

A large, light green circular logo with a stylized 'PJM' monogram inside. The 'P' and 'J' are on the left, and the 'M' is on the right, all in a bold, sans-serif font. The logo is semi-transparent and serves as a background for the title text.

State of the Market Report for PJM

Volume 2:
Detailed
Analysis

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

2009

3.11.2010

PREFACE

The PJM Market Monitoring Plan provides:

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. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.¹

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),² and is also known as the Independent Market Monitor for PJM (IMM), submits this *2009 State of the Market Report for PJM*, the twelfth such annual report.

¹ PJM Open Access Transmission Tariff (OATT), "Attachment M: PJM Market Monitoring Plan," § IVA, Sixth Revised Sheet No. 452-452A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

² OATT Attachment M § II(f).





TABLE OF CONTENTS

PREFACE	I
SECTION 1 – INTRODUCTION	1
<i>PJM Market Background</i>	1
<i>Conclusions</i>	1
<i>Role of MMU in Market Design Recommendations</i>	2
<i>Recommendations</i>	2
New Action	3
Detailed Recommendations in the 2009 State of the Market Report	5
Continued Action	8
<i>Total Price of Wholesale Power</i>	10
Components of Total Price	10
SECTION 2 – ENERGY MARKET, PART 1	13
<i>Overview</i>	13
Market Structure	13
Market Performance: Markup, Load and Locational Marginal Price	15
Demand-Side Response	16
Conclusion	17
<i>Market Structure</i>	18
Supply	18
Demand	19
Market Concentration	21
Local Market Structure and Offer Capping	24
Local Market Structure	26
<i>Market Performance: Markup</i>	41
Real-Time Markup	42
Day-Ahead Markup	47
Frequently Mitigated Unit and Associated Unit Adders – Component of Price	53
<i>Market Performance: Load and LMP</i>	55
Load	55
Locational Marginal Price (LMP)	63
Load and Spot Market	100
<i>Demand-Side Response (DSR)</i>	103
PJM Load Response Programs Overview	104
Economic Load Response	104
Emergency Load Response	107
Participation	111
Measurement and Verification	125
Conclusions: Demand Side	130



SECTION 3 – ENERGY MARKET, PART 2	133
Overview	133
Net Revenue	133
Existing and Planned Generation	134
Scarcity	135
Credits and Charges for Operating Reserve	136
Conclusion	137
Net Revenue	139
Theoretical Energy Market Net Revenue	140
Capacity Market Net Revenue	145
New Entrant Net Revenues	147
New Entrant Combustion Turbine	151
New Entrant Combined Cycle	153
New Entrant Coal Plant	154
New Entrant Day-Ahead Net Revenues	156
Net Revenue Adequacy	159
Actual Net Revenue	170
Existing and Planned Generation	177
Installed Capacity and Fuel Mix	177
Energy Production by Fuel Source	178
Planned Generation Additions	178
Scarcity and Scarcity Pricing	193
Scarcity Revenues: The Need for Administrative Mechanisms	193
Scarcity Mechanisms	194
Current Issues with Scarcity Implementation	194
Proposed Scarcity Pricing Approach	195
Transparent and Appropriate Scarcity Pricing Triggers	196
Mitigating Market Power and Within Hour Reserve Resources	197
Scarcity Revenues: The Offset	197
Accounting for Emergency Procedures and Emergency Actions	198
Operating Reserve	198
Credit and Charge Categories	200
Credit and Charge Results	203
Characteristics of Credits and Charges	213
Impacts of Revised Operating Reserve Rules	216
Concentration of Unit Ownership for Operating Reserve Credits	223
SECTION 4 – INTERCHANGE TRANSACTIONS	227
Overview	227
Interchange Transaction Activity	227
Interactions with Bordering Areas	228
Interchange Transaction Issues	230
Conclusion	238



<i>Interchange Transaction Activity</i>	240
Aggregate Imports and Exports	240
Interface Imports and Exports	242
<i>Transactions Basics</i>	249
Interchange Transactions – Real-Time Energy Market	249
Interchange Transactions – Day-Ahead Energy Market	250
Source and Sink in the Real-Time Market	251
Source and Sink in the Day-Ahead Market	251
Curtailement of Transactions	252
<i>Interface Pricing</i>	253
<i>Interactions with Bordering Areas</i>	254
PJM Interface Pricing with Organized Markets	254
Operating Agreements with Bordering Areas	265
Other Agreements with Bordering Areas	268
<i>Interchange Transaction Issues</i>	271
Loop Flows	271
Dynamic Interface Pricing	280
TLRs	281
Up-To Congestion	284
Interface Pricing Agreements with Individual Companies	288
Spot Import	294
Willing to Pay Congestion and Not Willing to Pay Congestion	296
Ramp Availability	297
SECTION 5 – CAPACITY MARKET	299
<i>Overview</i>	299
RPM Capacity Market	299
Generator Performance	304
Conclusion	305
<i>RPM Capacity Market</i>	310
Market Design	310
Market Structure	311
Market Conduct	320
Market Performance	325
<i>Generator Performance</i>	337
Generator Performance Factors	337
Generator Forced Outage Rates	338
SECTION 6 – ANCILLARY SERVICE MARKETS	353
<i>Overview</i>	354
Regulation Market	354
Synchronized Reserve Market	355
DASR	358
Black Start Service	358
Conclusion	359



<i>Regulation Market</i>	361
Market Structure	361
Market Conduct	367
Market Performance	368
Analysis of Regulation Market Changes	373
<i>Synchronized Reserve Market</i>	380
Market Structure	380
Market Conduct	387
Market Performance	391
<i>Day Ahead Scheduling Reserve (DASR)</i>	396
<i>Black Start Service</i>	399
Structure	401
Conduct	401
Performance	401
SECTION 7 – CONGESTION	403
<i>Overview</i>	403
Congestion Cost	403
Congestion Component of LMP and Facility or Zonal Congestion	404
Economic Planning Process	405
Conclusion	406
<i>Congestion</i>	407
Congestion Accounting	407
Total Calendar Year Congestion	409
Monthly Congestion	410
Congestion Component of LMP	410
<i>Congested Facilities</i>	411
Congestion by Facility Type and Voltage	412
Constraint Duration	416
Constraint Costs	418
Congestion-Event Summary for Midwest ISO Flowgates	419
Congestion-Event Summary for the 500 kV System	421
<i>Zonal Congestion</i>	423
Summary	423
Details of Regional and Zonal Congestion	425
<i>Economic Planning Process</i>	444
SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS	447
<i>Overview</i>	448
Financial Transmission Rights	448
Auction Revenue Rights	451
Conclusion	452
<i>Financial Transmission Rights</i>	453
Market Structure	454



FTR Credit Issues	458
Market Performance	461
Auction Revenue Rights	486
Market Structure	487
Market Performance	492
APPENDIX A – PJM GEOGRAPHY	505
APPENDIX B – PJM MARKET MILESTONES	509
APPENDIX C – ENERGY MARKET	511
Load	511
Frequency Distribution of Load	511
Locational Marginal Price (LMP)	514
Real-Time LMP	514
Day-Ahead and Real-Time LMP	518
Offer-Capped Units	524
APPENDIX D – INTERCHANGE TRANSACTIONS	529
Transactions Background	529
OASIS Products	529
Source and Sink	530
NERC Tagging	530
Neighboring Balancing Authority Checkout	531
Curtailement of Transactions	531
Transmission Loading Relief (TLR)	532
NYISO Issues	536
Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts	537
Initial Implementation of the FERC Protocol	539
APPENDIX E – CAPACITY MARKET	543
Background	543
Demand	543
VRR Curves	543
Load Obligations	543
Capacity Resources	545
Generation Resources	545
Load Management Resources	545
Energy Efficiency Resources	545
Qualified Transmission Upgrades	546
Obligations of Generation Capacity Resources	546
CETO/CETL	547
Generator Performance: NERC OMC Outage Cause Codes	547



APPENDIX F – ANCILLARY SERVICE MARKETS	549
<i>Area Control Error (ACE)</i>	549
Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)	549
<i>Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned</i>	552
APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS	555
<i>FTR Target Allocations and Congestion Revenue</i>	555
<i>ARR Prorating Procedure</i>	557
<i>ARR Credits</i>	557
<i>Self-Scheduled ARRs</i>	558
APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE	559
<i>Real-Time Hourly Integrated LMP and Real-Time Hourly Integrated Load</i>	559
<i>Day-Ahead Hourly LMP and Day-Ahead Hourly Load</i>	559
<i>Load-Weighted, Average LMP</i>	560
Real Time	560
Day Ahead	561
APPENDIX I – LOAD DEFINITIONS	565
<i>Peak Load</i>	565
<i>Accounting Load</i>	565
APPENDIX J – MARGINAL LOSSES	567
<i>Total, Average and Marginal Losses</i>	567
<i>Effect of Marginal Losses on LMP</i>	568
<i>Loss Revenue Surplus</i>	570
APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/ UNIT PARTICIPATION FACTORS	573
<i>Hourly Integrated LMP Using UPF</i>	574
<i>Hourly Integrated Markup Using UPFs</i>	575
<i>UPF-Weighted, Marginal Unit Markup</i>	577
<i>Hourly Integrated Historical, Cost-Adjusted, Load-Weighted LMP Using UPFs</i>	577
Fuel-Cost-Adjusted LMP	578
Cost-Adjusted LMP	579
<i>Components of LMP</i>	580
APPENDIX L – THREE PIVOTAL SUPPLIER TEST	583
<i>Three Pivotal Supplier Test: Background</i>	583
<i>Market Structure Tests and Market Power Mitigation: Core Concepts</i>	585
<i>Three Pivotal Supplier Test: Mechanics</i>	588
Defining the market	590



APPENDIX M – STANDARD MARKET METRICS	593
<i>Residual Supply Index (RSI)</i>	593
<i>Markup</i>	593
<i>Net Revenue</i>	594
<i>Market Share</i>	594
<i>Herfindahl-Hirschman Index (HHI)</i>	594
APPENDIX N – GLOSSARY	597
APPENDIX O – ACRONYMS	611





TABLES

SECTION 1 – INTRODUCTION	1
<i>Table 1-1 Total price per MWh: Calendar year 2009</i>	11
SECTION 2 – ENERGY MARKET, PART 1	13
<i>Table 2-1 Actual PJM footprint summer peak loads: 1999 to 2009</i>	20
<i>Table 2-2 PJM hourly Energy Market HHI: Calendar year 2009</i>	23
<i>Table 2-3 PJM hourly Energy Market HHI (By segment): Calendar year 2009</i>	23
<i>Table 2-4 Annual offer-capping statistics: Calendar years 2005 to 2009</i>	25
<i>Table 2-5 Offer-capped unit statistics: Calendar year 2009</i>	26
<i>Table 2-6 Three pivotal supplier results summary for regional constraints: Calendar year 2009</i>	28
<i>Table 2-7 Three pivotal supplier test details for three regional constraints: Calendar year 2009</i>	28
<i>Table 2-8 Three pivotal supplier results summary for the Central, East and West Interfaces: Calendar year 2009</i>	29
<i>Table 2-9 Three pivotal supplier test details for the Central, East and West interfaces: Calendar year 2009</i>	29
<i>Table 2-10 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2009</i>	30
<i>Table 2-11 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2009</i>	30
<i>Table 2-12 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2009</i>	31
<i>Table 2-13 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2009</i>	31
<i>Table 2-14 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2009</i>	32
<i>Table 2-15 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2009</i>	33
<i>Table 2-16 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2009</i>	34
<i>Table 2-17 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2009</i>	34
<i>Table 2-18 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2009</i>	35
<i>Table 2-19 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2009</i>	35
<i>Table 2-20 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2009</i>	36
<i>Table 2-21 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2009</i>	36
<i>Table 2-22 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2009</i>	37
<i>Table 2-23 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2009</i>	37
<i>Table 2-24 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2009</i>	38
<i>Table 2-25 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2009</i>	38



<i>Table 2-26 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2009</i>	39
<i>Table 2-27 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2009</i>	39
<i>Table 2-28 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: Calendar year 2009</i>	40
<i>Table 2-29 Three pivotal supplier test details for constraints located in the Pepco Control Zone: Calendar year 2009</i>	40
<i>Table 2-30 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2009</i>	41
<i>Table 2-31 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2009</i>	41
<i>Table 2-32 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): Calendar year 2009</i>	42
<i>Table 2-33 Type of fuel used (By real-time marginal units): Calendar year 2009</i>	43
<i>Table 2-34 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2009</i>	44
<i>Table 2-35 Average, real-time marginal unit markup index (By price category): Calendar year 2009</i>	44
<i>Table 2-36 Monthly markup components of real-time load-weighted LMP: Calendar year 2009</i>	45
<i>Table 2-37 Average real-time zonal markup component: Calendar year 2009</i>	46
<i>Table 2-38 Average real-time markup component (By price category): Calendar year 2009</i>	46
<i>Table 2-39 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): Calendar year 2009</i>	47
<i>Table 2-40 Day-ahead marginal resources by type/fuel: Calendar year 2009</i>	47
<i>Table 2-41 Average, day-ahead marginal unit markup index (By primary fuel and unit type): Calendar year 2009</i>	49
<i>Table 2-42 Average marginal unit markup index (By price category): Calendar year 2009</i>	49
<i>Table 2-43 Monthly markup components of day-ahead, load-weighted LMP: Calendar year 2009</i>	50
<i>Table 2-44 Day-ahead, average, zonal markup component: Calendar year 2009</i>	51
<i>Table 2-45 Average, day-ahead markup (By price category): Calendar year 2009</i>	52
<i>Table 2-46 The markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2009</i>	52
<i>Table 2-47 Frequently mitigated units and associated units (By month): Calendar year 2009</i>	54
<i>Table 2-48 Frequently mitigated units and associated units total months eligible: Calendar year 2009</i>	54
<i>Table 2-49 PJM real-time average load: Calendar years 1998 to 2009</i>	56
<i>Table 2-50 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009</i>	58
<i>Table 2-51 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2005 through 2009</i>	58
<i>Table 2-52 PJM day-ahead average load: Calendar years 2000 to 2009</i>	60
<i>Table 2-53 Cleared day-ahead and real-time load (MWh): Calendar year 2009</i>	61
<i>Table 2-54 Day-ahead and real-time generation (MWh): Calendar year 2009</i>	62
<i>Table 2-55 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2009</i>	65
<i>Table 2-56 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009</i>	65
<i>Table 2-57 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009</i>	66
<i>Table 2-58 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009</i>	67
<i>Table 2-59 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2009</i>	68



Table 2-60 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009	69
Table 2-61 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009	70
Table 2-62 RGGI CO ₂ allowance auction prices and quantities: 2009-2011 Compliance Period	73
Table 2-63 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method	73
Table 2-64 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2009	74
Table 2-65 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 to 2009	76
Table 2-66 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009	77
Table 2-67 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009	77
Table 2-68 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 to 2009	78
Table 2-69 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009	80
Table 2-70 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2008 to 2009	81
Table 2-71 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2009	82
Table 2-72 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2009	83
Table 2-73 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2008 to 2009	83
Table 2-74 Hub real-time, simple average LMP components (Dollars per MWh): Calendar year 2009	84
Table 2-75 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): Calendar year 2009	84
Table 2-76 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2009	85
Table 2-77 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2008 to 2009.	86
Table 2-78 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): Calendar year 2009	87
Table 2-79 Marginal loss costs by type (Dollars (Millions)): Calendar year 2009	89
Table 2-80 Marginal loss costs by control zone and type (Dollars (Millions)): Calendar year 2009	90
Table 2-81 Monthly marginal loss costs by control zone (Dollars (Millions)): Calendar year 2009	91
Table 2-82 Monthly volume of cleared and submitted INCs, DECs: Calendar year 2009	92
Table 2-83 Type of day-ahead marginal units: Calendar year 2009	92
Table 2-84 PJM virtual bids by type of bid parent organization (MW): Calendar year 2009	93
Table 2-85 PJM virtual bids by top ten aggregates (MW): Calendar year 2009	93
Table 2-86 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009	95
Table 2-87 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 to 2009	95
Table 2-88 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2005 to 2009	96
Table 2-89 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009	99



<i>Table 2-90 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009</i>	100
<i>Table 2-91 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2008 to 2009</i>	101
<i>Table 2-92 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar Years 2008 to 2009</i>	102
<i>Table 2-93 Overview of Demand Side Programs</i>	104
<i>Table 2-94 Economic Program registration: Within 2002 to 2009</i>	113
<i>Table 2-95 Economic Program registrations on the last day of the month: January 2007 through December 2009</i>	113
<i>Table 2-96 Distinct registrations and sites in the Economic Program: August 10, 2009</i>	114
<i>Table 2-97 Performance of PJM Economic Program participants</i>	115
<i>Table 2-98 Performance of PJM Economic Program participants without incentive payments</i>	115
<i>Table 2-99 PJM Economic Program by zonal reduction: Calendar year 2009</i>	117
<i>Table 2-100 Settlement days submitted by month in the Economic Program: 2007 through 2009</i>	118
<i>Table 2-101 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007 through 2009</i>	118
<i>Table 2-102 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2009</i>	119
<i>Table 2-103 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2009</i>	120
<i>Table 2-104 Registered sites and MW in the Emergency Program (By zone and option): August 10, 2009</i>	121
<i>Table 2-105 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2009</i>	121
<i>Table 2-106 Zonal monthly capacity credits: January 1, 2009, through December 31, 2009</i>	122
<i>Table 2-107 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2012/2013</i>	122
<i>Table 2-108 Load Management test results and compliance by zone for the 2009/2010 delivery year</i>	124
<i>Table 2-109 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period January 1, 2009 through December 31, 2009</i>	128
<i>Table 2-110 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period July 1, 2008 through December 31, 2008</i>	128

SECTION 3 – ENERGY MARKET, PART 2 **133**

<i>Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2009</i>	141
<i>Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2009</i>	142
<i>Table 3-3 2009 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2009</i>	146
<i>Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2009</i>	147
<i>Table 3-5 Average delivered fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2009</i>	149
<i>Table 3-6 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 calendar years 1999 to 2009</i>	150
<i>Table 3-7 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 calendar years 1999 to 2009</i>	150
<i>Table 3-8 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009</i>	151



Table 3-9 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009	152
Table 3-10 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009	152
Table 3-11 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009	153
Table 3-12 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009	154
Table 3-13 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009	155
Table 3-14 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009	155
Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009	156
Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009	157
Table 3-17 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009	157
Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009	158
Table 3-19 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 2009	158
Table 3-20 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 2009	159
Table 3-21 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))	159
Table 3-22 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009	160
Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009	161
Table 3-24 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009	163
Table 3-25 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009	164
Table 3-26 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009	166
Table 3-27 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009	167
Table 3-28 Internal rate of return sensitivity for CT, CC and CP generators	170
Table 3-29 Average energy and ancillary service net revenue by quartile for select technologies for calendar year 2009	171
Table 3-30 Avoidable cost recovery by quartile from energy and ancillary service net revenue for select technologies for calendar year 2009	172
Table 3-31 Average total net revenue by quartile for select technologies for calendar year 2009	172
Table 3-32 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2009	173
Table 3-33 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2007 through 2009	174
Table 3-34 Profile of coal units not recovering avoidable costs from all PJM Market net revenues by hours of operation	176
Table 3-35 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2009	177
Table 3-36 PJM generation (By fuel source (GWh)): Calendar year 2009	178



<i>Table 3-37 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 to 2009</i>	179
<i>Table 3-38 Queue comparison (MW): Calendar years 2009 vs. 2008</i>	179
<i>Table 3-39 Capacity in PJM queues (MW): At December 31, 2009</i>	180
<i>Table 3-40 Average project queue times: At December 31, 2009</i>	181
<i>Table 3-41 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2009</i>	182
<i>Table 3-42 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2009</i>	182
<i>Table 3-43 Existing PJM capacity 2009 (By zone and unit type (MW))</i>	183
<i>Table 3-44 PJM capacity age (MW)</i>	184
<i>Table 3-45 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018</i>	185
<i>Table 3-46 Capacity factor of wind units in PJM, Calendar year 2009</i>	186
<i>Table 3-47 Wind resources in real time offering at a negative price in PJM, June through December 2009</i>	186
<i>Table 3-48 Capacity factor of wind units in PJM by month, Calendar year 2009</i>	188
<i>Table 3-49 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, Calendar year 2009</i>	188
<i>Table 3-50 Operating reserve credits and charges</i>	198
<i>Table 3-51 Operating reserve deviations</i>	199
<i>Table 3-52 Balancing operating reserve allocation process</i>	200
<i>Table 3-53 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2009</i>	201
<i>Table 3-54 Monthly operating reserve charges: Calendar years 2008 and 2009</i>	202
<i>Table 3-55 Regional balancing charges allocation: Calendar year 2009</i>	203
<i>Table 3-56 Monthly balancing operating reserve deviations (MWh): Calendar years 2008 and 2009</i>	205
<i>Table 3-57 Regional charges determinants (MWh): Calendar year 2009</i>	205
<i>Table 3-58 Regional balancing operating reserve rates (\$/MWh): Calendar year 2009</i>	207
<i>Table 3-59 Credits by month (By operating reserve market): Calendar year 2009</i>	209
<i>Table 3-60 Credits by unit types (By operating reserve market): Calendar year 2009</i>	209
<i>Table 3-61 Credits by operating reserve market (By unit type): Calendar year 2009</i>	210
<i>Table 3-62 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2009</i>	210
<i>Table 3-63 PJM generation by unit type receiving operating reserve payments: Calendar year 2009</i>	211
<i>Table 3-64 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2009</i>	211
<i>Table 3-65 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2009</i>	212
<i>Table 3-66 Regional balancing operating reserve credits: Calendar year 2009</i>	213
<i>Table 3-67 Total deviations: Calendar year 2009</i>	213
<i>Table 3-68 Charge allocation under old operating reserve construct: Calendar year 2009</i>	213
<i>Table 3-69 Actual regional credits, charges, rates and charge allocation (MWh): Calendar 2009</i>	214
<i>Table 3-70 Difference in total charges between old rules and new rules: Calendar year 2009</i>	214
<i>Table 3-71 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): Calendar year 2009</i>	215
<i>Table 3-72 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2009</i>	216



<i>Table 3-73 Summary of impact on virtual bids under balancing operating reserve allocation: Calendar year 2009</i>	216
<i>Table 3-74 Impact of segmented make whole payments: December 2008 through December 2009</i>	217
<i>Table 3-75 Impact of segmented make whole payments (By unit type): December 2008 through December 2009</i>	218
<i>Table 3-76 Share of balancing operating reserve increases for segmented make whole payments (By unit type): December 2008 through December 2009</i>	218
<i>Table 3-77 Table 37 Unit Parameter Limited Schedule Matrix</i>	219
<i>Table 3-78 Units receiving credits from a parameter limited schedule: December 2008 through December 2009</i>	219
<i>Table 3-79 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2009</i>	221
<i>Table 3-80 Unit operating reserve credits for units (By zone): Calendar year 2009</i>	222
<i>Table 3-81 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2009</i>	223
<i>Table 3-82 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2009</i>	223
<i>Table 3-83 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2009</i>	224
<i>Table 3-84 Top 10 units and organizations receiving balancing generator credits: Calendar year 2009</i>	224
<i>Table 3-85 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2009</i>	225

SECTION 4 – INTERCHANGE TRANSACTIONS 227

<i>Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2009</i>	244
<i>Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2009</i>	245
<i>Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2009</i>	246
<i>Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2009</i>	247
<i>Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2009</i>	248
<i>Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2009</i>	249
<i>Table 4-7 Active interfaces: Calendar year 2009</i>	253
<i>Table 4-8 Active pricing points: 2009</i>	254
<i>Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): Calendar years 2008 and 2009</i>	257
<i>Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): Calendar years 2008 and 2009</i>	259
<i>Table 4-11 Con Edison and PSE&G wheeling settlement data: Calendar year 2009</i>	269
<i>Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2009</i>	273
<i>Table 4-13 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2009</i>	283
<i>Table 4-14 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through 2009</i>	285
<i>Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2009</i>	288
<i>Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009</i>	290
<i>Table 4-17 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through December 2009</i>	291
<i>Table 4-18 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009</i>	292
<i>Table 4-19 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009</i>	293



SECTION 5 – CAPACITY MARKET 299

<i>Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012</i>	313
<i>Table 5-2 PJM Capacity Market load obligation served: June 1, 2009</i>	314
<i>Table 5-3 Preliminary market structure screen results: 2009/2010 through 2012/2013 RPM Auctions</i>	316
<i>Table 5-4 RSI results: 2009/2010 through 2012/2013 RPM Auctions</i>	317
<i>Table 5-5 PJM capacity summary (MW): June 1, 2007 through May 31, 2012</i>	318
<i>Table 5-6 RPM load management statistics: June 1, 2008 through May 31, 2012</i>	319
<i>Table 5-7 ACR statistics: 2009/2010 RPM Auctions</i>	321
<i>Table 5-8 ACR statistics: 2010/2011 through 2012/2013 RPM Auctions</i>	321
<i>Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions</i>	322
<i>Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions</i>	326
<i>Table 5-11 RPM cost to load: 2009/2010 through 2012/2013 RPM Auctions</i>	327
<i>Table 5-12 RTO offer statistics: 2009/2010 RPM Base Residual Auction</i>	329
<i>Table 5-13 MAAC+APS offer statistics: 2009/2010 RPM Base Residual Auction</i>	331
<i>Table 5-14 SWMAAC offer statistics: 2009/2010 RPM Base Residual Auction</i>	333
<i>Table 5-15 RTO offer statistics: 2009/2010 RPM Third Incremental Auction</i>	335
<i>Table 5-16 MAAC+APS offer statistics: 2009/2010 RPM Third Incremental Auction</i>	336
<i>Table 5-17 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2005 to 2009</i>	340
<i>Table 5-18 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2005 to 2009</i>	341
<i>Table 5-19 Outage cause contribution to PJM EFOF: Calendar year 2009</i>	343
<i>Table 5-20 Contributions to Economic Outages: 2009</i>	344
<i>Table 5-21 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2009</i>	344
<i>Table 5-22 Contribution to EFOF by unit type: Calendar year 2009</i>	345
<i>Table 5-23 PJM EFORd vs. XEFORd: Calendar year 2009</i>	346
<i>Table 5-24 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009</i>	347
<i>Table 5-25 PJM EFORp data by unit type: Calendar years 2008 to 2009</i>	347
<i>Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2009</i>	348
<i>Table 5-27 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2009</i>	348

SECTION 6 – ANCILLARY SERVICE MARKETS 353

<i>Table 6-1 PJM Regulation Market required MW and ratio of supply to requirement: Calendar year 2009</i>	363
<i>Table 6-2 PJM regulation capability, daily offer and hourly eligible: Calendar year 2009</i>	364
<i>Table 6-3 PJM cleared regulation HHI: Calendar year 2009</i>	364
<i>Table 6-4 Highest annual average hourly Regulation Market shares: Calendar year 2009</i>	366
<i>Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2009</i>	367
<i>Table 6-6 Percent of hours when marginal unit supplier was pivotal: Calendar year 2009</i>	369
<i>Table 6-7 Total regulation charges: Calendar year 2009</i>	372
<i>Table 6-8 Summary of changes to Regulation Market design</i>	373
<i>Table 6-9 Regulation Market pivotal supplier test results: December 2008 through December 2009 and December 2007 through December 2008</i>	374
<i>Table 6-10 Impact of \$12 adder to cost based regulation offer: December 2008 through December 2009</i>	375



<i>Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule</i>	376
<i>Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2009</i>	378
<i>Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: December 2008 through December 2009</i>	379
<i>Table 6-14 Effect of transfer capacity change on synchronized reserve market scheduled, self-scheduled, and added MW, daily totals: March, 2009</i>	384
<i>Table 6-15 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2009</i>	387
<i>Table 6-16 Average PJM SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: Calendar year 2009</i>	390
<i>Table 6-17 2009 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices</i>	398
<i>Table 6-18 Black Start yearly zonal charges for network transmission use</i>	399

SECTION 7 – CONGESTION **403**

<i>Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2009</i>	409
<i>Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): Calendar years 2008 and 2009</i>	410
<i>Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2008 to 2009</i>	410
<i>Table 7-4 Annual average congestion component of LMP: Calendar years 2008 to 2009</i>	411
<i>Table 7-5 Congestion summary (By facility type): Calendar year 2009</i>	413
<i>Table 7-6 Congestion summary (By facility type): Calendar year 2008</i>	413
<i>Table 7-7 Congestion summary (By facility voltage): Calendar year 2009</i>	415
<i>Table 7-8 Congestion summary (By facility voltage): Calendar year 2008</i>	415
<i>Table 7-9 Top 25 constraints with frequent occurrence: Calendar years 2008 to 2009</i>	416
<i>Table 7-10 Top 25 constraints with largest year-to-year change in occurrence: Calendar years 2008 to 2009</i>	417
<i>Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2009</i>	418
<i>Table 7-12 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2008</i>	419
<i>Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2009</i>	420
<i>Table 7-14 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2008</i>	421
<i>Table 7-15 Regional constraints summary (By facility): Calendar year 2009</i>	422
<i>Table 7-16 Regional constraints summary (By facility): Calendar year 2008</i>	422
<i>Table 7-17 Congestion cost summary (By control zone): Calendar year 2009</i>	424
<i>Table 7-18 Congestion cost summary (By control zone): Calendar year 2008</i>	425
<i>Table 7-19 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	426
<i>Table 7-20 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	427
<i>Table 7-21 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	428
<i>Table 7-22 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	428
<i>Table 7-23 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	429
<i>Table 7-24 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	429
<i>Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	430
<i>Table 7-26 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	430
<i>Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	431



<i>Table 7-28 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	431
<i>Table 7-29 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	432
<i>Table 7-30 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	432
<i>Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	433
<i>Table 7-32 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	433
<i>Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	434
<i>Table 7-34 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	434
<i>Table 7-35 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	435
<i>Table 7-36 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	435
<i>Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	436
<i>Table 7-38 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	436
<i>Table 7-39 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	437
<i>Table 7-40 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	437
<i>Table 7-41 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	438
<i>Table 7-42 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	438
<i>Table 7-43 AP Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	439
<i>Table 7-44 AP Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	439
<i>Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	440
<i>Table 7-46 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	440
<i>Table 7-47 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	441
<i>Table 7-48 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	441
<i>Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	442
<i>Table 7-50 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	442
<i>Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2009</i>	443
<i>Table 7-52 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2008</i>	443

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS 447

<i>Table 8-1 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2010 to 2013</i>	455
<i>Table 8-2 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2009 to 2010</i>	456
<i>Table 8-3 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2010 to 2013</i>	460
<i>Table 8-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2009 to 2010</i>	461
<i>Table 8-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: Calendar year 2009</i>	461
<i>Table 8-6 Long Term FTR Auction market volume: Planning periods 2010 to 2013</i>	462
<i>Table 8-7 Annual FTR Auction market volume: Planning period 2009 to 2010</i>	463
<i>Table 8-8 Comparison of self scheduled FTRs: Planning periods 2008 to 2009 and 2009 to 2010</i>	464
<i>Table 8-9 Monthly Balance of Planning Period FTR Auction market volume: Calendar year 2009</i>	465
<i>Table 8-10 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): Calendar year 2009</i>	466
<i>Table 8-11 Secondary bilateral FTR market volume and weighted-average cleared prices (Dollars per MWh): Planning periods 2008 to 2009 and 2009 to 2010</i>	467
<i>Table 8-12 Long Term FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2010 to 2013</i>	468
<i>Table 8-13 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2009 to 2010</i>	470



Table 8-14 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): Calendar year 2009	472
Table 8-15 Long Term FTR Auction revenue: Planning periods 2010 to 2013	473
Table 8-16 Annual FTR Auction revenue: Planning period 2009 to 2010	476
Table 8-17 Monthly Balance of Planning Period FTR Auction revenue: Calendar year 2009	479
Table 8-18 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010	483
Table 8-19 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010	484
Table 8-20 Incremental ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010	490
Table 8-21 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2009 to 2010	490
Table 8-22 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2008, through December 31, 2009	492
Table 8-23 Annual ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010	493
Table 8-24 ARR revenue adequacy (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010	494
Table 8-25 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2008 to 2009	497
Table 8-26 FTR congestion hedging by control zone: Planning period 2008 to 2009	499
Table 8-27 ARR and FTR congestion hedging by control zone: Planning period 2008 to 2009	501
Table 8-28 TARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010	501
Table 8-29 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through December, 2009	502
Table 8-30 FTRs as a hedge against energy charges by control zone: January through December, 2009	503
Table 8-31 ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2009	504

APPENDIX C – ENERGY MARKET **511**

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2005 to 2009	512
Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2009	513
Table C-3 Multiyear change in load: Calendar years 1998 to 2009	513
Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2005 to 2009	515
Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009	516
Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2009	517
Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2008 to 2009	517
Table C-8 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2008 to 2009	517
Table C-9 PJM real-time constrained hours: Calendar years 2008 to 2009	518
Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2005 to 2009	519
Table C-11 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2009	520
Table C-12 On-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2009	522



<i>Table C-13 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2009</i>	522
<i>Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2009</i>	523
<i>Table C-15 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2009</i>	524
<i>Table C-16 Average day-ahead, offer-capped units: Calendar years 2005 to 2009</i>	525
<i>Table C-17 Average day-ahead, offer-capped MW: Calendar years 2005 to 2009</i>	525
<i>Table C-18 Average real-time, offer-capped units: Calendar years 2005 to 2009</i>	526
<i>Table C-19 Average real-time, offer-capped MW: Calendar years 2005 to 2009</i>	526
<i>Table C-20 Offer-capped unit statistics: Calendar year 2005</i>	527
<i>Table C-21 Offer-capped unit statistics: Calendar year 2006</i>	527
<i>Table C-22 Offer-capped unit statistics: Calendar year 2007</i>	527
<i>Table C-23 Offer-capped unit statistics: Calendar year 2008</i>	528
<i>Table C-24 Offer-capped unit statistics: Calendar year 2009</i>	528
APPENDIX D – INTERCHANGE TRANSACTIONS	529
<i>Table D-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2009</i>	535
<i>Table D-2 Con Edison and PSE&G wheel settlements data: Calendar year 2009</i>	540
APPENDIX E – CAPACITY MARKET	543
<i>Table E-1 NERC GADS cause codes that PJM deems outside management control (OMC)</i>	548
APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS	555
<i>Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration</i>	556
<i>Table G-2 ARR allocation prorating procedure: Illustration</i>	557
<i>Table G-3 ARR credits: Illustration</i>	558
<i>Table G-4 Self-Scheduled ARR credits: Illustration</i>	558
APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/UNIT PARTICIPATION FACTORS	573
<i>Table K-1 LMP at bus X</i>	573
<i>Table K-2 Components of PJM annual, load-weighted, average LMP: Calendar year 2009</i>	580
<i>Table K-3 Percentage of five minute intervals and marginal units having a UDS LMP override: Calendar year 2009</i>	581



FIGURES

SECTION 2 – ENERGY MARKET, PART 1	13
Figure 2-1 Average PJM aggregate supply curves: Summers 2008 and 2009	19
Figure 2-2 Actual PJM footprint summer peak loads: 1999 to 2009	20
Figure 2-3 PJM summer peak-load comparison: Monday, August 10, 2009, and Monday, June 9, 2008	21
Figure 2-4 PJM hourly Energy Market HHI: Calendar year 2009	24
Figure 2-5 Real-time, LMP contribution and load-weighted, unit markup index: Calendar year 2009	43
Figure 2-6 Day-ahead, LMP contribution and load-weighted unit markup index: Calendar year 2009	48
Figure 2-7 PJM real-time load duration curves: Calendar years 2005 to 2009	55
Figure 2-8 PJM real-time average load: Calendar years 2008 to 2009	57
Figure 2-9 PJM day-ahead load duration curves: Calendar years 2005 to 2009	59
Figure 2-10 PJM day-ahead average load: Calendar years 2008 to 2009	60
Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2009	61
Figure 2-12 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2009	63
Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95 th percentile: Calendar years 2005 to 2009	64
Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 to 2009	68
Figure 2-15 Spot average fuel price comparison: Calendar years 2008 to 2009	71
Figure 2-16 Spot average emission price comparison: Calendar years 2008 to 2009	72
Figure 2-17 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95 th percentile: Calendar years 2005 to 2009	75
Figure 2-18 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 to 2009	79
Figure 2-19 PJM day-ahead aggregate supply curves: 2009 example day	94
Figure 2-20 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2009	97
Figure 2-21 Monthly simple average of real-time minus day-ahead LMP: Calendar year 2009	97
Figure 2-22 PJM system simple hourly average LMP: Calendar year 2009	98
Figure 2-23 Demand Response revenue by market: Calendar years 2002 through 2009	112
Figure 2-24 Economic Program payments: Calendar years 2007 (without incentive payments), 2008 and 2009	116
SECTION 3 – ENERGY MARKET, PART 2	133
Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2009	143
Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2009	144
Figure 3-3 New entrant CT real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009	162
Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009	162



Figure 3-5 New entrant CC real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009 164

Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009 165

Figure 3-7 New entrant CP real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009 167

Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009 168

Figure 3-9 Frequency of coal units within energy net revenue ranges as a percentage of total coal units for calendar years 2008 and 2009 175

Figure 3-10 Frequency of sub-critical coal units within energy net revenue ranges as a percentage of total sub-critical coal units for calendar years 2008 and 2009 175

Figure 3-11 Average hourly real-time generation of wind units in PJM, Calendar year 2009 187

Figure 3-12 Average hourly day-ahead generation of wind units in PJM, Calendar year 2009 189

Figure 3-13 Marginal fuel at time of wind generation in PJM, Calendar year 2009 190

Figure 3-14 Daily RTO reliability and deviation rates (\$/MWh): Calendar year 2009 206

Figure 3-15 Daily regional reliability and deviation rates (\$/MWh): Calendar year 2009 207

Figure 3-16 Operating reserve credits: Calendar year 2009 208

SECTION 4 – INTERCHANGE TRANSACTIONS **227**

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2009 241

Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2009 241

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2009 242

Figure 4-4 PJM’s footprint and its external interfaces 254

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2009 255

Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through December 2009 256

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): Calendar year 2009 257

Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through December 2009 258

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2009 260

Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through December 2009 261

Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2009 262

Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar year 2009 263

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2009 264

Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: Calendar year 2009 264

Figure 4-15 Credits for coordinated congestion management: Calendar year 2009 267



<i>Figure 4-16 Neptune hourly average flow: Calendar year 2009</i>	270
<i>Figure 4-17 Linden hourly average flow: September through December 2009</i>	271
<i>Figure 4-18 Southwest actual and scheduled flows: January 2006 through December 2009</i>	275
<i>Figure 4-19 Southeast actual and scheduled flows: January 2006 through December 2009</i>	275
<i>Figure 4-20 PJM and Midwest ISO TLR procedures: Calendar years 2008 and 2009</i>	282
<i>Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar years 2008 and 2009</i>	282
<i>Figure 4-22 Number of PJM TLRs and curtailed volume: Calendar year 2009</i>	283
<i>Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through December 2009</i>	285
<i>Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: Calendar year 2009</i>	286
<i>Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: Calendar year 2009</i>	287
<i>Figure 4-26 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2009</i>	291
<i>Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2009</i>	292
<i>Figure 4-28 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2009</i>	293
<i>Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2009</i>	294
<i>Figure 4-30 Spot import service utilization: Calendar year 2009</i>	295
<i>Figure 4-31 Monthly uncollected congestion charges: Calendar year 2009</i>	296
<i>Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through December 2009</i>	297
SECTION 5 – CAPACITY MARKET	299
<i>Figure 5-1 History of capacity prices: Calendar year 1999 through 2012</i>	326
<i>Figure 5-2 RTO market supply/demand curves: 2009/2010 RPM Base Residual Auction</i>	330
<i>Figure 5-3 MAAC+APS supply/demand curves: 2009/2010 RPM Base Residual Auction</i>	332
<i>Figure 5-4 SWMAAC supply/demand curves: 2009/2010 RPM Base Residual Auction</i>	334
<i>Figure 5-5 RTO supply/demand curves: 2009/2010 RPM Third Incremental Auction</i>	335
<i>Figure 5-6 MAAC+APS supply/demand curves: 2009/2010 RPM Third Incremental Auction</i>	337
<i>Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2005 to 2009</i>	338
<i>Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009</i>	339
<i>Figure 5-9 PJM 2009 Distribution of EFORd data by unit type</i>	340
<i>Figure 5-10 Contribution to EFORd by duty cycle: Calendar years 2005 to 2009</i>	342
<i>Figure 5-11 PJM 2009 distribution of EFORd data by unit type</i>	349
<i>Figure 5-12 PJM peak month data</i>	350
<i>Figure 5-13 PJM peak month generator performance factors</i>	351
SECTION 6 – ANCILLARY SERVICE MARKETS	353
<i>Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2009</i>	365
<i>Figure 6-2 Off peak and on peak regulation levels: Calendar year 2009</i>	366
<i>Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): Calendar year 2009</i>	370



<i>Figure 6-4 Monthly average regulation demand (required) vs. price: Calendar year 2009</i>	371
<i>Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2009</i>	372
<i>Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2009</i>	382
<i>Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2009</i>	385
<i>Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: Calendar year 2009</i>	386
<i>Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2009</i>	388
<i>Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2009</i>	389
<i>Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2009</i>	391
<i>Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2</i>	392
<i>Figure 6-13 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated</i>	393
<i>Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone</i>	394
<i>Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2009</i>	395
<i>Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2009</i>	395

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS 447

<i>Figure 8-1 Long Term FTR auction clearing price duration curve: Planning periods 2010 to 2013</i>	469
<i>Figure 8-2 Annual FTR auction clearing price duration curves: Planning period 2009 to 2010</i>	471
<i>Figure 8-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2010 to 2013</i>	474
<i>Figure 8-4 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2010 to 2013</i>	475
<i>Figure 8-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2009 to 2010</i>	477
<i>Figure 8-6 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2009 to 2010</i>	478
<i>Figure 8-7 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 December 31, 2009</i>	480
<i>Figure 8-8 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 December 31, 2009</i>	481
<i>Figure 8-9 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 through December 31, 2009</i>	485
<i>Figure 8-10 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 through December 31, 2009</i>	486
<i>Figure 8-11 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 December 31, 2009</i>	495



APPENDIX A – PJM GEOGRAPHY	505
<i>Figure A-1 PJM's footprint and its 17 control zones</i>	505
<i>Figure A-2 PJM integration phases</i>	506
<i>Figure A-3 PJM locational deliverability areas</i>	507
<i>Figure A-4 PJM RPM EMAAC locational deliverability area markets, including PSEG North and DPL South</i>	508
APPENDIX C – ENERGY MARKET	511
<i>Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2009</i>	520
<i>Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2009</i>	521
APPENDIX D – INTERCHANGE TRANSACTIONS	529
<i>Figure D-1 Con Edison and PSE&G wheel</i>	538
APPENDIX F – ANCILLARY SERVICE MARKETS	549
<i>Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2009</i>	551
<i>Figure F-2 DCS event count and PJM performance (By month): Calendar year 2009</i>	552
APPENDIX L – THREE PIVOTAL SUPPLIER TEST	583
<i>Figure L-1 Definition of relevant market</i>	591





EQUATIONS

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS 447

Equation 8-1 Calculation of prorated ARRs 489

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS 555

Equation G-1 Calculation of prorated ARRs 557

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE 559

Equation H-1 LMP calculations 563

APPENDIX J – MARGINAL LOSSES 567

Equation J-1 LMP components 567

Equation J-2 Total transmission losses 567

Equation J-3 Total transmission losses 567

Equation J-4 Average transmission losses 568

Equation J-5 Marginal losses 568

Equation J-6 Total cost of generation 568

Equation J-7 Power Balance Constraint 568

Equation J-8 System 568

Equation J-9 Lambda 569

Equation J-10 Power Balance Constraint (from above) 569

Equation J-11 Penalty factor 569

Equation J-12 Excess loss revenue allocation 571

APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/UNIT PARTICIPATION FACTORS 573

Equation K-1 Hourly integrated load at a bus 574

Equation K-2 Load bus LMP 574

Equation K-3 Hourly integrated LMP at a bus 575

Equation K-4 Hourly total system cost 575

Equation K-5 Hourly load-weighted LMP 575

Equation K-6 System annual, load-weighted, average LMP 575

Equation K-7 UPF-based system hourly total cost 576

Equation K-8 System load-weighted LMP 576

Equation K-9 Cost-based offer system, hourly load-weighted LMP 576

Equation K-10 Impact of marginal unit markup on LMP 576

Equation K-11 Price-cost markup index 577

Equation K-12 UPF load-weighted, marginal unit markup 577

Equation K-13 Fuel-cost-adjusted offer 578

Equation K-14 Fuel-cost-adjusted, load-weighted LMP 578



<i>Equation K-15 Systemwide annual, fuel-cost-adjusted, load-weighted LMP</i>	579
<i>Equation K-16 Unit historical, cost-adjusted offer</i>	579
<i>Equation K-17 Unit historical, cost-adjusted, load-weighted LMP</i>	579
<i>Equation K-18 Systemwide, historical, cost-adjusted, load-weighted LMP</i>	579
APPENDIX L – THREE PIVOTAL SUPPLIER TEST	583
<i>Equation L-1 Incremental effective MW of supply</i>	588
<i>Equation L-2 Price of clearing offer</i>	588
<i>Equation L-3 Relevant and effective offer</i>	589
<i>Equation L-4 Relevant and effective supply of supplier <i>i</i></i>	589
<i>Equation L-5 Total relevant, effective supply</i>	589
<i>Equation L-6 Calculating the three pivotal supplier test</i>	589
APPENDIX M – STANDARD MARKET METRICS	593
<i>Equation M-1 Calculating the three pivotal supplier test</i>	593

SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2009, had installed generating capacity of 167,326 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}

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 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 2009:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;

¹ See the *2009 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 *2009 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 *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

- The Regulation Market results were not competitive;⁴
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

Role of MMU in Market Design 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.⁵

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: “In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview.”⁶

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The recommendations are for new action in areas where PJM has not yet identified a plan or where the plan should be modified. The recommendations for each category follow the order in which they appear in the report. The recommendations are for continued action where PJM has already implemented effective market rules or where PJM has already identified areas for improvement.

⁴ The regulation market results are not the result of the offer behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test. The regulation market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than its owner does.

⁵ PJM OATT Attachment M § IV.D.

⁶ 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”). In its order of December 18, 2009 on PJM’s filing in compliance with Order No. 719, the Commission required additional changes to ensure that the PJM Market Monitoring Plan fully conforms with Order No. 719’s requirements concerning the role of MMUs in market design. 125 FERC ¶ 61,250 at P 113 (2009) (“PJM’s OATT fails to specify the MMU’s responsibility for evaluating existing and proposed market rules, tariff provisions and market design elements, and for recommending proposed rule and tariff changes to PJM, the Commission’s Office of Energy Market Regulation and to other interested entities (i.e., state commissions and market participants). Attachment M, section IV.C, in this regard, provides only that, if the MMU “detects a design flaw or other problem with the PJM Markets,” it may initiate and propose changes to such market design. This language, however, is limited to “design” issues relating to existing provisions and thus does not address the full scope of the core MMU function addressed by the Commission in Order No. 719.”).

New Action

- The MMU recommends that the option to specify a minimum dispatch price under the Demand Side Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price.
- The MMU recommends that the Demand Side Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. There is no economic reason to compensate load reductions up to \$1,000/MWh during an emergency event regardless of the hourly LMP.
- The MMU recommends that PJM carefully consider the implications of the potential loss of the relatively small subcritical coal units identified as at risk in the MMU net revenue analysis and whether market design changes are required to address that potential loss.
- The MMU recommends that any proposal to modify scarcity pricing include the following essential components: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; a maximum price of \$1,000 per MWh; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; maintaining local market power mitigation mechanisms; and 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.
- The MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.
- The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.
- The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make the data necessary for loop flow analysis available to the RTOs and market monitors to make a full market analysis possible. PJM continues to face significant loop flows for reasons that continue not to be fully understood because PJM, other

balancing authority operators and market monitors have inadequate access to the data required for a complete analysis of loop flow in the Eastern Interconnection.

- The MMU recommends that the obligation of capacity resources to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price.
- The MMU recommends that the rules making capacity auctions mandatory for both load and generation be clarified. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In PJM, capacity has a must offer requirement, which means that all capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform. The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability.
- The MMU recommends that the must offer requirement for capacity should also apply generally to out of market transactions. Out of market transactions include the construction of new capacity by regulated utilities receiving out of market payments for such capacity via rate base treatment of the investment; by companies receiving out of market payments for such capacity via long term contracts; by companies receiving out of market payments for such capacity via Reliability Must Run (RMR) payments; and by companies receiving out of market payments for such capacity under renewable portfolio programs.
- The MMU recommends that PJM take the required steps to ensure that capacity prices reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETO/CETL analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. PJM should perform a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions, units that do not cover avoidable costs, and units that face significant investment requirements due, for example, to environmental requirements.
- The MMU recommends that the recently implemented modification to the definition of opportunity cost in the Regulation Market be reversed and that the correct definition of opportunity cost be reinstated. The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years.
- The MMU recommends that the recently implemented modification to the treatment of net revenues from the Regulation Market be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

- Based on the experience of the MMU during its eleventh year and its analysis of the PJM markets and based on the experience of the MMU during its first complete year as the external Independent Market Monitor, the MMU confirms that the market monitoring function remains independent, well-organized and consistent with the policies of the FERC.^{7, 8} The MMU has not identified any changes that are required to maintain the general effectiveness of the MMU, but recommends that the Commission continue to consider ways to strengthen the market monitoring function.

Detailed Recommendations in the 2009 State of the Market Report

This section includes the additional detailed recommendations made in the *2009 State of the Market Report for PJM*.

Section 2 – Energy Market Part 1

Demand-Side Response (DSR)

- Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification. This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results.
- The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.
- While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, the MMU recommends that LSE/EDCs should be able to initiate PJM settlement reviews.
- The MMU recommends that regression analysis capturing the effect of ambient temperature be incorporated in any GLD testing that estimates unrestricted load consumption based on a comparable day or a comparable set of days.
- While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the

⁷ PJM, "Open Access Transmission Tariff (OATT)," Attachment M: PJM Market Monitoring Plan," Fourth Revised Sheet No. 452 (Effective August 1, 2008). Section VII.A. states: "The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required."

⁸ On December 19, 2007, the parties filed a settlement with the Federal Energy Regulatory Commission, pursuant to the September 20, 2007, order in Docket Nos. EL07-56-000 and EL07-58-000 (consolidated).

testing program be modified to require verification of test methods and results. In addition, the MMU recommends that when used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include statistical analysis that captures the effect of ambient conditions.

- The MMU recommends two ways to further improve the Economic Program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation.

Section 4 – Transactions

- The MMU recommends that a change in the interface pricing methodology be addressed directly by the Broader Regional Markets group. The MMU recommends that the parties consider the uniform adoption of a GCA to 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.
- The MMU recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.
- The MMU supports congestion management agreements but recommends that such agreements be implemented on a regional basis rather than between RTOs and individual external utility companies. In addition, there are a number of issues in the PJM/PEC agreement that need to be addressed. Most fundamentally, any congestion management agreement must ensure that the interface price established reflects the economic fundamentals of an LMP market.
- The MMU recommends modifying the evaluation criteria for not willing to pay congestion transactions via a change to PJM's market software, to ensure that a not willing to pay congestion transactions is not permitted to flow in the presence of congestion.
- The MMU recommends that the EES application be modified further to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.
- Generating units that do not respond to RTO dispatch signals may contribute to the need for PJM and the Midwest ISO to implement market to market redispatch and result in payments under the JOA. The MMU recommends that the JOA be modified so as to eliminate payments between RTOs in the event that payments result from the failure of generating units to respond to appropriate pricing signals.
- At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing.

As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

Section 5 – Capacity Markets

- 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.
- The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.
- The MMU recommends that PJM review all requests for OMC outages carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines.

Section 6 – Ancillary Service Markets

- 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.
- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in 2009.
- The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections.

Section 8 – Financial Transmission Rights

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARR's do. This would include both FTRs that are directly self scheduled and FTRs on paths identical to the ARR, which are financially equivalent to self scheduled FTRs. ARR's are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. The underlying FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARR's when load switches.
- The MMU supports PJM's actions to reduce unsecured credit including the elimination of unsecured credit in PJM's FTR markets. The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

Continued Action

- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required.

PJM applies the three pivotal supplier test to determine whether local energy markets are structurally competitive. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The test is a flexible, targeted real-time measure of market structure which replaced the previous mitigation method of offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limits offer capping in the Energy Market to situations where the local market is structurally noncompetitive and where specific owners have structural market power.

- Retention, application and improvement of the RPM rules included in PJM's Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to limit market power by the application of clear and explicit market power mitigation rules. Implementation of enhancements to incentives for capacity resource performance to ensure stronger, market-based incentives for actual performance when needed.

Market power remains a serious concern in the PJM Capacity Market based on market structure conditions in this market including high levels of supplier concentration, frequent occurrences of pivotal suppliers and extreme inelasticity of demand. The RPM Capacity Market design explicitly allows competitive prices to reflect local scarcity without relying on the exercise of market power to achieve the objectives of the Capacity Market design and explicitly limits the exercise of market power via the application of the three pivotal supplier test.

RPM rules could be improved by ensuring that capacity payments are made only to units that perform, that the must offer requirement does not permit either physical or economic withholding, that the requirement for capacity resources to make offers in the Day-Ahead Energy Market explicitly require competitive offers and that locational price separation is determined by market fundamentals rather than by rule.

- Retention of the \$1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power.

The PJM market design includes a variety of rules that effectively limit the incentive to exercise market power and ensure competitive outcomes. These should be retained and enforced and any proposed PJM market rule change should be evaluated for its impact on competitive outcomes.

- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition.

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.
- Implementation of rules governing the definition of final prices to ensure certainty for market participants.

Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. PJM should consider and implement rules defining when prices are final. This approach to final prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

PJM has actively responded to this recommendation and there are several proposals being considered in the membership process.

- Modification of rules governing demand-side programs to ensure appropriate levels of payment and to ensure appropriate measurement and verification of demand-side response. Evaluation of additional actions to address institutional issues which may inhibit the evolution of demand-side price response.

PJM and the MMU should continue efforts to ensure that market power is not exercised on the demand side of the market, particularly via gaming of the measurement and verification process. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. Recent changes to the settlement review process represent clear improvements, but do not go far enough. Additional improvements in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets.

- Continued improvement of pricing between PJM and surrounding areas, both market and non market.

Transactions with other market areas are largely driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols, modeled on the PJM and Midwest ISO JOA, as soon as practicable.

Transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational price approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. The reverse can also occur. For interactions with non market areas, the goal should be to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

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 is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-1 provides the components of the total average price for wholesale power in PJM. Each of these items is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Load Weighted Energy component is the load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments in 2009.
- The Transmission Service Charge component is the average price per MWh of network integration charges and firm and non firm point to point transmission service.⁹
- The Operating Reserve (Uplift) component is the average price per MWh of day ahead and real time operating reserve charges.¹⁰
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.¹¹
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.¹²
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC²) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAILCo and PATH projects.¹³
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.¹⁴
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.¹⁵

9 PJM OATT Section 13.7, Section 14.5 & 27A and Section 34.

10 PJM Operating Agreement Schedules 1-3.2.3 & 1-3.3.3.

11 PJM OATT Schedule 2 and Operating Agreement Schedule 1-3.2.3B.

12 PJM Operating Agreement Schedules 1-3.2.2, 1-3.2.2A, 1-3.3.2, 1-3.3.2A and OATT Schedule 3.

13 PJM OATT Schedule 12.

14 OATT Schedule 1A.

15 PJM Operating Agreement Schedule 1-3.2.3A.01 and OATT Schedule 6.

- The Black Start component is the average cost per MWh of black start service.¹⁶
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.¹⁷
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.¹⁸
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.¹⁹
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.²⁰

Table 1-1 Total price per MWh: Calendar year 2009

Category	\$/MWh	Percent
Load Weighted Energy	\$39.05	70.2%
Capacity	\$10.75	19.3%
Transmission Service Charges	\$4.00	7.2%
Operating Reserve (Uplift)	\$0.49	0.9%
Reactive	\$0.36	0.7%
Regulation	\$0.34	0.6%
PJM Administrative Fees	\$0.31	0.5%
Transmission Enhancement Cost Recovery	\$0.09	0.2%
Transmission Owner (Schedule 1A)	\$0.08	0.2%
Synchronized Reserves	\$0.05	0.1%
Black Start	\$0.02	0.0%
RTO Startup and Expansion	\$0.01	0.0%
NERC/RFC	\$0.01	0.0%
Load Response	\$0.00	0.0%
Transmission Facility Charges	\$0.00	0.0%
Total	\$55.58	100.0%

¹⁶ OATT Schedule 6A.

¹⁷ OATT Attachments H-13 and H-14 and Schedule 13.

¹⁸ OATT Schedule 10-NERC and OATT Schedule 10-RFC.

¹⁹ Operating Agreement Schedule 1-3.6.

²⁰ Operating Agreement Schedule 1-5.3b.

