Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbines (CT), combined cycle (CC), and coal plant (CP) generating units. Only quarterly energy market net revenues are provided in this report.

Highlights

- Average real time LMP decreased by 29.1 percent in the first nine months of 2012 over the first nine months of 2011.
- Natural gas prices decreased by more than coal prices in the first nine months of 2012 compared to the first nine months of 2011. The price of Northern Appalachian coal was 15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; and the price of Powder River Basin coal was 34.1 percent lower. The price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower.[1]
- While average net revenues for all three technologies declined, only new entrant combined cycle units had net revenue increases in some zones. Comparing the first nine months of 2012 to the first nine months of 2011, energy net revenues for the new entrant combustion turbine unit were down 36.8 percent, energy net revenues for the new entrant combined cycle unit were down 8.7 percent, and energy net revenues for the new entrant coal unit were down 69.1 percent.[2]

Net Revenue

When compared to annualized fixed costs, 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 invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

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 annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity 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 annualized 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 encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[3]

Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Average real time LMP decreased by 29.1 percent in the first nine months of 2012 over the first nine months of 2011. Natural gas prices decreased by more than coal prices in the first nine months of 2012 compared to the first nine months of 2011. The price of Northern Appalachian coal was

1 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

2 Changes are simple zonal averages.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; and the price of Powder River Basin coal was 34.1 percent lower. The price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower.[4] The combination of lower energy prices, lower gas prices and lower coal prices resulted in lower energy net revenues for new entrant CC units in thirteen of seventeen zones and lower energy net revenues for the new entrant CT and CP unit in all zones in 2012.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets.

Analysis of Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[5] The coal plant is a sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NO_x control, a Flue Gas Desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.

All net revenue calculations include the hourly effect of actual hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[6,7] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[8]

A forced outage rate for each class of plant was calculated from PJM data.[9] This class-specific outage rate was then incorporated into all revenue calculations. Each plant was also given a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. Ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues.

Ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the

4 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

5 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.

6 Hourly ambient conditions supplied by Telvent DTN.

7 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.

8 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

9 Outage figures obtained from the PJM eGADS database.

reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. Reactive revenues are not included in energy market revenues.

Zonal net revenues reflect zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[10] The delivered cost of natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[11] The delivered cost of coal incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[12]

Average zonal operating costs in 2012 for a CT were $35.79 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $7.59 per MWh. Average zonal operating costs for a CP were $31.39 per MWh, based on a design heat rate of 9,240 Btu per kWh and a VOM rate of $3.22 per MWh. Average zonal operating costs for a CC were $20.85 per MWh, based on a design heat rate of 6,914 Btu per kWh and a VOM rate of $1.25 per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.

The net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched economically by PJM operations. It was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start up costs. If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least four hours, or any hours bordering the profitable day ahead or real time block.

Table 6-1 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[13] (See the 2011 SOM, Table 6-3)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	Change in 2012 from 2011
AECO	$11,373	$35,954	$43,566	$22,494	(48%)
AEP	$3,275	$9,026	$19,150	$15,188	(21%)
AP	$10,188	$24,704	$30,656	$19,975	(35%)
ATSI	NA	NA	NA	$16,687	NA
BGE	$13,644	$45,815	$45,075	$34,183	(24%)
ComEd	$2,286	$8,696	$14,681	$12,767	(13%)
DAY	$2,866	$9,477	$19,874	$17,150	(14%)
DEOK	NA	NA	NA	$14,814	NA
DLCO	$3,366	$14,995	$21,487	$17,841	(17%)
Dominion	$14,315	$36,788	$36,232	$23,921	(34%)
DPL	$12,718	$36,445	$41,529	$29,848	(28%)
JCPL	$10,527	$34,096	$41,388	$21,380	(48%)
Met-Ed	$9,982	$34,786	$38,159	$22,141	(42%)
PECO	$9,703	$33,483	$43,260	$23,282	(46%)
PENELEC	$6,276	$17,766	$30,057	$20,768	(31%)
Pepco	$16,205	$43,945	$41,107	$30,397	(26%)
PPL	$9,104	$29,513	$40,482	$19,781	(51%)
PSEG	$9,172	$33,308	$35,126	$21,250	(40%)
RECO	$7,838	$30,977	$29,697	$19,616	(34%)
PJM	$8,990	$28,222	$33,619	$21,236	(37%)

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched economically by PJM operations. It was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start up costs.[14] If the unit was not already committed day ahead, it was then run in real time in stand-

10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt prices obtained from Platts.

13 The energy net revenues presented for the PJM area in this section represent the simple average of all zonal energy net revenues.
14 All starts associated with combined cycle units are assumed to be hot starts.

alone profitable blocks of at least eight hours, or any hours bordering the profitable day ahead or real time block.

Table 6-2 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year) (See the 2011 SOM, Table 6-6)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	Change in 2012 from 2011
AECO	$53,515	$88,338	$107,347	$80,452	(25%)
AEP	$25,716	$35,573	$62,446	$73,119	17%
AP	$51,473	$66,543	$90,974	$82,714	(9%)
ATSI	NA	NA	NA	$76,668	NA
BGE	$56,858	$101,942	$104,716	$101,505	(3%)
ComEd	$18,383	$30,284	$40,530	$55,224	36%
DAY	$23,596	$36,247	$61,394	$77,200	26%
DEOK	NA	NA	NA	$68,306	NA
DLCO	$22,923	$41,189	$61,422	$75,101	22%
Dominion	$58,612	$93,795	$92,412	$85,538	(7%)
DPL	$55,142	$88,420	$103,217	$91,883	(11%)
JCPL	$52,935	$85,690	$103,883	$79,381	(24%)
Met-Ed	$47,338	$83,009	$92,175	$76,556	(17%)
PECO	$49,620	$83,203	$102,744	$78,781	(23%)
PENELEC	$42,010	$57,593	$87,883	$84,378	(4%)
Pepco	$58,923	$100,141	$97,364	$95,582	(2%)
PPL	$45,115	$73,814	$93,820	$72,960	(22%)
PSEG	$50,355	$84,626	$94,513	$76,239	(19%)
RECO	$44,897	$78,524	$77,172	$71,813	(7%)
PJM	$44,553	$72,290	$86,707	$79,126	(9%)

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched by PJM operations in the Day Ahead Market for all available plant hours, both reasonable assumptions for a large, efficient CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 6-3 PJM Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year) (See the 2011 SOM, Table 6-9)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	Change in 2012 from 2011
AECO	$67,257	$123,525	$73,347	$14,444	(80%)
AEP	$13,379	$48,458	$63,670	$24,484	(62%)
AP	$36,322	$81,508	$88,159	$37,546	(57%)
ATSI	NA	NA	NA	$29,135	NA
BGE	$36,606	$65,752	$56,066	$13,594	(76%)
ComEd	$30,169	$92,893	$81,958	$43,279	(47%)
DAY	$19,206	$65,403	$55,551	$23,385	(58%)
DEOK	NA	NA	NA	$18,426	NA
DLCO	$14,410	$67,832	$44,901	$34,318	(24%)
Dominion	$36,506	$119,130	$75,015	$9,782	(87%)
DPL	$30,404	$121,440	$92,578	$22,366	(76%)
JCPL	$57,382	$121,034	$69,361	$15,598	(78%)
Met-Ed	$45,652	$117,561	$60,001	$18,987	(68%)
PECO	$60,767	$118,052	$73,109	$16,810	(77%)
PENELEC	$59,243	$99,175	$85,430	$25,579	(70%)
Pepco	$54,534	$133,117	$71,482	$15,413	(78%)
PPL	$55,246	$96,923	$75,822	$11,884	(84%)
PSEG	$135,308	$103,660	$47,426	$14,164	(70%)
RECO	$54,556	$118,402	$57,467	$15,142	(74%)
PJM	$47,467	$99,639	$68,902	$21,281	(69%)

Figure 6-1 Energy Market net revenue factor trends: December 2008 through September 2012 (New Figure)