealth of Pennsylvania
SS:	)	
	)	County of Montgomery

AFFIDAVIT OF JOSEPH E. BOWRING

Joseph E. Bowring, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Joseph E. Bowring on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Joseph E Bowring

Joseph E. Bowring

Subscribed and sworn to before me this 29th day of August, 2005.

/s/ April Mays-Parks

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
April Mays-Parks, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Sept. 8, 2008
Member, Pennsylvania Association Of Notaries

My Commission expires: 9/8/08

ATTACHMENT I – REACTIVE REVENUE REQUIREMENTS.

Generator(s)	Initial FERC Docket #	Total Annual Reactive Power Revenue Charge	FERC Filing Installed MW	CT $/MW-Y
AEP Big Sandy	ER04-1103-000	$525,904	300	$1,753
AEP Rolling Hills	ER04-1098-000	$1,100,000	800	$1,375
AEP Wolf Hills	ER04-1102-000	$442,023	250	$1,768
Armstrong County	ER03-229-000	$1,435,113	600	$2,392
CED Rock Springs	ER05-288-000	$766,570	335	$2,288
Commonwealth Cheasapeake	ER02-2520-000	$1,270,980	342	$3,716
Duke Lee	ER04-641-000	$1,500,000	640	$2,344
FPL MH50 (Marcus Hook)	ER01-1676-000	$393,182	50	$7,864
Handsome Lake	ER03-269-000	$370,304	250	$1,481
IMPA Anderson	ER05-971-000	$489,001	169	$2,893
ISG Sparrows Point	ER03-852-000	$319,464	153	$2,095
Ocean Peakings	ER05-289-000	$952,555	330	$2,887
Old Dominion Louisa	ER05-1229-000	$1,064,654	546	$1,951
Old Dominion Rock Springs	ER05-682-000	$654,639	672	$974
Pleasants Energy	ER03-451-000	$722,906	300	$2,410
PPL University Park	ER04-911-000	$1,504,414	540	$2,786
Reliant Aurora	ER04-1066-000	$2,183,895	873	$2,502
Reliant Twelvepole Creek	ER04-1166-000	$1,457,832	458	$3,183
Riverside	ER05-328-000	$1,702,765	820	$2,077
Westwood Joilet	ER02-2361-000	$203,901	30	$6,797
Total / Weighted Avg		$19,060,102	8,457	$2,254

Cost of New Entry (CONE) Regions