



2009 Quarterly State of the Market Report for PJM:
January through September

Monitoring Analytics, LLC
Independent Market Monitor for PJM

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PREFACE

PJM has filed to amend Attachment M (PJM Market Monitoring Plan) to the PJM Open Access Transmission Tariff in order to provide, consistent with Order No. 719,¹ a requirement that the Market Monitoring Unit (MMU) “report on aggregate market performance on no less than a quarterly basis to Commission staff, to staff of interested state commissions, and to the management and board of directors of the RTOs or ISOs.”² Upon acceptance by the Commission, Section VI.A of Attachment M would read:

The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. The annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.³

Although the tariff language is not yet approved,⁴ Monitoring Analytics, LLC, which serves as the Market Monitoring Unit defined in Attachment M, has determined to meet the requirement for a quarterly report on the basis of the requirement established in Order No. 719. Accordingly, the MMU submits this *2009 Quarterly State of the Market Report for PJM: January through September*.

¹ 125 FERC ¶61,071 at PP 395, 413–19 (2008), *order on reh'g*, 128 FERC ¶61,059.

² 125 FERC ¶61,071 at PP 395, 413–19 (2008), *order on reh'g*, 128 FERC ¶61,059.

³ PJM OATT, “Attachment M: PJM Market Monitoring Plan,” Sixth Revised Sheet No. 452–452A (proposed to become effective June 29, 2009).

⁴ On May 27, 2009, Monitoring Analytics filed a Protest and Compliance Proposal of the Independent Market Monitor for PJM in FERC Docket No. ER09-1036. The Compliance Proposal addressed issues related to the independence of the market monitoring function but contained no proposed modifications of the provision quoted above.



TABLE OF CONTENTS

PREFACE	I	Frequently Mitigated Unit and Associated Unit Adders – Component of Price	19
SECTION 1 – INTRODUCTION.	1	<i>Market Performance: Load and LMP.</i>	20
<i>PJM Market Background</i>	1	Load	20
<i>Total Price of Wholesale Power</i>	1	Locational Marginal Price (LMP)	23
<i>Conclusions</i>	2	Load and Spot Market	37
<i>Recommendations</i>	2	Virtual Markets	38
New Recommendations in Quarter Three	2	<i>Demand-Side Response (DSR).</i>	38
Continuing Recommendations from Quarter Two	3	Emergency Program	38
SECTION 2 – ENERGY MARKET, PART 1	5	Economic Program	39
<i>Overview.</i>	5	Load Management (LM)	43
Market Structure	5	SECTION 3 – ENERGY MARKET, PART 2	45
Market Conduct	6	<i>Overview.</i>	45
Market Performance: Markup, Load and Locational Marginal Price	6	Net Revenue	45
Demand-Side Response	7	Existing and Planned Generation	46
Conclusion	8	Scarcity	46
<i>Market Structure</i>	9	Credits and Charges for Operating Reserve	48
Supply	9	Conclusion	49
Demand	9	<i>Net Revenue.</i>	50
Market Concentration	10	Capacity Market Net Revenue	50
Local Market Structure and Offer Capping	10	New Entrant Net Revenues	50
Local Market Structure	10	New Entrant Combustion Turbine	52
<i>Market Performance: Markup</i>	15	New Entrant Combined Cycle	53
Real-Time Markup	15	New Entrant Coal Plant	53
Day-Ahead Markup	17	New Entrant Day-Ahead Net Revenues	54



TABLE OF CONTENTS

- Net Revenue Adequacy 56
- Existing and Planned Generation 59*
 - Installed Capacity and Fuel Mix 59
 - Energy Production by Primary Fuel Source 59
- Operating Reserve 65*
 - Characteristics of Credits and Charges 68
 - Market Power Issues 70
- SECTION 4 – INTERCHANGE TRANSACTIONS 75**
 - Overview 75*
 - Interchange Transaction Activity 75
 - Interactions with Bordering Areas 76
 - Interchange Transaction Issues 77
 - Additional Interchange Transaction Analysis 79
 - Conclusion 80
 - Interchange Transaction Activity 81*
 - Aggregate Imports and Exports 81
 - Interface Imports and Exports 82
 - Interface Pricing 85*
 - Interactions with Bordering Areas 86*
 - Operating Agreements with Bordering Areas 89
 - Interchange Transaction Issues 92*
 - Spot Import 92
 - Loop Flows 94
- SECTION 5 – CAPACITY MARKETS 97**
 - Overview 97*
 - RPM Capacity Market 97

- Generator Performance 99
- Conclusion 99
- RPM Capacity Market 102*
 - Generator Performance 106*
 - Generator Performance Factors 106
 - Generator Forced Outage Rates 107
- SECTION 6 – ANCILLARY SERVICE MARKETS 111**
 - Overview 111*
 - Regulation Market 111
 - Synchronized Reserve Market 112
 - DASR 114
 - Black Start Services 114
 - Conclusion 115
 - Regulation Market 116*
 - Market Structure 116
 - Market Performance 117
 - Synchronized Reserve Market 118*
 - Market Conduct 119
 - Market Performance 119
 - Day Ahead Scheduling Reserve (DASR) 121*
 - Black Start Service 122*
- SECTION 7 – CONGESTION 123**
 - Overview 123*
 - Congestion Cost 123
 - Congestion Component of LMP and Facility or Zonal Congestion 123
 - Conclusion 124

- Congestion** 125
 - Congestion Accounting 125
 - Total Calendar Year Congestion 125
 - Monthly Congestion 126
 - Congestion Component of LMP 126
- Congested Facilities** 127
 - Congestion by Facility Type and Voltage 127
 - Constraint Duration 129
 - Constraint Costs 130
 - Congestion-Event Summary for Midwest ISO Flowgates 132
 - Congestion-Event Summary for the 500 kV System 134
- Zonal Congestion** 135
 - Summary 135
 - Details of Regional and Zonal Congestion 137
- SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS** 155
 - Overview** 155
 - Financial Transmission Rights 155
 - Auction Revenue Rights 157
 - Conclusion 158
 - Financial Transmission Rights** 159
 - Patterns of Ownership 159
 - Market Performance 160
 - Auction Revenue Rights** 166
 - Market Structure 166
 - Market Performance 166



TABLES

SECTION 1 – INTRODUCTION. 1

Table 1-1 Total price per MWh: January through September 2009 (New Table) 1

SECTION 2 – ENERGY MARKET, PART 1 5

Table 2-1 Actual PJM footprint quarter three peak loads: 2005 to 2009
(See 2008 SOM, Table 2-2) 9

Table 2-2 PJM hourly Energy Market HHI: January through September 2009
(See 2008 SOM, Table 2-3) 10

Table 2-3 Annual offer-capping statistics: Calendar years 2005 through
September 2009 (See 2008 SOM, Table 2-5) 10

Table 2-4 Offer-capped unit statistics: January through September 2009
(See 2008 SOM, Table 2-6) 10

Table 2-5 Three pivotal supplier results summary for regional constraints:
January through September 2009 (See 2008 SOM, Table 2-7) 10

Table 2-6 Three pivotal supplier test details for regional constraints: January
through September 2009 (See 2008 SOM, Table 2-8) 11

Table 2-7 Three pivotal supplier results summary for the East and Central
interfaces: January through September 2009 (See 2008 SOM, Table 2-13) . . . 11

Table 2-8 Three pivotal supplier test details for the East and Central interfaces:
January through September 2009 (See 2008 SOM, Table 2-15) 11

Table 2-9 Three pivotal supplier results summary for constraints located in the
PSEG Control Zone: January through September 2009 (See 2008 SOM,
Table 2-17) 11

Table 2-10 Three pivotal supplier test details for constraints located in the
PSEG Control Zone: January through September 2009 (See 2008 SOM,
Table 2-18) 11

Table 2-11 Three pivotal supplier results summary for constraints located in the
AP Control Zone: January through September 2009 (See 2008 SOM,
Table 2-19) 12

Table 2-12 Three pivotal supplier test details for constraints located in the AP
Control Zone: January through September 2009 (See 2008 SOM, Table 2-20) . 12

Table 2-13 Three pivotal supplier results summary for constraints located in the
AEP Control Zone: January through September 2009 (See 2008 SOM,
Table 2-21) 12

Table 2-14 Three pivotal supplier test details for constraints located in the
AEP Control Zone: January through September 2009 (See 2008 SOM,
Table 2-22) 12

Table 2-15 Three pivotal supplier results summary for constraints located in
the PENELEC Control Zone: January through September 2009 (See 2008
SOM, Table 2-25) 13

Table 2-16 Three pivotal supplier test details for constraints located in the
PENELEC Control Zone: January through September 2009 (See 2008 SOM,
Table 2-26) 13

Table 2-17 Three pivotal supplier results summary for constraints located in the
Dominion Control Zone: January through September 2009 (See 2008 SOM,
Table 2-27) 13

Table 2-18 Three pivotal supplier test details for constraints located in the
Dominion Control Zone: January through September 2009 (See 2008 SOM,
Table 2-28) 13

Table 2-19 Three pivotal supplier results summary for constraints located in the
AECO Control Zone: January through September 2009 (See 2008 SOM,
Table 2-31) 13

Table 2-20 Three pivotal supplier test details for constraints located in the
AECO Control Zone: January through September 2009 (See 2008 SOM,
Table 2-32) 13

Table 2-21 Three pivotal supplier results summary for constraints located in the
DLCO Control Zone: January through September 2009 (See 2008 SOM,
Table 2-33) 13

Table 2-22 Three pivotal supplier test details for constraints located in the
DLCO Control Zone: January through September 2009 (See 2008 SOM,
Table 2-34) 13

Table 2-23 Three pivotal supplier results summary for constraints located in
the ComEd Control Zone: January through September 2009 (See 2008
SOM, Table 2-35) 14

Table 2-24 Three pivotal supplier test details for constraints located in the
ComEd Control Zone: January through September 2009 (See 2008 SOM,
Table 2-36) 14

Table 2-25 Three pivotal supplier results summary for constraints located in the
PECO Control Zone: January through September, 2009 (See 2008 SOM,
Table 2-37) 14

Table 2-26 Three pivotal supplier test details for constraints located in the
PECO Control Zone: January through September 2009 (See 2008 SOM,
Table 2-38) 14

Table 2-27 Three pivotal supplier results summary for constraints located in
the BGE Control Zone: January through September 2009 (New Table) 14

Table 2-28 Three pivotal supplier test details for constraints located in the
BGE Control Zone: January through September 2009 (New Table) 15

Table 2-29 Three pivotal supplier results summary for constraints located in
the Pepco Control Zone: January through September 2009 (See 2008 SOM,
Table 2-39) 15

Table 2-30 Three pivotal supplier test details for constraints located in the
Pepco Control Zone: January through September 2009 (See 2008 SOM,
Table 2-40) 15

Table 2-31 Marginal unit contribution to PJM real-time, annual, load-weighted
LMP (By parent company): January through September 2009 (See 2007 SOM,
Table 2-31) 15

Table 2-32 Type of fuel used (By real-time marginal units): January through
September 2009 (See 2007 SOM, Table 2-32) 15

Table 2-33 Average, real-time marginal unit markup index (By price category):
January through September 2009 (See 2007 SOM, Table 2-34) 16



Table 2-34 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2009 16

Table 2-35 Monthly markup components of load-weighted LMP: January through September 2009 (See 2007 SOM, Table 2-35) 16

Table 2-36 Average real-time zonal markup component: January through September 2009 (See 2007 SOM, Table 2-36) 17

Table 2-37 Average real-time markup component (By price category): January through September 2009 (See 2008 SOM, Table 2-41) 17

Table 2-38 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through September 2009 (See 2007 SOM, Table 2-31) 17

Table 2-39 Day-ahead marginal resources by type/fuel: January through September 2009 (See 2007 SOM, Table 2-32) 17

Table 2-40 Average, day-ahead marginal unit markup index (By price category): January through September 2009 (See 2007 SOM, Table 2-34) 18

Table 2-41 The markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September 2009 (New Table) 18

Table 2-42 Monthly markup components of day-ahead, load-weighted LMP: January through September 2009 (See 2007 SOM, Table 2-35) 18

Table 2-43 Day-ahead, average, zonal markup component: January through September 2009 (See 2007 SOM, Table 2-36) 19

Table 2-44 Average, day-ahead markup (By price category): January through September 2009 (See 2007 SOM, Table 2-37) 19

Table 2-45 Frequently mitigated units and associated units (By month): January through September 2009 (See 2008 SOM, Table 2-42) 19

Table 2-46 PJM real-time average load: Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-44) 20

Table 2-47 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009 (See 2008 SOM, Table 2-45) 21

Table 2-48 PJM day-ahead average load: Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-46) 21

Table 2-49 Cleared day-ahead and real-time load (MWh): January through September 2009 (See 2008 SOM, Table 2-47) 22

Table 2-50 Day-ahead and real-time generation (MWh): January through September 2009 (See 2008 SOM, Table 2-48) 22

Table 2-51 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-49) 23

Table 2-52 Zonal real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-50) 24

Table 2-53 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-51) 24

Table 2-54 Hub real-time, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-52) 24

Table 2-55 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-53) 25

Table 2-56 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-54) 25

Table 2-57 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-55) 26

Table 2-58 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through September 2009, year-over-year method (See 2008 SOM, Table 2-56) 26

Table 2-59 Components of PJM annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57) 27

Table 2-60 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-61) 27

Table 2-61 Zonal day-ahead, simple average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-62) 28

Table 2-62 Day-ahead, simple average LMP (Dollars per MWh) by jurisdiction: January through September 2008 and 2009 (See 2008 SOM, Table 2-63) 28

Table 2-63 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2005 through September 2009 (See 2008 SOM, Table 2-64) 28

Table 2-64 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-65) 29

Table 2-65 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-66) 29

Table 2-66 Components of PJM day-ahead, annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57) 29

Table 2-67 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through September 2009 (See 2008 SOM, Table 2-67) 30

Table 2-68 Zonal real-time, simple average LMP components (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-68) 30

Table 2-69 Hub real-time, simple average LMP components (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-69) 30

Table 2-70 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-70) 31

Table 2-71 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 through September 2009 (See 2008 SOM, Table 2-71) 31

Table 2-72 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through September 2008 and 2009 (See 2008 SOM, Table 2-72) 32

Table 2-73 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-73) 33

Table 2-74 Marginal loss costs by type (Dollars (Millions)): January through September 2009 (See 2008 SOM, Table 2-74) 33

Table 2-75 Marginal loss costs by control zone and type (Dollars (Millions)): January through September 2009 (See 2008 SOM, Table 2-75) 33

Table 2-76 Monthly marginal loss costs by control zone (Dollars (Millions)): January through September 2009 (See 2008 SOM, Table 2-76) 34

Table 2-77 Type of day-ahead marginal units: January through September 2009 (See 2008 SOM, Table 2-77) 34

Table 2-78 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-78)	35	Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2009 (See 2008 SOM, Table 3-4)	50
Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-79)	35	Table 3-3 Average delivered fuel price in PJM (Dollars per MBtu): January through September 2008 and 2009 (See 2008 SOM, Table 3-6)	50
Table 2-80 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): 2005 through September 2009 (See 2008 SOM, Table 2-80)	36	Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)	51
Table 2-81 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-81)	37	Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)	51
Table 2-82 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-82)	37	Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)	52
Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2008 through September 2009 (See 2008 SOM, Table 2-83)	37	Table 3-7 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-10)	52
Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2008 through September 2009 (See 2008 SOM, Table 2-84)	38	Table 3-8 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-11)	52
Table 2-85 Monthly volume of cleared and submitted INCs, DECs: January through September 2009 (See 2008 SOM, Table 2-85)	38	Table 3-9 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-12)	53
Table 2-86 Zonal capability in the Emergency Program for the 2009 peak day through September (By option): August 10, 2009 (See 2008 SOM, Table 2-86)	38	Table 3-10 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-13)	53
Table 2-87 Zonal monthly capacity credits: January through September 2009 (See 2008 SOM, Table 2-87)	39	Table 3-11 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-14)	53
Table 2-88 Economic Program registration on the last day of the month: January 2007 through September 2009 (New Table)	39	Table 3-12 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-15)	53
Table 2-89 Distinct Registrations and Sites in the Economic Program: August 10, 2009 (See 2008 SOM, Table 2-89)	40	Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-16)	54
Table 2-90 PJM Economic Program by zonal reduction: January through September 2009 (See 2008 SOM, Table 2-92)	41	Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-17)	54
Table 2-91 Settlement days submitted by month in the Economic Program: 2007, 2008 and January through September 2009 (New Table)	41	Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-18)	55
Table 2-92 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007, 2008 and January through September 2009 (New Table)	42	Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-19)	55
Table 2-93 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 2009 (See 2008 SOM, Table 2-93)	42	Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-20)	55
Table 2-94 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 2009 (See 2008 SOM, Table 2-94)	43		
Table 2-95 Available LM MW by program type: Delivery years 2007 through 2009 (New Table)	43		
Table 2-96 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007 through 2012 (New Table)	43		
SECTION 3 – ENERGY MARKET, PART 2	45		
Table 3-1 2009 Calendar Year PJM RPM auction-clearing capacity prices and capacity revenues by LDA and zone: Effective for January through September 2009 (See 2008 SOM, Table 3-3)	50		



Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-21). 56

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2008 SOM, Table 3-22) 56

Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-24). 56

Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-26). 57

Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-28). 58

Table 3-23 PJM installed capacity (By fuel source): January 1, May 31, June 1, September 30, 2009 (See 2008 SOM, Table 3-30) 59

Table 3-24 PJM generation (By fuel source (GWh)): January through September 2009 (See 2008 SOM, Table 3-31) 59

Table 3-25 Year-to-year capacity additions: Calendar years 2000 through September 2009 (See 2008 SOM, Table 3-32) 60

Table 3-26 Queue comparison (MW): Calendar years 2009 vs. 2008 (See 2008 SOM, Table 3-33) 60

Table 3-27 Capacity in PJM queues (MW): At September 30, 2009 (See 2008 SOM, Table 3-34) 60

Table 3-28 Capacity additions in active or under-construction queues by control zone (MW):At September 30, 2009 (See 2008 SOM, Table 3-36) 61

Table 3-29 Existing PJM capacity on September 30, 2009 (By zone and unit type (MW)) (See 2008 SOM, Table 3-37). 61

Table 3-30 PJM capacity age (MW) (See 2008 SOM, Table 3-38) 61

Table 3-31 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2009 (See 2008 SOM, Table 3-39) 62

Table 3-32 Comparison of generators 40 years and older with planned capacity additions (MW): Through 2018 (See 2008 SOM, Table 3-40). 62

Table 3-33 Capacity factor of wind units in PJM, January through September 2009 (New Table) 63

Table 3-34 Wind resources in Real-Time offering at a negative price in PJM, June through September 2009 (New Table). 63

Table 3-35 Monthly operating reserve charges: January through September 2008 and 2009 (See 2008 SOM, Table 3-45). 65

Table 3-36 Regional balancing charges allocation: January through September 2008 and 2009 (New Table) 65

Table 3-37 Monthly balancing operating reserve deviations (MWh): January through September 2008 and 2009 (See 2008 SOM, Table 3-46) 66

Table 3-38 Regional charges determinants (MWh): January through September 2009 (New Table) 66

Table 3-39 Average regional balancing operating reserve rates: January through September 2009 (See 2008 SOM, Table 3-48) 67

Table 3-40 Credits by month (By operating reserve market): January through September 2009 (See 2008 SOM, Table 3-49) 68

Table 3-41 Credits by unit types (By operating reserve market): January through September 2009 (See 2008 SOM, Table 3-50). 68

Table 3-42 Credits by operating reserve market (By unit type): January through September 2009 (See 2008 SOM, Table 3-51) 68

Table 3-43 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: January through September 2009 (See 2008 SOM, Table 3-52) 68

Table 3-44 PJM generation (By unit type receiving operating reserve payments): January through September 2009 (See 2008 SOM, Table 3-53) 68

Table 3-45 PJM unit type generation distribution (By unit type receiving operating reserve payments): January through September 2009 (See 2008 SOM, Table 3-54) 69

Table 3-46 Monthly balancing operating reserve charges and credits to generators (By location): January through September 2009 (See 2008 SOM, Table 3-55). 69

Table 3-47 Top 10 units and organizations receiving total operating reserve credits: January through September 2009 (See 2008 SOM, Table 3-57). 70

Table 3-48 Top 10 units and organizations receiving day-ahead generator credits: January through September 2009 (See 2008 SOM, Table 3-58). 70

Table 3-49 Top 10 units and organizations receiving synchronous condensing credits: January through September 2009 (See 2008 SOM, Table 3-59). 70

Table 3-50 Top 10 units and organizations receiving balancing generator credits: January through September 2009 (See 2008 SOM, Table 3-60) 71

Table 3-51 Top 10 units and organizations receiving lost opportunity cost credits: January through September 2009 (See 2008 SOM, Table 3-61). 71

Table 3-52 Top 10 operating reserve revenue units markup: January through September 2009 (See 2008 SOM, Table 3-62) 72

Table 3-53 Average real-time weighted markup by unit type receiving balancing credits: January through September 2009 (New Table) 72

Table 3-54 Regional balancing operating reserve credits: January through September 2009 (New Table) 72

Table 3-55 Total deviations: January through September 2009 (New Table) 72

Table 3-56 Charge allocation under old operating reserve construct: January through September 2009 (New Table) 72

Table 3-57 Actual regional credits, charges, rates and charge allocation MWh: January through September 2009 (New Table) 73

Table 3-58 Difference in total charges between old rules and new rules: January through September 2009 (New Table) 73

Table 3-59 Difference in total charges between old rules and new rules: January through September 2009 (New Table) 73

SECTION 4 – INTERCHANGE TRANSACTIONS 75

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-1) 82

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-2) 83

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-3) 83

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-4) 84

Table 4-5 Day-ahead gross import volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-5) 84

Table 4-6 Day-ahead gross export volume by interface (GWh): January through September 2009 (See 2008 SOM, Table 4-6) 85

Table 4-7 Active interfaces: January through September 2009 (See 2008 SOM, Table 4-7) 85

Table 4-8 Active pricing points: January through September 2009 (See 2008 SOM, Table 4-8) 86

Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): Calendar year 2008 and January through September 2009 (See 2008 SOM, Table 4-9) 87

Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): Calendar year 2008 and January through September 2009 (New Table) 87

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through September 2009 (See 2008 SOM, Table 4-10) 89

Table 4-12 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (See 2008 SOM, Table 4-11) 90

Table 4-13 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009 (See 2008 SOM, Table 4-11) 90

Table 4-14 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (New Table) 91

Table 4-15 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009 (New Table) 91

Table 4-16 Net scheduled and actual PJM interface flows (GWh): January through September 2009 (See 2008 SOM, Table 4-12) 94

SECTION 5 – CAPACITY MARKETS 97

Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012 (See 2008 SOM, Table 5-1) 102

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009 (See 2008 SOM, Table 5-2) 103

Table 5-3 Preliminary market structure screen results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-3) 103

Table 5-4 RSI results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-4) 104

Table 5-5 PJM capacity summary (MW): June 1, 2008, through May 31, 2012 (See 2008 SOM, Table 5-5) 104

Table 5-6 RPM load management and energy efficiency statistics: June 1, 2008 through May 31, 2012 (See 2008 SOM, Table 5-6) 105

Table 5-7 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-10) 105

Table 5-8 RPM cost to load: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-11) 106

Table 5-9 Contribution to EFORd by unit type (Percentage points): Calendar years 2005 to 2009 (January through August) (See 2008 SOM Table 5-17) . . 107

Table 5-10 Five-year PJM EFORd data by unit type: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Table 5-19) 107

Table 5-11 Outage cause contribution to PJM EFOF: January through August 2009 (See 2008 SOM Table 5-20) 108

Table 5-12 Contributions to Economic Outages: January through August 2009 (See 2008 SOM Table 5-21) 108

Table 5-13 Contribution to EFOF by unit type for the most prevalent causes: January through August 2009 (See 2008 SOM Table 5-22) 109

Table 5-14 Contribution to EFOF by unit type: January through August 2009 (See 2008 SOM Table 5-23) 109

Table 5-15 PJM EFORd vs. XEFORd by unit type: January through August 2009 (See 2008 SOM Table 5-24) 110

Table 5-16 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009 (January through August) (New Table) 110

Table 5-17 PJM EFORp data by unit type: Calendar years 2008 to 2009 (January through August) (New Table) 110

Table 5-18 Contribution to PJM EFORd and EFORp by unit type: Calendar year 2009 (January through August) (New Table) 110

Table 5-19 PJM EFORd and EFORp data by unit type: Calendar year 2009 (January through August) (New Table) 110

SECTION 6 – ANCILLARY SERVICE MARKETS 111

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement: January through September 2009 (See 2008 SOM Table 6-1) . . 116

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through September 2009 (See 2008 SOM Table 6-2) 116

Table 6-3 PJM cleared regulation HHI: January through September 2009 (See 2008 SOM Table 6-3) 116

Table 6-4 Highest annual average hourly Regulation Market shares: January through September 2009 (See 2008 SOM Table 6-4) 116

Table 6-5 Regulation market monthly three pivotal supplier results: January through September 2009 (See 2008 SOM Table 6-5) 117

Table 6-6 Total regulation charges: January through September 2009 (See 2008 SOM Table 6-6) 118

Table 6-7 Average SRMCP when all cleared synchronized reserve is DSR: January through September 2009 (See 2008 SOM Table 6-8) 120

Table 6-8 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2009 (See 2008 SOM Table 6-9) 121

Table 6-9 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results: January through September 2009 (See 2008 SOM Table 6-10) 121

Table 6-10 Black Start yearly zonal charges for network transmission use: January through September 2009 (See 2008 SOM Table 6-11) 122

SECTION 7 – CONGESTION 123

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to September 2009 (See 2008 SOM Table 7-1) 125

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through September 2008 and 2009 (New Table) 126



Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): January through September 2008 and 2009 (See 2008 SOM Table 7-2) 126

Table 7-4 Annual average congestion component of LMP: January through September 2008 and 2009 (See 2008 SOM Table 7-3) 126

Table 7-5 Congestion summary (By facility type): January through September 2009 (See 2008 SOM Table 7-4) 127

Table 7-6 Congestion summary (By facility type): January through September 2008 (See 2008 SOM Table 7-5) 127

Table 7-7 Congestion summary (By facility voltage): January through September 2009 (See 2008 SOM Table 7-6) 128

Table 7-8 Congestion summary (By facility voltage): January through September 2008 (See 2008 SOM Table 7-7) 128

Table 7-9 Top 25 constraints with frequent occurrence: January through September 2008 and 2009 (See 2008 SOM Table 7-8) 129

Table 7-10 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 2009 (See 2008 SOM Table 7-9) 130

Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): January through September 2008 (See 2008 SOM Table 7-10) 131

Table 7-12 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through September 2009 (See 2008 SOM Table 7-11) 132

Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through September 2008 (See 2008 SOM Table 7-12) 133

Table 7-14 Regional constraints summary (By facility): January through September 2009 (See 2008 SOM Table 7-13) 134

Table 7-15 Regional constraints summary (By facility): January through September 2008 (See 2008 SOM Table 7-14) 134

Table 7-16 Congestion cost summary (By control zone): January through September 2009 (See 2008 SOM Table 7-16) 135

Table 7-17 Congestion cost summary (By control zone): January through September 2008 (See 2008 SOM Table 7-17) 136

Table 7-18 AECO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-18) 137

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-19) 138

Table 7-20 BGE Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-20) 139

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-21) 139

Table 7-22 DPL Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-22) 140

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-23) 140

Table 7-24 JCPL Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-24) 141

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-25) 141

Table 7-26 Met-Ed Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-26) 142

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-27) 142

Table 7-28 PECO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-28) 143

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-29) 143

Table 7-30 PENELEC Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-30) 144

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-31) 144

Table 7-32 Pepco Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-32) 145

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-33) 145

Table 7-34 PPL Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-34) 146

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-35) 146

Table 7-36 PSEG Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-36) 147

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-37) 147

Table 7-38 RECO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-38) 148

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-39) 148

Table 7-40 AEP Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-40) 149

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-41) 149

Table 7-42 AP Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-42) 150

Table 7-43 AP Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-43) 150

Table 7-44 ComEd Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-44) 151

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-45) 151

Table 7-46 DAY Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-46) 152

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-47) 152

Table 7-48 DLCO Control Zone top congestion cost impacts (By facility): January through September 2009 (See 2008 SOM Table 7-48) 153

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): January through September 2008 (See 2008 SOM Table 7-49) 153

*Table 7-50 Dominion Control Zone top congestion cost impacts (By facility):
January through September 2009 (See 2008 SOM Table 7-50). 154*

*Table 7-51 Dominion Control Zone top congestion cost impacts (By facility):
January through September 2008 (See 2008 SOM Table 7-51). 154*

**SECTION 8 – FINANCIAL TRANSMISSION AND
AUCTION REVENUE RIGHTS 155**

*Table 8-1 Monthly Balance of Planning Period FTR Auction patterns of
ownership by FTR direction: January through September 2009 (See 2008
SOM Table 8-5). 159*

*Table 8-2 Monthly Balance of Planning Period FTR Auction market volume:
January through September 2009 (See 2008 SOM Table 8-9). 160*

*Table 8-3 Monthly Balance of Planning Period FTR Auction buy-bid bid and
cleared volume (MW per period): January through September 2009 (See
2008 SOM Table 8-10). 161*

*Table 8-4 Secondary bilateral FTR market volume: Planning periods 2008 to
2009 and 2009 to 2010 (See 2008 SOM Table 8-11) 161*

*Table 8-5 Monthly Balance of Planning Period FTR Auction cleared, weighted-
average, buy-bid price per period (Dollars per MWh): January through
September 2009 (See 2008 SOM Table 8-14) 162*

*Table 8-6 Monthly Balance of Planning Period FTR Auction revenue: January
through September 2009 (See 2008 SOM Table 8-17) 163*

*Table 8-7 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning
periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-18) 164*

*Table 8-8 Monthly FTR accounting summary (Dollars (Millions)): Planning
periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-19) 165*

*Table 8-9 ARRs and ARR revenue automatically reassigned for network load
changes by control zone: June 1, 2008, through September 30, 2009
(See 2008 SOM Table 8-22) 166*

*Table 8-10 ARR revenue adequacy (Dollars (Millions)): Planning periods 2008
to 2009 and 2009 to 2010 (See 2008 SOM Table 8-24) 166*

*Table 8-11 ARR and FTR congestion hedging: Planning periods 2008 to 2009
and 2009 to 2010 (See 2008 SOM Table 8-28) 167*

*Table 8-12 ARRs and self-scheduled FTR credits as a hedge against energy
charges by control zone: January through September, 2009 (New Table) 168*

*Table 8-13 FTRs as a hedge against energy charges by control zone: January
through September, 2009 (New Table) 169*

*Table 8-14 ARRs and FTRs as a hedge against energy charges by control zone:
January through September, 2009 (New Table). 170*



FIGURES

SECTION 2 – ENERGY MARKET, PART 1 5

Figure 2-1 Average PJM aggregate supply curves: July through September 2008 and 2009 (See 2008 SOM, Figure 2-1) 9

Figure 2-2 PJM quarter three peak-load comparison: Monday, August 10, 2009, and Friday, July 18, 2008 (See 2008 SOM, Figure 2-2) 9

Figure 2-3 Real-time, LMP contribution and load-weighted, unit markup index: January through September 2009 (See 2007 SOM, Figure 2-4) 16

Figure 2-4 Day-ahead, LMP contribution and load-weighted unit markup index: January through September 2009 (See 2007 SOM, Figure 2-4) 18

Figure 2-5 PJM real-time load duration curves: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-4) 20

Figure 2-6 PJM real-time average load: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-5) 20

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-6) 21

Figure 2-8 PJM day-ahead average load: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-7) 21

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): January through September 2009 (See 2008 SOM, Figure 2-8) 22

Figure 2-10 Day-ahead and real-time generation (Average hourly volumes): January through September 2009 (See 2008 SOM, Figure 2-9) 22

Figure 2-11 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-10) 23

Figure 2-12 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-11) 25

Figure 2-13 Spot average fuel price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-12) 26

Figure 2-14 Spot average emission price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-13) 26

Figure 2-15 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-14) 27

Figure 2-16 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-15) 29

Figure 2-17 PJM day-ahead aggregate supply curves: 2009 example day (See 2008 SOM, Figure 2-16) 35

Figure 2-18 Hourly real-time minus hourly day-ahead LMP: January through September 2009 (See 2008 SOM, Figure 2-17) 36

Figure 2-19 Monthly average of real-time minus day-ahead LMP: January through September 2009 (See 2008 SOM, Figure 2-18) 36

Figure 2-20 PJM system hourly average LMP: January through September 2009 (See 2008 SOM, Figure 2-19) 37

Figure 2-21 Economic Program Payments: Calendar years 2007 (without incentive payments), 2008 and January through September of 2009 (See 2008 SOM, Figure 2-20) 40

SECTION 3 – ENERGY MARKET, PART 2 45

Figure 3-1 New entrant CT zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-3) 57

Figure 3-2 New entrant CC zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-5) 58

Figure 3-3 New entrant CP zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-7) 58

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through September 2009 (New Figure) 64

Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through September 2009 (New Figure) 64

Figure 3-6 Marginal fuel displacement by wind generation in PJM, January through September 2009 (New Figure) 64

Figure 3-7 Daily RTO reliability and deviation rates: January through September 2009 (New Figure) 67

Figure 3-8 Daily regional reliability and deviation rates: January through September 2009 (New Figure) 67

Figure 3-9 Operating reserve credits: January through September 2009 (See 2008 SOM, Figure 3-11) 67

Figure 3-10 Cumulative distribution of units receiving credits (By operating reserve category): January through September 2009 (See 2008 SOM, Figure 3-12) 71

Figure 3-11 Cumulative distribution of billing organizations receiving credits (By operating reserve market): January through September 2009 (See 2008 SOM, Figure 3-13) 71

SECTION 4 – INTERCHANGE TRANSACTIONS 75

Figure 4-1 PJM real-time scheduled imports and exports: January through September 2009 (See 2008 SOM, Figure 4-1) 81

Figure 4-2 PJM day-ahead scheduled imports and exports: January through September 2009 (See 2008 SOM, Figure 4-2) 81

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through September 2009 (See 2008 SOM, Figure 4-3) 82

Figure 4-4 PJM's footprint and its external interfaces (See 2008 SOM, Figure 4-4) 86



Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through September 2009 (See 2008 SOM, Figure 4-5) 86

Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2009 (See 2008 SOM, Figure 4-6) 86

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through September 2009 (New Figure) . . 87

Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through September 2009 (New Figure) 87

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2009 (See 2008 SOM, Figure 4-7) . . . 88

Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through September 2009 (See 2008 SOM, Figure 4-8) 88

Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September 2009 (New Figure) 88

Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January through September 2009 (New Figure) 88

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through September 2009 (See 2008 SOM, Figure 4-9) 89

Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through September 2009 (New Figure) 89

Figure 4-15 Credits for coordinated congestion management: January through September 2009 (See 2008 SOM, Figure 4-10) 89

Figure 4-16 Neptune hourly average flow: January through September 2009 (See 2008 SOM, Figure 4-11) 90

Figure 4-17 Linden hourly average flow: September 2009 (New Figure) 90

Figure 4-18 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2009 (New Figure) . . . 90

Figure 4-19 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2009 (New Figure) 91

Figure 4-20 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September 2009 (New Figure) 91

Figure 4-21 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September 2009 (New Figure) 91

Figure 4-22 Spot import service utilization: January through September 2009 (See 2008 SOM, Figure 4-12) 92

Figure 4-23 Monthly uncollected congestion charges: January through September 2009 (See 2008 SOM, Figure 4-13) 92

Figure 4-24 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through September 2009 (See 2008 SOM, Figure 4-14) 92

Figure 4-25 PJM and Midwest ISO TLR procedures: Calendar year 2008 and January through September 2009 (See 2008 SOM, Figure 4-15) 93

Figure 4-26 Number of different PJM flowgates that experienced TLRs: Calendar year 2008 and January through September 2009 (See 2008 SOM, Figure 4-16) 93

Figure 4-27 Number of PJM TLRs and curtailed volume: January through September 2009 (See 2008 SOM, Figure 4-17) 93

Figure 4-28 Monthly up-to congestion bids in MWh: January 2006 through September 2009 (See 2008 SOM, Figure 4-18) 93

Figure 4-29 PJM/MECS Interface average actual minus scheduled volume: January through September 2009 (See 2008 SOM, Figure 4-19) 94

Figure 4-30 PJM/TVA average flows: January through September 2009 (See 2008 SOM, Figure 4-21) 94

Figure 4-31 Southwest actual and scheduled flows: January 2006 through September 2009 (See 2008 SOM, Figure 4-22) 95

Figure 4-32 Southeast actual and scheduled flows: January 2006 through September 2009 (See 2008 SOM, Figure 4-23) 95

SECTION 5 – CAPACITY MARKETS 97

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012 (See 2008 SOM, Figure 5-1) 105

Figure 5-2 PJM equivalent outage and availability factors: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-7) 106

Figure 5-3 Trends in the PJM equivalent demand forced outage rate (EFORD): Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-8) 107

Figure 5-4 Contribution to EFORD by duty cycle: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-9) 107

SECTION 6 – ANCILLARY SERVICE MARKETS 111

Figure 6-1 PJM Regulation Market HHI distribution: January through September 2009 (See 2008 SOM Figure 6-1) 116

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): January through September 2009 (See 2008 SOM Figure 6-2) 117

Figure 6-3 Monthly average regulation demand (required) vs. price: January through September 2009 (See 2008 SOM Figure 6-3) 117

Figure 6-4 Monthly load weighted, average regulation cost and price: January through September 2009 (See 2008 SOM Figure 6-4) 117

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through September 2009 (See 2008 SOM Figure 6-5) 118

Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through September 2009 (See 2008 SOM Figure 6-6) 118

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through September 2009 (See 2008 SOM Figure 6-7) 118

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through September 2009 (See 2008 SOM Figure 6-8) 119

Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September 2009 (See 2008 SOM Figure 6-9) 119

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2: January through September 2009 (See 2008 SOM Figure 6-10) 119

Figure 6-11 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through September 2009 (See 2008 SOM Figure 6-11). 119

Figure 6-12 Synchronized reserve purchases by month; PJM scheduled, self-scheduled, and added: January through September 2009 (See 2008 SOM Figure 6-12). 120

Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: January through September 2009 (See 2008 SOM Figure 6-13) 120

Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): January through September 2009 (See 2008 SOM Figure 6-14). 120

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2009 (See 2008 SOM Figure 6-15). 121

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS 155

Figure 8-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-7) 162

Figure 8-2 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-8) 162

Figure 8-3 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-9) 165

Figure 8-4 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-10) 165

Figure 8-5 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2009 to 2010 through September 30, 2009 (See 2008 SOM Figure 8-11). 167



SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2009, had installed generating capacity of 167,269 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.¹ As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.^{2, 3}

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price includes the price of energy, capacity, ancillary services, transmission service, administrative fees, regulatory support fees and uplift charges. This total price is an average price and actual prices vary by location.

Table 1-1 Total price per MWh: January through September 2009 (New Table)

Category	\$/MWh	Percent
Load Weighted Energy	\$39.57	73.4%
Capacity	\$9.03	16.8%
Transmission Service	\$3.54	6.6%
Operating Reserves (Uplift)	\$0.44	0.8%
Regulation	\$0.33	0.6%
Reactive	\$0.32	0.6%
PJM Administrative	\$0.31	0.6%
Transmission Cost Recovery	\$0.18	0.3%
Transmission Owner (Schedule 1A)	\$0.08	0.1%
Synchronized Reserves	\$0.03	0.1%
Black Start Services	\$0.02	0.0%
RTO Startup and Expansion	\$0.01	0.0%
NERC/RFC	\$0.01	0.0%
Load Response	\$0.00	0.0%
Total	\$53.87	100.0%

¹ See the 2008 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

² See also the 2008 State of the Market Report for PJM, Volume II, Appendix B, "PJM Market Milestones."

³ Analysis of 2009 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the 2008 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography."

Conclusions

This report assesses the competitiveness of the markets managed by PJM during the first nine months of 2009, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

The MMU concludes that in the first nine months of 2009:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results were competitive;
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

Recommendations

The PJM Market Monitoring Plan provides under the heading “Market Design,” in the section setting forth the MMU’s function and responsibilities:

PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the design of the PJM Markets. If the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such market. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues.⁴

In addition, the PJM Market Monitoring Plan provides, in describing the State of the Market Report: “In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview.”⁵ Pursuant to its explicit mandate under the PJM Market Monitoring Plan, the MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for continued competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The MMU’s recommendations from the *2008 State of the Market Report for PJM* remain recommendations.

In this *2009 Quarterly State of the Market Report for PJM: January through September*, the MMU makes specific recommendations, some of which were included in the *2009 Quarterly State of the Market Report for PJM: January through June*. Further details can be found in the referenced sections.

New Recommendations in Quarter Three

- Section 3, Energy Market Part 2, at “Modifications to Scarcity Pricing” (page 47):⁶
 - If there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues.
 - The current single scarcity price signal should be replaced by locational signals.
 - The objective should be to create a system that recognizes scarcity in needed reserves, that redispatches units to maintain needed reserves and to meet the need for energy, and that provides market signals consistent with this redispatch and with any failure to maintain needed reserves.

⁵ PJM OATT Attachment M § VI.A. See also Order No. 719 at P 357 (“[W]e do expect the MMU to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes. Likewise, in the event an RTO or ISO files for a proposed tariff change with which the MMU disagrees, we expect the RTO or ISO to inform the Commission of that disagreement, although not necessarily to include a written proposal with its filing.”), codified at 18 C.F.R. § 35.28 (g)(3)(ii)(A) (“The Market Monitoring Unit must perform the following core functions: (A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-Approved independent system operator or regional transmission organizations, to the Commission’s Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants”).

⁶ For ease of reference, all the recommendations from the quarterly state of the market reports related to scarcity are listed here, including those from Quarter Two and Quarter Three.

⁴ PJM OATT Attachment M § IV.D.

- PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism as current measures are not adequate.
- Any scarcity pricing mechanism should also include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.
- To avoid market power, the provision of reserves must continue to be based on unit characteristics included in a participant's energy offers, not on the basis of separate offers to provide reserves.
- The reserve penalty factor curve methodology also requires a mechanism to eliminate the effect of non-market administrative emergency measures used during scarcity situations.
- Section 4, Interchange Transactions, at “Loop Flows at PJM’s Northern Interfaces” (page 78): The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a Generation Control Area (GCA) to Load Control Area (LCA) pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

Continuing Recommendations from Quarter Two

- Section 2, Energy Market Part 1, at “DSR” (page 7): A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.
- Section 4, Interchange Transactions, at “Up-To Congestion” (page 77): The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific

buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- Section 4, Interchange Transactions, at “Data Required for Full Loop Flow Analysis” (page 79): The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would contribute to the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flow data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.
- Section 4, Interchange Transactions, at “Conclusion” (page 80): In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities as a first step. ... PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent, accurately reflects actual LMP impacts on PJM, and that all participants have access to the defined pricing when in the same position. The goal of such pricing agreements should be to replicate LMP price signals that reflect the actual loads and the actual dispatch of units.
- Section 5, Capacity market, at “Conclusion, Market Design” (page 99): The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.
- Section 5, Capacity Market, at “Conclusion, Market Design” (page 99): A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
- Section 5, Capacity Market, at “Conclusion, Market Power” (page 101): The performance incentives in the RPM Capacity Market design need to be strengthened.

- Section 6, Ancillary Services, at “Black Start Services” (page 114): The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.
- Section 6, Ancillary Services, at “Conclusion” (page 115): The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test.
- Section 8, Financial Transmission and Auction Revenue Rights, at “Conclusion” (page 158): The MMU recommends that the rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.