Net Energy and Ancillary Services Revenue Offset for PJM and Subregions

Introduction

Pursuant to Attachment DD, Section 5.10(a)(v)(A, B and C) of the PJM Tariff changes approved by the FERC on December 22, 2006 with an effective date of June 1, 2007, PJM provides the net energy and ancillary services revenue offset data for the PJM Region and each subregion for which the cost of new entry is determined, using the Peak-Hour Dispatch method.

The relevant parts of Attachment DD are:

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource during a period of consecutive calendar years (as specified in (B) below) preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region, with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $5.00 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,254 per MW-year.

B) For each of the first three Delivery Years of the Transition Period, such determination shall be based on the six consecutive calendar years preceding the relevant BRA. For any subsequent Delivery Year, such determination shall be based on the three consecutive calendar years preceding the relevant BRA.

C) The Office of the Interconnection also shall determine a Net Energy and Ancillary Market Revenue Offset each year for each subregion of the PJM Region for which the Cost of New Entry is determined, as identified above, using the same procedures and methods as set forth in the previous paragraph; provided, however, that: (1) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region-average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; ; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed

Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

The Peak-Hour Dispatch Method

The Peak-Hour Dispatch method was used to calculate PJM regional and subregional net revenues, consistent with the tariff. The details of the method are reviewed here.

Analysis of the real-time energy market net revenues available for a new entrant Combustion Turbine (CT) was performed for the CONE (Cost of New Entry) plant configuration consisting of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.

Net revenue calculations include the use of actual hourly ambient air temperature[1] and the effect of the ambient air temperature on plant heat rates[2] and generator output.[3] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air condition variations.[4]

NO_x and SO_2 credit costs are included in the hourly plant dispatch cost, where applicable, consistent with the PJM definition of marginal cost. NO_x and SO_2 emission credit costs were obtained from actual historical daily spot cash prices for the prompt year.[5] NO_x credit costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 credit costs were included for the entire year.

A forced outage rate for the CT plant was calculated from PJM data.[6] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, the CT plant was assigned a 15-continuous-day, planned annual outage in the fall season.

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1 Zonal hourly ambient conditions supplied by Meteorlogix.

2 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to PJM, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for PJM.

3 Pasteris Energy, Inc.

4 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since the Combustion Turbine plant is dispatched at full load for every economic hour and is off for every uneconomic hour.

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

6 Outage figures obtained from the PJM eGADS database.

Variable operations and maintenance (VOM) expenses were $5.00 per MWh for the CT plant, per the tariff. The basis for the VOM cost is an estimate provided by a consultant to PJM and is based on quoted, third-party contract prices.[7] The VOM expenses for the CT plant include accrual of anticipated routine major overhaul expenses.[8] The daily burner tip fuel cost for natural gas is from published[9] commodity daily cash prices, with a basis adjustment for transportation costs. The average annual burner tip fuel prices are shown in Table 1.

Table 1 Burner tip average fuel price (Dollars per MBtu): Calendar years 2001 to 2006

	AE, BG&E Natural Gas	ComEd Natural Gas
2001	$4.52	NA
2002	$3.81	NA
2003	$6.45	NA
2004	$6.65	NA
2005	$9.73	$8.63
2006	$7.40	$6.75

Ancillary service revenues for the provision of spinning reserve service for the CT plant are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 spinning reserve in PJM. Ancillary service revenues for the provision of regulation service for the CT are also set to zero since this plant type typically does 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.

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 reactive service revenues are set to $2,254 per installed MW-year per the tariff, Attachment DD.

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7 Pasteris Energy, Inc.

8 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder, consistent with "PJM Manual 15: Cost Development Guidelines." This figure was established by Pasteris Energy, Inc. and is consistent with actual operation and maintenance costs from similar PJM generating units.

9 Gas daily cash prices obtained from Platts. TransCo Non NY Zone 6 prices are used for AE and BG&E subregions and Chicago City Gate hub prices are used for the ComEd subregion. There is a basis added for plant delivery transportation.

Calculated Net Revenues Using Peak-Hour Dispatch Method

Per the tariff, Attachment DD, the calculated net revenues reflect the Peak-Hour Dispatch method for energy market revenues from all hours during 2001 to 2006 for the real-time energy market. Per the defined Peak-Hour Dispatch method, it was assumed that the CT plant could be dispatched by PJM operations 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 real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[10] for at least two hours during each four-hour block.[11] The blocks are dispatched independently, and, if there were not at least two economic hours in any given block, the CT was not dispatched. The calculations account for operating reserves based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions defined above. The results are shown in Table 2, Table 3, Table 4 and Table 5.

[10] Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platts fuel prices. Per “PJM Manual 15: Cost Development Guidelines,” Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM Settlements. No-load costs are included in the heat rate.

[11] 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 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

Table 2 PJM region balancing energy market net revenue (Dollars per installed MW-year): Peak-hour dispatch net revenue for calendar years 2001 to 2006

	Peak-Hour Dispatch	Reactive	Total
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
2005	$6,141	$2,254	$8,395
2006	$11,002	$2,254	$13,256
AVG	$10,929	$2,254	$13,183

Table 3 ComEd subregion balancing energy market net revenue (Dollars per installed MW-year): Peak-hour dispatch net revenue for calendar years 2001 to 2006

	Peak-Hour Dispatch	Reactive	Total
2001	NA	NA	NA
2002	NA	NA	NA
2003	NA	NA	NA
2004	NA	NA	NA
2005	$1,747	$2,254	$4,001
2006	$7,135	$2,254	$9,389
Avg	$4,441	$2,254	$6,695

Table 4 Atlantic Electric subregion balancing energy market net revenue (Dollars per installed MW-year): Peak-hour dispatch net revenue for calendar years 2001 to 2006

	Peak-Hour Dispatch	Reactive	Total
2001	$40,825	$2,254	$43,079
2002	$19,449	$2,254	$21,703
2003	$5,274	$2,254	$7,528
2004	$6,765	$2,254	$9,019
2005	$18,309	$2,254	$20,563
2006	$23,177	$2,254	$25,431
Avg	$18,967	$2,254	$21,221

Table 5 Baltimore Gas and Electric subregion balancing energy market net revenue (Dollars per installed MW-year): Peak-hour dispatch net revenue for calendar years 2001 to 2006

	Peak-Hour Dispatch	Reactive	Total
2001	$23,048	$2,254	$25,302
2002	$20,049	$2,254	$22,303
2003	$4,196	$2,254	$6,450
2004	$2,899	$2,254	$5,153
2005	$22,293	$2,254	$24,547
2006	$31,741	$2,254	$33,995
Avg	$17,371	$2,254	$19,625

Summary

The PJM Region and subregion net revenues, calculated per the Peak-Dispatch method, are shown in the table below.

Table 6 Summary zonal balancing energy market net revenue (Dollars per installed MW-year): Peak-hour dispatch net revenue for calendar years 2001 to 2006

	Peak-Hour Dispatch			
	PJM Region	ComEd	Atlantic Electric	Baltimore Gas & Electric
2001	$32,508	NA	$43,079	$25,302
2002	$16,750	NA	$21,703	$22,303
2003	$5,017	NA	$7,528	$6,450
2004	$3,173	NA	$9,019	$5,153
2005	$8,395	$4,001	$20,563	$24,547
2006	$13,256	$9,389	$25,431	$33,995
Avg	$13,183	$6,695	$21,221	$19,625