PJM ENERGY PRICES – 2005

Response to Howard M. Spinner Paper

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Response to Howard M. Spinner Paper Re: PJM Energy Prices – 2005

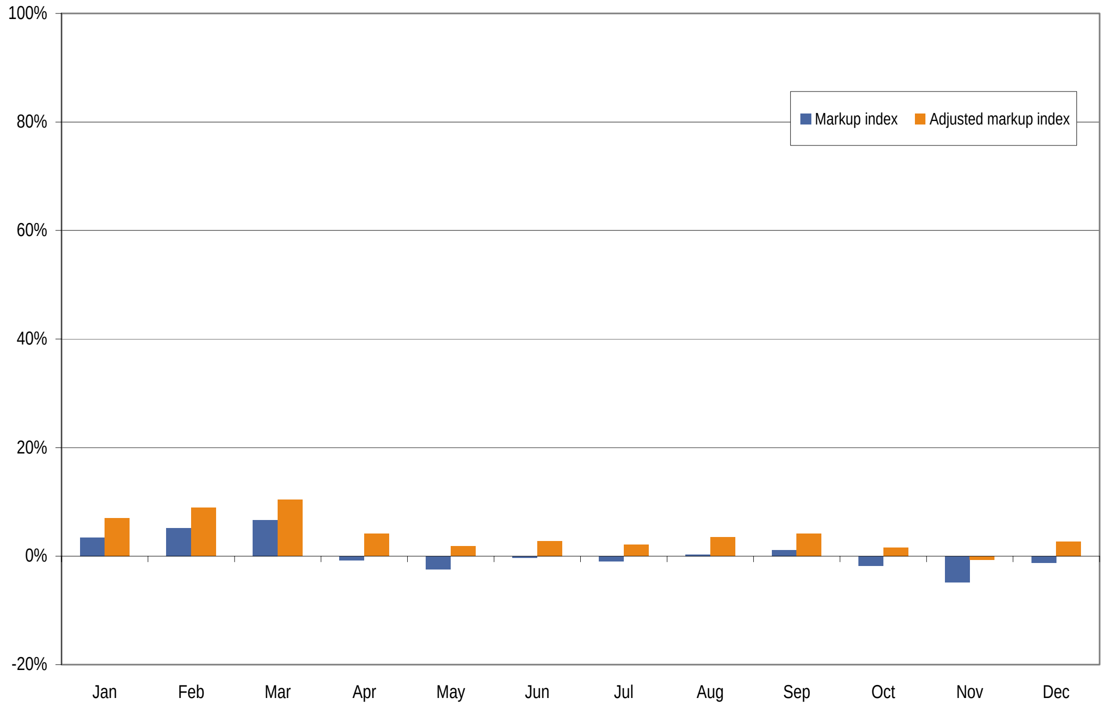
A March 13, 2006 paper ("Spinner paper") by Howard M. Spinner of the Virginia State Corporation Commission (VSCC) staff raises the question of whether the observed increase in PJM Interconnection average system prices in the second half of 2005 was the result of fuel price increases and increased loads or the result of market power. The Spinner paper "suggests" that the increase in prices in PJM was not the result of higher loads or fuel prices but was the result of the exercise of market power. The Spinner paper suggests that the result of this asserted market power was an increase in net revenues to generators of $6.4 billion.

The results reported in the Spinner paper are incorrect. There is no evidence of market power in 2005 or of increased market power in the latter half of 2005. This was demonstrated in the PJM Market Monitoring Unit's 2005 State of the Market Report. The increase in PJM prices in 2005, particularly in the latter half of 2005, was the result of increased fuel prices and increased demand. The conclusions in the Spinner paper are based on a series of incorrect and untested assumptions about the types of units on the margin, the frequency of unit types on the margin and the efficiency of the units on the margin. In addition, the Spinner paper fails to posit any mechanism by which the suggested significant increase in market power could have been exercised in the second half of 2005.

In the PJM Energy Market, prices are set by the marginal unit or units. Under economic dispatch, the lowest cost available units are dispatched in ascending order of cost to meet the load in real time. The last unit dispatched, the highest cost unit of the dispatched units, is the marginal unit. When there are binding transmission constraints, multiple marginal units and multiple prices result. Thus, the behavior of marginal units is critical in evaluating the competitiveness of the PJM Market.

The PJM Market Monitoring Unit (MMU) analyzes the offer behavior of every marginal unit in every five-minute interval during the year. In particular, the MMU examines the relationship between the price offer and the cost-based offer of every marginal unit in every five-minute interval. In a competitive market, it is expected that the price and cost-based offers would be very close, after accounting for risk, opportunity cost and measurement issues. The difference between price and cost-based offers is termed the markup. The MMU found that in 2005, the markup index was very low and declined in the second half of 2005. (See Figure 1.) The difference between price offers and cost-based offers for marginal units was very low and did not increase in the second half of 2005. The load-weighted average markup index was 0.3 percent in 2005, with a maximum of 6.7 percent in March and a minimum of -4.8 percent in November.[1] Based in part on these results, the MMU concluded that the energy market results were competitive in 2005.

Figure 1: Load –weighted, average monthly markup indices: Calendar year 2005



Based on the significance of marginal units in determining prices, the Spinner paper attempts to estimate the hourly system marginal cost of energy by estimating the costs of marginal units. Mr. Spinner estimates the hourly system marginal cost of energy using a combination of hourly data on the type of fuel on the margin in the Real-Time Market, posted by PJM, and his own assumptions regarding unit type and heat rate. The simple monthly average of the resultant hourly marginal cost is compared to simple monthly average of PJM hourly prices in the Day-Ahead Market and the difference between the two is the basis for the assertions regarding market power.

1 These results use the definition of marginal cost from PJM Manual M-15 and include a ten percent adder.

PJM currently posts the time-weighted hourly fuel type for each hour of the year for the Real-Time Market. In order to translate the hourly fuel type into information about marginal costs, Mr. Spinner had to make assumptions about the type of unit burning the fuel. The three fuel types that are primarily on the margin in PJM are coal, oil and natural gas. While it is generally reasonable to assume that coal is burned in a base load steam unit, gas and oil may be burned in units with very different characteristics and corresponding costs. For gas-fired units, the two primary unit types are combustion turbine units (CT) and combined cycle units (CC). CTs are peaking units that are relatively inefficient and CCs are more efficient midmerit units. For oil-fired units, the two primary unit types are steam units and CTs. The efficiency of fuel-burning generating units is generally measured by the heat rate, in BTU of fuel input per KWh of output. A higher heat rate means that a unit is less efficient and a lower heat rate means that a unit is more efficient. As a result of the differences in fuel efficiency across unit types, the assumptions made about the marginal unit type in the Spinner paper have a significant impact on the conclusions of the paper. The incorrect conclusions drawn in the Spinner paper stem largely from these assumptions.

The Spinner paper incorrectly assumes that when gas is the marginal fuel, more efficient gas-fired combined cycle units are on the margin most of the time. The Spinner paper incorrectly assumes that gas-fired combustion turbine units are on the margin only in the months of January, December, June, July and August and only when hourly load is greater than or equal to 95 percent of the maximum monthly load for the two winter months and 90 percent for the three summer months. The author’s assumption that CCs are generally on the margin when gas is the marginal fuel is incorrect. In fact, gas-fired CTs were on the margin in 25,499 five-minute intervals in 2005 (24 percent of all intervals) while the Spinner paper assumes that gas-fired CTs were on the margin in only 1,357 intervals (1 percent of all intervals).

Assuming that CCs are on the margin when gas is the marginal fuel is equivalent to assuming that costs are lower than they are. Similarly, assuming that oil-fired steam units are on the margin when oil is the marginal fuel is equivalent to assuming that costs are lower than they are. The author uses a heat rate of 7,500 BTU/KWh for gas-fired CC units and 12,000 BTU/KWh for gas-fired CT units. These assumptions are significant because, using these heat rates, CCs are about 1.6 times more efficient and therefore have costs about thirty percent lower than the costs of a CT. For example, assuming a heat rate of 7,500 Btu/KWh for a CC and 12,000 for a CT and a gas price of $10.00 per MBtu, the fuel component of the marginal cost of a CC is $75.00 per MWh while the fuel component of the marginal cost of a CT is $120.00 per MWh. The fuel component of marginal cost of the CT is 60 percent higher than that of a CC. In addition, the Spinner paper incorrectly assumes that when oil is the marginal fuel, an oil-fired unit with a heat rate of 11,000 is on the margin. In fact, the heat rate for oil-fired steam units is about 12,600 and for oil-fired CTs is about 14,100.[2]

While the rationale for these restrictive assumptions in the Spinner paper is unclear, it is clear that these assumptions are wrong and that the assumptions significantly impact the results. While the Spinner paper recognizes that the heat rate assumptions largely determine the results, the paper does not report any sensitivity analyses to test those assumptions nor does it provide any rationale for the assumptions about marginal unit types.

The Spinner paper suggests that these assumptions are less significant because the observed relationship between estimated costs and prices is stable for 18 months and changes only during the latter half of 2005. That is not correct. The apparent difference between cost and price during the latter half of 2005 is the direct result of the assumptions. The fact that gas prices increased significantly in the latter half of 2005 made the results for that period more sensitive to the unit type assumption. The spot market price of natural gas in the second half of 2005 was 69 percent higher than over the prior 18 months, the spot market price of light oil in the second half of 2005 was 41 percent higher than over the prior 18 months while the spot market price of coal increased less than 1 percent over the same period.[3] (Figure 2 shows fuel prices.) The result of the increase in gas prices was an increase of 69 percent in the difference between the costs of a gas-fired CC and a gas-fired CT. (Figure 3 shows the cost per MWh associated with the fuel prices in Figure 2.)

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2 Mr. Spinner asserts that a "crucial flaw" in his study results from the fact that he did not have access to commercially sensitive heat rate data. PJM does not collect heat rate data from generators so the data is not available from PJM. The general heat rates cited in this MMU paper were obtained by the MMU from public and commercial sources for the generators in the PJM footprint. In addition, it is Mr. Spinner's assumptions that drive his results and those assumptions are the result of analytical choices and the failure to perform reasonable sensitivity analyses rather than a lack of data. Mr. Spinner did not attempt to discuss his assumptions or methodology with the MMU. The MMU and PJM encourage such dialogue on the type of issues that Mr. Spinner addresses.

3 See 2005 State of the Market Report, pages 97-98.

Figure 2: Delivered Fuel Price (FOB Station): Calendar Years 2004 and 2005

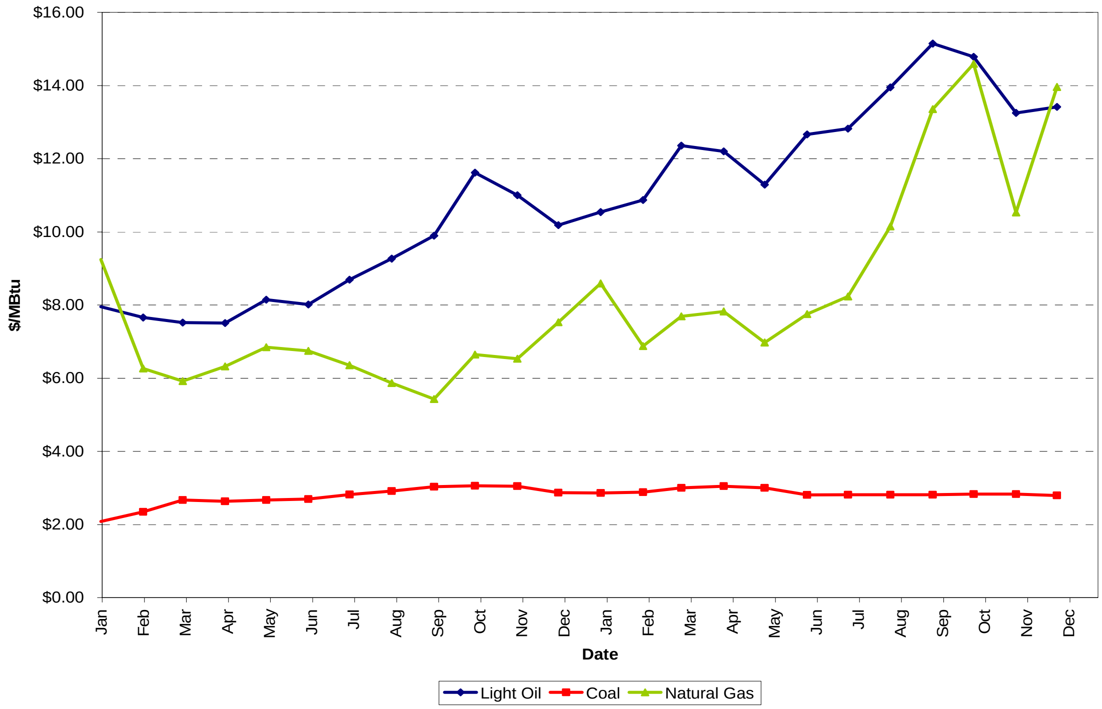
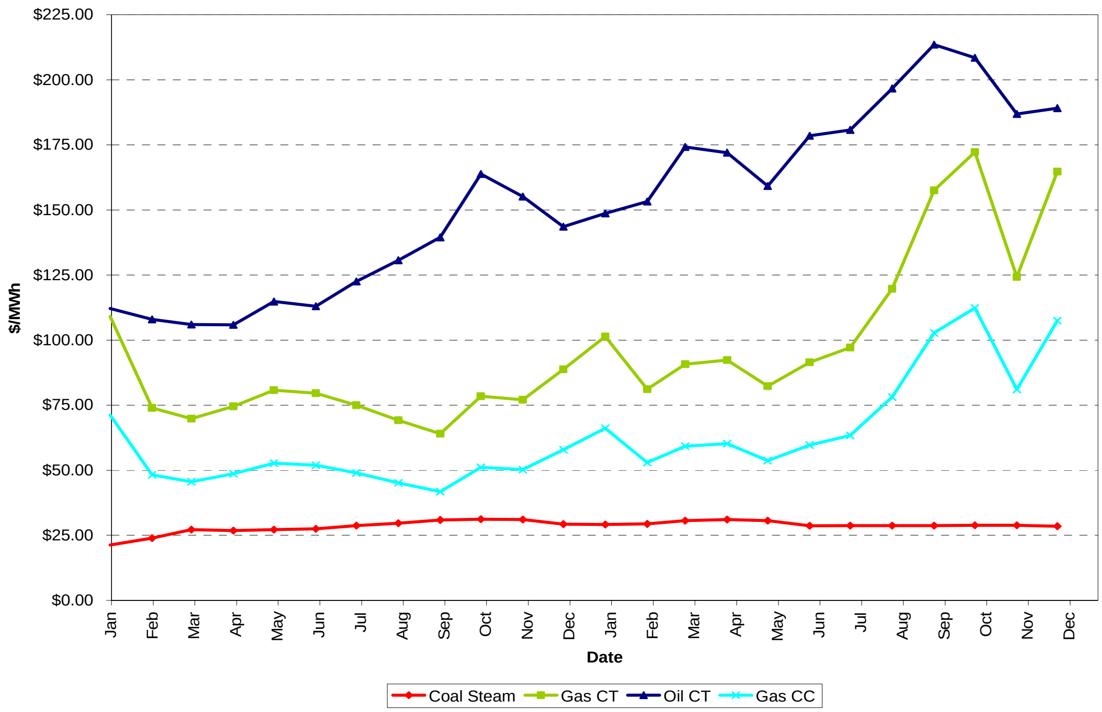


Figure 3: Fuel Component of Generation: Calendar Years 2004 and 2005



The Spinner paper also fails to account for the additional components of marginal cost associated with variable operation and maintenance expense (VOM) and the cost of emissions allowances. Together, these typically add about $2.00 to $2.50 per MWh for a gas-fired CC, $8.50 to $9.00 per MWh for a gas-fired CT and about $18.00 per MWH for coal-fired steam units. These costs include emission credit costs for the May through September attainment season for NOx. It should be noted that there are a significant number of older, less efficient CTs on the PJM system with much higher heat rates and much higher VOM expenses than these typical numbers reflect.

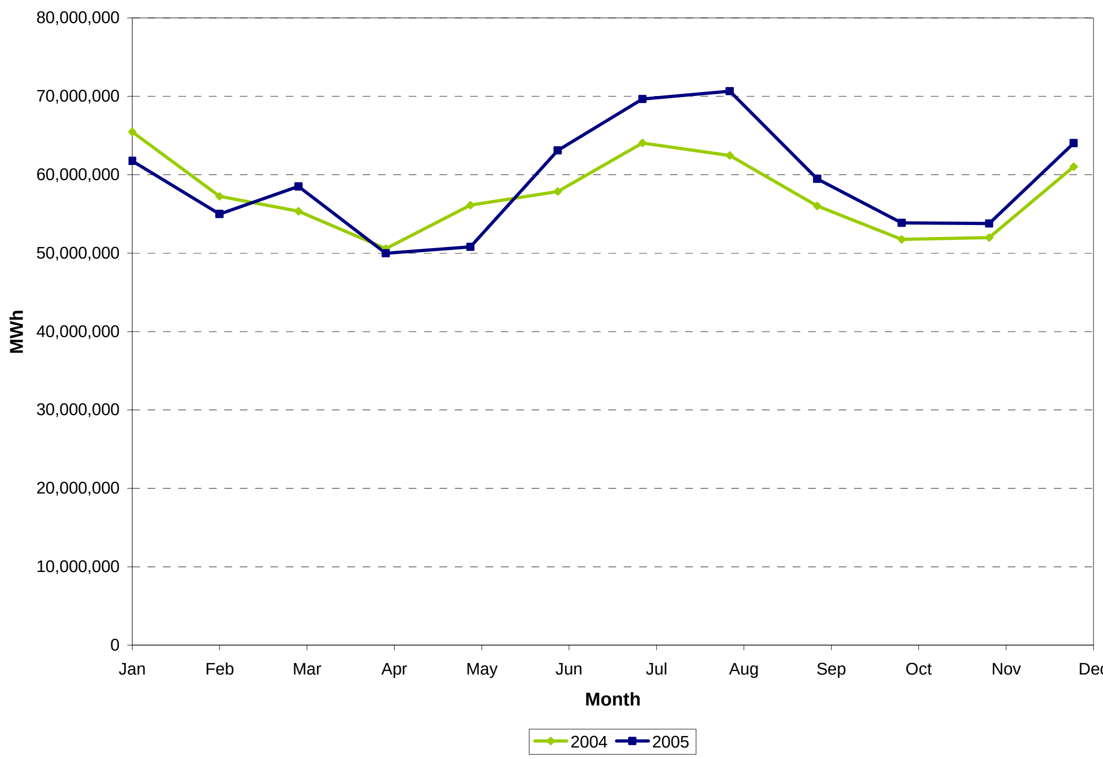
In summary, the interaction of heat rate assumptions in the Spinner paper and fuel price increases explains why the paper underestimates costs and overestimates the difference between prices and marginal costs for the latter half of 2005. There was, in fact, no increase in the markup and no increase in market power in the latter half of 2005.

The Spinner paper also fails to posit a mechanism by which the asserted significant increase in market power could have been exercised in the second half of 2005. The Spinner paper does not assert that there was a change in market structure. The Spinner paper does not provide any suggestion as to how market participants in the second half of 2005 were able to exercise market power in the PJM Energy Market when they had not been able to do so in the 18 preceding months.

MMU Analysis of 2005 PJM Energy Market

Prices increased in PJM in 2005 as the result of increased fuel prices and increased demand rather than from an increase in market power. In a competitive market, it is expected that increased input prices will result in increased marginal costs and increased prices. The 2005 State of the Market Report concluded that, on a fuel-cost adjusted basis, prices in PJM increased by 1.5 percent. In a competitive market, it is also expected that prices will increase as demand increases and more expensive resources are on the margin. Overall demand in 2005 was about 3 percent higher than in 2004. Demand in the latter half of 2005 was about 7 percent higher than in the latter half of 2004 with a maximum month over month increase of 12 percent in August. (Figure 4 shows the monthly average load in PJM, consistent with the current footprint including Dominion.)

Figure 4: PJM Total Monthly Load – Current Footprint: Calendar Years 2004 and 2005



Net revenue is an indicator of generation investment profitability and thus is a measure of the overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from all PJM markets. Net revenue equals gross revenue received less variable costs. From an energy market perspective, gross revenues are the hourly Locational Marginal Price (LMP) multiplied by a unit's output in MWh while variable costs are fuel, operation and maintenance expense and emissions costs.

While higher PJM prices resulted in higher net revenues for all unit types in 2005, the increase was significant only for coal units. This is consistent with the underlying reasons for the price increases. The increase in net revenues for base load coal units was the result of higher PJM prices which were in turn the result of higher gas prices and higher demand. Higher gas prices resulted in higher prices when gas-fired units were marginal. This did not result in higher net revenues for marginal gas-fired units selling power at marginal cost but did result in higher net revenues for coal-fired units because the spread between gas prices and coal prices increased.

The 2005 State of the Market Report found that net revenues for CTs were 14 percent of the total annual costs of a new CT in 2005, that net revenues for CCs were 44 percent of the total annual costs of a new unit in 2005 while net revenues for coal units were 10 percent above the level of total annual costs of a new unit in 2005. On average, over the seven years of PJM's energy markets, the net revenues of CTs have been 45 percent of the total annual costs of a new unit, the net revenue of CCs has been 61 percent of total annual costs of a new unit and the net revenue of coal units has been 70 percent of total annual costs of a new unit. (Table 1, Table 2, Table 3.)

Table 1: CT 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year)
Calendar years 1999 to 2005

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$80,990	112%	$74,537	103%
2000	$72,207	$38,924	54%	$30,946	43%
2001	$72,207	$72,477	100%	$63,462	88%
2002	$72,207	$36,996	51%	$28,260	39%
2003	$72,207	$19,956	28%	$10,565	15%
2004	$72,207	$15,687	22%	$8,543	12%
2005	$72,207	$20,037	28%	$10,437	14%
Average	$72,207	$40,724	56%	$32,393	45%

Table 2: CC 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year)
Calendar years 1999 to 2005

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$109,754	117%	$100,700	108%
2000	$93,549	$65,445	70%	$47,592	51%
2001	$93,549	$101,413	108%	$86,670	93%
2002	$93,549	$65,286	70%	$52,272	56%
2003	$93,549	$58,782	63%	$35,591	38%
2004	$93,549	$57,996	62%	$35,785	38%
2005	$93,549	$73,517	79%	$40,817	44%
Average	$93,549	$76,028	81%	$57,061	61%

Table 3: CP 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year)
Calendar years 1999 to 2005

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$126,097	61%	$118,021	57%
2000	$208,247	$138,141	66%	$134,563	65%
2001	$208,247	$140,776	68%	$129,271	62%
2002	$208,247	$116,648	56%	$112,131	54%
2003	$208,247	$176,138	85%	$169,510	81%
2004	$208,247	$144,908	70%	$133,125	64%
2005	$208,247	$237,870	114%	$228,430	110%
Average	$208,247	$154,368	74%	$146,436	70%

The MMU found that PJM Energy Market results were competitive in 2005 based on detailed analyses of market structure, participant behavior and market results. There is no evidence of market power in 2005 or of increased market power in the latter half of 2005. The price increases in 2005 were the result of increased fuel costs and increased demand. Net revenues continue to be less than required to meet the annual fixed costs of new CT and CC entrants while exceeding the annual fixed costs for a new coal plant in 2005.